Title: **Energy Bill 2012 Impact Assessment: reducing barriers to securing long-term contracts for independent electricity generation investment** **IA No: DECC0097** **Lead department or agency: DECC** **Other departments or agencies: N/A**	Impact Assessment (IA) **Date: 30/04/2013** **Stage: Final** **Source of intervention:** Domestic **Type of measure: Primary Legislation** **Contact for enquiries:** **Vikram.Balachandar@decc.gsi.gov.uk; Matt.Coyne@decc.gsi.gov.uk**

Summary: Intervention and Options

RPC: RPC Opinion Status

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, One-Out?**	**Measure qualifies as**
-£0.26m	£0	£0	Yes	Zero Net Cost

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

For any power generation investment, investors will want to be certain that risks can be efficiently managed during the investment payback period. Some independent generators rely on long-term offtake contracts, known as Power Purchase Agreements (PPAs), to give lenders this certainty. In July 2012 Government launched a call for evidence, now closed, aiming to improve understanding of the issues facing independent generation developers. Independent electricity generators have reported that they are finding it increasingly difficult to secure long-term contracts for sale of generation on bankable terms i.e. that costs are higher and fewer firms are submitting tenders.

The main rationale for taking enabling powers is that there may be market failures preventing an efficient level of investment in generation, and that these are not addressed sufficiently with existing primary powers.

What are the policy objectives and the intended effects?

Government's objective is to provide investors in generation with certainty that EMR will fulfil its objectives of delivering decarbonisation, renewables and security of supply goals at least cost, by ensuring efficient routes to market for independent generators. We aim to do this whilst minimising any potentially negative impacts incurred through the taking of primary powers.

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

We consider the following options in the "cost-benefit analysis" section below.

- Option 1: "Do nothing": Secretary of State does not take primary powers;
- Option 2: The Secretary of State takes powers in the current Energy Bill;
- Option 3: Carrying out further analysis of the issue, and seeking powers in a future Energy Bill

We are also actively considering alternatives to regulation, and consider that these could be beneficial.

Our preferred option is Option 2. Option 2 can be seen as a valuable option for Government to intervene, should it become apparent, following further evidence gathering and analysis, that there are clear issues that require Government intervention. A large part of the value of this option is sacrificed under Option 3, as powers may not come into force in time to address any problems that arise in the transition period from the RO to CfD. The principal cost under Option 2 is regulatory uncertainty, which would be greater than under Option 3, though we still believe uncertainty under Option 2 should be limited.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** 2018/19

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: N/A**		**Non-traded: N/A**

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

Signed by the responsible Minister: Michael Fallon Date: 30/04/2013

Summary: Analysis & Evidence

Policy Option 2 (preferred)

Description: Taking powers to support delivery of EMR, with constraints on using the powers;

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2013	Time Period 7 years	Net Benefit (Present Value (PV)) (£m)		
			Low: N/A	High: N/A	Best Estimate: -0.26

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate	0.26		N/A	**0.26**

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

Government staff and consultancy costs on the use of primary powers (i.e. policy development and stakeholder engagement).

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

The act of taking powers could lead to some increase in regulatory uncertainty for market participants, increasing costs of capital and potentially increasing the costs to society of meeting Government's decarbonisation and security of supply goals for the electricity sector. However, we believe the impacts on uncertainty should be limited.

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

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

N/A

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

Taking powers increases the probability that Government can reduce barriers to entry to independent generation, increasing market contestability and potentially reducing the costs to society of meeting Government's decarbonisation and security of supply goals for the electricity sector.

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

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: N/A	Benefits: N/A	Net: 0.0	Yes	Zero Net Cost

Evidence Base (for summary sheets)

Contents

Background 4
GB electricity trading arrangements 4
The Renewables Obligation 4
Government's EMR programme 4
RO/CfD transition 6
The role of Power Purchase Agreements (PPAs) 6
Ofgem's review of cash-out arrangements 7
Problem under consideration 7
Rationale for intervention 8
Policy objective 9
Options under consideration 10
Alternatives to regulation 10
Other options considered 10
Cost-benefit analysis 11
Summary and comparison of options 11
Option 1: Do Nothing 11
Option 2: Taking powers now 13
Option 3: Seeking powers later 14
Net direct costs to business 15
Specific impact tests 15
Microbusiness impacts 15
Equalities 15
Post-implementation Review 15
Annex 1 – Potential Intervention Options 16
Supplier Obligation to offer terms 16
Offtaker of last resort (OLR) 17
Annex 2 – Background 18
GB electricity trading arrangements 18
Annex 3 – Market Failures Analysis 20
Current issues in the market 21
Future issues in the market 25

Background

1. This Impact Assessment (IA) examines the arguments for and against the Government taking powers in the forthcoming Energy Bill to intervene to reduce barriers to securing long-term contracts (Power Purchase Agreements) for independent electricity generation investment, in order to support delivery of Government's Electricity Market Reform (EMR) programme. This follows a recent call for evidence on the issue, which closed on 16 August[1]. The impacts of any specific interventions, if these powers were exercised, would be examined separately, alongside any consultation on secondary legislation, with a full impact assessment.

2. This section provides background on:

- GB electricity trading arrangements;
- the Renewables Obligation (RO);
- Government's EMR programme;
- the transition from the RO to EMR;
- the role of Power Purchase Agreements (PPA); and
- Ofgem's review of cash-out arrangements.

GB electricity trading arrangements

3. 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.

4. 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.

5. Generally, market participants trade:

   - Forward to mitigate "price risk", i.e. to give some certainty of price for electricity sales/purchases; and
   - Spot and prompt to fine-tune positions (as factors such as weather, demand, and plant availability are better known).

6. Participants are incentivised to contract fully against metered output/consumption through the use of imbalance charges, known as "cash-out" prices. See Annex 2 for more background on GB electricity trading arrangements.

The Renewables Obligation

7. The Renewables Obligation (RO)[2] 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.

8. 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. This is set at £40.71 per ROC for 2012/13 (linked to RPI). 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.

Government's EMR programme

9. 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")[3]. The EMR White Paper sets out key measures to attract low carbon investment, reduce the impact on

[1] http://www.decc.gov.uk/en/content/cms/consultations/call_ren_inves/call_ren_inves.aspx
[2] http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/renew_obs/renew_obs.aspx
[3] http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx

consumer bills, and create a secure mix of electricity sources including gas, new nuclear, renewables, and carbon capture and storage.

10. Key elements of the reform package include:

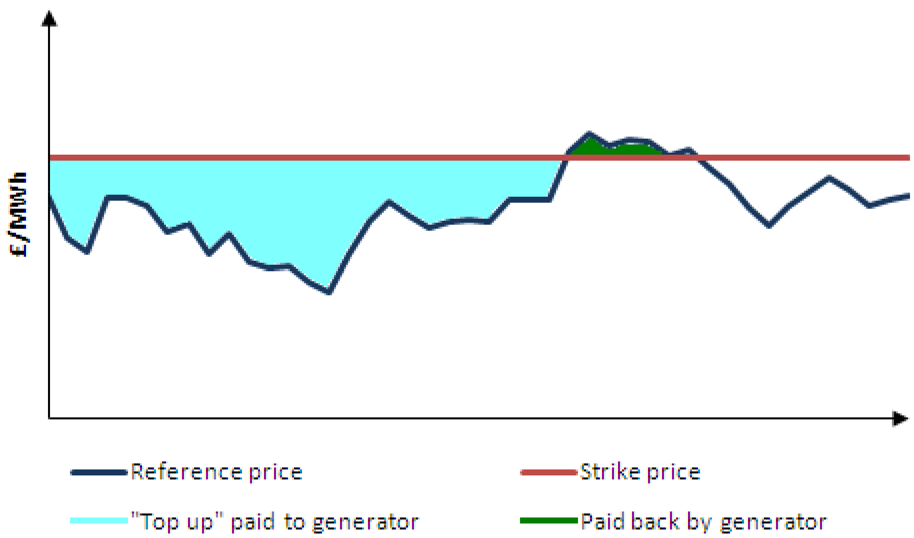
- a Carbon Price Floor (announced in Budget 2011) to reduce investor uncertainty, putting a fair price on carbon and providing a stronger incentive to invest in low-carbon generation now;
- the introduction of new long-term contracts (Feed-in Tariff with Contracts for Difference) to provide stable financial incentives to invest in all forms of low-carbon electricity generation. A contract for difference approach has been chosen over a less cost-effective premium feed-in tariff;
- an Emissions Performance Standard (EPS) set at 450g CO2/kWh to reinforce the requirement that no new coal-fired power stations are built without CCS, but also to ensure necessary short-term investment in gas can take place; and
- a Capacity Mechanism, including demand response as well as generation, which is needed to ensure future security of electricity supply.

