Department of Energy & Climate Change

REDPOINT a business of Baringa

Power Purchase Agreements for independent renewable generators – an assessment of existing and future market liquidity

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Status of this document

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1.1	23/05/2013	Draft	Edward Crosthwaite Eyre, Baringa Eamonn Boland, Baringa	**Ilesh Patel, Baringa**
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Final	**16/07/13**	**Final**	**Edward Crosthwaite Eyre, Baringa**	**Ilesh Patel, Baringa**

Contact

www.baringa.com,
eas@baringa.com
Tel: +44 (0)203 327 4220

www.redpointenergy.com

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1. EXECUTIVE SUMMARY

1.1. Objectives of this report

In February 2013, DECC commissioned Redpoint Energy, a business of Baringa Partners, to assess the issues facing independent renewable generators in securing commercially viable Power Purchase Agreements ("**PPAs**") and how that might evolve in the future with a move to Contract for Differences ("**CfDs**"). Our work has been based on evidence provided by respondents to the call for evidence launched by Department of Energy and Climate Change ("**DECC**") in 2012 along with a small number of targeted interviews. Our report is primarily concerned with the availability of long term PPAs to independent generators who are looking to use long term, limited recourse debt finance to fund the their projects - i.e. what is termed a "bankable PPA".

1.2. Key conclusions

1.2.1. State of the market today

There is evidence to support the conclusion that the terms being offered by the historical providers of long-term PPAs have been deteriorating over the last five years, with a sharp deterioration approximately three years ago in 2010. The key factors driving this observed change are as follows:

- **Reluctance to take long term price risk in the form of a floor on the electricity price** – PPA providers have become increasingly reluctant to offer acceptable wholesale price protection in long term PPAs, especially at the levels required to sustain target leverage. This is driven by uncertainty as to the impact on wholesale prices of a greater penetration of intermittent renewable generation, government energy policy (i.e. capacity market and carbon price floor) and changes to supply / demand fundamentals.

- **Reduced appetite amongst large VIUs to contract long term for ROCs** – With the closure of the RO to new projects in 2017, supplier appetite to contract long term for ROCs seems to have reduced. Suppliers are increasingly able to meet their renewable obligations from their own assets or from already contracted assets, with a significant pipeline of large VIU owned renewable projects coming on line in the short term. This could leave only a limited number of suppliers left in the ROC market, with an increasing tendency for these remaining players to manage the year-on-year fluctuations in the level of their obligation (driven by churn in the retail customer base) through short term ROC trading.

- **Increased balance sheet / credit rating impact of long term PPAs** – Ratings agencies are treating the long term liabilities under PPAs increasingly stringently, which has significantly affected the ability of VIUs to enter into these types of agreement. With their balance sheets under pressure and significant capital programs of their own, large VIUs are tending to use their residual balance sheet strength to make investments in their own pipeline (where the margins are more attractive) rather than contract with independents.

- **Increased regulatory uncertainty** – PPA providers are increasingly looking to push back a level of change in law risk onto the generator that is not acceptable to lenders. This is being driven primarily by uncertainty as to the long term impact of EMR and Ofgem's Electricity Balancing Significant Code Review ("**EBSCR**") and the potential ramifications of market splitting precipitated by full implementation of the EU third package and/or Scottish independence.

1.2.2. Likely evolution under CfDs

CfDs will significantly reduce the risk position of a generator given that it is no longer required to manage long-term price risk and does not have to find a buyer for its ROCs. Nevertheless, in order to attract limited recourse debt to its project, a generator is likely to still need a long term PPA to insulate the project from uncertain imbalance cost and provide guaranteed offtake for the tenor of the debt.

There are reasons to believe that the availability of such a product could improve under CfDs relative to the state of the long term PPA market today. This is driven by a number of factors:

- Offtakers will no longer be required to provide wholesale price floors as generators are likely to only be looking for a route-to-market product that guarantees a price per MWh at a fixed discount to the market reference price in the CfD (i.e. to eliminate basis and balancing risk).
- This materially reduces the level of risk assumed by the PPA provider, which may drive a more favourable treatment of long term PPAs by credit rating agencies.
- The removal of the need to market ROCs will eliminate one of the key short term constraints on VIUs' willingness to enter into long term PPAs with independents – namely their appetite to contract long term for ROCs. It also removes an important barrier for entry for new entrant aggregators, as they no longer have to take long term ROC liquidity risk.

However, while the availability of long term PPAs is expected to improve with a move to CfDs, a number of open questions and issues remain:

- It will continue to be challenging for prospective offtakers to price imbalance risk over a 12-15 year period, given the uncertainty as to the future generation mix and cash out prices.
- Allocation of change in law risk may remain a constraint, in particular the impact of future changes in the balancing arrangements and the ramifications of market splitting. The materiality of this issue will depend on the final drafting of the change in law provisions of the CfD itself.
- There is a risk that ratings agencies will continue to consider long-term PPAs a material risk, so they may continue to absorb balance sheet capacity of the large VIUs.
- The level of competition in the long term PPA market may continue to be limited by the stringent requirements of the lending community on offtakers' long term credibility and creditworthiness. This may restrict the available bankable counterparties under CfDs to a relatively small number of offtakers with strong credit ratings and an enduring presence in the GB energy market.
- With limited competition, it is unclear what the incentives and strategic drivers on existing incumbent PPA providers (predominantly large VIUs) will be to continue to contract long term with renewable generators under the CfD regime. Ultimately, it seems that the answer to this question will depend on:
    - whether managing a generator's long term imbalance and liquidity risk through a CfD PPA is sufficiently profitable relative to alternatives to encourage VIUs to offer that product; and
    - whether a bankable long term route to market / balancing service under the CfD aligns with the strategic priorities of a large vertically integrated business as that evolves under EMR.

2. INTRODUCTION

2.1. Objective of this report

In response to feedback over the last 12 months from independent renewable generators that they are finding it increasingly difficult to secure commercially viable Power Purchase Agreements ("**PPAs**"), the Department of Energy and Climate Change ("**DECC**") issued an open call for evidence to the industry in July 2012[1]. This report assesses the responses of stakeholders to this call for evidence (supplemented by a small number of targeted interviews) to answer three questions that are set out in Table 1 below:

Table 1: Key objectives of this report

Objective	Description
Market assessment	Assess the state of the PPA market and establish whether there is evidence to support the assertion that the availability of viable, or "bankable", PPA terms for independent renewable generators have reduced over the last three to five years.
Drivers of market change	To the extent that the availability of bankable PPA offers for independent generators have reduced, appraise the evidence presented by stakeholders as to the possible drivers of this change in the PPA market.
Evolution under EMR	Assess how the identified drivers will manifest and evolve in the future with introduction of Contracts for Difference ("**CfDs**") as the mechanism proposed (subject to the successful enactment of the current Energy Bill) for supporting large scale (>5 MW) renewable and other low carbon forms of generation.

2.2. Key definitions

Before looking at these three key questions however, it is necessary to establish two key definitions that have significant implications for the scope of this report: namely the meaning of an "independent generator" and a "bankable" PPA offer.

2.2.1. Meaning of an Independent Generator

DECC defines independent generators, or "independents" as: *"…..those renewable projects that are not owned by the six large vertically integrated utilities (VIU) or projects in which those large companies do not have a significant stake."*[2] For the purposes of this report, we add a further level of

[1] A call for evidence on barriers to securing long-term contracts for independent renewable generation investment (DECC, 2012)

[2] Section 3.1 - A call for evidence on barriers to securing long-term contracts for independent renewable generation investment (DECC, 2012)

granularity by defining independents as not only generators without an associated retail position, but also those who meet the following criteria:

- **Financing strategy** – Independents are generators that tend to rely on limited recourse finance to fund the capital costs associated with the construction of their renewable energy plants. As is discussed further below, the source of finance has significant implications on their contracting strategy and associated risk allocation. For example, large European utilities that have built utility (i.e. large) scale renewable energy projects in the UK have done so using their own balance sheets rather than with an asset level finance solution, which has allowed them a more flexible approach to how they contract for the sale of the output of these plants.

- **Subsidy regime** – It is also important to distinguish between generators that are subsidised under the small scale fixed FIT regime and those that are developing medium to utility scale projects that fall under the Renewables Obligation (the "**RO**"). Developers of FIT projects are assured market access through the associated regulatory arrangements (via an obligation on suppliers to pay generators a specified tariff for electricity generation and exports) which again drives less constrained contracting strategies. This is because lenders can be assured of a guaranteed offtake at the level of the fixed FIT tariffs, leaving equity providers with greater freedom to market the plant's output in the short term PPA market by opting out of the export tariff. Generators under the RO have no such guaranteed offtake, meaning that the significance of the PPA and counterparty take on a greater importance to finance providers.

2.2.2. Meaning of a "Bankable PPA"

The term PPA covers a broad umbrella of contracts which follow a number of general structures but have considerable variation both in term of the length of the commitment (tenor) and the way in which risks are allocated between the counterparties. Annex 1 sets out the different roles that a PPA can play and the general structures that are presently available to generators, however it is important to set out at the outset that this report focuses on the availability of "*bankable*" PPA offers to independents. Broadly speaking, this is defined as a PPA offer that will support long term limited recourse project finance debt in sufficient volumes to meet target leverage levels for equity investors.

Table 2 below sets out what, in the present market, we understand would be considered to be the key terms of a PPA that would satisfy this requirement.

Table 2: Key pre-requisites of a "bankable" PPA for independents

Requirement	Description
Counterparty	▶ Banks will require a PPA counterparty with a strong balance sheet and a minimum credit rating of BBB-.
Tenor	▶ The PPA will need to have a tenor between 12 and 15 years following commissioning. ▶ This should cover the debt repayment period plus a buffer to cover a down side scenario.
Price Floor	▶ The PPA will need to provide the project with a degree of protection against wholesale electricity price risk by guaranteeing a minimum price

	per MWh of output.
ROC offtake	▶ The PPA will need to guarantee an offtake of 100% of the ROCs (and other benefits) allocated to the generator.
Imbalance risk transfer	▶ Subject to the generator undertaking to provide a reasonable forecast of the capacity of plant available to generate in any delivery period, the offtaker should take full responsibility for forecasting output and taking all risks associated with energy imbalance costs as a result of forecast errors.
Change in law risk mitigation	▶ Banks will need a degree of protection from the impact of a future legislative change, or a change to an industry code, where this could reduce the value of the plant's output.

We note that while this report focuses on PPAs being used to support limited recourse debt financing, the evidence from stakeholder responses suggests that competition amongst offtakers for the provision of *short term* PPAs to generators is not as constrained by the requirements of lending banks and this market appears to have a number of very active participants able and willing to offer terms.

