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#	Type of Option	Description of DECC Options	Mainstream Response
1.	Market led initiatives	Market participants to: (i) establish PPA contract models consistent with the CfD regime; and/or (ii) develop codes of practice covering issues such as pricing transparency and market participation.	The development of contract models and codes of practice can in some circumstances prove helpful. However, it is unlikely that without any obligation to implement or follow the codes (or penalties for failing to do so) these will result in any change of practice by suppliers. These measures are therefore unlikely to provide independent generators with the clear route to market that is needed. Measures such as these require a degree of industry consensus and it is unlikely that this will be achieved within a suitable timeframe to address the issues faced by independent generators in the market. A standard industry approach can only work where there is consensus between participants and as soon as divergence between participants appears the synergies will be lost. (i) PPA contract models - whilst this may represent a low cost option this would not necessarily ensure that the terms offered are financeable. Standardisation already exists to some extent in the PPA market. However, due to the differing nature of projects - locational issues, capacity and risk appetite - it is not possible to create a fixed contract model and any PPA will always require a certain amount of negotiation. It is not the degree of standardisation which is the issue; it is the deterioration in the TERMS being offered within established PPA structures. It is also likely that some PPA providers will be seeking to provide bespoke solutions to try and offer some upside to generators against the reference price. Such models are unlikely to fit within the constraints of a generic standard and indeed a generic standard may in fact discourage such flexibility. (ii) Codes of practice – code development can be unwieldy and time consuming and it may be difficult to reach consensus or engage active participation across the industry. As with PPA contract models, codes of practice will not necessarily ensure that terms offered are financeable. It is unlikely that codes of practice will also deliver the effective competition that is currently missing from the PPA market. Transparency is only useful if it is accompanied by effective competition, which is not being addressed. (iii) By the time these "solutions" are demonstrated to be ineffective it will be too late to implement an alternative and independent generators will have withdrawn from the market place

2.	Competition Measures	Such steps could include: (i) improving liquidity. Ofgem have set out their approach to this and we have seen industry initiatives deliver significant increases in day ahead liquidity. (ii) cash out reform. This could provide more predictable costs of imbalance which could reduce the costs of managing the risks. (iii) measures to support independent aggregators. This could introduce additional competition to the market and reduce costs to independent generators. (iv) Adjustment of market reference price to system sell price or price at gate closure	**Liquidity measures -** these will be important to increase competition and trading options where clear price signals and the ability to effectively manage trading risks are essential. However, these measures will not directly help projects where a PPA is essential for generators that do not have/cannot support an internal trading capability or where the existence of a PPA is a fundamental requirement for project financing. It is clear that successful implementation of the CfD will require a liquid wholesale energy market to ensure a pricing structure that can enable the market to continue to deliver projects. As we have previously noted, the failure to address the deficiencies in the underlying **market** frameworks and structures within the original scope of the EMR process remains a fundamental barrier for independents. BETTA was designed for different circumstances and worked adequately whilst they endured. This is no longer the case. Its entire structure both rewards and encourages vertical integration, discourages "liquidity" and punishes those on "one side of the market only", even more so for those who rely on third parties to provide the necessary balancing services, the vast majority of which are in the possession of the VIUs. We understand the reluctance of government to address the issue, but without a recognition that the fundamental nature of the Trading Arrangements themselves are part of the liquidity problem, attempts to distort them to "kick start liquidity" will only result in "compliance activities" rather than genuine liquidity motivated by commercial opportunity. These will fail to provide sufficient confidence for external stakeholders to review their judgement of risk. Whilst there has been significant growth in the volumes of electricity traded through exchanges (particularly in the day ahead market) by the VIUs and others, the Retail Market Review consultation carried out by Ofgem identified ongoing concerns that the current market structure is still not providing sufficient access to a range of traded products required by independent electricity generators (or an adequate pricing mechanism for traded products) to allow independent generators to hedge against the risk of future wholesale price movements. . Liquidity measures may be assisting liquidity in the short term, based on the implied threat of more draconian action, but they are not increasing liquidity in <u>long term</u> PPA products. Measures being implemented by Ofgem (for example the mandatory auction mechanism) whilst adding to "headline" market liquidity, may appear to be attractive. However, liquidity in itself (forced or otherwise) does not guarantee competition comes forward as a result. Liquidity can be measured in several different ways, if liquidity is based on voluntary or "forced" agreements rather than the inherent commercial opportunities provided by the underlying Trading Arrangements, there is no reason to expect that the necessary variety of products will be traded in an effective manner. Similarly, if liquidity is based on voluntary agreements there is no reason to be expect it to be enduring, any new entrant to the market will be aware of how easily that liquidity could be