11. A Feed-in Tariff with Contract for Difference (FiT 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 FiT CfD, payments can flow from the contract counterparty to the generator, and vice versa. By providing stability of revenues, the FiT CfD should increase the rate of investment and lower the cost of capital, thereby reducing costs to consumers.

12. In terms of setting the “strike price”, the Government is minded to move from administrative price discovery processes for low-carbon technologies to more competitive forms of price discovery such as auctions or tenders when the wider conditions in the market will support their successful deployment. This is because the price discovery characteristics of an auction should enable financial support to be set at a level just high enough to promote deployment but not high enough to lead to excessive profits, with bids driven down by competition.

13. A “two-way” FiT 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. That is, generators return money to consumers if electricity prices are higher than the agreed tariff. See Figure 1 below for an illustration.

Figure 1 Operation of FiT CfD



14. In the EMR White Paper, the Government proposed[4] that “intermittent”[5] generators would receive a FiT CfD referenced to a day-ahead market price, while “baseload”[6] generators would receive a FiT CfD referenced to a year-ahead baseload price[7].

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

15. Publication of the White Paper marks the first stage of the reform process. The Government intends to legislate for the key elements of this package in the second session of this Parliament, which starts in May 2012, and for legislation to reach the statute book by the third session (November 2013) so the first low-carbon projects can be supported under its provisions around 2014.

RO/CfD transition

16. While the FiT CfD mechanism is intended to start in early 2014, RO support will continue to be available for new renewable projects until 31 March 2017. During this transition period developers will have a choice of support mechanism for new renewables generation projects.

The role of Power Purchase Agreements (PPAs)

17. 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:

- offtake risk - the risk that power cannot be sold at an efficient price with a viable route to market;
- 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;
- volume risk - the risk that the total generation of the installed capacity falls short of what was expected;
- price risk - the risk that the underlying wholesale price changes and the power that is generated does not achieve the expected price; and
- basis risk - the risk of deviation between the market price achieved by the generator and the reference price in, for example, a CfD.

18. 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 and trading options.

19. However, there are some projects that will not be directly helped by these measures, in particular independent generators that currently rely on long-term offtake contracts, known as Power Purchase Agreements (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[8], but the overall discount may be affected by the level of competition amongst PPA providers (i.e., offtakers).

20. It is likely the most important reason why independent generation projects rely on PPAs is that these projects rely on non-recourse project finance[9] to part-fund the investment which, given the long length of financing, 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 markets are theoretically available, in the majority of cases financiers will require a PPA. 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

21. Whilst current structures of PPAs vary, they typically fall into three types, which deal with risk in the following ways.

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[5] 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.

[6] 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.

[7] These proposals are subject to the final design of any Capacity Mechanism.

[8] 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.

[9] 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.

- **Variable price PPA.** The PPA provider pays the generator the wholesale electricity price less a percentage discount that reflects the value of the risks that have been transferred under the PPA. Under the Renewables Obligation (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.
- **Variable price PPA with floor price.** As above, but the PPA provider guarantees a minimum price (either across all benefits – wholesale, ROCs and 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 percentage 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.
- **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. 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 top-up and potentially exposed to paying back more than they received from the PPA if the reference price went above the strike price.

Ofgem's review of cash-out arrangements

22. On 1 August 2012 Ofgem launched their electricity balancing Significant Code Review[10], which is primarily concerned with reforms to the short-term balancing arrangements and imbalance (cash-out) price regime, including:

- a more marginal main cash-out price;
- single or dual cash-out prices;
- single or separate trading accounts;
- pay-as-bid or pay-as-clear for energy balancing services

23. Ofgem's primary considerations also include new electricity balancing arrangements, such as consideration of a balancing energy market and alternative arrangements for renewable generation. Initial consultation ends in October 2012 and Ofgem plan to publish their final decision on any code modifications in early 2014. While the objective is to make balancing arrangements more efficient, uncertainty over changes to the balancing mechanism may lead to uncertainty about the costs of balancing in the future.

Problem under consideration

24. On 5 July 2012, the Government launched a call for evidence[11], aiming to improve our understanding of the issues facing independent developers. The call for evidence closed on 16 August 2012.

25. Independent developers have reported that they are finding it increasingly difficult to attract PPA offers on bankable terms i.e. that discounts are higher and fewer firms are submitting PPA tenders. Other issues have been raised including alleged higher discounts applied to PPAs in GB compared to other European markets.

26. Routes to market for independent generators under the CfD was highlighted as a serious issue by the Energy and Climate Change Committee (ECC) in their pre-legislative scrutiny report on the Draft Energy Bill[12]. The ECC recommended the introduction of a buyer of last resort be examined (see Annex 1 for more details on this particular intervention option).

27. Government's analysis of the available evidence and preliminary discussions with stakeholders does suggest there has been a decline in the number of counterparties and a concentration of market activity. Whereas during 2006-2010, the market in each year was reasonably well distributed between different counterparties, in both 2011 and 2012 one participant seems to have accounted for the majority of the market[13]. This may, of course, represent normal competitive market activity.

[10] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20Launch%20Statement.pdf
[11] http://www.decc.gov.uk/en/content/cms/consultations/call_ren_inves/call_ren_inves.aspx
[12] http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenergy/275/275.pdf
[13] Based on data available from 'Infrastructure Journal'.

28. Some of the factors that may be affecting the PPA market were set out in the draft CfD Operational Framework published in May 2012. These include the following issues raised by stakeholders (with more detail at Annex 3):

- liabilities assumed in long-term contracts by PPA providers being recognised on balance sheets or by ratings agencies, which could put a company's credit rating at risk. This appears to be a greater issue with PPAs with fixed or floor prices[14], for which demand is increasing, as financers (banks) are increasingly taking a more cautious approach to risk management;
- an increasing proportion of intermittent generation on the system will lead to uncertainty of the costs of balancing in the future, and requires more active trading and higher collateral requirements for hedging. Possible changes to the balancing mechanism will also add to this uncertainty;
- large vertically-integrated utilities subject to the Renewables Obligation increasing the size of their own RO-eligible portfolios and thereby seeing a route for meeting their obligation through their own generation in the coming years;
- a lack of liquidity and forward trading that damages price formation and investment signals, and may be limiting participation from independent aggregators;
- uncertainty over impact of EMR on power prices and transition to CfDs; and
- limited competition due to the small number of credit-worthy PPA counterparties that satisfy external debt providers.

29. To inform the Gas Generation Strategy, due to be published in the Autumn, DECC issued a Call for Evidence on the role of gas in the electricity market, which closed at the end of June. There were responses from a wide range of stakeholders, including independent generators. Some of the responses received highlighted the importance of being able to access long-term offtake contracts as a driver of investment in new gas-fired generation capacity, with some saying that there is a lack of long-term contracts. The factors that these generators considered to be contributing to this are similar to those set out above, namely:

- Unpredictability of long-term prices, which means that suppliers are less willing to take on credit risk related to long-term offtake contracts;
- A lack of liquidity in forward markets;
- Large power companies focusing on self build, already owning enough capacity or already having enough generation on contracts already.