2.3. Evidence Base

DECC issued its Call for Evidence inviting responses from stakeholders on the 5th of July 2012, with responses to be returned by the 16th of August 2012. DECC received a total of 56 responses, a full list of which can be found in Annex 2. The breakdown of different stakeholder types is set out in Table 3 below[3]:

Table 3: Breakdown of responses

Independents	PPA providers	Industry associations
47%	**24%**	**29%**

A further seven interviews were conducted by the Baringa team with specific stakeholders to develop and test the assertions made in these responses. Discussions with other stakeholders were held independently by DECC and any further input was received by the Baringa team and factored into our assessment in this report. The stakeholders that were interviewed are shown in Table 4:

Table 4: Stakeholder interviews

Stakeholder Group	
Aggregators	Statkraft
	NEAS Energy

[3] Individual responses can be found on the DECC website

	Smartest Energy
Small Suppliers	Good Energy
Generators	Helius Energy
	RES
Financiers	Low Carbon Finance Group

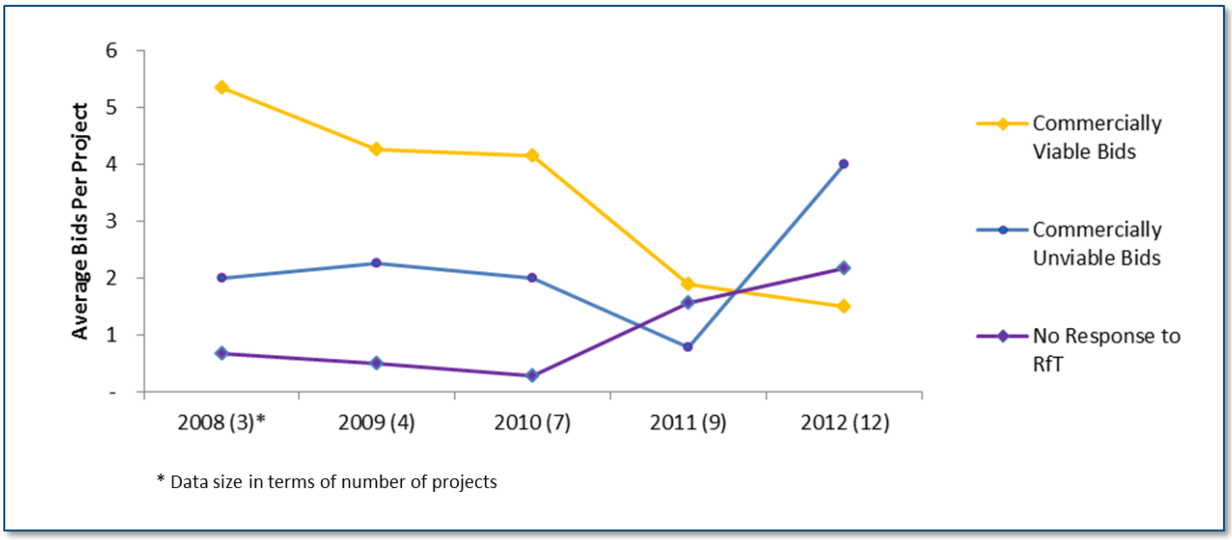
3. MARKET ASSESSMENT

This section looks at the state of the PPA market to establish whether there is evidence to support the assertion that the availability of viable or "bankable" PPAs to independent generators has fallen.

3.1. General overview of liquidity

Overall, there was a general consensus amongst respondents that the PPA market has changed over the past three to five years. Specifically, there seems to have been a progressive reduction in the number of viable or bankable PPA offers received by independent developers from incumbent, historically active, PPA providers in response to tenders. This is clearly shown in Figure 1 below which aggregates quantitative feedback from developers on key market performance indicators, namely the number of PPAs tendered split into commercially viable PPAs offered (representative of the developer's view of what constitutes a commercially viable PPA), non-commercially viable PPA offers and no responses to a Request for Tender ("**RfT**").

Figure 1: Nature of offers per project



The evidence set out in Figure 1 above demonstrates that:

- The number of bids considered by independents to be commercially viable received per project seems to have decreased steadily since 2008, with an abrupt decrease in 2010.

- The number of PPA providers who are declining to tender for PPA contracts has increased since 2010.

We note, however, that feedback from interviewees indicates that the market may have slightly improved in the last six months, with one developer stating that they had six or seven responses to a PPA tender launched in late 2012, of which three were bankable.

3.2. Competition in the PPA market

3.2.1. Participation of the large VIUs

Responses provided by the independent generator community almost unanimously assert that the drop in the number of viable bids received by projects looking for an offtake agreement has been because of an almost complete withdrawal of larger vertically integrated utilities (VIUs) from the PPA market. Table 5 below sets out some anecdotal evidence provided by developers supporting this view:

Table 5: Independent generator comments on participation of VIUs in the long term PPA market

Quotes
"In 2008 all six VIUs responded…..In 2010 only two of the VIUs responded."
"In the past three years we have seen an almost complete withdrawal of the large utilities from the PPA market."
"*Our most recent tender has seen the number of responses fall by 50% with some utilities indicating that their terms would not be bankable and other utilities deciding not to quote.*"
"*Since the announcement of the EMR we have seen a number of the [big six] withdraw from the market, either through unwillingness to provide a bid or an unwillingness to provide a commercially viable bid.*"

The responses given by VIUs present a conflicting view that they are all generally active in the long term PPA market (with one exception). However, in almost all the responses by the VIUs, while the headline message was that they are still responding to tenders and that broadly speaking their offering had not materially changed, they did concede that the terms that they are able to offer have deteriorated (either explicitly or implicitly by acknowledging that they were winning less tenders). A selection of statements from the returned consultation responses of the six largest VIUs are set out in Table 6 below:

Table 6: Large suppliers' views on participation in the long term PPA market

Quotes from consultation response
"*Our desire to enter into PPAs is strong. However…whilst our short term PPAs (of up to five years in duration) remain competitive, the structures we can offer for long term PPAs have become increasingly restricted.*"
"*The terms we have offered have not changed significantly over the last three years. We have made adjustments to respond to changes in our view of the future risks arising from the UK generation mix and margin, market conditions and the prevailing economic climate.*"
"*Our assessment of the market would be that the number of offtakers offering PPAs has not necessarily declined, but that the number of successful offtakers may instead be reducing.*"
"*Over the last three years [we have] continued to offer PPAs on the same terms and the in the same*

volumes, [we have] historically. [We are] a keen and active member of the PPA market and endeavor to meet all requests for PPAs. However, we continue to find this a highly competitive market in which it is challenging to win business."
"*We recognise that the risks for PPA providers have increased and that this may have resulted in a reduction in the number of providers willing to provide PPAs at any given price.*"

As such, it would seem that while the large VIUs are to a large extent responding to tender requests from independents, the suitability of those offers to support limited recourse financing needs has deteriorated. It should be noted, however, that one interviewee commented that, since the call for evidence closed, a number of the larger utilities had "re-entered" the market in the last six months, with more viable long term offtake offers.

In terms of their response rate to requests for tenders, most PPA providers assert that they look to respond to all tender requests but that volumes of requests for PPAs, both long and short term, had increased significantly over the last three years. In some cases, the large VIUs admitted that this increase in demand had stretched the capacity of their origination teams to deal with all tenders, which may be driving the increase in failures by VIUs (or others) to respond to tenders.

3.2.2. Smaller Suppliers

Smaller suppliers have, historically, been unable to play a significant role in providing long term PPAs to new build utility scale renewable energy projects. This is because lenders tend to find it difficult to get comfortable with the credit risk given their limited balance sheets and small retail positions. That is not to say that small suppliers have not been active in the provision of PPA market, but that they have been more focused on offering short term PPA contracts to smaller renewable energy projects supported under the small scale FIT, where the financing constraints are less stringent as the generator has an institutionally enshrined guaranteed offtake (see Section 2.2.1 above).

3.2.3. New entrant PPA providers

While it is relatively clear that the terms from the large VIUs, which have historically been the principal providers of PPAs to independent generators, have deteriorated, a number of new entrants have been active. These are as are set out in Table 7 below:

Table 7: New entrants in the long term PPA market

Utility	*Explanation*
International Utilities / Oil Majors	▶ There is universal acknowledgement across generators and suppliers of the importance that a leading new entrant aggregator has played in terms of providing bankable route to market options for independent developers. This aggregator entered the PPA market around 2010 and has since taken a large proportion of the market over the past three years. ▶ Indeed, a number of independent developers commented that this aggregator has to a large extent averted a complete standstill in the long term PPA market for independents. ▶ There were suggestions in the responses that oil majors were also looking at

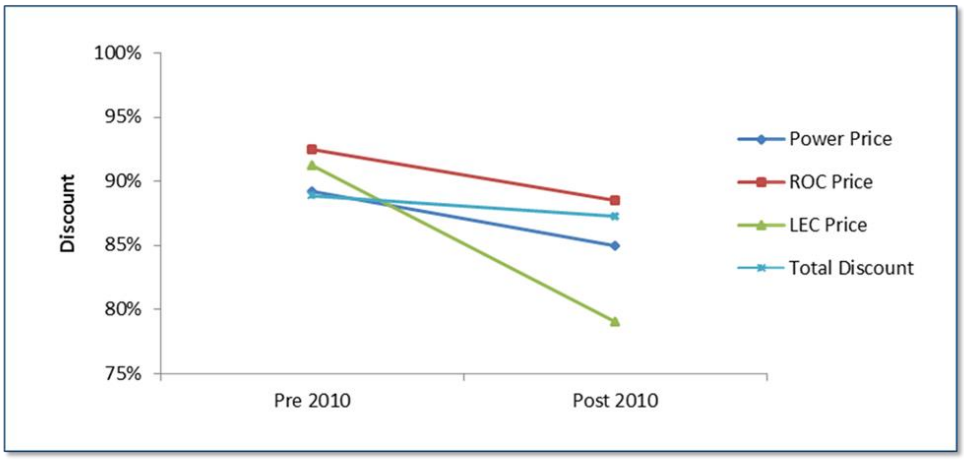
		entering the long term PPA market, however as of yet we have not seen evidence of major commitments being made and the offers received so far typically do not include sufficient wholesale price protection.
End users	▶	The last few years has seen the emergence of end users, like large retailers, looking to contract directly with generation projects to procure energy with greater long term price certainty as well as meeting corporate social responsibility goals.
	▶	However, these "sleeving" structures seem to be limited by the size of project that they can support (up to 30MW) and still require utility / aggregator involvement to manage the imbalance risk and take the ROCs and LECs.
Aggregators	▶	Aggregators are still finding it difficult to write long term bankable PPAs to wind projects, notwithstanding the fact that in some cases they have started offering guarantees from corporate parents, to give greater comfort around the credit risk.
	▶	Having said that, there are reports that an aggregator has provided a bankable 15 year offtake to more flexible assets (like STOR projects) or where there is limited imbalance risk and limited exposure to the electricity wholesale price.
	▶	In addition, lenders have confirmed that an aggregator does have a potentially bankable 15 structure for solar projects involving a 5 year rolling fixed price (with banks getting comfortable in relation to pricing risk by building in structural protections in the financing package (e.g. cash sweeps, mandatory repayments, lock-up ratios)).

3.3. PPA Terms

As described above, there is evidence that, notwithstanding the contribution of a number of new entrants and the emergence of the end user segment, PPA terms have deteriorated over the last three years, as set out in Table 8 below.

Table 8: Reported changes in PPA terms

Term	Description
Discounts	**General** All of the independent generator responses stated that the offers that are being made by PPA providers have higher discounts when compared to historic terms.

	Figure 2: Reported discounts across Power, ROCs and LECs  It is worth noting that while the change in discounts for LECs shows the largest move, LECs only represent a very small proportion of the overall project revenues.[4]
Price Floors	A limited number of offtakers are willing to provide a floor at sufficient value to support target leverage. Where floors are offered, offtakers have tended to limit it by setting it at a conservative level, stepping it down over time or not indexing it to inflation.
Index / Profile Risk	PPA providers have started to offer PPAs indexed to the day-ahead or intra-day market index rather than season or month ahead as was more common historically. This exposes generators to the medium term risk of lower captured value as a result of cannibalisation of the electricity prices in periods of correlated output of intermittents (primarily wind).
Imbalance risk	Generators have reported a move by offtakers to shift imbalance risk back onto the generator through: ▶ More onerous data access and reporting requirements (although generators conceded that these requirements were probably not beyond the capabilities of a Reasonable Prudent Operator); ▶ An annual or periodic re-opener clause on the discount applied to the brown power in respect of increase in imbalance costs (although this was not consistently reported); ▶ Indemnities in respect of failure to deliver output (although this seems to a relatively rare requirement).
Change in law	The consistent message from both generators and PPA providers in consultation responses is that change in law clauses are becoming increasingly difficult to negotiate. Key areas in which greater change in law risk is being pushed back onto

[4] 2013 electricity prices of approx £50/MWh, ROC buy-out (which sets the theoretical floor on the ROC price) is £42.02MWh and Climate Change Levy (that sets maximum LEC price) is £5.24/MWh.

	generators are: ▶ Inclusion of a termination right in the event of a material change in law; ▶ Widening of definitional scope, in particular in relation to change in law that affects imbalance costs/ risk; ▶ Widening of the elements of the commercial deal that are subject to the reopener – most importantly the "sanctity" of the floor price which the banks need to be able to rely on for debt sizing; and ▶ Inclusions of bespoke clauses to deal with specific regulatory uncertainties that are difficult to negotiate and assess from a risk allocation perspective.
Tenors	Generators stated that the tenors being offered by PPA providers have reduced, with some PPA providers only offering PPAs to the end of the EMR transition period. Indeed, a couple of the VIUs did state that they were increasingly focusing on the short term PPA market.

