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Offtaker of Last Resort Advisory Group Discussion Paper 5.1: COST ASSESSMENT

Overview

Headlines:

- We have previously considered a hybrid allocation mechanism for the OLR that would combine a regulatory allocation process when generators first entered backstop PPAs with competitive retendering if a further backstop PPA was required.

- For this hybrid allocation, Ofgem would be required to estimate a backstop offtaker's costs and benefits associated with entering into a backstop PPA in two situations (a) to determine the compensation paid to an offtaker on the first administrative allocated backstop PPA and (b) to set the reserve price for subsequent auctions.

- We now judge that, due to the complexities involved for Ofgem in assessing these aspects, **regulatory allocation may not be practicable** – a view strengthened if baseload generators are eligible for the OLR.

- We are therefore minded to **use a purely competitive allocation process with a much simpler levelisation process** that would not require an independent cost assessment.

- However, would are minded to **retain a 'reserve power' to direct Ofgem to allocate a generator to an offtaker through a regulatory process** if there was risk of a competitive approach failing.

Key Questions:

Q1: Does the Group agree with our assessment of how each of these costs and benefits might be assessed under regulatory cost assessment , and the difficulties associated with doing so?
Q2: Does the Group agree that the risks to offtakers and/or consumers of using a regulatory cost assessment is likely to be too high?
Q3: Do you agree that a purely competitive process could be bankable if credit-worthy offtakers were required to submit bids as a condition of their supply licences, and generators were guaranteed to be allocated an offtaker within a minimum time-frame?
Q4: Do you agree that (a) a 'no regrets' notification period of 2-3 months would not increase the collateral requirements in open market PPAs; and (b) offtakers should be able to determine what bids to make in a competitive process within the space of a week?
Q5: Do you agree that the risk to consumers from uncompetitive auctions is mitigated by the factors outlined in the relevant section?
Q6: Do the Group agree that a purely competitive allocation mechanism has potential, and should be worked up in more detail?
Q7: Do the Group agree that a reserve power to allocate generators on a regulatory basis should be retained if pure competitive allocation is implemented?

Introduction

This paper is concerned with determining how each offtaker's profit or loss, under the backstop PPA (bPPA) to which it is party, would be calculated ('cost assessment'). A separate paper considers the process for levelising the total costs of the OLR mechanism across suppliers.

There are two broad approaches to cost assessment, depending on the method for allocating a generator seeking a backstop PPA to a backstop offtaker:

1. Regulatory cost assessment, in which Ofgem determines the offtaker's costs and benefits associated with entering into a backstop PPA with a generator; or
2. Competitive cost assessment, in which offtakers make their own assessment of costs and benefits and reflect this in the amount they bid in a competitive allocation process.

The hybrid allocation process, discussed at a previous OLRAG, would be formed from a combination of these cost assessment methods, with initial allocation through a regulatory process, but subsequent allocations (where a generator requests a further bPPA after expiry of its initial bPPA) through a competitive process.

Specifically, this paper considers:

- How regulatory cost assessment would need to operate under a hybrid allocation mechanism, in order for it to be a robust reflection of costs and benefits to a backstop offtaker.
- Potential methods for doing this, and the challenges involved.
- A review of the allocation mechanism in light of the regulatory cost assessment requirements.

Assessment Criteria

In determining the approach to the cost assessment process it should, where possible, accurately reflect the costs incurred and benefits received by an offtaker while maintaining incentives to minimise the cost to consumers of performing that role.

Specific proposed assessment criteria are set out in Table 1 below.

Table 1: Assessment criteria

Criteria	Description
Minimise system costs	▶ The approach to calculating offtaker P&Ls should retain the correct incentives for offtakers to forecast and balance optimally.
Impact on suppliers	▶ Minimise the risk that the cost assessment process significantly underestimates the actual cost of providing a backstop PPA and leaves individual offtakers out of pocket.
Potential for market distortions	▶ Minimise the risk of over compensation such that it could distort the wider retail market.
Practicality and cost of implementation and administration	▶ Cost assessment methodology should be sufficiently simple to minimise cost of implementation and administration and allow assumptions to be updated efficiently.
Legal risk and potential compliance cost	▶ Cost assessment should be fair, transparent and proportionate to minimise risk of challenge.