			removed from the market and will discount its importance accordingly. Any mandatory liquidity reforms (of whatever effectiveness) are unlikely to be fully implemented in time to avoid a 2015 investment hiatus. Any improvement of PPA terms depends on the effects of increased competition arising from genuine commercial opportunity, rather than forced liquidity. Liquidity in itself (particularly short term liquidity) provides no benefit to projects that would normally rely on a PPA for their route to market and price risk management. As DECC have already identified (in the draft CfD Operational Framework published in May 2012), the use of PPAs often reflects the scale of a project or the ability, sophistication and/or resources of a generator to have its own trading function and manage imbalance risks. A PPA or other arrangement demonstrating an ability to both manage imbalance risk and to access the reference price directly will remain a FUNDAMENTAL requirement for the project financing process post EMR. It is also essential to recognise that in many cases independent generators reliance on PPAs is an inherent part of the project's financial viability. Where projects are part funded by non-recourse project finance, there will be a requirement that a long term PPA is in place with a creditworthy counterparty to provide certainty over project revenue. Fundamental change in any market mechanism is highly likely to create an investment hiatus as banks and investors both come to terms with new arrangements during transitional periods and monitor a period of post implementation operation to properly assess the risks and effectiveness of the new arrangements in practice. **Cash Out Reform** – This needs to address the fundamentals of a changing generation mix, the need for effective balancing capability to be provided and suite of incentives on the transmission system operator and other market participants on a holistic basis. Merely addressing one area in isolation prioritizing "sharper incentives to balance" based on the current opaque, unpredictable and unhedgeable mechanism will provide no benefit either to the market as a whole, or to individual participants. Any reforms need to provide more certainty, predictability and manageability with respect to the costs of balancing, which in turn should enable the costs of managing the risks associated with imbalance to be reduced. The proposal for a sharper cash-out price, without reform in other areas, acts against these objectives and will have a very high cost associated with it. There will be a high direct cost from the balancing fees themselves. More significantly, without providing the appropriate incentives for the provision of greatly increased capability in balancing services at reasonable cost, per unit balancing costs will increase sharply as more variable generation increases the requirements for total system balancing services. This will inevitably be reflected in discounts priced into PPAs on a very aggressive basis. A proper review of cashout, balancing services, their provision, incentives and costs is required to address this important determinant of a key element of PPA

			terms. However, even a credible beneficial reform process would not directly lead to an increase in competitiveness in the PPA market and a delivery of PPA terms that are bankable. Any benefits which might be derived from appropriate cash out reform measures will not be delivered early enough to address the concerns regarding the current PPA market and the PPA market as EMR takes effect. A hiatus in 2015 is highly likely. The costs of balancing and lack of clarity on how those balancing costs will develop presents a significant barrier to entry for new aggregators coming into the market. The main benefits that would have been generated from a centralised renewables market have been ruled out of scope, even though this option offers the potential to provide a holistic solution to overall system balancing and flexibility into the future. Balancing costs could be reduced by centrally aggregating renewable generation and having a single imbalance payment, potentially accompanied by revised despatch rules agreed with the system operator. **Measures to support independent aggregators –** any measures that increase the number of PPA providers and thereby increase competition will be helpful for generators participating in the market. In theory, an aggregation role can play an important role in managing imbalance risk as they are potentially able to manage risk across a portfolio of generation types. However, in practice those generation (and demand) assets which are able to provide a reduction in overall portfolio risk will seek to maximise their *individual* returns, not minimise the *overall* portfolio costs. Aggregation will therefore result in a benefit through diversity, but within a portfolio exhibiting predominantly common mode risk characteristics The net effect will be to reduce aggregate risk from 100% to (say) 95%. This inability to develop a diversified portfolio that includes different types of generation and demand will dramatically reduce the portfolio benefits potentially available to aggregators (and *more importantly* their potential customers) considering entering the market and managing balancing costs. Further analysis will be required to identify what effective measures could be put in place to support aggregator roles – including assessment of the actual effectiveness of proposed measures and how quickly they could be implemented to address the current market issues. It is unlikely that aggregators will ever be able to provide a full and acceptable service which obviates the need for a PPA by renewable generators. Even if this were to be the case, the identification and implementation of measures to support market entry by independent aggregators will not allow the development of a proven risk management tool for independent generators in time to avoid an investment hiatus. As such these measures need to pursued alongside regulatory measures which would directly facilitate a route to market for independents. The independent aggregator market can then be developed and its ability to provide suitable services tested from a position of certainty.