Rationale for intervention

30. At this stage, Government is only considering whether it is appropriate for the Secretary of State to take enabling powers to intervene to reduce barriers to securing long-term contracts. These powers may not necessarily be used.

31. In summary, the main rationale for taking enabling powers is that it gives Government a valuable option to intervene, should it become clear that there are market failures preventing cost-effective investment in electricity generation, which are not addressed sufficiently with existing primary powers. Furthermore, while we believe some of the issues reported by independent electricity generation developers will be eased by the introduction of the CfD, there may be a longer than anticipated transition period in which developers, banks etc need to adjust. Thus if powers were taken at a later stage there is a risk these powers would not come into force in time to address any problems in the transition period.

32. The responses to Government's call for evidence suggest there are many factors driving poor and/or worsening PPA availability and terms. We have examined the issues raised by stakeholders and have analysed whether these constitute market failures (with more detail at Annex 3). In summary:

- Regulatory uncertainty over Government and Ofgem reforms is an issue, implying a general need to work to continue policy development to resolve regulatory uncertainty.
- Achieving Ofgem's objectives on the Retail Market Review (including liquidity) is likely to be beneficial. Many of the barriers faced by independent suppliers and generators will be shared by independent aggregators.
  - Note: whether the Secretary of State should take powers on wholesale market liquidity is being considered in a separate Impact Assessment (DECC0078).

[14] PPAs with floor prices may be especially risky to offtakers given the risk of "wind cannibalisation". This describes a scenario where, given expected higher future deployment of wind generation, offtakers perceive risks that power prices on any given day might be driven down by high volumes of wind.

- Some drivers appear to reflect efficient market behaviour (e.g. firms' perception of risks, see paragraph 28 above), and therefore do not appear to warrant additional intervention from Government or the regulator. However, we are exploring the role for innovative market-led developments (see below, from paragraph 45) that could improve the situation for independent generators.
- Additional Government intervention could be needed to address a possible market failure which reduces the contestability of offtaker entry: "reciprocal externalities".

33. The term "reciprocal externalities" is used to describe the situation where the level of activity of one agent depends positively on the level of activity of another agent. Thus, if one agent is active, another agent will be active and vice versa. The existence of reciprocal externalities was used in the 1980s, initially by Peter Diamond[15], as a method of explaining involuntary unemployment.[16].

34. These ideas can be adapted to consider contestability in the PPA market; in other words, the possibility that there are self-sustaining low and high equilibrium states of PPA market participation. In particular, many stakeholders have suggested that lenders' requirements for offtakers to have a strong credit rating is a key barrier to many potential offtakers providing longer-term PPAs.

35. Clearly this reflects lenders' perceptions of risks, and would therefore generally be viewed as efficient, given competitive markets. However, one stakeholder has suggested that this restriction in the pool of available PPA counterparties reinforces the need for banks to work with an offtaker with a strong credit rating, further reducing the pool of available PPA counterparties. This is because, in a world with few offtakers, lenders may be more worried about the possibility of lengthy delays and/or costs to the generator of finding an alternative offtaker, in the event that the original offtaker defaults.

36. Thus, there is a possibility that the PPA market is slipping into an equilibrium state of limited participation. If this is so (and the evidence on this is currently unclear), significant increases in PPA market contestability would require a large external shock; without such an influence, the market would be unlikely to create a material increase in contestability. This "shock" could require additional Government intervention. The hope is that this kick-start to independent aggregation would have the potential to lead to a virtuous circle of aggregator entry, boosting innovation in contractual structures and in wind balancing and forecasting, leading to an improvement in PPA terms and availability.

37. As noted above, however, the evidence on the extent to which market failures are affecting the PPA market is unclear, though we are in the process of developing our evidence base. Hence, the primary rationale for seeking to take powers now is that it gives a valuable option to intervene, should it become clear that market failures are affecting the electricity market. While we believe some of the issues reported by independent electricity generation developers will be eased by the introduction of the CfD, there may be a longer than anticipated transition period in which developers, banks etc need to adjust. Thus if powers were taken at a later stage there is a risk these powers would not come into force in time to address any problems in the transition period.

Policy objective

38. Government's objective in considering whether the Secretary of State should take primary powers is to provide investors in generation with certainty that EMR will fulfil its objectives of delivering decarbonisation, renewables and security of supply goals at least cost, by ensuring efficient routes to market for independent generators. We aim to do this whilst minimising any potentially negative impacts incurred through the taking of primary powers.

39. Should the Secretary of State take primary powers, our objective for any intervention would be to minimise the costs to consumers of achieving our decarbonisation and security of supply goals by reducing, where possible, barriers to participation and investment by independent developers while maintaining efficient operation of the electricity market and preserving incentives for the market to develop its own solutions to offtake risk. Any intervention might therefore be time limited, would need to be consistent with future market developments, should enable a smooth transition to a market-based solution, and should minimise any unintended consequences or market distortions.

[15] "Aggregate demand management in search equilibrium", Journal of Economic Studies, 90, pp 881-894

[16] It's essential insight was that both high and low steady state equilibrium levels of involuntary unemployment can exist. The low unemployment level is characterised by numerous trading opportunities and thus strong incentives to produce. Conversely, a high unemployment level involves few trading opportunities and hence low incentives to produce. Market imperfections, such as coordination failures, mean that it is difficult for the economy to move from one equilibrium state to another.
The equilibrium level of unemployment in which an economy remains depends on the initial level of unemployment and whether, and what type, of shocks to the economy have subsequently occurred. Only a large shock will move the economy from one equilibrium to another: small shocks may cause temporary deviations from the equilibrium but the economy will in time return to the same equilibrium. The concept has been applied to other aspects of economic activity.

Options under consideration

40. We consider the following options in the “cost-benefit analysis” section below.

- Option 1: “Do nothing”: Secretary of State does not take primary powers;
- Option 2: The Secretary of State takes powers in the current Energy Bill to reduce barriers to securing long-term contracts for electricity generation;
- Option 3: Carrying out further analysis of the issue, and seeking powers in a future Energy Bill

41. Option 2 would involve the Secretary of State taking powers to reduce:

- difficulties independent developers face in securing long-term contracts on bankable terms needed to secure investment; and
- the existence of barriers to entry into the wholesale electricity markets for independent power aggregation businesses.

42. Option 2 would involve enabling the Secretary of State to take powers to modify electricity generation and supply licence conditions in order to remove barriers to market entry in the GB wholesale electricity market, should it become clear that these barriers have not improved. Government is planning on taking forward non-regulatory approaches and the decision to take powers would be complimentary to this.

43. Under Option 2, we would expect Royal Assent in 2013, and would continue to monitor the market and develop policy options during the passage of the Bill. Before implementing policy interventions we would need to consider how the market has responded to non-regulatory approaches and consult on specific proposals. A high-level consideration of particular intervention options is at Annex 1. Ofgem would have enforcement responsibility, oversee delivery of any mechanism and modify licence conditions as necessary. We would have the potential to remove any obligation should market conditions develop sufficiently to support a competitive PPA market.

44. Option 3 would involve further monitoring of the PPA market and gathering of evidence, and may also involve further development of the potential options for intervention as well as a clarification and narrowing of potential powers.

Alternatives to regulation

45. Taking powers to intervene does not rule out the possibility of pursuing non-regulatory approaches (e.g. voluntary approaches). We are actively considering market-led solutions, and are aware of the potential benefits. If voluntary solutions give businesses more flexibility to meet Government’s objectives, there is a possibility that net costs to business might be lower than with Government intervention.

46. A credible regulatory threat, with clear objectives, could increase the likelihood of industry achieving the objectives Government wants to see. This may lead to some industry participants bearing direct costs, relative to the costs industry would have borne in the absence of a threat of intervention. However, we would only expect industry to pursue these non-regulatory alternatives if the benefits to the wider market exceeded the costs to particular participants.