Hybrid approach

General principles

The hybrid allocation mechanism for the OLR (as previously articulated at OLRAG meeting 1) would combine a regulatory allocation process when generators first entered backstop PPAs, with competitive retendering if a further backstop PPA was required. In summary, the hybrid approach would work as follows:

- Once a generator declares to Ofgem the need for a bPPA, the generator is matched with an offtaker on a regulatory basis
- The offtaker is paid (or pays) an amount per MWh generated to reflect its loss or profit under the bPPA, as determined by Ofgem using a regulatory cost-assessment process.
- On the expiry of this initial regulatory-allocated bPPA, Ofgem would run a tender in which potential offtakers would bid a management fee to enter into the next, and all subsequent, bPPAs.
- To protect against gaming or limited competition, a reserve price will be set by Ofgem at the level of the amount determined through the regulatory cost assessment process.
- If the reserve price is not met, the bPPA would be reallocated to one of the mandatory offtakers on the same regulated basis as the initial bPPA.

The hybrid approach potentially delivers the following key benefits:

- It allows generators to be assigned a bPPA rapidly, thereby minimising their collateral requirements under generators open market PPAs;
- It leverages the benefits of competitive allocation following initial entry into the OLR when there is time enough to run an open and competitive tender.
- It protects consumers from the risk of non-cost reflective bidding by including a reserve price mechanism.

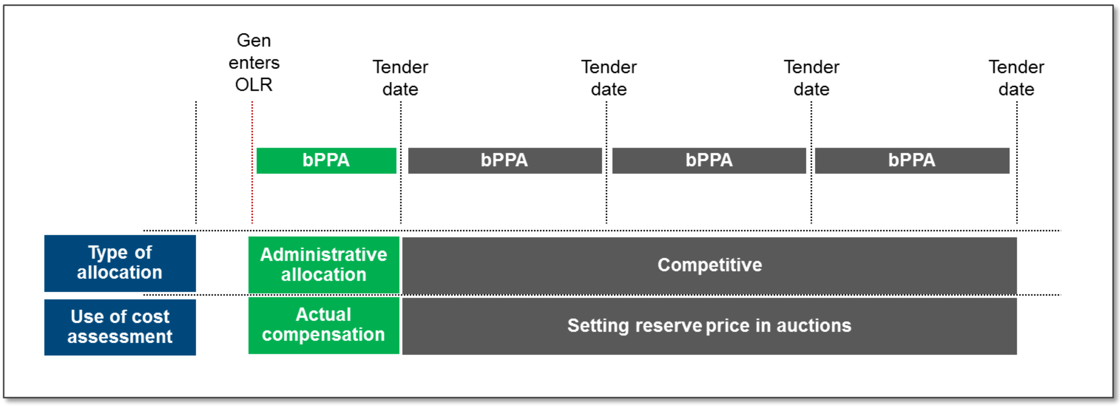
However, it also has some potential drawbacks:

- it requires a regulatory cost-assessment process, which risks over or under-compensating suppliers, which could either increase costs to consumers or negative impact on suppliers' profitability and / or credit ratings;
- if the reserve price is too low, there is a risk that no offtakers will participate in the competitive tender.

Cost assessment under the hybrid approach

Under the hybrid approach a single cost assessment exercise would be carried out for both (a) compensating initial bPPA providers and (b) setting the reserve price for the auction of all subsequent PPAs. This is shown in Figure 1 below.

Figure 1: Cost assessment within a hybrid allocation process



This regulated cost assessment would be performed by Ofgem and would need to quantify the following factors:

- The costs to offtakers of performing the obligations under the bPPA
  - Imbalance costs arising from imperfect forecasts
  - Costs of trading in the power markets (trading systems, staff, etc.)
  - Cost of carry incurred when payments to generators precede reimbursement
  - Cost of PPA credit support where an offtaker does not already meet the credit requirements
  - Cost of accessing liquidity in the power market (i.e. the bid offer spread)
  - Outage / default costs requiring offtakers to rebalance their positions