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			The costs of balancing and lack of clarity on how those balancing costs will develop will continue to provide a significant barrier to entry for new aggregators coming into the market.
3.	Regulatory Measures	There are a number of possible regulatory measures some of which have been suggested by independent renewable developers. An obligation on large suppliers to offer a PPA to any renewable developer that requested, offer terms on a commercial basis. An off-taker of last resort who is obliged to offer standard, administratively set terms priced above the expected terms from a competitive bidding process.	In general, regulatory measures or interventions are less attractive than solutions which are congruent with generic market evolution. However, where the underlying market structure is a fundamental part of the issue, regulatory intervention is the only effective route to resolution. (i) Obligation on large (creditworthy) suppliers to offer a PPA to any renewable developer on commercial terms - It is not clear how this could be enforced effectively or even made to work at all, what would demonstrate non-compliance and what the costs of non-compliance would be. A mechanism for *enforcing* supplier compliance with any Obligation would be required and it is unclear how this could be delivered (with respect to assessing whether or not the terms offered are 'commercial' or compliant with the "requirements"). Without a clear understanding of how this could/would be enforced, and the penalty regime for non-compliance, it is unlikely to ensure that PPA terms which are offered are either financeable or financially viable. (ii) Offtaker of Last Resort – we prefer the description of **Offtaker of First Option**, rather than last resort. First Option provides an acceptable benchmark and route to market to allow qualifying projects to proceed, whilst still allowing the ability for the developer to assess any other (presumed available) viable offers from the wider market. There would be certain administrative and regulatory costs associated with establishing an offtaker (or enhancing an existing body to take on the role) that is credit worthy, sufficiently capitalised and able to manage the volumes that it may be required to contract for. These would be minimal when compared against the benefits that the body would deliver. **Crucially, these benefits would include an effective guarantee for counterparties that PPA terms were both financially viable and financeable.** Further synergies and benefits could be captured by combining this function with that of the CfD counterparty body. For independent developers, this would allow the removal of credit and collateral requirements associated with CfD operation and translate the commercial arrangement into the equivalent of a conventional PPA, with uni-directional payments flowing

			from the counterparty to the generator. The Offtaker would be enabled to use a variety of tools to ensure best value for money for the power purchased, including auctions such as those conducted by the NFPA – to ensure effective price discovery when placing the power in the market. We do not necessarily agree with the assertion that the terms offered by an administrative process would be priced above the expected terms from a competitive bidding process. In a competitive market, competition to offer PPAs would be expected to drive prices *above* a sustainable minimum. Secondly, the explicit and implicit guarantees offered by an **Offtaker of First Option** would be reflected in a lower risk weighted cost being incorporated in the project model. This in turn would lead to a lower cost of capital and the ability to accept a commensurately lower contract price from the OFO. We believe that this proposal is the only measure from the suite of options set out by DECC that has the potential, assuming that a creditworthy offtaker can be established, to ensure that the PPA terms are viable, financeable and available.
		Other regulatory measures to support independent generators:	
		Financial incentive (Carbon intensity allocation of support costs)	We note that DECC has the stated intention of recovering the costs of support under all scenarios on a pro-rata basis. However, notwithstanding any complexities of administration and potential interactions with other low carbon incentives (e.g. carbon floor price), we believe that allocation of cost in proportion to carbon intensity does provide a fundamental and powerful incentive on those subject to it, to respond positively. **It provides a strong incentive to ensure that PPA terms are financially viable and financeable.** It ensures that the strategic objectives of the utilities are aligned with government policy in a seamless manner. There may be an impact on the degree of volatility that suppliers are exposed to in their CfD costs, but mechanisms could be devised to manage this. There would be certain administrative and regulatory costs associated with establishing an offtaker (or enhancing an existing body to take on the role) that is credit worthy, sufficiently capitalised and able to manage the volumes that it may require to contract for. These would be minimal when compared against the benefits that the body would deliver. There is a precedent