47. Voluntary approaches are more likely to succeed if it is in business’ (collective) commercial interests to agree to taking action. But there may be co-ordination failures hindering action, and there may be a role for Government in resolving these.

Other options considered

48. Other options have been considered which could be implemented without taking additional powers but we do not think offer viable ways forward:

- **Premium FIT:** a Premium FIT would essentially entitle a generator to a guaranteed “top up” payment over and above the market price for every unit of electricity it actually generates. We do not believe that a Premium FIT would provide any additional incentive or obligation to offer long-term offtake contracts and therefore this would not address the problem. In our view, the reasons for the currently constrained PPA market are not associated with the likely future support mechanism.
- **CfD banding**: as with the Premium FIT proposals, banding the CfD in order to provide smaller projects with more support would not in itself create any additional incentive to offer PPAs. It may enable smaller projects to pay higher PPA discounts, however we think a better approach would be to improve competition in the PPA market in order to bring down discounts rather than risk creating opportunities for rents;
- **Financial incentive:** this proposal has been promoted by certain renewable developers who have suggested a financial incentive to purchase low-carbon power. The proposal is to recover the costs of

CfD support in proportion to the amount of fossil fuel generation (or carbon) in a supplier's fuel mix. This would provide an incentive for suppliers to support more electricity from low-carbon sources to avoid paying higher CfD costs. However there is no guarantee that they would do so by offering PPAs. In addition, this approach could distort the incentives put in place by other energy policies (such as the Carbon Price Floor) and may disincentivise investment in gas-fired generation which is essential for meeting our security of supply objectives;

- **Extended Renewables Obligation:** some market participants have suggested that the proposed move from the RO to CfD has damaged the PPA market and that to extend the availability of the RO for new projects beyond 2017 would be helpful. It may be the case that the prospective end of the RO has reduced the number of PPA offers (because the large vertically integrated utilities will not want to over-contract for Renewables Obligations Certificates), but we do not believe that is the sole or principal reason for the current problems and, therefore, an RO extension may have little or no impact on the PPA market. Not ending the RO as planned is likely to create significantly increased investor uncertainty and call into question the Government's commitment to the CfD regime. There are also administrative questions including the need for a further banding review beyond the current exercise, and issues around whether this approach would increase costs to the consumer.

Cost-benefit analysis

Summary and comparison of options

49. This section first describes what might happen under "Do Nothing" and then examines the costs and benefits of Option 2 and Option 3, relative to doing nothing. The cost-benefit analysis focuses on the "direct" impacts of taking primary powers, i.e. the costs and benefits that can be attributed to the act of introducing primary legislation alone. Some of the potential indirect impacts of taking powers are also examined. The impacts of any proposed interventions would be examined more fully, alongside any consultation on secondary legislation, with a full impact assessment. At Annex 1, we set out the high-level impacts of potential interventions that might achieve our objectives.

50. To summarise, Option 2 is our preferred option. Option 2 can be seen as a valuable option for Government to intervene, should it become apparent, following further evidence gathering and analysis, that there are clear issues that require Government intervention. The principal cost of Option 2 is regulatory uncertainty, though we believe this should be limited.

51. Under Option 3, regulatory uncertainty could be minimised as further evidence is gathered and the scope of potential interventions clarified. However, delaying the taking of powers to a later date may risk those powers not coming into force in time to address any problems that arise in the transition period from RO to CfD, thus sacrificing a significant part of the value of the option to intervene.

Option 1: Do Nothing

52. In summary, the transition from the RO to CfD in itself should, other things being equal, improve PPA availability and terms for renewable developers. However, there may be a transitional period as developers, financers and offtakers become more comfortable with the new system. Over time (though not as a direct result of the CfD), increasing levels of intermittent wind penetration will tend to increase balancing costs.

53. Our view is that the CfD should, other things being equal, improve the terms of PPAs for renewable developers, as under the CfD the main risk covered by the PPA is the imbalance risk:

- CfDs largely remove price risk. Assuming the generator can achieve the reference price, then under the CfD price risk to the generator is removed, as the wholesale price is topped up to strike price. Linking the PPA to the market reference price for the CfD entirely removes any basis risk between payments under the PPA and the reference price for the CfD. Floor prices should become obsolete, which should ease balance sheet pressures on offtakers and reduce barriers to entry.
- Energy-only PPAs could also be more attractive to independent aggregators as there will no longer be a requirement to monetise the ROC. Removing this barrier to new market entrants may therefore lead to a more competitive market[17].
- Volume risk remains with the generator and is not covered by the PPA.

[17] Under the Renewables Obligation a supplier is required to monetise the ROC, and although there is no requirement for power and ROCs to be sold together, in practice it is simpler for a generator to agree one PPA that covers both. As such the CfD mechanism is likely to enable independent aggregators to compete more effectively in the PPA market and could help increase competition.

- Imbalance risk does not change directly as a result of moving from the RO to the CfD, but, as discussed above, imbalance costs are uncertain and will likely increase in the future.

54. Given that PPAs will generally no longer need to cover price risk, it is possible that financers could, with time, become more comfortable with shorter-term PPAs offered by less credit-worthy counterparties. This could potentially provide enough of a “shock” to the market to improve contestability of the PPA market, addressing the reciprocal externalities issue discussed in paragraphs 33 to 36 above. However, the impact is uncertain. In addition, whether shorter-term PPAs become more widely used may depend on establishing a track record of projects trading outside of the traditional longer-term PPA structure, and on the balance between CfDs and PPAs in the change in law protection offered. Lenders will generally prefer that projects are not exposed to regulatory risk, so to the extent that this is not covered by the CfD, they may continue to require this to be covered by a longer-term PPA.

55. Table 1 below summarises how the PPA market may develop over time, in the absence of additional regulatory intervention by Government.

Table 1 Development of PPA market over time under Option 1, “Do Nothing”

Driver	Impact on current market	Impact on future market – during RO/CfD transition	Impact on future market – CfDs only	Comment
Uncertainty over cash-out reform	A	G	G	Assumption that uncertainty resolved by time first CfDs are issued.
Liabilities assumed in PPAs (particularly floor price) being recognised on balance sheet	R	A	A/G	For plant receiving CfD, there is no need for a floor price – so reduced barriers to providing PPAs.
Uncertainty over key CfD provisions	R	A	G	Once CfDs implemented fully, no uncertainty over key provisions, although may be learning period for offtakers, generators and financiers during RO/CfD transition.
Banks’ continued requirement for a long-term PPA/ The requirement for a credit-worthy PPA counterparty	R	A/R	A	Though the outlook is uncertain, it is possible that, given the removal of price risk under a CfD, financiers could become more comfortable with shorter-term PPAs under a CfD, which would reduce barriers to entry to independent aggregators increase market contestability.
Purchase obligation – requirement to go through suppliers to monetise ROCs	R	A	A/G	Removal of purchase obligation should, in time allow independent aggregators to compete more effectively.
Uncertainty over impact of increasing wind penetration on balancing costs	R	R	A/R	As time goes on, offtakers may gain more certainty on balancing costs, or develop more sophisticated techniques for managing it, but this is uncertain. Any move to shorter-term PPAs under the CfD could make this issue less significant.
General level of balancing costs (compared to other markets)	A	A	A/G	In time, Ofgem cash-out reform and other reforms to the wholesale market could make balancing costs more efficient

Note: RAG ratings intended to indicate progression (relative to the starting point) in the significance of any given driver over time. RAG ratings are not intended to indicate absolute significance of various drivers or relative importance of different drivers.