- The benefits received by offtakers under a bPPA:
  - Value of the electricity itself
  - Levy Exemption Certificates (LECs) benefits accruing to offtakers
  - Embedded Benefits that pass to offtakers (e.g. avoided transmission costs)
  - Balancing mechanism (e.g. curtailment) allowed under the bPPA terms and conditions that may provide additional revenue to offtakers Any interest accrued as a result of benefits received under the bPPA preceding payments to Ofgem

Set out in Annex A is a strawman approach to how such a cost assessment process might be carried out. This methodology has been developed within the following constraints:

- To allow it to be used to set a reserve price, it is an *ex ante* not an *ex post* process;
- To minimise the risk that mandatory offtakers are not significantly undercompensated (either on initial allocation or where an auction does not clear below the reserve price), the methodology assumes worst case assumptions for those factors that are outside an offtaker's control.
- To ensure that offtakers are sufficiently incentivised to minimise costs, the methodology assumes "best in class" in relation to those factors that are within the control of the offtaker.

Key issues and conclusions

Annex A explains in more details some of the specific issues and difficulties with developing a cost assessment process for a hybrid allocation process as articulated above. However, in summary, we believe that there are a number of issues with this approach that may make it highly complex to implement and very difficult to ensure it meets the objectives above:

- Complexity arising from the fact that many costs faced will be generator/offtaker specific;

- Requires use of historical data for the purposes of setting compensation in the next period which may not be a reliable proxy (without more sophisticated and complex statistical techniques);
- There is a lack of robust (and unbiased) data sources on certain costs (e.g. particularly with regard to estimating forecast error);
- In order to be used as an effective reserve price, the cost assessment process cannot assume an "average" cost. However, by regulating costs by reference to the "worst in class" for factors that are outside of an offtaker's control (e.g. generator outage performance, correlation of error with the system), the risk of over compensation in the initial bPPA (prior to competitive allocation) is material;
- The alternative of developing two separate cost assessment process for the purposes of determining compensation under the initial PPA and the reserve price on all subsequent re-allocations is unlikely to be a viable approach given the administrative burden and complexity involved.

Overall therefore, we judge that any form of regulated cost assessment, and as a result any form of hybrid allocation mechanism, comes with a high risk of error and significant administrative complexity, and therefore may not be viable.

Q.1 Does the Group agree with our assessment of how each of these costs and benefits might be assessed, and the difficulties associated with doing so?
Q2: Does the Group agree that the risks to offtakers and / or consumers of using a regulatory cost assessment is likely to be too high?

Competitive allocation

Allocation Interplay

Given the complexity of the regulatory cost assessment process, as set out in Annex A, we are reconsidering whether a pure competitive allocation mechanism would be viable. In this scenario, offtakers would judge for themselves the likely costs and benefits of entering into a backstop PPA with a generator, with no need for any assessment by Ofgem.

The key issues that we identified with a pure competitive allocation process were:

1. Whether it could be considered 'bankable'.
2. The time taken to establish and run a competitive process (especially initially) and the impact this could have on the cost and level of collateral that would be required by generators in their open market PPAs as a result.
3. The risk that the process would be uncompetitive, with offtakers submitting very high bids and thus increasing costs to consumers.

We have considered these in more detail, and now believe that they are either not material or can be mitigated through the design of the process.

Bankability

Following discussions with lenders, we believe that as long as a number of credit-worthy offtakers are required to submit bids as a condition of their supply licences, and there is a guarantee that the generator will be allocated an offtaker within a defined period of time, a purely competitive process can be bankable.

Q3: Do you agree that a purely competitive process could be bankable if credit-worthy offtakers were required to submit bids as a condition of their supply licences, and generators were guaranteed to be allocated an offtaker within a minimum time-frame?

Time to run a competitive process

We were concerned that it might take some time to run a competitive process, especially in the initial allocation, due to the need:

- for Ofgem to put in place the appropriate mechanism; and,
- to give offtakers a reasonable period of time to assess the characteristics of a generator seeking a backstop PPA in order to determine what price to bid.

The potential issue with having a long period before a generator can access a bPPA is that it could increase the length of time that they would need collateral cover for in their open market PPAs, increasing costs. However, there are two separate periods of time to consider, which have different impacts on the level of collateral required:

1. How much notice a generator must give of its *potential need* for a bPPA ('notification period').
2. How far in advance a generator must *commit to entering* into a bPPA ('commitment period').