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		Obligation on suppliers to purchase renewables (via a central purchasing agency	in that the functions of the body closely match those of the NFPA (in its active phase). **It ensures that PPA terms are financially viable and financeable.** It ensures that the strategic objectives of the utilities are aligned with the government policy in a seamless manner. Implementation may prove challenging in a timescale to avoid a 2015 hiatus. The non-compliance penalty would need to be sufficient to incentivise desired actions.

Annex 2: Energy Market Reform

The Need to Address Deficiencies in BETTA

Introduction

There is an urgent need to examine the performance of the current electricity market trading arrangements as an essential element of the wider EMR proposal being considered by Government. Without this consideration, there is a risk that the current trading arrangements could inhibit realisation of the Government's policy goals.

In order to understand why the trading arrangements need reform, we have tested their appropriateness against the following challenges:

- how has BETTA performed in terms of meeting its design objectives but also in the light of new objectives flowing from government policy?
- how might recognised deficiencies in trading structures be addressed to support desirable changes identified by the Government?
- what changes would enable better alignment with current policy moving forward, and how might they be implemented with minimum disruption to wider commercial arrangements within the sector?

The Current Situation

The GB electricity market incorporates a residual feature to deal with uncontracted trades – the Balancing Mechanism (BM). The BM is used by the system operator on behalf of the market as a last resort to meet uncontracted supplies and any metered imbalances against contract. Its central defining feature is that it is based deliberately upon the premise of decentralised bilateral contracts with strong incentives on trading parties to avoid uncontracted trades.

- there is no centralised market place but instead multiple bilateral contractual arrangements, which are largely opaque to the wider market.

- bilateral contracts are effectively obligatory as the market rules render uncontracted trading a high-risk option, which additionally attracts unpredictable balancing costs targeted through imbalance prices.

- all parties with rights to flow on to the transmission system (TEC) can self-commit or self-despatch as long as the physical system is available and subject to pre-despatch notification. If there is over-supply as a result of contract nominations exceeding actual demand or if the local transmission system is over-loaded or unavailable, despatchable generators can be constrained back and are compensated provided they offer in through the BM.

The issue of establishing a route to market is a major problem under BETTA for all but the largest trading parties. This is because of a number of factors, including:

- market domination by a small number of participants who control 75% of generation and over 90% of supply to consumers. The benefit of a large portfolio is that trading can be largely avoided or discretionary at the margin. Independent trading parties are then faced with a choice of contracting with counter-parties who have considerable market power, or to find credit worthy counter-parties among a dwindling number of other players;

- one natural consequence of this is the poor liquidity levels in traded markets compared with other traded products; and also with international electricity markets. Risk management options for independent developers are minimal;

- the absence of a central market place has militated against the emergence of suitable reference prices to foster trading and risk management, and the bilateral markets are opaque.

The ability of renewables to compete on a level playing field is compromised by the way imbalance pricing – the mechanisms applied for pricing uncontracted trades – works. It is intended to encourage parties to contract with one another by reflecting short-run costs onto parties that do not contract cover. But for many those options to trade do not exist or are heavily circumscribed because trading is limited to short-term products typically traded in large strips between the largest players. Another key side-effect has been that the market structure has provided a strong incentive to vertically integrate. While vertical integration will take place in any market structure because of the natural hedge provided between generation and energy supply, the BETTA design with a fundamental emphasis on balancing encourages strong links between generation and suppliers because of the ability to avoid trading.

Furthermore, while imbalance prices may or may not be reasonably benign, they remain unforecastable and unknown *until after the event and cannot be hedged*. Any price excursions (positive or negative) have the scope to cause disproportionate financial harm to one-sided players who struggle to be in contractual balance. Again this reinforces incentives to integrate.

These drivers are mutually reinforcing under the current arrangements. Supply businesses will grow and verticos will buy/build generation until they can fully self hedge, insulating themselves from exposure to imbalance prices.