Option 2: Taking powers now

Direct benefits

56. As discussed in the “Rationale for intervention” section above, we believe there are risks of market failures, which, if unaddressed, could lead to inflated costs and/or reduced availability of PPAs. The probability and severity of these risks, given the available evidence, is uncertain. However, if they materialised, barriers to entry to independent generation would be raised, reducing market contestability and potentially increasing the costs to Government of meeting its decarbonisation and security of supply goals for the electricity sector.

57. It is difficult to monetise the value to society of taking primary powers. This depends on the probability that intervention may be needed, and the precise (net) benefits of Government intervention, both of which are unclear at this stage. However, it is possible to give some sense of order of magnitude of the risks, and their importance.

58. We understand that typical discounts on the wholesale price contained in PPAs are in the range of 10-15% of the wholesale price. To the extent that more competition in offering PPAs, as a result of reforms to reduce barriers to aggregator entry, may reduce discounts offered on the wholesale price (e.g. by some combination of reducing the margins earned by PPA providers and reducing the fundamental costs of doing business), this could also reduce the costs to consumers of investment in independent low carbon generation.

59. Independent development companies are likely to play a continuing and significant role in bringing forward further renewable generation. There is also expected to be an increasing role for a distinct type of independent development company in the onshore and offshore arenas over time. Based on data available today, across onshore and offshore wind, independent development companies currently fully control 7.5GW of projects in construction, planning or development.

- Independent development companies look likely to remain key to deployment in onshore wind. Independent renewable developers are either building or seeking consent for over 3GW of onshore wind generation capacity. Combined with independent development companies’ ownership of over 2GW of operating onshore capacity, and noting that not all of the projects in consent will get built, independent development companies will control between 2.4 and 5GW of onshore wind capacity in due course[18].
- The scale of independent involvement in offshore wind is also significant, albeit focussed on a different group of investors (large European utilities, oil companies and finance houses). There are around 4.5GW of projects across Round 1, Round 2 and Round 3 extensions and in Scottish Territorial waters where these categories of independents are not in consortia with the vertically integrated utilities (VIUs)[19].

60. Both VIUs and independents are also interested in expanding biomass generation through enhanced co-firing and conversion of fossil fuel plant to dedicated biomass. Approximately 3.2GW of new build biomass plant has been consented across all technologies, 2.9GW of which is being developed by independents. The Energy from Waste (EfW) pipeline shows 847MW of consented projects awaiting construction and 277MW under planning consideration. These projects are almost exclusively being taken forward by independents, as are developments of new advanced conversion technologies (e.g. anaerobic digestion, pyrolysis and gasification).

Direct costs

61. In terms of costs, the act of taking powers could itself lead to some increase in uncertainty for market participants. Any uncertainty could raise the perceived risks to operating in the GB wholesale market, thus raising costs of capital for investors, thereby increasing costs to consumers.

62. This could be the case if, for example, it was unclear how long the powers would be valid for, and whether they might be used for wider purposes at some point in the future. This perception could arise since legislative powers tend to be broadly drafted and the nature of the market failures that require additional legislation is as yet unresolved.

63. However, we believe the impacts on uncertainty should be limited, since:

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[18] Analysis conducted on data extracted from RUK webpages: http://www.bwea.com/ukwed/construction.asp; http://www.bwea.com/ukwed/planning.asp; http://www.bwea.com/ukwed/operational.asp. Planning data limited to submissions since the start of 2010.

[19] A vertically integrated utility (VIU) is a market participant with assets in both electricity generation and supply.

- The Government has clearly communicated its interest in the issue, including issuing a call for evidence, which suggested particular intervention options;
- The powers envisaged have reasonably focussed objectives, and would be carefully communicated;
- Any intervention would be subject to consultation and more detailed Impact Assessments;

64. In addition, time limits[20] on the powers (through use of a sunset clause) could serve to limit negative impacts on wider uncertainty of when the powers might be used, or whether they may be used in the future to pursue wider objectives.

65. Furthermore, Option 2 would result in a direct increase in resource costs of further policy development and stakeholder engagement, borne by Government, primarily staffing and consultancy, estimated at £0.26m, based on current team size and a one-year completion rate.

<u>Indirect benefits and costs</u>

66. The section above focuses on the direct costs of taking powers. There may also be indirect costs at secondary stage, if powers are exercised, associated with particular intervention options. We would aim to develop the evidence on the impacts of potential intervention options as part of any consultation on secondary legislation. At Annex 1 we set out the high-level impacts of some potential interventions suggested in the Call for Evidence that might achieve our objectives. This list is not exhaustive and it is possible alternative options may be suggested in the future.

67. The main benefit of an offtaker of last resort (OLR) is that it would guarantee a route to market for independent generators. However, the costs of an OLR are likely to be significant, including the costs of setting up and running an OLR, setting a discount that reflects accurately reflects a transfer of risk and of honouring projects which would otherwise not have been economically viable.

68. A supplier obligation to offer terms could increase transparency and levels of market participation, potentially increasing competition and so reducing PPA discounts. Furthermore, the administrative costs would likely be less than for an OLR. However, there may be an increase in costs to business of preparing tenders and entering contracts that would not have occurred otherwise.

Option 3: Seeking powers later

<u>Direct benefits</u>

69. The expected benefits of Option 3, relative to Option 1, are less than Option 2. This is because there is a risk that a delay in enabling powers may result in those powers not being enforced in time to address issues arising during the transition period from the RO to CfD. Hence, it foregoes a significant part of the "value of the option to intervene" under Option 2.

70. We cannot quantify the exact amount of independent generation potentially coming forward during this transition period, which would indicate the amount of investment potentially disadvantaged (relative to Option 2). However, it is likely to be a significant proportion of the capacity currently in the pipeline (see paragraphs 59 and 60 above).

<u>Direct costs</u>

71. Compared to Option 2, Option 3 would likely result in reduced costs of regulatory uncertainty relative to "Option 1". This is because further monitoring of the issues, gathering of evidence, developing of potential interventions and a possible narrowing and clarification of powers would mean less uncertainty over how any powers, if taken, would be used.

72. As with Option 2, Option 3 relative to the "do-nothing" scenario would result in some government staff and resource costs. For simplicity, we assume these would be the same as under Option 2, i.e around £0.26m, although there may be differences over the timing of spending.

<u>Indirect costs and benefits</u>

73. It is more difficult to describe the potential impacts of secondary legislation under Option 3, as it is possible that the interventions chosen may be different. Any costs and benefits would occur further in the

[20] Time limits could potentially apply to the primary powers themselves, or to any obligation actually introduced as a result of secondary legislation, by introducing a "sunset clause". Domestic legislation that imposes a regulatory burden on businesses or civil society organisations and which comes into force on or after April 2011 is now required to include a sunset clause.
The inclusion of a sunset clause in a new regulation means that the regulation will expire automatically on a certain date unless positive action is taken to renew it. Sunset clauses should ordinarily take effect seven years after commencement unless some other time period is appropriate in a particular case. See HM Government, "REDUCING REGULATION MADE SIMPLE", December 2010.

future – as discussed above, this could involve foregoing a significant proportion of the potential benefits from intervening.

Net direct costs to business

74. The section above ("Cost-benefit analysis") discusses cost and benefits to society at large, including business, from taking powers. For the purposes of one-in, one-out (OIOO), we believe the direct impacts on business, as a result of taking powers, are:

- A probability of reduced PPA discounts:
  - To the extent that these arise due to cost reductions to PPA providers, this could result in an expected net saving to business;
  - To the extent that these arise due to reductions in margins for PPA providers, this would result in a loss to some business (PPA providers), but equivalent benefits to others (independent generators);
- A possible increase in regulatory uncertainty for wider market participants, which might result in higher costs of capital (negative impact on business).

75. All impacts are difficult to monetise. We argue above that the increase in regulatory uncertainty is limited. We believe that there is a positive probability that taking powers could lead to cost reductions to PPA providers. Hence, we believe it reasonable to assume that the net direct impacts of taking primary powers is negligible. We thus assess the proposal to be a "Zero Net Cost" IN.