Regardless of the existence of the OLR, generators (or their lenders) are likely to require collateral cover in open market PPAs sufficient to allow them a period of time to negotiate a new PPA if their original PPA provider defaults – likely to be in the order of 3-4 months at least. Therefore, any requirement to notify Ofgem of a *potential need* for a bPPA is unlikely to have a material impact on levels of collateral in open market PPAs as long as it is not longer than 3-4 months. The generator is free to continue negotiating an open market PPA during this period, which could allow Ofgem to put in place the processes for running a competitive tender, including (for example) notifying suppliers of the anticipated auction date, contacting Elexon to initiate the process for registering new additional BMUs, and compiling and publishing details of the generator(s) that will take part.

In contrast, once a generator has to *commit* to entering into a bPPA it cannot continue negotiating open market PPAs. Therefore, this period will require collateral cover *on top of* the requirements that a generator would otherwise have in its open market PPA, so it is the length of this period which has the potential to increase costs to generators.

We had previously considered that offtakers may require several weeks to assess the potential costs and benefits from a particular bPPA with a generator, and therefore what level of bid to put into an auction. However, feedback from the earlier advisory group meeting on allocation suggested that this might be possible in a much shorter period of time. With a longer 'no regrets' notification period, we believe it should be possible to reduce the 'commitment period' to 1-2 weeks, therefore minimising any additional collateral requirements in open market PPAs, and therefore additional costs for generators.

Q4: Do you agree that (a) a 'no regrets' notification period of 2-3 months would not increase the collateral requirements in open market PPAs; and (b) offtakers should be able to determine what bids to make in a competitive process within the space of a week?

Risk for consumers of uncompetitive auctions

We previously flagged the risk that the prices bid by offtakers in an auction for a backstop PPA might be high. This stems from a number of risks:

1. **That a large volume of generators entering the OLR would coincide with a stress event that might result in a reduction in liquidity in the open market:** This is a risk if the market coalesces around long-term PPAs with weaker credit. However, it is mitigated to an extent by the fact that long-term PPA providers may offer terms with explicit buy-out clauses meaning that downside risk will be capped, thus decreasing the likelihood of a stress event pushing new entrant PPA providers out of the market or into insolvency.

2. **That liquidity in the open PPA market will not flow into the bPPA market because either:**

   - Offtakers don't want to participate: This could occur if, for example, generators are too small to be worth bidding on or the market is too small relative to the opportunity. However, the NFPA auctions suggest that these concerns are not valid. If the unavoidable cost of participating does outweigh the opportunity and thus lead to higher costs than in the open market then this could be deemed an efficient outcome and, with more volumes, prices will decrease as the opportunity grows. In any event, the OLR will require a robust design that minimises the costs and barriers to participation to maximise the efficiency of pricing.

- Offtakers want to participate but a significant portion of them can't due to structural barriers: Such barriers could include the requirement for a supply licence or minimum credit requirements. However, our view is that a requirement for a supply licence is unlikely to pose a significant barrier to entry for most aggregators on the basis they will need one in any event to be able to offer PPAs to embedded generators (and this is reflected in the market today with all of Smartest, NEAS etc having supply licences). Moreover, credit provisions in the bPPA should be in line with those in the open market, and should eliminate the need for stringent separate eligibility requirements for voluntary offtakers (i.e. by reference to minimum credit rating or balance sheet strength).

3. **That the supply market does not result in a minimum level of competition and/or cost reflective bidding by offtakers.** We judge that the market should be reasonably competitive. The precedent from the NFPA e-Power auctions demonstrates that even small projects typically receive multiple bids and efficient prices. Whilst much larger projects may be eligible for the OLR than are currently auctioned through the NFPA, we propose breaking these down into multiple smaller PPAs, reducing the risk to any individual offtaker and improving competition. The fact that total cost of the scheme is levelised across all suppliers should give suppliers an incentive to price their bids accurately, as they will end up subsidising their competitors' profits if – by entering an unrealistic bid – another supplier wins the contract for a high price.

Q5: Do you agree that the risk to consumers from uncompetitive auctions is mitigated by the factors outlined above?