3.4. Conclusions

The evidence base supports the following conclusions:

- The terms being offered by the large VIUs, historically the most material PPA providers, have deteriorated over the last three years.
- There have been some new entrants over that period, including one very large aggregator and end use non-domestic retail customers looking for long term purchasing strategies. However these new entrants alone have not been able to avert a general reduction in bankable PPA terms.
- The number of offtakers willing to make PPA offers of sufficient tenor has reduced, and where the requisite tenor is available, terms have generally deteriorated across the board. Most significantly from a bankability perspective:
  - ✓ Availability of a floor at a level that will support target leverage and which is sufficiently robust to be counted as a firm revenue for lender debt sizing;
  - ✓ Discounts on power prices, ROCs and LECs have increased; and
  - ✓ Change in law has become a particularly heavily negotiated provision with offtakers looking to increase definitional scope, reduce carve outs (i.e. the integrity of the floor) and introduce bespoke drafting outside of the general change in law (i.e. to maintain same risk reward) to deal with specific change in law scenarios envisaged (i.e. market splitting, capacity market).

The impact that this is having on independents is set out in Table 9 below:

Table 9: Impact on independents of deterioration in PPA terms

Term	Description
Squeeze on equity returns	▶ With a progressive reduction of risk that can be transferred through the PPA, in the event that lenders are prepared to lend, the terms on which they are willing to do so have deteriorated. ▶ Independent generators have reported that the consequent lower gearing, higher coverage ratios and short debt tenors have meant that equity returns for independents have been falling.
Perceived development risk	▶ There was evidence to suggest that the route-to-market uncertainty was significantly increasing the perceived development risk that is attached to the investments needed to secure consents and grid connection.
Market Exit?	▶ One potential consequence of the deterioration in the PPA market is that independent project developers might exit the market to invest in alternative and more attractive markets. ▶ This is difficult to assess from the evidence provided as no specific question along these lines was asked. However, we note that no generators who responded to the consultation specifically noted that PPA market conditions had forced them to cancel or walk away from projects in which they already invested significant spend during the development phase.

4. REASONS FOR OBSERVED CHANGES

4.1. Overview

The evidence presented in Section 3 above suggests that on a project-by-project basis there has been a general deterioration in the number of bankable long term PPA offers available to independent generators. This section looks to bring together the range of reasons cited by different market participants for this observed trend and to appraise their materiality. These are summarised in Table 10 below and further explored in detail in Sections 4.2 to 4.10 below.

Table 10: Summary of reasons cited by respondents for changes in PPA terms / availability

Reason	Hypothesis	Materiality
Increased wholesale price risk	*"The reduction in the availability of long term PPAs for independent renewable generators is being driven by a reduced appetite amongst offtakers to offer sufficient wholesale price protection."*	**Causal factor**
Reduced appetite for long term ROCs	*"The reduction in the availability of long term PPAs for independent renewable generators is being driven by a reduced appetite amongst the large suppliers for significant volume of ROCs procured over long term arrangements."*	**Causal factor**
Increased balance sheet / credit rating impact	*"The reduction in the appetite of large suppliers to enter into long term PPAs with independent renewable generators has been triggered by a change in the treatment by the credit rating agencies of these arrangements that increases their balance sheet impact/cost".*	**Causal factor**
Increased regulatory & policy risk	*"The availability of bankable long term PPAs for independent renewable generators has been increasingly restricted by a general reluctance of offtakers to absorb significant change in law risk through the PPA."*	**Causal factor**
Greater imbalance risk	*"Greater uncertainty as to long term imbalance costs is increasing the discounts charged by existing incumbents to accept this risk and is restricting the pool of offtakers willing (and able) to price imbalance risk over a 15 year period."*	**Contributory Factor**
Reduced competition and barriers to entry	*"Structural barriers to entry have meant that there have been limited numbers of new entrants that have entered the GB market to compete with existing incumbents, notwithstanding the deterioration in terms."*	**Contributory Factor**
Increased demand for PPAs from	*"There is a surplus of projects looking to secure long term PPAs from the existing incumbents, which has resulted in a saturation of the market and driven a progressive deterioration in terms*	**Limited effect**

generators	*available to independents".*	
Change in lenders requirements	"*The observed reduction in the number of bankable PPAs offers available to independents has been caused by a shift in the risk appetite of the lending community that has changed the requirements of a bankable PPA*"	**Limited effect**

As can be seen from Table 10 above and in the assessments in Sections 4.2 to 4.9 below, we have ascribed a grade in terms of perceived materiality against each of the potential reasons cited by stakeholders for the observed deterioration in the market for PPAs. The criteria behind these grades are as follows:

- **Causal factor** – means a factor for which there seems to be significant evidence to suggest a causal link with the recent observed deterioration in the long term PPA market for independents;
- **Contributing factor** – means a factor which is impacting the terms of PPAs and the structure of the market, but for which there does not seem to be evidence to suggest a causal link with the recent observed deterioration in the market for long term bankable PPAs; and
- **Limited Effect** – means a factor which does not seem to be materially affecting the availability of bankable PPAs to independents.

4.2. Reluctance of offtakers willing to take long term wholesale electricity price risk

Summary

As described above, one of the key issues with regard to the provision of a bankable PPA is the ability of the offtaker to provide sufficient protection from the wholesale electricity price risk in the form of a floor. Generators have reported that while indexed 15 year floors of £28-30/MWh were widely available until around 2010, there has been a progressive reduction in the number of PPA providers willing and capable of providing floors at this level and tenor. This deterioration in terms is summarised in Table 11 below:

Table 11: Erosion of price certainty in long term PPAs

Issue	Description
Refusal to take price risk at all	▶ A refusal on behalf of the some incumbents to offer a floor on the wholesale electricity price at all.
Availability of a reduced floor	▶ Where floors have been offered, there seems to have been an increasing tendency to erode its value from the perspective of protecting debt capacity of projects by reducing its absolute value or stepping it down over time (i.e. limiting its tenor and not indexing it to inflation such that its real value decreases over time).
Re-openers	▶ PPA providers have been pushing for a price re-opener on change in law that affects the value of the electrical output of the renewable generators,

	the scope of which is increasingly widely drafted.

Both VIUs and independent generators have acknowledged that one reason for the reduction in the availability of acceptable wholesale price protection is the increased risk that such a position represents to a PPA provider, especially at the levels required to sustain target gearing levels. Respondents highlighted a number of issues that could be contributing to the increased long term price risk, which are set out in Table 12 below.

Table 12: Drivers of increased price uncertainty cited by respondents

Driver	Explanation
Impact of increased renewable penetration	▶ EMR heralded a move by the UK government to drive the GB energy sector towards greater low carbon generation, and when combined with an assumption around compliance with the EU 2020 targets, suggests a greater penetration of intermittent generation such as wind and solar. ▶ Experience from other European markets like Germany and Spain with higher levels of renewable deployment has shown the effect that greater volumes of wind and solar can have on wholesale electricity prices, with a greater probability of periods of low or even negative prices. ▶ As the actual make-up of the generation mix – and, crucially, of plant that determine prices – will be driven less by the wholesale power market and more by overall energy and low carbon support policy, it is arguably more difficult for PPA providers assessing the merits of taking on a fixed price or floored price exposure to be confident in their assessment of future wholesale prices.
Impact of the capacity market	▶ The impact of the capacity market is as yet uncertain as the details of the framework of support are not yet fully finalised. ▶ However, there were views that the capacity market is likely to take at least some value out of the energy market by allowing owners of flexible thermal plant to recoup a proportion of their costs under capacity contracts, rather than through infra-marginal and scarcity rents in the electricity market as is the case today. ▶ As such, PPA providers are becoming more circumspect about taking long term electricity price risk in the shadow of a policy whose principle aim is to remove the requirement for price setting thermal plant to recoup their long run marginal costs through the energy market only.
Confidence in prolonged carbon price support	▶ The intention of the carbon price floor is to reduce uncertainty in the future price of carbon. This is achieved through a tax on fossil fuel generators that reflects the difference between the future market price of carbon and the floor price determined by Government in each annual budget. The trajectory of the carbon price floor published by the Treasury in 2011 is 30 £/t (real 2009) in

	2020 rising to as much as 70 £/t (real 2009) by 2030. ▶ However, for this policy to feed through into investment decisions in low carbon plant, and in particular provide confidence to PPA providers in writing long term price floors, market participants must have confidence in the Government's projected trajectory. ▶ As the level of that support is reviewed annually through the government budgetary process, there seems to be a perceived political and regulatory risk associated with taking long term power price exposure based on forecasts that assume all in carbon prices in line with these government CPF projections.
Impact of market fundamentals on long term electricity prices	▶ The other potential explanation cited by respondents as to why PPA providers might be reluctant to floor the electricity price at a level acceptable to independent generators is uncertainty as to future wholesale electricity prices driven by market fundamentals. ▶ Potential explanations provided by both generators and VIUs for this bearish outlook on power prices are as follows: ✓ Conservative demand projections given the reduction in economic activity in the short to medium term caused by the recession, along with uncertainty in relation to the anticipated growth in demand driven by electrification of heating and transport. ✓ Uncertainty associated with future capacity margins in 2015/2016 and beyond with increased interconnection, biomass conversions of old LCPD[5] plant and the option of bringing mothballed first generation Combined Cycle Gas Turbine ("**CCGT**") plant back on line to bridge any short term capacity gap.[6] ✓ Uncertainty as to the likely long term gas price and the impact of significant additional volumes from shale gas production causing a reduction in electricity prices.

Materiality

Classification	Justification
Causal factor	▶ Increased long term price uncertainty appears to be a very material constraint on the availability of bankable PPAs in the market today. ▶ It was a key issue highlighted by large VIUs in term of the reduced

[5] Large Combustion Plant Directive

[6] It is worth noting, in this regard, that most of the LCPD opt-out capacity has closed (leaving little option for 'saving' the remainder). Moreover, the biomass conversions for Tilbury and Ironbridge might only be until end-2015, and little remaining capacity is likely to opt into the IED via SCR installation

	attractiveness of offering long term PPAs. ▶ The availability of floor prices was highlighted by the vast majority of independent generators ▶ The deterioration in the availability of acceptable floor prices does seem to largely coincide with (a) the announcement of the reform of the electricity market and (b) the recessionary drop in demand.