Specific impact tests

Microbusiness impacts

76. Primary legislation is not expected to have significant direct impacts on microbusinesses. The potential impact on microbusinesses will be considered in more detail if secondary legislation is introduced.

Equalities

77. Primary legislation is not expected to have any differential impacts on the basis of the protected characteristics. We will consider equality impacts in more detail, if the Secretary of State decides to use primary powers.

Post-implementation Review

78. The Secretary of State would further develop the evidence base, examine the scope for market-led solutions and the direction of travel of the market before deciding whether to exercise his/her powers, and if so, what intervention to take. The powers themselves would likely be subject to a sunset or review clause. We envisage that monitoring and enforcement of any intervention would be the role of Ofgem, and that further details of the monitoring and evaluation process would be made available at a more advanced stage of policy development.

Annex 1 – Potential Intervention Options

79. This Annex describes potential intervention options that could be consulted on, should the Secretary of State take primary powers. It also describes, at a high level, the expected benefits, costs, and risks associated with each of the options. This is not an exhaustive list and it is possible that other feasible options may be suggested in the future.

Supplier Obligation to offer terms

80. Designated licensed suppliers would be obliged to offer PPA terms and, if selected, subsequently enter into PPAs. The obligation would apply to large licensed suppliers including, but not necessarily limited to the large VIUs (the Big 6). Small suppliers below a specified threshold would not be covered by the obligation but, along with other parties (independent aggregators, power traders etc.), could choose to participate.

81. The mandatory obligations would extend to:

- Offering PPA terms to any developer making a request and if selected, entering into a PPA contract. The minimum terms for the offer should cover at least construction + 15 year metered output purchase commitment (a 'Primary Mandatory PPA'); tender processes do not limit participation and enable independent aggregators to compete – this builds the market rather than undermining the position of independent aggregators.
- Offering offtake terms within a [TBD] notice period and, if selected, seeing through contract execution within a [TBD] notice period with CfD eligible projects for the remaining life of the CfD eligibility in circumstances where the original mandatory offtaker has been terminated under their contract for breach/non-performance or been the subject of insolvency (a 'Secondary Mandatory PPA'). This may well enable projects to accept (and be able to bank) less credit-worthy contracts with the Big 6 providing a back-up in case of default.

82. Other commercial terms are left open for negotiation between the counterparties (including the pricing of imbalance risk).

83. This approach would be complementary to industry-led development of a voluntary PPA market code. This could include development of model PPA contracts setting out a standard approach to required contract components, principles of risk allocation and pro-forma agreements. These market-led approaches are being considered alongside these regulatory approaches.

<u>Benefits</u>

84. These arrangements would provide a guarantee of a PPA (but not its terms), increase levels of market participation and, in all likelihood, increase overall competition including increased transparency.

- The obligation to offer terms is likely to enable a bank to agree a less credit-worthy counterparty as a PPA provider because there is a guarantee that an alternative credit-worthy provider is available. Independent aggregators will only need to provide guarantees or letters of credit to cover the short period during which a replacement provider is appointed and are therefore likely to be able to offer more PPAs. This could directly address the reciprocal externalities theory discussed in paragraphs 33 to 36 above.
- The option is relatively straightforward and consistent with the development of a competitive market as PPA providers (whether obliged to participate) or not compete against each other in the normal way.

<u>Costs</u>

- Administrative/set up costs – would be lower than for an offtaker of last resort
- Costs of participation for large suppliers – e.g. preparing tenders that might not otherwise be needed
- Large suppliers may need to execute long-term contracts into which they would otherwise not have entered – those contracts would need to be accounted for.

<u>Risks</u>

- The obligation is not an absolute offtake obligation and may lead to PPA offers that are not bankable i.e. lenders are not satisfied with risk transfer or required returns are not achieved.
- Less-credit worthy counterparties could compete on flexibility or price in order to counter-balance their financial strength, to make their PPA terms more attractive to generators. If intervention provides a route for the market to become more comfortable with the credit standing of all suppliers (given the

safety net of utility offers in default) there is a risk that the less-credit worthy suppliers could fall more into line with the pricing terms of their large utility competition.

- Lenders may also be concerned with the risk that the obligation to offer terms is removed at some stage (essentially political risk) which may leave then exposed if they have accepted an initial PPA with a less credit-worthy counterparties.
- Risks that increased transparency could facilitate collusion - but this would be mitigated by the ability of other players to participate in the tender

Offtaker of last resort (OLR)

85. A market participant would be appointed to enter into long-term PPAs with CfD eligible projects that have not been able to secure a bankable PPA through the market. This offtaker of last resort (OLR) would be obliged to offer standard terms that are priced above the outcome expected from a competitive PPA market – this is the key difference compared to the previous option. Ofgem will be responsible for oversight and enforcement and may need to take a view on whether the rules relating to pricing are being met.

86. The OLR would be intended to provide a backstop to the market which could easily be beaten by a competitive PPA market. We would only expect developers to use the OLR if the market is uncompetitive and prices are not reflective of the costs. As such, this would provide a guaranteed route to market for eligible generation, although no guarantee that the resulting PPA is bankable.

87. We envisage that each supplier will have an individual obligation that can be discharged through a central offtake body (similar to the way the NFPA operates) . Each supplier could be the counterparty or guarantor to specific offtake agreements or the central offtake body could be financed by suppliers in order to underwrite the PPAs entered into.

88. The alternative is to establish a licensed body or other institution specifically created to act as offtaker of last resort. Costs of setting this up and running it could be socialised across suppliers in proportion to their supply base. We think this sort of approach is outside the scope of existing drafting.

<u>Benefits</u>

89. This approach would provide a guaranteed route to market. Although the discount would be higher than that which a competitive market would offer, the generator would also be guaranteed the CfD top-up payment. By setting the discount above a competitive rate, space would be retained for new market entrants to provide more attractive terms – this could allow for a gradual transition to a CfD based market

<u>Costs</u>

- Costs of setting up and running the OLR.
- Costs associated with honouring contracts that may not be economically attractive. Obligated parties would also need to post collateral to facilitate the operation of the OLR.
- Administrative costs associated with setting, and subsequently periodically adjusting, pricing structure that reflects the risks transferred and a margin for the OLR.
- Complexity – in particular setting pricing rules and entitlement and allocating costs and counter-party responsibilities.

<u>Risks/other issues</u>

- May delay or displace development of competition. To the extent it does, this could reduce innovation over time, e.g. in wind forecasting.
- Would only be an effective solution if our analysis shows that the problem is caused by a lack of competition in the market.
- Would need to consider wind-up arrangements for the OLR to allow for a time when a competitive market means there is no requirement for such an arrangement. At this time any PPAs held by the OLR could be sold on to other offtakers, possibly by auction.
- The least commercial projects will tend to be attracted to the offtaker of last resort, potentially leaving it with higher liabilities than the non-regulated sector would have taken on.

Annex 2 – Background

GB electricity trading arrangements

90. 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.

91. 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.

92. The GB electricity market (BETTA[21]) is based on bilateral trades between buyers and sellers (usually between generators and suppliers, who sell directly to consumers). Power is traded in different ways according to the needs and capabilities of market participants:

- Off-market: These are trades arranged directly between two market participants. Such trades could include internal transfer within a vertically integrated group. Another mechanism for trading energy is through structured contracts, where energy is purchased directly from generators or producers using contracts that are arranged bilaterally, often on a long-term basis (structured contracts are often considered as a subset of the OTC market). Structured contracts may not enhance liquidity as the energy is not sold via the wholesale markets (OTC platforms or exchanges), although volumes sold using structured contracts may be subsequently traded in GB wholesale markets (contributing to liquidity). However, the volumes and prices of such contracts may not be known which frustrates transparency, in particular price discovery.
- Over-the-Counter (OTC): In this document, OTC trades are taken to refer to trades arranged through a third-party broker who matches the requirements of each counter-party. Trades are posted through market information platforms. Counterparty risk is borne by the counterparties themselves, although in some cases brokerages may clear trades through exchanges or offer bespoke clearing services.
- On power exchanges: These allow parties to anonymously trade commodities, derivatives and other financial instruments. Exchanges trade standardised contracts on standard terms and conditions and provide clearing services that help to eliminate counterparty risk for traders. Trading can be continuous or through periodic auctions.