Way forward

Given the considerations above, we judge that a purely competitive mechanism is a feasible process for allocating generators to offtakers, and would have considerable advantages in terms of simplicity, reduced impact on suppliers, and reduced legal risk to Ofgem. We are therefore working up the process in more detail to understand how it could operate and what risks there might be.

Q6: Do the Group agree that a purely competitive allocation mechanism has potential, and should be worked up in more detail?

However, we believe it might be worth retaining a 'reserve power' for Ofgem to allocate a generator to an offtaker in a regulatory way, if Ofgem or the Secretary of State judged there was risk of a competitive approach failing or leading to a poor outcome for consumers – either with respect to individual projects (for example, particularly larger ones) or systematically (e.g. if there was extreme concentration in the supply market so there were very few eligible backstop offtakers). This process could involve Ofgem putting in place a reserve price based on a less stringent cost assessment process, which would eliminate one of the key drawbacks of the hybrid allocation mechanism identified above – namely, the potential over-compensation of the provider of the initial bPPA. There circumstances in which this power was used would be clearly specified in the scheme rules.

Q7: Do the Group agree that a reserve power to allocate generators on a regulatory basis should be retained if pure competitive allocation is implemented?

Annex A – Straw man cost assessment

Note: this Annex only considers cost assessment for intermittent generators. We have not yet considered cost assessment for baseload generators.

Assessing costs

Cost	Description	Valuation approach	Risks

Imbalance	- Cost of managing forecast error
	- Covers both:
	  ○ "basis risk" of managing changes in forecast error between DAH and gate closure
	  ○ Imbalance cost associated with outturn delivered volumes being different from the gate closure forecast
	- Ex-ante cost assessment requires a forward-looking assessment of imbalance costs for a "generic" generator
		- Define representative sample of "virtual" wind farms distributed across GB and with a range of load factors and power curves
		- Obtain historic wind forecasts for each site and for each half hour period over past two years showing day-ahead, gate closure, and actual out-turn, and convert to power output using power curves.
		- From this derive, for each half hourly period:
		  ○ "Intra-Day Imbalance Volume" (i.e. the change in forecast output between day-ahead and gate closure)
		  ○ "Post Gate Imbalance Volume" (i.e. the assumed difference between gate closure and actual delivery).
		- In parallel, from historic half hourly prices, calculate:
		  ○ Intra-Day Price Differential (i.e. DAH price less the MIP)
		  ○ Post Gate Closure Price Differential (i.e. DAH Price less Cash Out)
		- Then calculate the Total Imbalance Opportunity Cost for each virtual wind farm by summing:
		  ○ Intra-Day Opportunity Cost for each period (Intra-Day Imbalance Volume multiplied by Price Differential)
		  ○ Post-GC Opportunity Cost for each period (Post-GC
			High
			- Forecasting provided to Ofgem may not reflect offtaker's own forecasts
			- Over-simplification of intra-day trading behaviour
			- Ofgem would require access to forecast data
			- Actual imbalance could be different from historic benchmark (even if 2 or 3 average years used)
			- Could be costly for Ofgem to carry out
			- Could overlook difficulties of forecasting real assets (e.g. locational features not picked up in "virtual" forecasting)

		Imbalance Volume multiplied by Price Differential) ▶ For each virtual power plant, divide by the actual delivered volumes (as estimated using actual wind speeds and the power curve as above) to derive £/MWh cost. ▶ Choose the site with the highest imbalance cost as the "worst case" for the purposes of cost assessment.	
Trading costs	▶ Cost to the backstop offtaker of trading the power in a liquid market	▶ Even in a well-functioning market, trading activity imposes a cost on offtakers ▶ Cannot be offtaker specific if it is to be used to set a reserve price ▶ However, Ofgem could ask offtakers for cost data (as per small scale FIT) including trading systems, personnel, trading collateral & fees and use these to identify trading cost proxies (e.g. by offtaker size) ▶ Cost assumed should be the "best in class" of the "worst class" (i.e. identify the type of offtaker with high trading costs (small trading systems, high collateral requirements) but set cost against the best of this class of offtaker (maximum efficiency, reasonable staffing levels)	Low ▶ Trading costs should be relatively consistent across market participants'. ▶ The only exception might be the cost of trading collateral, however for an Intermittent RtM agreement at least the amount of collateral required should be relatively modest (given only a DAH position