4.3. Reduced appetite from large suppliers for long term ROCs

Summary

The second potential driver of a reduction in bankable PPAs is a reluctance of large VIUs to contract long term for ROCs. Generators have reported a material increase in discounts on ROCs of approximately 4 percentage points since 2010 and an increased propensity of large VIUs to make PPA offers which do not take 100% of the ROCs, but instead offer to take 100% of the power and only half of the ROCs (sometimes with an option to buy the remaining ROCs). This reduced long term ROC demand is explained by three interrelated factors which are set out in Table 13 below:

Table 13: Reasons cited by respondents for a reduced appetite amongst large suppliers for long term ROCs

Issue	Description
Impact of the closure of the obligation	▶ At a strategic level, with the closure of the RO to new projects in 2017, the large suppliers are left with an RO exposure that is no longer long term and rising. ▶ As such, the incentive to lock in significant volumes of ROCs under long term arrangements is potentially reduced, especially since the obligation will start to reduce after 2017 when projects start rolling off the scheme.
Reduced number of VIUs with significant RO exposure	▶ Research from Cornwall Energy, that looked at the supply and demand dynamics of the ROC market out to 2016 – 2017, suggests at least one of the large suppliers will be able to meet its renewable obligation in 2012-2013 with ROCs sourced from its own assets or from already contracted assets. ▶ The research predicts that this trend is likely to continue with a significant pipeline of VIU owned utility scale renewable projects coming on line in the short term, most notably the offshore round 2 and round 3 wind farms. ▶ As such, the number of large suppliers in the market for a long term ROC position is potentially decreasing.
Increased reliance on a growing short	▶ A number of respondents suggested that those suppliers that still have an obligation to meet are adopting contracting strategies that rely to a greater extent on the short term ROC market than on longer term offtake

term ROC market	agreements. ▶ This is rationalised as follows: ✓ Historically, in the early days of the RO where there was limited vertical integration of renewable generation development, suppliers generally sourced their ROCs from independents. ✓ As these independents tended to use limited recourse debt finance, these ROCs were generally contracted under long term PPAs. ✓ However, this left suppliers potentially exposed to the risk of over-contracting for ROCs as their annual obligation fluctuates each year with their share of the retail market, which depending on the level of competition and customer switching, will itself change through time. ✓ However, over the last three to five years, the availability of sellers of ROCs that are prepared to contract on a shorter term basis has increased. This is being driven by two dynamics; ❖ An increasing volume of older renewable plant for which the original PPA arrangements have expired; and ❖ The growing market share of European utilities who have built assets on their balance sheet instead of relying on project finance. ✓ With a more diverse supply of ROCs that are not tied to long term offtake agreements, large suppliers have been free to adopt a contracting strategy whereby they look to hedge their certain long term “firm” ROC position with ROCs procured under long term arrangements (i.e. from plant owned within the utility’s portfolio or under long term PPAs with an independent). As a supplier’s share of the obligation is calculated by reference to its market share in that particular compliance year, it is likely to calculate its annual “firm” ROC requirement by reference to the segment of its customer base that are unlikely to switch supplier with great frequency, its so called “sticky” customer base. However, in relation to any additional ROC exposure over and above this long term demand implied by its “sticky” customers, a supplier would instead look to purchase under shorter term or even spot contracts as this reduces its year on year risk of being left with a long ROC position. It is worth noting that to the extent that it is not possible for a supplier to pick up the requisite ROCs at the right price in the ROC market, it can always just pay the buy-out price instead.

Materiality

Classification	Justification
Causal factor	▶ Availability of bankable PPAs coincides with (a) the announcement of the phase out of the RO (b) significant investment by VIUs in their own asset portfolios and (c) the emergence of more diverse RO demand. ▶ As such there does seem to be a causal link between the deterioration in the long term PPA market and the change in position of the big suppliers in terms of their appetite for long term ROCs.

4.4. Balance sheet / credit rating impact of long term PPAs

Summary

A number of the VIUs assert that their capacity to offer bankable long term PPAs has become increasingly restricted by the credit rating agencies treatment of these arrangements, which has become more stringent following the financial crisis[7]. This is because of an issue known as "imputed debt" where by the financial risk inherent in signing a long term PPA is measured by credit rating agencies and imputed onto a supplier's balance sheet for the purposes for assessing the company's creditworthiness. Indeed, it seems that the impact of imputed debt is most acute where a supplier has entered into a PPA under which it has committed to pay a fixed or minimum price per MWh of output for a period beyond the forward curve, which is around three years. It is important to note that this process essentially treats a price floor as an open obligation for the tenor of the contract, and gives little credence to the fact that the offtaker's liability under the PPA is in fact subject to the contractual caps on liability, (which tends to be a fixed multiple of the floor price, rather than the full mark to market valuation of the contract).

Bringing these liabilities onto a VIU's balance sheet puts pressure on the coverage ratios that it is required to maintain its credit rating. As VIUs will look to maintain ratios within certain parameters acceptable to the credit ratings agencies to avoid a downgrade and higher borrowing costs, there is in effect an upper limit on the capacity of these companies to enter into long term power purchase arrangements which have a risk allocation that is likely to trigger a balance sheet impact. Indeed, with the balance sheets of the large VIUs under increasing pressure owing to reduced energy demand which places pressure on margins, higher borrowing costs as a result of the financial crisis and significant capital programmes, this restricted balance sheet capacity has become all the more evident over the last three to five years. This change in the treatment of PPAs potentially places incentives on the large VIUs to use their residual balance sheet strength to make investments in their own pipeline of projects, as this is seen as a better deployment of that spare capacity in terms of value creation.

[7] Centrica being required to recognise £500 million of liabilities on its balance sheet in 2011 signaled a change of treatment.

Materiality

Classification	Justification
Causal factor	▶ Consistently cited by large VIUs as one of the major constraints limiting the extent of long term risk transfer they can accept under long term PPAs ▶ Coincides with weakening balance sheets and greater scrutiny by credit rating agencies following the financial crisis and greater involvement by VIUs in large scale offshore wind projects which require a significant portion of these utilities spare capital.

4.5. Increased policy and regulatory risk

Summary

Evidence provided by both generators and PPA providers supports the conclusion that increased perceived policy and regulatory risk since 2010 has significantly impacted the ability of independent generators to secure financeable offtake arrangements. Generators and offtakers alike have reported that the change in law provisions in a PPA are becoming increasingly difficult to negotiate. While historically PPA providers have provided a level of change in law protection to generators, offtakers are now increasingly reluctant to fix certain key commercial terms (namely the level of the floor and the discounts) in the face of what they perceive to be an increasingly uncertain regulatory landscape. This has manifested itself as:

- Offtakers looking to push all change of law risk back onto the generator with a termination right for material change in law;
- An insistence on including the impacts of changes to the industry codes governing the allocation of imbalance risk (following the launch by Ofgem of its Electricity Balancing SCR);
- A widening of the elements of the commercial deal that are subject to the reopener (i.e. how robust the floor is);
- Bespoke drafting in the PPA outside of the general change in law clause looking to deal with specific change in law possibilities envisaged – e.g. the impact of zonal pricing or the capacity market on electricity prices.

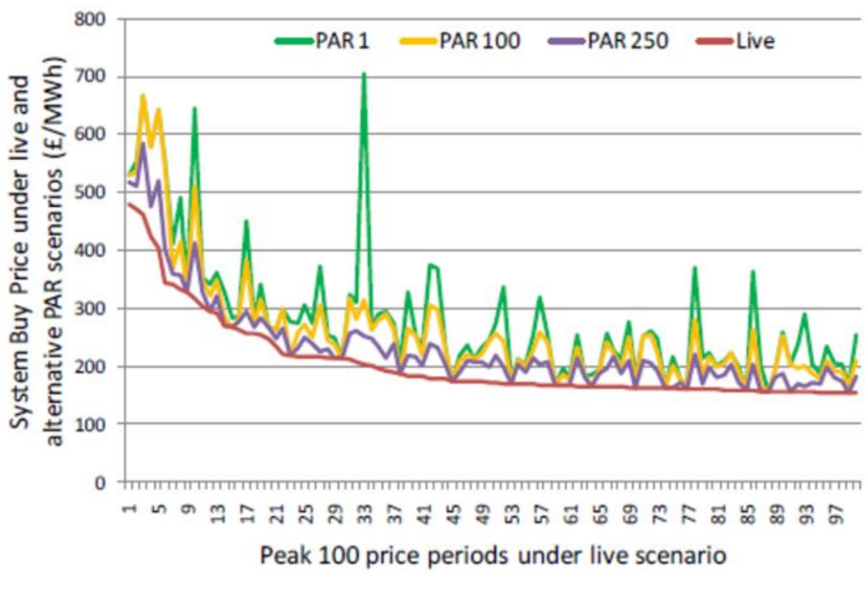
There are a number of potential drivers of this uncertainty and these are set out in Table 14 below. We note that there is close correlation between the reasons behind an increased concern in relation to the allocation of regulatory uncertainty in this context and the underlying drivers behind a reluctance of offtakers to take wholesale price risk described in the section 4.2 above, namely the long term impact of EMR and the anticipated change in generation mix. However, change in law risk goes beyond EMR to encompass wider unknowns in relation to market structure and perceived increase in policy risk.

Table 14: Additional change in law risk in addition to EMR

<table>
<tr><th>Issue / Change</th><th>Explanation</th></tr>
<tr><td>Uncertainty of SCR on the cost of imbalance</td><td>

- It is arguable that change in law risk in relation to imbalance charges historically has been relatively limited. This is because a code review process could only be initiated by parties to the BSC. This changed in 2010 with the introduction of the significant code review procedure ("**SCR**") where Ofgem acquired greater powers to make changes to these industry codes.
- The consistent message from most stakeholders was that this perceived regulatory risk has significantly increased following the launch by Ofgem of its SCR on Electricity Balancing arrangements. Indeed, this uncertainty is due to remain until a final policy decision is made in early 2014. As an illustration of the materiality of this issue, Figure 3 below shows how cash-out prices will differ with different methodologies for the calculation of the cash out price:

Figure 3: Potential extent of cash-out variation across averaging methodology[8]



- One respondent commented that this regulatory uncertainty is further exacerbated by a lack of a clear regulatory philosophy underpinning Ofgem's review on the likely shape of the balancing arrangements.
- In particular, while the proposals to move towards a more marginal cash-out price, sharpen the allocation of reserve cost and attribute a cost to non-costed actions are looking to sharpen the imbalance signal, other elements of the reform package, namely a move to a single cash out signal, single

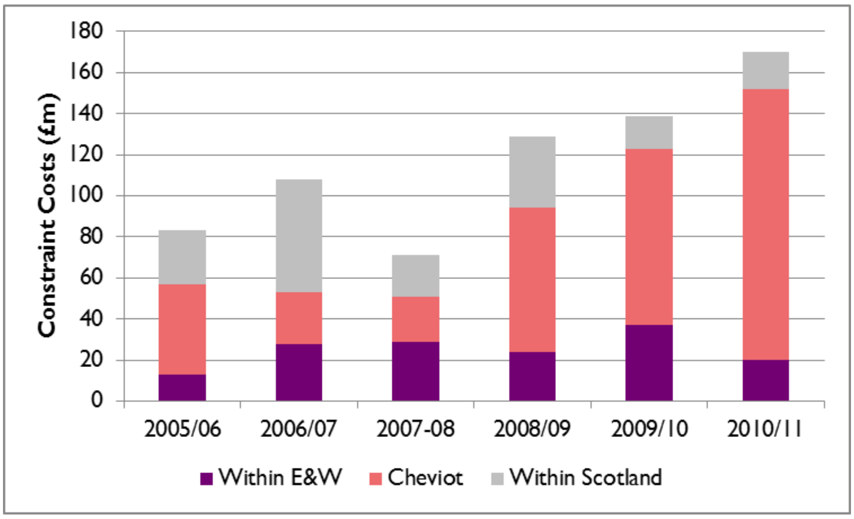
</td></tr>
</table>

[8] Ofgem, Electricity Balancing Significant Code Review: P217A Preliminary Analysis, August 2012.

	trading accounts and extension of the contract notification period, seem to be looking to make imbalance charging arrangements less penal.[9]
Uncertainty in relation to market splitting	▶ Implementation of the EU Third Package, and the network codes that will underpin it, requires, amongst other things, National Grid to propose, and Ofgem to consider, the merits of separate price zones to manage internal constraints in GB more efficiently - so called "market splitting". A price zone is defined as a zone of the transmission network where it can be shown that there is no significant internal congestion. ▶ The rationale behind this is, broadly speaking, to ensure efficient cross border flows of electricity, more cost reflective energy prices to drive generators' locational decisions and improved investment signals for transmission reinforcement. ▶ However, market splitting also introduces significant price uncertainty for generators (and therefore PPA providers who have taken wholesale electricity price risk) as the electricity price received will be determined by reference to the supply and demand fundamentals of each particular bidding zone rather than the GB system as a whole. ▶ This basis risk might be mitigated by (a) grandfathering old plant with financial transmission rights that leave them broadly in the position that they would have been under a single GB price zone, and/or (b) through a change in transmission charging. However, the exact arrangements required should market splitting occur are unknown. ▶ As such, agreeing the allocation within a PPA of any adverse financial impact that such a reform might create is difficult, with little certainty as to the likelihood of these reforms occurring and the shape or timing of its implementation. ▶ While EU Target Model compliance is the principal driver behind the increasing probability of market splitting occurring in the UK, it is worth noting that the possibility of Scottish independence has further strengthened the perception that this is a credible risk in the medium term. ▶ Indeed, this is particularly pertinent given that the priority transmission constraint to price in a market splitting context would likely be the Cheviot boundary between England and Scotland. Figure 4 below shows how the proportion of total constraints costs in the GB system attributable to this boundary increase through time.