Another consequence of the current Trading Arrangements is that an overall merit order designed to deliver efficient despatch, does not exist. Each of the large utilities effectively manages its own internal merit order, trading only at the margin. In an electricity market increasingly being constrained by the lack of timely investment in transmission, and with a greater penetration of variable renewables, options for "sharing" transmission capacity are being investigated with greater urgency. Sharing can be facilitated by incentives for overall efficient despatch, but as noted above, the current arrangements provide incentives which are directly contrary to this initiative.

The current structure of the BM can be characterised as acceptable, where the majority of the market comprises flexible, despatchable plant, and was an effective solution to the previous concerns about market power and the basis on which market prices were set. It allows for more efficient use of some conventional plant in that it allows a generator to run at their most efficient level and set a price (or cost) for deviating from that but without setting a marginal price for all flexible generation[1]. However, it increases risk for virtually all low-carbon technologies, which are either typically variable or inflexible - because of their likelihood of moving into imbalance.

As we move forward increasing tranches of variable and must-run generation will be coming onto the system. Conventional generation will move to mid-merit operation with an increasingly important need to provide stand-by and back-up. At some point over the medium term the current arrangement will become untenable due to the potential large volumes of imbalance and associated costs. Ensuring orderly despatch of must-run plant will be a much more important consideration.

The Solution

For these reasons a system which incorporated the benefits of a more centralised or pooled system, without replicating the shortfalls of the previous Pool design, would deliver real competitive and efficiency benefits. If it could incorporate the desirable elements of BETTA and provide a smooth transition, then discontinuities could be minimised.

Key Features

In the past a key issue – but a distraction – was whether the pool should be mandatory or voluntary. This does not matter provided the largest players active on both sides of the market are required to trade their requirements within minimum defined parameters creating a liquidity pool. The lack of liquidity under the current arrangements, and the problems surrounding prospective measures to achieve it, are a major source of both risk and uncertainty for stakeholders, in mapping out how the government's initial proposals for Energy Market Reform would actually deliver their objectives in practice. It is probable that a fundamental reform to address liquidity will be needed under the BETTA arrangement.

Recognising this liquidity imperative, a revised trading structure could be based on what the US market designers term the **two settlement process**, with an ex ante stage (perhaps day ahead) based around a liquid traded market and a real-time market to deal with flexibility and operational exigencies.

The market would need to be **two-sided**. Both generation and supply above a *defined level* should be required to take a position.

[1] The BM is based on "pay-as-bid" pricing.

All generation would be able to offer into the **ex ante auction** probably at the day-ahead stage giving both generation and supply parties a guaranteed market. Low carbon technologies would be able to freely access the market price in each half hour under their contracts for committed quantities, in addition to additional support provided by government policy mechanisms [RO, Premium FiT etc].

Renewables incentives and CCS funding streams would continue to be administered out with the market, but the existence of the "pool" would provide a *ready reference point* and *reliable market index* for political support mechanisms looking to regulate pre-determined levels of technology support. The day-ahead traded prices would also provide a credible benchmark against which any guaranteed minimum carbon price could be administered.

All suppliers would have access to power, subject to meeting a **single credit test** but, critically, they would no longer be price takers as they were under the old Pool. They too would need to commit quantities and prices for contracted power and prices for any uncontracted power they bid in. Current multiple, over-lapping credit requirements could be dispensed with, and credit risk could be administered through a single underwritten scheme by the market administrator.

Under this approach, although the day-ahead market would be a financial market, **physical contracts** could still be the main commercial focus of trading parties if that is what they chose. However, with an appropriate form of centrally coordinated daily auction there would be a reference price for each half hour trading period that would permit trading parties to strike contracts for differences/financial contracts as well if they were so minded.

This would not necessitate a *radical upheaval,* as those with physical bilateral deals that wished to stay outside the trading arrangements could keep their current delivery contracts or migrate to new arrangements as existing contracts expired. Exactly as at present, they would need to nominate committed quantities. If their price bids were not cleared at the ex ante stage, uncontracted trades as at present would be dealt with through the real-time market.