Cost of carry	▶ Cost of funding working capital required between paying out under bPPA and reimbursement under levelisation	▶ Cost is a function of the amount of working capital required, the time between paying out and being reimbursed, and the cost of finance for each offtaker ▶ Assume that working capital for bPPA provision will be additional to the offtaker's current balance sheet ▶ Assume bPPAs pay out gradually throughout period (or can be volume weighted) before being reimbursed, so interest accrues, on average, over half this period ▶ Cost of short term finance (i.e. working capital) can be assessed from the banking market (i.e. what is the rate of interest / commitment fees on a revolving credit facility with utilities of different sizes) ▶ Set costs on the basis of the offtaker with the highest cost of carry.	High ▶ Cost of finance is likely to vary significantly, particularly between voluntary and mandatory offtakers. ▶ Therefore risk of setting the reserve price too low for voluntary offtakers and too high for mandatory offtakers. ▶ Cost of finance could increase, either in the market as a whole, or because of a reduction in offtaker credit rating
Cost of PPA credit support	▶ bPPA providers need to meet minimum credit requirements ▶ Could require either expanding balance sheet capacity or providing collateral	▶ One approach would be to use quotes from the banking market for the provision of an LC facility equal to the maximum liability under the bPPA. ▶ Could assume the credit rating one or two notches below the minimum credit rating of the backstop offtake in the bPPA.	**High** ▶ As with cost of carry, cost of finance is likely to vary significantly across offtakers. ▶ Would overcompensate large utilities in the initial bPPA as most are likely to meet the minimum credit rating and therefore will not be required to provide an LC in any event.
Cost of "Liquidity"	▶ Cost of bPPA provider being unable to access MRP due to low volumes and large B-O spread	▶ For intermittents, could assume zero liquidity costs since offtaker should be bidding unpriced bids into an auction and therefore are guaranteed to be able to access the clearing price.	High ▶ There is no standard metric of OTC transaction costs (they are derived from the price of executed trades).

	▶ Would need to differentiate between bPPAs provided to intermittent and baseload generators	▶ For baseload, estimate OTC Bid Offer spreads in the forward market for baseloads (e.g. using ICIS Heren data as per the Ofgem liquidity study[1]) ▶ For consistency across offtakers, would need to assume the worst case for mandatory offtakers, which is to take the historic estimated Bid Offer spread for the baseload MRP product (S+1 & S+2)	▶ True cost to offtakers could be over- or under-estimated depending on their trading behaviour
Outage / default costs	▶ Any cost incurred because of a generator's actions (e.g. unplanned outages) ▶ Cost needs to be assessed *ex ante*, need to estimate number and magnitude of such costs	▶ Obtain information on the historic (2-year) generator performance ▶ Assume well-run generator will have fixed number of unplanned outages per year. Estimate based on a "worst case", such as the 90th percentile (i.e. only 10% of generators had more outages in a year) ▶ Estimate difference between cashout price and MRP (whether intermittent or baseload) and volume of sold power unmatched by generation ▶ Multiply cumulative volume dropped by the average cashout-MRP differential to estimate cost of balancing this position ▶ Option 2 – use the prevailing market price being paid by buyers with a compliance obligation.	**Medium** ▶ Number of outages assumed might not reflect reality ▶ May over- or underestimate cost depending on assumption made around offtaker ability to rebalance position in intra-day market ▶ If cashout price is not independent of outage probability, average opportunity cost may not be a fair metric. ▶ This could instead be done on an ex post basis (with suppliers not required to price outage risk at all), however this would increase the complexity of cost assessment.