[9] See Annex 3 for further details on the nature of the SCR proposals in relation to changes to the balancing arrangements.

	Figure 4: Location of National Grid's constraint costs – 2005/06 to 2010/11[10]



Materiality

Classification	Justification
Causal factor	▶ Change in law risk consistently cited by all stakeholders as one of the major barriers to securing financing. ▶ Announcement of Electricity Balancing SCR and EMR all align with deterioration in the PPA market over the last three years. ▶ General increase in perceived regulatory risk following retrospective cuts in subsidy in southern Europe 2008 – 2009.

[10] Data from: National Grid, 'Electricity SO incentives – Historic Costs 2005/06 to 2010/11'.

4.6. Greater uncertainty of long term imbalance costs

Summary

One of the key issues with regard to the provision of a bankable PPA is the full transfer of all imbalance risk away from the generator[11]; and the provision of a fixed and certain cost (or discount) for accepting that imbalance risk for the tenor of the PPA - being 12 to 15 years. Generators have reported that not only have discounts on the electricity price increased in recent years (affecting equity returns), but in some cases PPA providers are starting to push imbalance risk back on to the generator. This is summarised in Table 15 below.

Table 15: Change in the cost and allocation of imbalance risk in PPAs

issue	Description
Imbalance pricing	▶ Discounts on electricity price have increased with an increase in the average reported electricity discount of around 4.25 percentage points since 2010.
Allocation of imbalance risk	▶ Increasing number of offers received from PPA providers that look to shift imbalance risk back onto the generator through: ✓ More onerous data access and reporting requirements; ✓ An annual or periodic re-opener clause on the discount applied to the brown power in respect of increase in imbalance costs; ✓ Indemnities in respect of failure to deliver output.

Ignoring the uncertainty in relation to the balancing and cash-out arrangements (which we have discussed in the allocation of change in law risk in Section 4.6 above), the key reason cited for this deterioration in terms is uncertainty as to the impact that a greater penetration of intermittent renewables will have on cash-out prices. With higher level of wind on the system, the imbalance volumes should increase in periods of high wind. This will in effect require the System Operator to hold greater volumes of reserve and move up the marginal cost curve to take more and more expensive actions which are reflected back onto those participants that were out of balance in that period.

Materiality

Classification	Justification
Contributory factor	▶ It is clear from the responses that imbalance risk is becoming increasingly difficult to price in long term (i.e. 15 year) contracts, which is impacting the discounts charged by offtakers, as well as the number of entities willing

[11] Other than any imbalance charges incurred by the PPA provider as a result of a generator's failure to forecast its *availability* as a reasonable prudent operator.

	and able to price a 15 year exposure. ▶ What is less clear is whether the level of imbalance risk has in some way materially changed in the last three years that has led to the reduced availability in offtakers willing to provide bankable PPA offers to independents. ▶ Arguably, as with wholesale electricity price, the introduction of EMR, in particular the move from the RO to the CfD, has raised the prospect of higher (and less certain) volume of intermittents on the system with knock on effects on cash out prices. However, there was no consensus that EMR, in of itself, had made imbalance risk more difficult to price. ▶ Indeed, the evidence from stakeholders seemed to indicate that while imbalance is a material and growing concern in the pricing of PPAs, it is not the principle cause of the observed deterioration in the long term PPA market over the last three years.

4.7. Reduced competition and barriers to entry

Summary

A number of respondents highlighted that competition in the long term PPA market for renewable energy projects was structurally limited by a number of significant barriers to entry. While not an exhaustive list, Table 16 sets out the most material issues identified

Table 16: Identified barriers to entry for new entrants

Change	Explanation
Credit / Credibility	▶ A number of respondents and interviewees highlighted the fact that one of the most significant barriers experienced by new entrants looking to offer long term PPAs in the GB market is building confidence amongst the lending community both in terms of their long term credibility and creditworthiness. ▶ Under the RO, a PPA is a project's sole source of income with which it can service its debt obligations and involves significant risk transfer (i.e. price risk, imbalance risk, liquidity risk). In this way, offtaker credit risk is a key element of any lender's appraisal of the bankability of any given project structure. ▶ As a starting point lenders will require a PPA counterparty (or a parent providing a guarantee) to have a minimum credit rating of BBB- or above. In addition, lenders will also consider capitalisation, long term experience in energy markets, strategic position and credibility. In other words, banks will ask themselves, "Can this entity take everything that the energy sector can throw at them for the next 15 years?" Indeed, this question has become increasingly pertinent given the perceived rise in regulatory risk over the last three years. ▶ This has the effect of creating a natural preference for a large VIU offtaker on the basis that not only do they have large balance sheets and a relatively stable supply base, they are also seen as being strategically invested in the GB market in a way that makes it very difficult for them to walk away from long term contracts and liabilities. ▶ This is not to say that lenders have an exclusive "big six" policy. A large new entrant aggregator has managed to persuade the lending community that, as a state owned entity with a strong experience in both electricity generation and the trading of electricity, it has the requisite competence and has made a sufficiently concrete commitment to the GB market. ▶ However, this is nevertheless a relatively onerous process that has to date proved insurmountable for other prospective new entrant aggregators, notwithstanding the fact that some are capable on paper of providing a PCG from a creditworthy parent company.
Lack of liquidity	▶ As the primary role of PPA is to provide a guaranteed route to market for

in the wholesale power markets	independents, a key pre-requisite to competition in this market place is a deep pool of liquidity in the underlying wholesale electricity market. A significant number of respondents highlighted the fact that a lack of liquidity in the wholesale electricity market was a significant barrier to new entrants, aggregators or suppliers looking at providing long term PPAs. ▶ While consultation responses generally acknowledged that day-ahead liquidity has improved in recent years, there were still concerns this day-ahead liquidity may not remain long term given that it is being driven by voluntary commitments by large VIUs that could be withdrawn at any point. ▶ In addition, while the liquidity at day-ahead stage may well have deepened: ✓ A lack of liquidity along the forward curve restricts the ability of new entrants to manage price risk. This is particularly pertinent given that in order to provide a bankable PPA, an offtaker must accept price risk. ✓ A lack of liquidity in the spot / intraday market restricts the ability for new entrants to price competitively for accepting imbalance risk as they may not be able to trade out changes in forecasted output between day-ahead and gate closure.
ROC liquidity	Without a significant retail position, new entrants can find it difficult to provide price certainty to generators under long term PPAs in relation to the value of ROCs and this has been cited as a significant barrier to entry into the long term PPA market. This is because: ▶ A significant proportion of the value of a ROC is the avoided cost for a supplier with a compliance obligation in relation to the buy-out price. As such, to be confident in being able to realise the full value of a ROC, it is a major advantage for the purchaser to have a large enough retail position to cover the number of ROCs purchased. ▶ Smaller suppliers or aggregators looking to write significant numbers of long term PPAs to independent generators will not generally have the customer base against which to realise the value and as such will instead need to find a large supplier that is short on its ROC obligation to buy their ROCs. ▶ This effectively leaves only six potential purchasers of ROCs. Indeed, in recent years, this pool of potential buyers may have contracted to just one or two given an increasingly asymmetric distribution of the appetite for ROCs across the big suppliers. ▶ This increasing imbalance building in the market exposes smaller parties/aggregators with ROC surpluses to greater risk in relation to their ability to realise the value of surplus ROCs. ▶ It is worth pointing out that the negotiating position of large suppliers is significantly strengthened by the fact that they do not have an obligation to buy ROCs, but instead can pay the buy-out prices. As the cost of the RO is already priced into their rates to retail customers, large suppliers are

	therefore largely kept whole from the RO penalty structure for failure to surrender ROCs. As such, a large supplier will only purchase ROCs if there is sufficient incentive on them to do so. Indeed, limited competition for the ROCs can drive greater premiums, as the loss for an aggregator with a potentially stranded ROC position is far greater relative to the loss of profit for the large supplier of fulfilling its obligation at a slightly higher cost. ▶ Indeed, empirical evidence provided by stakeholders supports the suggestion that fees charged by suppliers on ROC purchases from aggregators are increasing. In the early days of the RO, fees per ROC were 10-20 pence rising to 80 pence in 2010 and up to £1.25 in 2011.

Materiality

Classification	Justification
Contributory factor	▶ Credit requirements of banks and the liquidity issues in the wholesale electricity and ROC markets are no doubt significant barriers to entry, and will need to be solved to ensure greater competition in the long term PPA market. ▶ However, these do not necessarily account for the present deterioration in the PPA market as of today. ▶ These barriers have been structurally limiting the market for a period that long pre-dates the reported reduction in the availability of a route to market for independents. ▶ Indeed, while it might be argued that concerns regarding ROC liquidity may have risen with a greater perceived imbalance in the distribution of demand amongst the large suppliers, it is instructive to note that this is exactly the period over which a leading new entrant aggregator has taken a significant ROC position without commensurate growth in its retail position.

4.8. Increase in the number of generators looking for long term PPAs

Summary

One potential reason cited for deterioration in PPA terms available to independent generators is that there are simply a greater number of projects seeking long term PPAs than previously, which has saturated the market. Figure 1 in section 3.1 above certainly supports this conclusion with the number of PPA tenders run by independents rising. Indeed, evidence provided by PPA providers also supports this view, with a number reporting that there had been an increase in the PPA tenders over the last three years and that this was stretching the resources of their origination teams.

In addition to an overall increase in the number of projects coming to market, a number of respondents also highlight that the nature of the demand for PPAs has changed which could be contributing to some of the difficulties experienced by independents in engaging major suppliers in PPA processes:

- Firstly, a number of suppliers have reported that regulatory uncertainty introduced by the RO banding review has created a "lumpy" project pipeline with a significant number of projects coming to market immediately after new subsidy levels were confirmed. This has limited the ability of their origination teams to cater for demand in those periods.

- Secondly, a number of PPA providers commented that over the last three years there has been a reduction in the number of requests for PPAs from viable "shovel ready" projects. This deterioration in the maturity of projects coming to market could be driven by the increasing development risk for project developers (as highlighted in Table 8 of section 3.4 above), who are reluctant to commit significant capital into consenting projects and securing grid connection with the greater uncertainty as to whether a viable route to market will be available. Whatever the reason, suppliers are generally reluctant to commit significant resources to projects that do not have a significant probability of being built, and this may account for reports by independent generators of difficulties in engaging with some of the VIUs.

- Thirdly, a number of PPA providers indicated that while demand for long term PPAs has not necessarily changed materially, these projects now have to compete with a greater number of renewable projects looking for shorter term PPA positions. For example:

  - ✓ Firstly, there is an increasing capacity of older renewable plant that are no longer contracted under long term offtake arrangements put in place to underpin the original project finance debt (that has now been partially or fully repaid). These assets, now in the twilight of their operational life with no debt to service, are looking for short term PPA positions that allow them to maximise value capture and equity return.