93. Trading can take place on spot, prompt or forward markets[22].

- Spot trading refers to trading for delivery on the same day as the trade (within-day).
- Prompt trading refers to trading for delivery between (but not including) within-day trading and the next month (front month). This includes a number of products, such as products for delivery in the following day (e.g. day-ahead), weekend, weekdays, and trades for the balance of week and balance of month.
- Forward trading generally consists of trades over a longer duration than prompt and spot trading, with contracts for delivery over months, seasons or years.

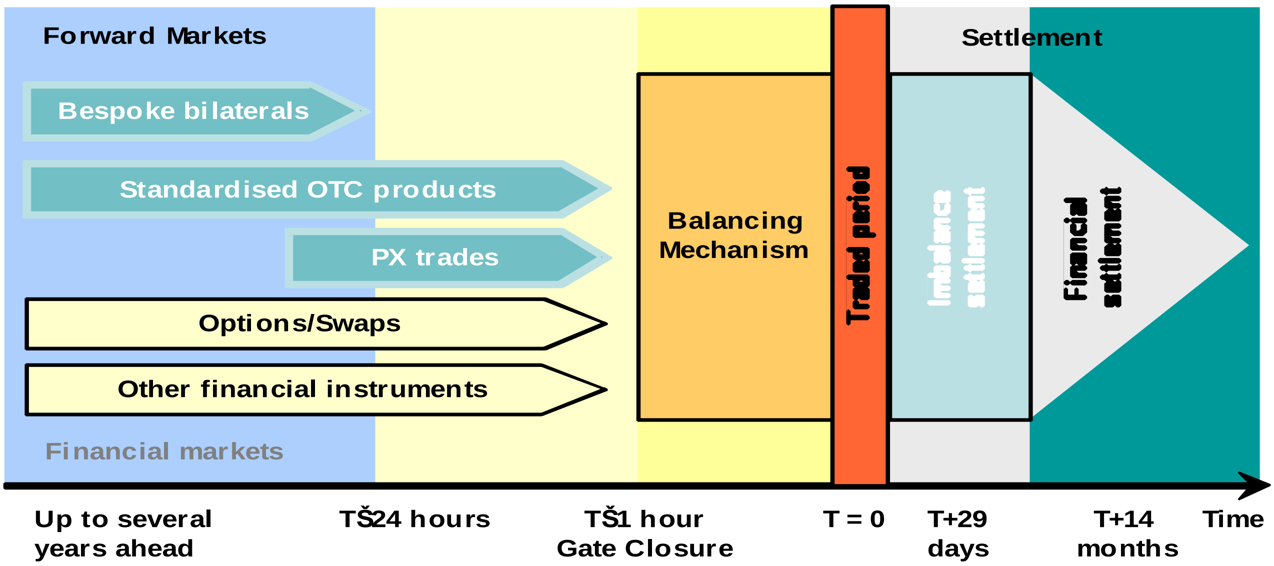
94. Generally, market participants trade:

- Forward to mitigate “price risk”, i.e. to give some certainty of price for electricity sales/purchases; and
- Spot and prompt to fine-tune positions (as factors such as weather, demand, and plant availability are better known).

95. Participants are incentivised to contract fully against metered output/consumption through the use of imbalance charges, known as “cash-out” prices. Figure 2 below provides a schematic overview of BETTA.

[21] British Electricity Trading and Transmission Arrangements.
[22] Ofgem, “Liquidity in the GB Wholesale Energy Markets”, 8 June 2009. Definitions of these terms can vary across different markets.

Figure 2 BETTA Schematic Overview



96. Products that are traded can be:

- "baseload" (i.e. continuously supplied over a 24 hour or longer period);
- "peak" (matching morning and evening peak demand above baseload); or
- "shaped" (i.e. a combination of peak and baseload that matches typical customer demand).

97. Products also vary seasonally e.g. between winter and summer. Power products tend to be sold in defined contract sizes ("clip sizes", usually expressed in MW).

Annex 3 – Market Failures Analysis

98. This Annex summarises drivers of worsening PPA terms / availability reported by stakeholders as part of our call for evidence, and considers whether any of these would constitute market failures.

99. In summary, the analysis suggests that:

- Regulatory uncertainty over Government and Ofgem reforms is an issue, implying a general need to work to continue policy development to resolve regulatory uncertainty.
- Achieving Ofgem's objectives on the Retail Market Review (including liquidity) is likely to be beneficial. Many of the barriers faced by independent suppliers and generators will be shared by independent aggregators.
- Some drivers appear to reflect efficient market behaviour (e.g. firms' perception of risks) and therefore do not appear to warrant additional intervention from Government or the regulator. However, we are exploring the role for innovative market-led developments that could improve the situation for independent generators.
- Additional Government intervention could be needed to address a possible market failure which reduces the contestability of offtaker entry: "reciprocal externalities".

100. The analysis looks at the following categories of drivers:

- Current issues in the market:
  - General drivers of poor/worsening terms (also potential barriers to new offtaker entry);
  - Lenders' requirements;
  - Appetite of large Vertically-Integrated Utilities (VIUs) to sign PPAs;
- Future issues in the market:
  - Transition towards EMR;
  - General drivers of poor/worsening terms and barriers to independent aggregation;
  - Lenders' requirements.

Current issues in the market

General drivers of poor/worsening terms (also potential barriers to new offtaker entry)

	Reported driver of worsening PPA terms / availability	**Do we agree?**	**Is it a market failure / government failure?**
	Lack of forward market liquidity.	Yes, Ofgem assessment shows market not yet meeting its longer-term liquidity objectives.	Caused by a market failure – “reciprocal externalities” (liquidity breeds liquidity). Ofgem is currently investigating solutions.
	Lack of near-term liquidity (including intra-day).	Ofgem’s assessment is that near-term liquidity is sufficient, but Ofgem is keeping under review.	Caused by a market failure – “reciprocal externalities” (liquidity breeds liquidity)
	Uncertainty over Ofgem liquidity reform and risks associated with valuing future costs of managing imbalances. (Insofar as this uncertainty is increased, this will likely raise PPA discounts).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Possible regulatory failure, to the extent that Ofgem could be giving more certainty over its policy development process.
	Cash-out reform and regulatory risk associated with valuing future imbalance costs. (Insofar as this uncertainty is increased, this will likely raise PPA discounts).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Possible regulatory failure, to the extent that Ofgem could be giving more certainty over its policy development process.
	Barriers to entry to retail supply / complexity of UK market (makes it difficult for independent aggregators to find a route to market).	Yes – Ofgem has been considering as part of its Retail Market Review.	Ofgem has been considering need for intervention as part of its Retail Market Review.
	Liabilities assumed in PPAs (particularly floor price) being recognised on balance sheet – could affect credit ratings of offtakers.	Yes, this seems plausible for current (RO-based) market, and reportedly one of the key drivers of PPA terms.	Reflects market perceptions of risk. Starting assumption that this is efficient. Going forward, CfD should largely resolve this issue for low-carbon generation, by removing the need for a floor price.