The **real-time market** would be an on-the-day market, rolling through the day potentially from one-hour out to the close of each half-hour trading period. It could operate along similar lines to the BM but supplemented by the ex ante market that allows parties to nominate (and commit) their positions.[2] It would be operated by the system operator, although reconciliation and settlement process would logically continue to be operated by a market administrator as at present. In effect generators, suppliers *and* large customers could then sell back flexibility (including load interruption)/peak reduction into the real-time market.[3] The scope of engagement by the system operator would be consistent with its current role of residual balancer.

[2] The ex-ante market effectively produces physical notifications through trading parties nominating schedules or committing parties to contracts for uncontracted plant that is offered/bid in.

[3] At present only flexible generators avail themselves of this option.

It is a point for debate whether the ex ante and real-time markets should be based on a marginal auction or as at present pay-as-bid. But unlike the day-ahead market which would be based on simple quantity/price bids and offers, the system operator would, as now, need to take into account plant inflexibilities and locational effects.

A two-settlement market would provide an opportunity for demand-side managers to fully participate in the market. A major shortcoming in the current arrangements is that there is no indicative real-time price. This would need to be communicated to the market [e.g. 15 minutes] ahead of the start of each trading period. Flexible generation and demand would need to finalise schedules or supplemental offers and bids at this point. A market price would also permit the offer of half hourly prices by suppliers to customers, also encouraging flexible demand, subject of course to commitments made in the ex-ante market.

Market prices would be uncapped, but the two-settlement process would also be able to administer a capacity pricing mechanism (if one were introduced at some future date). Alternatively the market operator could administer a contracting obligation on suppliers[4]. The more sophisticated US pools combine the two through capacity trading markets that sit along-side the organised energy markets.

There is no necessity under this reformed market to move to new business processes and systems. Significant elements of the current arrangements could be retained – BM processes and systems, schedules (in effect contract notifications), metering and settlement. Even cash-out *could* be retained largely in its current form as, given the availability of a must-run/can buy market, all parties will be much more able to access power at market-related prices, and imbalance would be calculated against the nominated schedules and the metered output. In a world of *fully and easily accessible* market access, imbalance prices could potentially be made more marginal at times of system stress—provided these prices reflected true energy costs.

With regard to central despatch there is no reason why, once participants have nominated their production/consumption schedules, there should be central despatch. In fact using schedules in this way (effectively in place of contract nominations) would allow the current imbalance pricing mechanism to work as part of the real-time market, rather than as at present, an administered mechanism to which market participants are unable to respond.

There would, of course, need to be some form of market power monitoring to deal with price setting worries by generators with potential market power, and the large vertically-integrated players would need to be required to declare volumes in the ex ante market.

In summary, it should be possible to build on current structures, introduce a centralised trading system but without the many and significant failings of the England and Wales Pool. At the same time it should be possible to preserve some of the design objectives and concepts that informed the NETA vision.

[4] Such an obligation could only be contemplated where **all** suppliers can fairly access contracts or quantities.

Would it be worth the major investment and time needed to set up?

Yes, definitely. The proposed arrangements would guarantee a liquidity pool and be able to accommodate increasing volumes of must-run plant. They would also be compatible with any administered arrangements with regard to carbon pricing and generation capacity support.

But the change-over need not be such a radical shift as the proposals might suggest. Much of the current contract notification processes (for nominations); reconciliation and settlement systems could be retained largely in their current form. The BM already provides the framework for a real-time market. Noting the system operator's current significant investment in replacement market systems based on the existing design, this ability to make a smooth and efficient transition, is a key feature.

EDL and current physical communication protocols could also be retained.

Crucially it would be possible to retain choice for merchant generators that wanted to exist outside the arrangements and preserve their current physical delivery contracts and reflect this in the design of the reformed market. The arrangements need not be more onerous than the current ones whereby physical parties above 100MW (generation) and 5MW (supply) nominate quantities and give physical notifications.

Conclusion

We believe that the concepts outlined in this paper—in particular the two-settlement concept—provide a valid solution to the challenges posed by deep seated lack of market liquidity and the penal nature of the current balancing mechanism - to the promotion of the necessary reforms proposed in the Energy Market Reform Consultation. We recognise that there is further work required to transform the concepts into a detailed and fully coherent set of proposals. However, we believe that framework has the potential to provide effective solutions to some underlying defects in the energy market and look forward to the opportunity to work with government to achieve the desired outcome.