  - ✓ Secondly, the renewable energy market has seen the emergence of greater diversity amongst developers in term of financing strategies which has affected the nature of demand for PPAs. Traditionally, the bulk of demand for PPAs has come from independent developers looking to secure project financing and as such require long term PPAs that underwrite significant project risks. However, the last four to five years has seen the emergence of large European utilities (i.e. DONG, Vattenfall, Statkraft, Statoil, Stadtwerke München) that are using balance sheet finance to fund construction of their pipeline of renewable energy projects, but do not wish to trade the electrical output themselves. With less reliance on long term project level debt, these non-VIU generators are looking for simpler short term PPAs that cover liquidity and balancing risk, but with less stringent requirements in relation to wholesale price risk. These PPAs are simpler products which can be offered more easily by a broader range of market participants.

Materiality

Classification	Justification
Limited effect	▶ There is some evidence of an increase in demand for PPAs ▶ However: ✓ It is difficult from the evidence to differentiate between demand for

	PPAs generally (i.e. short and long term) and demand from independents looking for bankable offtakers. ✓ While the majority of suppliers reported an increase in demand, a number of large VIUs noted that demand for PPAs has actually dropped indicating that certain suppliers may be receiving more requests than others. ✓ It is also difficult to distinguish between indications of a rise in demand and *changing* nature of demand (i.e. maturity, financing solution, impact of banding uncertainty on pipeline) ▶ As such, while demand from independents for bankable PPAs may be marginally greater than before, this is unlikely to be a major driver of deterioration in terms.

4.9. A change in lender requirements

Summary

There is no doubt that there was a shift in credit conditions following the financial crisis in 2008, that has made it more challenging for independents to secure finance for projects. This has both directly and indirectly affected the allocation of risk in PPAs.

- **Reduced competition** - The financial crisis and the increased weight of financial regulation that has followed (i.e. Basel III, CRD IV) has made the lending community more risk averse and reduced the availability of 12-15 year money. This has shrunk the pool of banks willing and able to lend long term, which has no doubt affected the level of competition in the banking market.
- **Impact of the collapse of the syndication market** - In addition, with the collapse of the secondary / syndication market, independent project sponsors have had to secure financing through so called "club deals" involving a group of banks all of whom intend to lend and hold. With the reduced competition in the market, sponsors have generally found it difficult to maintain redundancy in these syndicates of potential lenders. This has reduced the ability of sponsors (and as a result PPA providers) to drive a greater level of project risk.

There is clear evidence that these changes in the lending market have driven changes in the nature of what constitutes a bankable PPA. These changes are set out in Table 17 below:

Table 17: Headline shift in lender requirements as to a "Bankable" PPA

Change	Explanation
Price floor	▶ While a floor has generally been a pre-requisite for long term financing since offtakers stopped offering fixed price brown-green bundles around 2005, we understand that prior to the financial crisis there were a limited number of lenders who had started to bank projects with less robust floors (in terms of their resilience on change in law).

	▶ However, following 2008 and the tightening of credit conditions, lenders have required protection from wholesale electricity price risk through a floor price that is subject to limited (if any) re-openers. ▶ This, together with the value of the ROC and other benefits, is used by lenders as the basis of the project's "firm revenues" against which debt is sized and leverage determined.
Limits on liability	▶ Banks also seem to have started to push for high limits of liability in the event of breach of contract by the PPA provider. ▶ This is normally a multiple of the floor price and is intended to ensure that the project is kept whole for a period of time while a replacement PPA is secured.
Change in law	▶ With the retrospective cuts in subsidy levels in southern Europe and the introduction of market reform in GB, both generators and VIUs have confirmed that banks scrutiny of change in law provisions has increased.
Offtaker Credit	▶ Increased risk aversion has driven a greater scrutiny by banks of offtaker credit quality, and the form and nature of credit support provided by potential offtakers (i.e. letters of credit and parent company guarantees).

Materiality

Classification	Justification
Limited effect	▶ While banks' requirements with regard to an acceptable allocation of risk in a PPA have no doubt changed since 2008, and securing finance has become more challenging, evidence from stakeholders seems to suggest that these issues predate the deterioration in the PPA market in 2010. ▶ As such, a change in lender requirements is unlikely to be the driving factor limiting the availability of a bankable route to market for independent generators. ▶ Indeed, responses from both independent generators and banks indicate that the requirements of a "bankable" PPA as set out in Section 2.2.2 have remained broadly consistent over the last three to five years. ▶ What is clear, however, is that deterioration in the PPA market has left independent project sponsors in an increasingly constrained position, with any attempt by a prospective offtaker to shift risk towards the project either resulting in an ever decreasing pool of available lenders and/or a decreasing project debt capacity, leverage and equity return.

5. ROUTE TO MARKET UNDER FIT CFD

The final objective of this paper is to assess whether independents will have a viable route to market with the introduction of the CfD. This objective has been approached by examining the requirements for a PPA for a generator under the CfD and the how the availability of PPAs might change when CfDs are implemented, with specific questions set out in Table 18 below:

Table 18: Evolution of Route to Market (RtM) under CfDs - framework of analysis

Requirement for a PPA	▶ How does a CfD change the risks that a generator is required to manage? ▶ Given this bundle of project risks, will independent generators using limited recourse finance still require a 15 year PPA? ▶ If so, what will that PPA look like?
Availability of PPAs	▶ To the extent that a long term PPA is still required: ✓ Will the availability of a CfD to generators remove some of the issues identified in the present market in relation to the availability of long term PPAs? ✓ Are there any residual issues that are likely to persist that will materially affect the availability of long term PPAs at reasonable terms to generators?

5.1. Requirements for a PPA

The CfD, by its very nature, changes the project risks that a generator is exposed to and therefore has the potential to change the way in which independents access the market. This section looks to explore whether a generator operating under a CfD will still require a long term PPA given the change in risk profile, and if so what that PPA or "route to market" agreement will look like.

5.1.1. Change in project risks with a move from RO to CfD

The move from the RO to the CfD undoubtedly changes the nature of the risks a generator is exposed to. It is therefore important to look at exactly how this position will change before assessing the viability of different routes to market. This is set out in Table 19 below.

Table 19 - Project Risks within a CfD Regime

Project Risk - RO		Status under CfD	Description
Availability risk		Unchanged	▶ Volume and availability risks are largely unavoidable risks and are specific to the technology type, its fuel source (or plant location) and its operational regimes.
Fuel / resource risk		Unchanged	
Long Term Price Risk	Power	Removed	▶ CfD indexes provide a guaranteed top up payment for every MWh produced against the market reference price, therefore long term price risk is removed. ▶ In addition, intermittents like wind generators are no longer exposed to wind cannibalisation risk, other than in extreme negative pricing scenarios. ▶ However, we note that biomass is still exposed to short/medium term price risk as the market reference price in a baseload CfD will include longer dated market indexes.
	ROCs	Removed	▶ With the move away from the RO, the generator is also no longer exposed to uncertainty in its level of subsidy (i.e. ROC price volatility). ▶ Although, this had been broadly addressed by the introduction of the headroom concept in any event (subject to entering into a PPA which allows the generator to access the full value of its ROCs).
Liquidity Risk	Power	Unchanged	▶ The CfD still requires the generator to sell its power into the market. ▶ Their driving motivation will be to sell that power at the Market Reference Price to ensure its all in revenues when combined with its top up payment will equal the strike price.
	ROCs	Removed	▶ With the closure of the RO to new plant and a move to a CfD, access to subsidy is no longer tied to the ability to find an offtaker for the ROCs.

Imbalance risk	Unchanged	▶ A generator will still be required to manage its output and forecast appropriately and will be exposed to the imbalance cost associated with any difference between its notified contracted position and its delivered output.

Therefore, on the basis that:

- availability risk will be managed under the generator's construction, turbine supply and operation and maintenance contracts;
- resource risk for intermittents will be managed at a project level with appropriate location and technology choices; and
- fuel risk for biomass generators will be managed under long term fuel contracts, then
- a generator under CfD is left with power liquidity risk[12] and imbalance risk to be managed in some way either by the generator itself or through an agreement with a third party – i.e. a PPA.

5.1.2. Management of residual risk

The next question is the magnitude of the residual risk that is left with generators and how independents will be required by banks to manage that risk in terms of their strategy on route-to-market?

In answering this question, it is worth noting that some market participants have suggested that the need for a route-to-market is ameliorated in a CfD world for the following reasons:

- As shown in Table 19 above, a generator is no longer required to market ROCs to a supplier with an obligation who can realise that value and take price risk both on the value of the ROCs and the power.
- In relation to an intermittent CfD only, liquidity risk on accessing the market is arguably less of an issue where a generator is not required to manage long term price risk as there is no need to access the forward curve, which is historically thinly traded. Instead, generators could in theory submit un-priced (or negative) bids into the day-ahead auction (which has higher levels of liquidity) and receive the market clearing price.
- Imbalance / volume risk for intermittent CfD indexed to a day-ahead price is arguably less of an issue as there is no need to hedge price exposure by selling uncertain volume forward contracts. Instead, a generator is required to sell all output at the day-ahead stage and manage the forecast risk from day-ahead stage to the actual delivery.

However, notwithstanding these improvements above, feedback from discussions with generators and the lender community suggests that independents will still require a 15 year PPA with a creditworthy

[12] We note that in this context we are treating the ability of a generator to access the market reference price ("**MRP**") as liquidity risk. This could equally be treated as *short term* price risk for a baseload CfD which is required to sell its output forward to access the season-ahead indices that are proposed to form the basis of the MRP.

counterparty in order to access limited recourse debt. The reasons for this are as set out in Table 20 below.

Table 20: Reasons why lenders are likely to continue to require a 15 year PPA

Issue	Description
Cost of accessing the market	▶ Typically, independent generators do not have the energy trading assets, systems or personnel to allow them to trade their generated electricity. ▶ A number of respondents highlight the fact that to do so would require a fixed capital and operational investment which is simply not a viable proposition for all but the largest utility scale installations. ▶ For baseload CfDs which have to access the forward price this cost increases as the collateral requirements increase.
Risk of continuing access to the market	▶ While some respondents highlight that the day-ahead market is relatively liquid and an un-priced bid submitted into the auction would guarantee the market reference price for intermittent generators, those on baseload CfDs (i.e. biomass) with a MRP based on a basket of indices will find it more challenging to access a more thinly traded bilateral forward market. ▶ In addition, respondents highlighted a general perception that there is a not an insignificant risk that liquidity in the day ahead market may dry up and that the ability of any generator to access this price for the duration of its CfD is not guaranteed. ▶ A good summary of the financial community's position in this regard is a quote from the Low Carbon Finance Group in response to DECC's call for evidence: *"…in the absence of a move to an institutionalised guaranteed access to the power market for all generators through, for example, an underlying reform to the electricity market, bankable PPAs will continue to be an absolute requirement of third party finance providers."*
Ability to manage imbalance risk	▶ There is a perception that the cost of imbalance is increasingly uncertain and as such, notwithstanding the fact that the lenders are no longer exposed to long term price risk, they may still require the generator to fix this uncertain cost for at least the tenor of the debt, especially for wind generators.

5.1.3. What will this new CfD PPA look like?

Independent generators may therefore still need to secure a long term PPA or route to market agreement with a tenor of 15 years which provides a trading service, guaranteed market access at a forecastable price (that is as close as possible to the market reference price) and manages imbalance at a fixed cost. This agreement might look something like that set out in Table 21.

Table 21: Potential route-to-market agreement under CfDs

Component	Description
Counterparty	▶ PPA provider has balance sheet and credibility to get banks comfortable that it is an insolvency-remote counterparty (i.e. will be there for 15 years).
Tenor	▶ As discussed above, at least initially, this will probably still need to be 15 years (in particular for wind) given the perception that a generator's imbalance costs are highly uncertain, along with its ability and cost of accessing the market.
Reference price	▶ Guarantees the generator access to the market reference price in its CfD for every MWh produced (less fees and discounts).
Trading fee	▶ Charges the generator a cost for trading / collateral / administrative costs of providing a route to market - this might be variable or fixed or a combination of both. ▶ Prices in the risk to the offtaker of accepting liquidity risk. ▶ Includes a profit margin for providing the services.
Imbalance Fee	▶ Includes a charge for taking imbalance risk away from the generator. ▶ This might be priced on a £/MWh basis, or on a fixed % discount against the electricity price. ▶ Might be a combination of both with fixed charge in the short to medium term flipping to a fixed discount in later years.
Change in law risk	▶ Passes through in relation to adjustments to the strike price which relate to the changes that affect the PPA provider's position in relation to the provision of services. ▶ In relation to all other change in law passed through under the CfD, risk sharing provision that akin to the change in law provisions already in the existing PPAs

5.2. Impact of existing constraints on the PPA market

5.2.1. Overview

Given the conclusion set out above that a generator may still require a long term PPA with the characteristics set out in Table 21 above (at least initially), the key question is whether this product will actually be available to participants at a viable price.