	Reported driver of worsening PPA terms / availability	Do we agree?	Is it a market failure / government failure?
	Lack of transparency in breakdown between different elements of PPAs, in contrast to foreign markets (e.g. Nordic market), which allegedly inhibits competition.	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Not clear whether this is a market failure – it could simply reflect difficulty in separating various elements. However, it could also reflect the position of retail suppliers as the only market participants able to monetise ROCs. To the extent this is true, this may reduce demand for independent aggregation of renewable power and separation of balancing costs from other costs, e.g. costs of managing ROC cash flows. May suggest some role for Government in co-ordinating market-led approaches, e.g. working with market participants to explore improvements to transparency.
	Revenues from providing balancing services may not be “bankable” – i.e. may be difficult for aggregators to raise finance for their operations.	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Reflects market perceptions of risk. Starting assumption that this is efficient. May suggest some role for Government in working with banks to explore whether they could become more comfortable with lending to offtakers.
	Projects are large and lumpy – needs large-scale offtakers.	Yes, this seems plausible, and most banked PPAs are with large-scale offtakers.	Not a market failure – reflection of efficient scale of doing business.
	Margins may not be big enough for independent aggregators.	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Not a market failure. If margins are persistently not big enough to incentivise entry, this should indicates a contestable market.
	Uncertainty over capacity mechanism (raising PPA discounts by increasing uncertainty over costs of back-up generation).	Yes, this seems plausible, although no clear evidence to suggest significance of this specific issue.	Possible regulatory failure, to the extent that Government could be giving more certainty over its policy development process.
	Announcement of EMR - regulatory risk (including increased difficulties agreeing change in law provisions and uncertainty over CfD allocation).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Possible regulatory failure, to the extent that Government could be giving more certainty over its policy development process.

Lenders' requirements

	Reported driver of worsening PPA terms / availability	Do we agree?	Is it a market failure / government failure?
	The requirement for a credit-worthy PPA counterparty.	Yes, based on current feedback from stakeholders.	Reflects market perceptions of risk. Starting assumption that this is efficient. May suggest some role for Government in co-ordinating market-led approaches, e.g. working with market participants to explore new financing structures. There is potentially a market failure – "reciprocal externalities": the requirement for a credit-worthy counterparty restricts the pool of counterparties, which further reinforces the importance of working with one that is credit-worthy – in a world with few offtakers, lenders may be more worried about the possibility of lengthy delays and/or costs to the generator of finding an alternative offtaker, in the event that the original offtaker defaults. This would suggest some role for Government to intervene to "kick-start" aggregator entry by reducing barriers to entry.
	Poor financial climate, esp. changing attitude to credit support.	Yes, based on current feedback from stakeholders.	Potentially, but out of scope of this project, as goes beyond what can be tackled through energy and climate change legislation.

Appetite of large VIUs to sign PPAs

	Reported driver of worsening PPA terms / availability	Do we agree?	Is it a market failure / government failure?
	Large VIs developing renewables in-house, reduced need for ROCs.	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Not a market failure. VIs are making trade-offs between use of scarce equity capital – i.e. whether to use capital to offer long-term PPAs or to build own renewables, using balance sheet. Balance sheet finance may be a cheaper way to build renewables, or be a less risky way of meeting RO commitments for large VIUs.
	Large VIs own generation is cheaper to manage (because of control).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Not a market failure. May simply reflect high costs of drawing up long-term contracts.
	Large suppliers want own renewable generation, as allows to capture rents across the value chain (e.g. getting full value of ROCs, rather than losing out by giving a share of ROC value to an independent offtaker).	Not clear whether this is true. • Unclear whether there are significant rents to be captured. By building their own generation rather than securing output through a PPA, suppliers gain the full value of the ROC and avoid costs of handling ROC cash-flows on behalf of independent generation, but also lose out on revenues from managing the ROC cash-flows. • We would generally expect companies to grow a given part of a business (e.g. generation vs. supply/offtake) based principally on the true profitability of the particular activity, unless there are significant economies of scope through integrating vertically.	Even if true, would not necessarily reflect a market failure.
	Pressure from “home” markets (increased scrutiny of new offtake agreements by boards of foreign parent companies).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Reflects market perceptions of risk. Starting assumption that this should be efficient.

Future issues in the market

<u>Transition towards EMR</u>

	Reported driver of worsening PPA terms / availability	Do we agree?	Is it a market failure / government failure?
	Removal of purchase obligation (i.e. RO) reduces incentives for suppliers to contract with independent renewable generation.	No. Government views the RO as a "soft" obligation – ultimately it is possible to "buy-out" of the obligation. It is also possible for large VIUs to build own generation to meet the obligation, so not clear that the RO necessarily benefits independents currently.	Removal of the RO could be argued to be the correction of a regulatory failure. Even if the RO created a binding obligation to purchase renewable electricity, inefficient to force suppliers to contract with generators. • Creates a barrier to entry to independent aggregation – as only retail suppliers can monetise ROCs. • A binding obligation may constrain suppliers' ability to contract on commercial terms, potentially disguising true costs of PPAs.
	Creation of basis risk through introduction of CfDs.	Compared to the RO, cashflows for renewable generation should be overall more stable under the CfD as price risk up to the day-ahead stage is removed. The emergence of a robust day-ahead reference price should minimise basis risk. Exposure to residual risk (i.e. intraday and imbalance price volatility) provides incentives for forecasting / managing imbalance.	The CfD is designed to reduce risk, but still leaves some risk with the generator. It may be the case that generators should be largely insulated from forecasting / imbalance risk as well. This depends on whether managing imbalance risk is a natural monopoly activity: i.e. do the efficiency benefits from a single body (e.g. system operator) managing forecast errors on behalf of all wind generators outweigh the potential dynamic benefits from competition and innovation in wind forecasting and balancing?
	RO/CfD transition (offtaker resources diverted away from defining RO-based PPAs and towards CfD PPAs).	Yes, this seems plausible, although no clear evidence to suggest significance of the issue.	Even if true, not clear that it would be a market failure. Participants are deciding that, given transition to CfD and costs of RO-based PPAs, not worth investing resources in defining RO-based PPAs. Possible regulatory failure, though, due to delayed transition to CfD – if it means extra administrative costs of defining PPAs against two different systems.

General drivers of poor/worsening terms (also potential barriers to new offtaker entry)

	Reported driver of worsening PPA terms / availability	**Do we agree?**	**Is it a market failure / government failure?**
	Uncertainty over impact of "wind cannibalisation" – the risk that increased deployment of low marginal cost technology leads to lower electricity prices in the future. From an offtaker point of view, this is a particular risk for PPAs with floor prices, as it creates uncertainties over the level of liabilities associated with guaranteeing a floor price for independent generation.	Yes, this seems plausible issue for current (RO-based) market, and potentially significant.	Not a market failure – agents taking rational views of risk, given uncertainty over future wind deployment. Starting assumption that this is efficient. Arguably, uncertainty caused by the presence of Government climate change/ renewables goals, which themselves might be uncertain. However, Government cannot give complete certainty over the future generation mix.
	Uncertainty over impact of increasing wind penetration on balancing costs. (Insofar as this uncertainty is increased, this will likely raise PPA discounts).	Yes, this seems plausible, and potentially significant.	Not a market failure – agents taking views of risk, given uncertainty over future wind deployment. Starting assumption that this is efficient. Arguably, uncertainty caused by the presence of Government climate change/ renewables goals, which themselves might be uncertain. However, Government cannot give complete certainty over the future generation mix.
	General level of balancing costs (compared to other markets).	No clear evidence to back this up.	Possible concerns around whether balancing arrangements are efficient, which Ofgem is considering as part of cash-out review.

Lenders' requirements

	Reported driver of worsening PPA terms / availability	Do we agree?	Is it a market failure / government failure?
	Banks' continued requirement for a long-term PPA.	Yes, current feedback suggests banks will continue to require a long-term PPA (with a floor price under the RO, and then a long term route to market PPA under the CfD). Shorter-term PPAs could be a future possibility, but may depend on establishing track record and on balance of change in law protection offered by CfD and PPA.	Reflects market perceptions of risk. Starting assumption that this is efficient, but may suggest some role for Government in co-ordinating market-led approaches, e.g. working with market participants to explore new PPA structures.