[1] https://www.ofgem.gov.uk/ofgem-publications/40483/gb-wholesale-electricity-market-liquidity-summer-2010-assessment.pdf

Valuing the benefits

Benefit	Description	Valuation approach	Risk
Value of Electricity	▶ Value of the power received under the bPPA	▶ Value at the Market Reference Price (intermittent or baseload) for the given delivery period ▶ May need to assume an initial period where the offtaker receives the system sell price for the power, before SCADA links have been established to allow the offtaker to forecast the output accurately. Would need more data to understand how long this process takes and to what extent it is in the control of the offtaker.	**Low** ▶ Should be unproblematic, once accounting for the trading and liquidity costs associated with the power
Levy Exemption Certificates (LECs)	▶ Energy intensive customers pay the Climate Change Levy, but electricity from renewables is exempt ▶ Renewable generators can monetise value through the receipt and sale of Levy Exemption Certificates (LECs)	▶ Could use the prevailing Climate Change Level (CCL) rate (which as of today stands at £5.24/MWh), but this is likely to overstate the true value to offtakers. The CCL rate represents the cap on LEC values, but real value could fall (due to oversupply post 2014). This would therefore not appropriate for setting a reserve auction price. ▶ Alternative approach would be to benchmark against the prevailing discount in the short term PPA market. For example, if offtaker are paying 50% of the prevailing CCL rate in the open market then this is the best indication of the actual value	**Medium** ▶ This approach relies on good visibility of pricing of CCLs in open market PPAs. ▶ Ofgem may have this given the intention to put in place wider obligations of posting PPA market information by generators if they want access to the OLR.
Embedded Benefits	▶ These are avoided costs accruing either to the embedded generator or the offtaker contracting with an embedded generator ▶ Relate to the fact that the	▶ It is important to note that embedded benefits can either be: ○ <u>Implicit benefits -</u> A benefit that accrues to the generator, either in the actual MRP because the MRP reflects costs to transmission generators that the embedded generator is not exposed (e.g. Avoided generator share of TNUoS, transmission losses, BSUoS respectively); or in actual payments that accrue to the generator (i.e. negative DNUoS	**High** ▶ This could lead to distortions in the open market as all embedded benefits normally captured by the sale and purchase under an open market PPA ▶ Administrative allocation process

	generator is connected to the distribution system not the transmission system. These include: ○ Avoided Transmission Network Use of System charges (TNUoS); ○ Avoided Transmission Network Losses; ○ Avoided Balancing Services Use of System charges (BSUoS); ○ Negative Distribution Network Use of System charges (DUoS); and ○ Avoided Distribution Network Losses;	Charges) ○ Explicit benefits – A benefit that accrues to the offtaker as an avoided cost (i.e. avoided supplier share of TNUoS, Transmission Line Losses, Distribution Line Losses, BSUoS). ▶ Leave all "implicit" benefits (i.e. benefits that accrue to the generator) with the generator under the backstop PPA ▶ Assume TNUoS saving is zero (i.e. assume that intermittent generator is not generating during the triad periods). ▶ For avoided transmission and distribution network losses, this could be calculated as the product of: ○ The forecast volume of the embedded generator last year ○ The average power price in that year; ○ The prevailing share of the line loss factor for suppliers (either at the transmission or distribution level) ▶ For avoided BSUoS, this could be calculated as the product of: ○ The total volume of energy generated by the embedded generator last year ○ The BSUoS charge levied on suppliers for the that period	would need to ensure that a generator entering the OLR is allocated to a supplier with demand base at the GSP to be able to monetise the benefits ▶ This methodology may underestimate saving as generators (particularly wind) could be generating in at least one of the Triad ▶ Using historic electricity prices / output may not accurately reflect the savings that accrue
Balancing mechanism	▶ Any margin made by offtaker from bidding into the BM (using its rights under the bPPA), e.g. curtailment	▶ Assume bids made at true opportunity cost (i.e. generator top-up less the SRMC of generating) in compliance with transmission constraint licence condition.	**Low** ▶ Limited competition behind a constraint could result in non-cost-reflective bidding behaviour and so underestimate the BM value ▶ However, behaviour rare and increasingly unlikely given regulated by new licence conditions
Accrued	▶ Where any benefit is	▶ Assume this is seen as a negative cost of carry	**Low**

Interest	accrued prior to levelisation, interest can be made on that cash	▶ Interest would then be paid (or received) on the net cost and benefit of providing bPPAs ▶ Assessed at prevailing interest rate on a deposit account (i.e. by reference to a basket of reference banks)	▶ True interest achievable may be lower if not accounted for as an avoided debt