Table 22 below sets out a summary of how a move to CfDs may affect the issues currently materially affecting the availability of bankable PPAs, as identified in Section 4 previously (i.e. those identified as limiting or contributory factors).

Table 22: How have market issues been affected?

Component	Status
Causal Factors	
Reluctance to take long term wholesale electricity price risk	Removed
Reduction in appetite for long term renewable power	Uncertain
Balance Sheet treatment	Reduced impact
Reluctance to take change in law risk	Uncertain
Contributory factors	
Reluctance to take Imbalance Risk	Unchanged
Barriers to entry to the provision of long term PPAs	Reduced impact

5.2.2. Removal of long term price risk

The central design feature of the CfD is that it removes long term price risk from the generator and as such a PPA with long term wholesale electricity price protection in the form of a floor should no longer be required. As such, one of the key constraints on the availability of bankable PPAs to generators should be removed. However, that is not to say that the CfD removes *all* price risk as the generators will still need to access the market reference price. For intermittent generators the MRP is proposed to be a day-ahead index, so the extent to which they can access that price will depend on the trading costs of participating in day-ahead auctions along with the imbalance cost associated with managing day-ahead to delivery forecast error. However, for biomass that will be supported under a baseload CfD, a PPA will need to take a certain degree of short / medium term price risk as the offtaker will need to guarantee a fixed discount against the market reference price (which is likely to include month ahead/season ahead).

5.2.3. Incentives on incumbents to buy renewable power

The move from the RO to CfDs clearly removes the short term constraint identified in Section 4.3 above as the appetite of the big suppliers to enter into PPAs is no longer driven (in part at least) by their requirement for ROCs. Indeed, as identified in section 5.2.7 below, a move away from the RO potentially opens up the pool of potential PPA providers beyond the existing incumbent VIUs in any event.

However, a number of respondents have highlighted the fact that the phase out of the RO also removes two drivers for large suppliers to invest in or contract with renewable power, representing a significant proportion of the existing pool of bankable offtakers. These are set out in Table 23 below.

Table 23: Incentives on large suppliers to invest in or contract with renewable power under the RO versus CfD

Driver	Description
Economic Incentives	▶ The CfD removes an economic incentive to buy renewable power. This is driven not by the obligation to present a proportional share of ROCs at the end of each year (which could be met by paying the buy-out price) but because the cost of the buy-out is priced into the tariffs charged to consumers and therefore any discount of the ROC price achieved through a PPA is a profit driver for the supplier of contracting in the renewable asset class. ▶ In this way the reasonable question being asked is what would be the incentive on the large suppliers to offer a long term route-to-market / balancing service as highlighted in Section 5.1.3 above in the absence of this value driver?
Strategic Drivers	▶ The second issue raised by generators is the extent to which being seen to be strategically aligned with GB government's energy policy was a driver for big six involvement in the renewable generation sector generally, and the long term PPA market in particular? ▶ While the RO was never a hard "obligation" on suppliers, as they could always just pay the buy-out price, it is arguable that each supplier's RO exposure did provide a centrally administered signal of the UK government's aspirations in relation to renewable penetration - that went above and beyond the actual economic incentive of reducing the buy-out cost highlighted above.

In view of the potential change in incentives and drivers with a phase out of the RO, the key question is therefore what in a CfD world might drive a large supplier to offer long term bankable PPAs to independent generators? The key questions and considerations in this regard are as follows:

- **Hedging levy exposure** - One potential driver that has been identified is that large suppliers might be incentivised to write PPAs with CfD plant to enable them to hedge their exposure to the CfD levy. Our view is that this is unlikely to materialise given that they could just as easily do this by trading in the day-ahead market without the increased volumetric risk of entering into a long term PPA with respect to specific intermittent plant.

- **Strategic priorities & fit** – It may be questionable as to whether a bankable long term route to market / balancing service under the CfD aligns with the strategic priorities of a large supply business. One respondent highlighted that the CfD will not offer any price certainty for its "sticky" supply base, which may reduce its attractiveness as a tool to hedge retail prices (although we note that PPAs today do not necessarily give suppliers this price certainty either as fixed price structures are uncommon). Secondly, suppliers have highlighted the fact that increased competition in their retail base combined with uncertainty over long term demand growth makes contracting renewable capacity under long term agreements with uncertain volumes of generation less attractive. This might be accentuated by the fact that suppliers have increasingly invested in their own assets "soaking up" the tranche of volumes implied by their certain or "firm" retail base.

In view of the observations above, it would seem that the appetite of suppliers (and indeed any other potential PPA provider) to provide PPAs to generators under the CfD will be determined by an assessment of the earnings (in terms of PPA discounts) of providing that product relative to the costs and risks it is required to assume. With CfD strike prices only recently being published, it is not entirely clear how this will evolve. The critical question is what discount on the electricity price will a supplier, (or any other offtaker) need to make the risk reward trade-off for taking long term imbalance and liquidity risk away from the generator an attractive proposition? This will ultimately be driven by the level of uncertainty in long term imbalance costs, the PPA costs priced into the strike price and the level of competition from new entrants (see Section 5.2.7 below).

It is instructive in considering this question to examine experience in other markets which do not have a green certificate scheme (i.e. a regime that places an "obligation" on suppliers to procure specific volumes of generation) but require generators to secure a route to market for their output. Table 24 below sets out what insights can be drawn from taking Germany as a case study.

Table 24: Incentives on PPA provision in the absence of a green certificate regime in Germany

Example	Lessons learnt
Introduction of "direct marketing"	▶ To encourage greater participation of renewable energy plant in the energy market, specifically to reduce the cost of balancing and move away from central dispatch of renewable by the TOs, Germany has introduced a "direct marketing" incentive for renewables on the fixed FIT. ▶ This allows a generator to opt out of the fixed FIT and instead market its power in the electricity market directly. In much the same way as the CfD, the generator receives a top up payment against the fixed FIT level based upon assumed electricity revenue, as well as a fixed premium or "management rate" to compensate the generator for the additional balancing and trading costs of actively participating in the market.
Market response	▶ This has spawned a growth in "direct marketers" who offer a route-to-market service to generators in return for a slice of the additional revenues, (i.e. the management fee and beating the assumed market price for the purposes of calculating the top up). ▶ Over 80% of wind plant have opted into this scheme, with one leading new entrant aggregator taking one of the largest market shares of this nascent

	market.
Key distinctions with the GB market	▶ This example demonstrates that route-to-market services will be provided where there is a clear incentive to do so (i.e. in the absence of a green certificate scheme). ▶ However, there are two key distinctions that are worth drawing between this example and the UK generators operating under a CfD: ✓ Firstly, liquidity in the German markets is much deeper, in particular in the intra-day spot market making it easier for "direct marketers" to trade out imbalance volumes prior to gate closure. ✓ Secondly, generators in Germany are always left with the option of opting back into the fixed FIT and as such do not need to contract with PPA providers for the tenor of the debt for the purposes of satisfying lenders that they have a guaranteed route to market. As such, the risk being assumed by PPA providers in this context is significantly less than PPA providers in the UK, who will need to provide a guaranteed route to market and fixed imbalance exposure for at least 12-15 years. Moreover, lender scrutiny of offtaker credibility and credit is likely to be less rigorous on the basis that they are likely to size their debt off the guaranteed fixed FIT rather than the additional revenue that can be secured through direct marketing.

5.2.4. Balance sheet / credit rating treatment

The removal of the requirement for a minimum price floor significantly changes the level of risk being assumed by an offtaker under a CfD PPA. We understand this may have a positive effect when it comes to the balance sheet / credit rating impact that these long term contracts will be given.

- ***Lease accounting*** – From a lease accounting perspective, we understand that the removal of a price floor is expected to mean that PPAs are less likely to be classified as a lease in the first place. Moreover, in the event that a CfD PPA is classified as a lease, we understand that the likelihood of it being classified as a financial lease requiring consolidation is significantly reduced on the basis that a CfD PPA does not transfer substantially all the risk and reward associated with the output of the plant. Having said that, it is arguable that lease accounting would have becomes less of an issue in any event, regardless of whether a floor price was required or not, on the basis that the new accounting rules due to be published in spring 2013 will most likely remove the requirement to classify a PPA as a lease on the basis that it has a floor price.

- ***Credit rating treatment*** - The credit rating agencies are likely to continue to look through the lease accounting rules to the financial substances (i.e. the way it allocates risk, the exposures entailed and the credit worthiness of the entities involved) of any long term arrangement. Having said that, credit rating agencies might view the removal of price risk inherent in a floor as removing significant risk of financial loss - therefore reducing risk of imputed debt. However the approach of the credit rating agencies is still to be confirmed. The key issue is likely to be their view of the magnitude of the risk being assumed by a PPA provider under a long term 15 year arrangement – in particular:

- ✓ Is a floating payment obligation actually a fixed payment obligation if there is no underlying liquidity in the wholesale electricity market? This is likely to be a more significant risk for those new entrant aggregators who do not have recourse to a "sticky" customer base to pass through any payments in the extent that wholesale liquidity risk dries up.
- ✓ What is the extent of the imbalance risk and what is the size of the discount on the electricity price the offtaker is receiving in return (i.e. level of imbalance risk / return)?

It therefore seems that a move to CfDs and the requirement for an index linked PPA with no price floor may ameliorate the credit rating impact of participating in the long term PPA market. However, 15 year commitments underwriting a generator's long term imbalance and liquidity risk are still likely to have some, yet to be determined, impact on a PPA provider's credit rating.

5.2.5. Regulatory and policy uncertainty

The change in law exposure under a CfD has no doubt changed from a generator's position under the RO. However, the extent to which this will affect the level of change in law protection that is required through a CfD PPA is not yet clear. This section firstly explains how a generator's aggregate change in law position will change under a CfD before the looking at how this may affect the availability of PPAs.

Change in law risk – CfD vs. RO

The move from the RO to the CfD should remove some change in law risk from the generator which should have an impact on the extent of risk transfer required under the PPA. This is for two reasons:

- Firstly, the proposed CfD actually provides for strike price adjustments in relation to a change in law that affects the cost base or revenues of just that generator or that class of generator (i.e. all CfD plant, same technology etc.) – i.e. specific / discriminatory changes in law.
- Secondly, the generator is no longer exposed to structural changes to the market that reduce the wholesale electricity market (for example, the capacity market, market splitting[13]).

However, having said that, the structure of the CfD does potentially expose the generator to new change in law risk which it was protected against under the RO – namely in relation to a general change in law that affects the cost base of all generators equally (or only affects a class of generators indirectly or consequentially). Under the RO, a change in law that affected a large part of the market was likely to be priced into the wholesale electricity price thus keeping the generator whole through increased income. However, for a CfD generator, whose long term revenues are capped at the strike price, no such safety value will exist.

Change in law risk – allocation in a PPA under a CfD

While it is clear that the allocation of change in law risk will be different under the CfD, the market still seems to be assessing whether a generator's position is better or worse. Moreover, it is not clear what impact these changes will have on the level of change in law risk that offtakers will be asked to absorb through a long term bankable PPA.

[13] Provided the drafting of the CfD allows for the possibility of the market reference price changing for different zones.

Change in law provisions in the CfD are only intended to deal with the scenario where a change in law affects the balance of risk and reward between the parties. For example, under the RO, a change in law that affects electricity prices would increase the risk attached to providing a floor. In this way, to the extent that the floor is to be maintained (as would be required by banks), the discounts that the offtaker puts on the electricity price it offers would need to increase. The same is true with a change in imbalance arrangements that made it more expensive to manage the output of a plant. To the extent covered by change in law, this could trigger a re-opener on the discounts. In this way, the change in law provision looks to preserve the commercial balance in relation to risks *actually managed under the PPA.*

As a CfD transfers certain risks to the consumer, the risks that will need to be managed under the PPA should therefore reduce (as discussed above). As such, theoretically the change in law provisions will most likely deal only with those risks transferred – which broadly speaking will amount to cost of imbalance and the cost of accessing the market. While this could make change in law less of a barrier to the availability of PPAs, it should be noted that the basket of change in law risk that the generator is exposed to more generally will remain. Whether banks will be able to get comfortable with a greater level of change in law risk at the project level will remain to be seen and some risks may still need to be managed through the PPA, notwithstanding the fact that the change in law might not specifically relate to the risk and reward in relation to the services actually being provided under that PPA.

5.2.6. Imbalance risk

As explained above, imbalance risk will remain a potential issue in a world of CfDs as a generator is still required to manage this risk. As the perception is that this risk is uncertain, banks will require firm pricing for the mitigation of this risk for at least the tenor of the debt, therefore preserving the existing requirement for a long term PPA. This will in effect have two impacts:

- Firstly, the cost of pricing imbalance risk over 12-15 years will need to be factored into the strike price.
- Secondly, there may be a limited number of offtakers willing and able to price imbalance risk over such time scales (see section 5.3.7 below in relation to barriers to entry).

The extent to which this risk manifests itself in terms of restricting an available route to market will, however, very much depend on the technology in question. Arguably, for solar or biomass where the imbalance risk is less significant, pricing imbalance costs may be less of an issue. As such, it seems that it is primarily in relation to wind projects that imbalance risk could manifest itself in the way described above.

5.2.7. Barriers to entry to the provision of long term PPAs

A move to CfDs will remove some of the barriers to entry for new entrant aggregators looking to provide long term PPAs to independent generators (as identified in Section 4.7 above), since:

- Firstly, new entrant PPA providers will no longer be required to take a view on their ability to realise fair value for a long ROC position.
- Secondly, for an intermittent CfD at least, liquidity risk should be less of an issue for new entrants as they will not need to manage price risk by hedging along the forward curve which is at present thinly traded.

However, there are still a number of open questions that may continue to restrict the level of competition in the provision of long term PPAs under CfDs (some of which have already been touched on):

- Firstly, for intermittents with significant forecasting risk (e.g. wind) the level of uncertainty over long term cash out prices and imbalance risk could limit the number of players willing and able to price that over a 12-15 year period required for debt financing. There are of course potential contracting structures that could emerge that transfer an element of the short term imbalance risk back to the project, however the bigger issue for PPA provider is likely to be the longer term uncertainty. This issue is exacerbated by the fact that liquidity in the intra-day market is poor at present which is likely to impact new entrants' ability to provide a balancing service at competitive price (as in a worst case scenario they will have to take on the full exposure between day-ahead forecast and actual outturn).

- Secondly, wholesale electricity liquidity could still remain an issue for a new entrant looking to provide PPAs to biomass generators. This is because, to offer a bankable product, the offtaker will probably need to be able to guarantee the market reference price (less a discount) which will require it to manage its short / medium term price risk. As the forward curve is relatively thinly traded at the moment, it may be difficult for new entrants to enter the market and provide this product.

- Finally, with no institutionally enshrined guaranteed route to market, lenders are still likely to retain the same stringent credit requirements in relation to acceptable offtakers. While it might be argued that an offtaker is assuming less risk under a CfD PPA and therefore the risk of insolvency is significantly reduced, banks are still likely to view the risk of being exposed to long term PPA liquidity and imbalance cost uncertainty in the event of an offtaker insolvency as significant. As such, lenders will most likely continue to look beyond the short-term business risk / opportunities to the entity's long term standing and strategic interest in the GB electricity sector. There is therefore a significant risk that credit committees will prefer offtakers like the big VIUs and a small number of other European utilities, which could leave the industry with the same structural limitation on the PPA counterparties that existing under the RO.

ANNEX 1 - ROLE OF A PPA / OFFTAKE ARRANGEMENT

A PPA or offtake agreement can insulate a generator from one or more of a number of key project risks. This annex looks to firstly set out the bundle of project risks that a generator is exposed to generally and then look at how different PPA products can provide protection from one or all of these.

1. Key Project Risks

A summary of the main risks that a generator is exposed to are as set out in Table 25 below:

Table 25 – Key project risks

Project Risk	Nature of Risk
Availability risk	Availability risk is an earnings risk arising from unavailability of generation plant due to, for example, technical failure or unscheduled outage.
Volume risk	Volume risk is an earnings risk arising from uncertainty of available generation capacity due to unavailability of resources (i.e. wind speeds, solar radiance levels, availability of biomass fuel)
Liquidity Risk	Liquidity risk relates to the risk that a generator cannot access the market price for every MWh of power it produces or every benefit that accrues to the power plant
Price risk	Price risk is an earnings risk stemming from volatility and changes in the wholesale price of electricity and green benefit subsidies.
Profile Risk	This is a risk that is particularly pertinent to intermittents like wind and solar. It relates to the risk that high penetrations of correlated generators will effectively reduce the power price in the periods when the generator is actually generating electricity. This dynamic is known as price "cannibalisation".
Imbalance risk	Imbalance risk relates to the threat of imbalance penalty costs that a generator would accrue it they cannot meet their contracted power generation position
Change in law risk	There is a risk premium associated with uncertainty in the regulatory regimes that govern the present and future energy markets. Changes in law can negatively affect a project's business case such that the commercial terms no longer represent the allocation of risk and reward agreed at the outset.

2. PPA Structures

A PPA or offtake agreement can insulate an independent generator from some of the risks described in Table 25 above. The range of products can be broadly classified as follows:

Table 26 – PPA Structure Options

Structure	Summary
Tolling Agreement	The independent generator is paid an agreed fee for making the generation plant available to the offtaker for the purposes of generating electricity.
Fixed Price/Floor	The independent generator agrees to supply all power generated by the plant and the offtaker agrees to buy that power and pay a fixed price or a minimum price per unit of output.
Route to Market	The independent generator agrees to supply all power generated by the plant and the offtaker agrees to buy that power and pay the prevailing market price (less a trading fee) for each unit of output.
Trading Style	The PPA provider agrees to manage and sell the power produced by the independent generator, and to allow the generator to hedge price risk by contracting future positions

A summary of the risks mitigated by the differing PPA structures is given in Table 27 below.

Table 27: Management of project risks

Project Risk	Tolling Agreement	Fixed Price/Floor	Route to Market	Trading Style
Availability risk	×	×	×	×
Volume Risk	✓	×	×	×
Liquidity Risk	✓	✓	✓	✓
Price Risk	✓	✓	×	×
Profile Risk	✓	(✓/×)	(✓/×)	×
Imbalance risk	✓	✓	✓	(✓/×)
Change in law risk	(✓/×)	(✓/×)	(✓/×)	(✓/×)

3. Market segments

The PPA/offtake market can be further classified by the tenor of the PPA being sought, namely a categorization between short and long term PPAs. This report focuses on the long term PPA market of independent renewable generators, but as the long and short term markets interact it is important to note the interrelations and distinctions between the two. Table 28 below summarises some of the differences.

Table 28 - PPA Contract Types

	Short Term Market	Long Term Market
Agreement	1 – 5 years	10- 15 years

tenor		
Agreement Structure	Route to Market, Trading style	Tolling Agreement, Fixed Price
Agreement Purpose	Value maximisation	Long term revenue certainty to underpin project finance structure
	Medium term risk management	
Types of Generator	Operational, Balance sheet funded, Utility scale	New build, Utility Scale, Project Financed
	Small scale FiT opting out of generation tariff	
	Older plant in "merchant tail"	

ANNEX 2 - RESPONDENTS TO DECC'S PPA CALL FOR EVIDENCE

Table 29 – Respondents to DECC's PPA Call for Evidence

Group	Party
Independent Generators	Horizon IREGG Mainstream Welsh Power Renerco Dalkia Cooperatives UK Banks Renewables Dong Energy ESBI Airvolution AES REG Windpower Ltd Community Windpower Ltd Eneco West Coast Energy Ltd Velocita InterGen Infinis Mitie Asset Management

	Falck Renewables Wind Ltd Eggborough Power Ltd Forth Energy Estover Energy EDP renewables Cradle Infrastructure
VIUs	SSE Scottish Power EDF Energy E.ON RWE npower Centrica Energy Ltd
Aggregators	Statkraft Smartest Energy Utilyx
Small suppliers	Ecotricity Good Energies
Sleeved PPA purchaser	Scottish Water Airproducts
Financiers	LCFG
Associations	CHPA Carbon Capture and Storage Association Renewable UK Renewable Energy Association Scottish Renewables

Others	Cornwall Energy NFPA Hove Civic Society's renewable Infrastructure Group Mayor of London Electricity Storage Network National Grid Community Energy Scotland & Highlands and Islands Enterprise Friends of the Earth Ernst & Young

ANNEX 3 - FURTHER DETAILS ON OFGEM'S SCR PROPOSALS ON ELECTRICITY BALANCING ARRANGEMENTS

Ofgem is looking at a variety of different interventions under its Significant Code Review (SCR) in relation to balancing arrangements in the GB market. Some of these changes could increase the sharpness of the cash-out signal, and potentially increase the risk associated with providing a balancing service to independent generators, while others may potentially reduce this risk. These are set out in sections 1 and 2 below:

1. Proposed reforms that may increase cost of imbalance

The reforms include a number of proposals that would in effect "sharpen" the cash-out signal and therefore the increase the cost to a PPA provider of accepting imbalance risk in relation to intermittent output. Broadly speaking, these areas as follows:

- **A more marginal cash-out price** - Current cash-out prices are calculated by averaging the 500MWh most expensive trades made by the SO to balance demand and supply. Ofgem is considering a move to base this calculation on the marginal volume – or a more marginal volume instead.
- **Sharpening the allocation of reserve cost -** At present, the cost of contracted reserves that the SO bids into the balancing mechanism does not take into account its true cost, because the availability fees are allocated into periods where reserve was historically used, instead of targeted solely at the periods in which it is actually used. Instead, Ofgem is looking at new ways in which the targeting of all reserve costs could be made more cost reflective.
- **Attributing a cost to non-costed actions** - Ofgem is looking at whether it is appropriate to continue to calculate cash-out prices in such a way that does not reflect the cost of all actions taken by the SO. For example, this could include attributing a price to demand reductions when consumers are disconnected, which are not currently included in the calculation.

2. Proposed reforms that may decrease the cost of imbalance

It should be noted, however, that while the SCR proposals could significantly increase the cost of balancing, there are a number of other proposals that may have the opposite effect. These are as follows:

- **A move to a single cash out price** – This would remove the current one sided exposure whereby a generator is penalised in the event that it is out of balance in the "wrong" direction (i.e. the both the generator and the wider system is either long or short), but does not receive the benefit where it is out of balance in the a direction that actually helps the system (i.e. the generator is long in a half hourly period when the system is short, or the generator is short in a period where the system is long).
- **Single or separate trading accounts** – Ofgem is looking at the merits of allowing parties with both generation and supply businesses to net their opposite balance positions from the two

trading accounts. Given that currently VIUs must balance both their generation and supply sides separately, this proposal should reduce imbalance risk for vertically integrated players.

- **Timing of gate closure notifications** – Ofgem are considering whether there could be benefits of decreasing the contract notification period prior to gate closure to reduce the period of time between notifying forecasted volumes and the actual delivery period. This should have the effect of reducing forecast error and allowing extra time for balancing actions for PPA offtakers managing intermittent output.