## Consultation Questions

### Identifying the Problem

1. *Please could you provide a summary of your experiences with the PPA market over the past three years? Specific areas for which detailed information would be particularly helpful are set out in the Annex.*

Mainstream's projects are currently in the development phase and approaching the point at which initial specific PPA discussions with potential offtakers are being initiated. Whilst we do not have a detailed record of past offers leading to either successful conclusion or re-evaluation, the general deterioration in the health of the PPA market is having a significant impact on our business activities. The uncertainty regarding the availability, financeability and viability of PPA terms is contributing to a reduction in confidence among the investment community. This in turn is affecting both the availability and terms which providers of capital are willing to offer to the independent wind development sector in the UK. A core element of our business model is to widen the investor and partnership base of our projects as they proceed through the development process. We have held detailed discussions with investors from around the world, with a view to concluding agreements to participate in our projects. These investors view the UK as a *potentially* attractive place to invest and view offshore wind in particular as a sound investment class. These prospective new entrants to the UK power will not accept the risks presented by the current and *future* market dynamic without the security afforded by an appropriate long term PPA, which both underpins the required revenue stream and provides a route to market over the necessary term. Prospective new entrants rightly conduct their own independent due diligence into *inter alia* the prospects of securing PPAs on acceptable terms and the risks associated with operation in the GB market. We have direct experience of engagement with leading global businesses looking to invest in the UK, which has been compromised by the uncertainty and risk associated with this central, fundamental issue. We would welcome the opportunity to share this experience with Govt on a bi-lateral basis.

2. *Have you seen significant changes to the PPA market over the past three years, and if so, what do you think has driven this? If you have asked PPA providers for explanations of why changes have occurred, what reasons have been provided?*

It can be argued that the requirement to use or offer long term PPAs to potential competitors and facilitate their entry into the market is not a "natural" feature of a steady state market, characterised by vertically integrated utilities that can self fund the necessary asset portfolio to meet their objectives. A mixture of own generation and a strategic short/medium term marginal trading capability is the natural profit maximising strategy for a utility.

The availability of PPAs to third parties/*prospective competitors* relies on a ***disruptive change or requirement*** imposed on the market, which forces the utilities to look outside their own plans for asset/energy provision. So far this has been the incentive/penalty mechanism of the RO (with its previous expectation of *longevity/liability for cost, through the 2020s*), coupled with the relatively short timescale set for radical change in the generation mix by govt/EU policy - which has meant the utilities could not meet the challenge from internal resources. The utilities will not have been concerned with renewable targets directly, merely the costs associated with meeting/not meeting the mechanisms used by govt to incentivise a change in behaviour.

The vertically integrated utilities now have enough renewable generation operational or "in the pipeline" to meet the needs of their de-facto franchises (those customers who may be expected to be relatively "sticky" and hence provide a hedge for upstream generation assets over the medium to long term). There is a now a significant risk that any additional long term contracts with third parties may be "stranded" in the future as customers change supplier or move out of the "orbit" of the VIUs altogether due to new entrants in supply.

3. *How does the GB market for PPAs compare to other international markets? If you operate in other markets, how do PPA structures and terms differ? If terms differ what are the drivers behind the differences?*

Mainstream is developing a major offshore wind project, scheduled to connect and operate in the German market. The contrast in complexity and risk between Germany and the UK is stark, despite the shared objectives of minimising risk and providing a secure predictable and viable revenue stream for independent generators. Germany uses a straightforward Feed in Tariff, which is acceptable to the investment community, the UK proposes to use a CfD FiT, which in its present state of development, is not.

4. *What are the factors preventing or encouraging participation in the GB market? How (and why) do you expect these to change over time?*

As we explain further in Annex 1 and 2, both the structure of the GB market, dominated by large vertically integrated utilities and the Trading Arrangements (BETTA) which underpin the market, act to deliver a singularly effective barrier to entry for prospective new entrants. In many ways the two are self reinforcing - the Trading Arrangements promote and incentivise vertical integration (at scale) and the VIUs are able to use the Trading Arrangements to reinforce their positions in the market. It presents a *Perfect Storm* for those countenancing entry into the market. The EMR process has not addressed this fundamental issue of underlying **Market Reform** and as such will continue to struggle to provide a viable solution to the needs of independent generators.

5. *Do you expect the EMR package to change the PPA terms that you might offer/receive and if so how do you believe they will change? What do you think is the primary driver for these changes?*

Please see our answer to Q2 above and Annex 1.

EMR will not address market structure. It will not address the deficiencies in the Trading Arrangements. It has already removed any long term incentive for the vertically integrated utilities to provide PPAs to third parties/prospective competitors by relieving them of any continuing financial exposure, by terminating the expected ongoing liabilities under the RO from 2017. EMR provides no differential incentive for the VIUs to de-carbonise and no time constraints in which to achieve it. The prospects for PPAs in terms of availability, viability and financeability will only deteriorate.

6. *What has been the determining factor in selecting a preferred PPA and PPA provider?*

Selecting a PPA is a function of the terms offered in the PPA and the credit risk of the PPA counterparty. The terms in a standard PPA, are term length, price reference or indices used relationship of contract price to indices and any floor/cap to contract prices. Term length has to be long enough to satisfy the demands of project sponsors. For project finance lenders, this usually means a PPA length of 15 years. For long term asset owners, (e.g. pension funds), a similar term is also preferable. A minimal discount from market prices is always desirable but a larger discount could be acceptable if balanced by favourable terms elsewhere (such as a higher minimum price). Although some service and risk management costs are justifiable (due to the costs of market participation), the size of the discounts seen is proportional to the commercial position of the two parties, in turn dictated by any lack of competition or incentive to procure which may be in the market. A price floor is a standard requirement for most independent developers in order to provide certainty to lenders regarding minimum cash flow requirements. The PPA counterparty must be of sufficient size and credit quality to allay any concerns that the counterparty will default and the revenue certainty that would otherwise by guaranteed by the terms of the PPA are not achieved. A typical offshore wind farm of some 500MW capacity represents an investment of approximately £1.5 billion. This in turn defines the counterparties who are able to meet the risk and financial criteria which are commensurate with such a project. It is unlikely that the typical aggregator, with a relatively small balance sheet, would qualify.

7. *Have you seen a change in investment returns as a result of the changing nature of PPA terms and can you provide an example, including how this has been calculated? Do you expect the EMR package to change investment returns, and if so what is the driver for this?*

Please see our answer to Q2 above and Annex 1.

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Prospective new entrants/partners in the independent generation sector rightly conduct their own independent due diligence into *inter alia* the prospects of securing PPAs on acceptable terms and the risks associated with operation in the GB market. We have direct experience of engagement with leading global businesses looking to invest in the UK, which has been compromised by the uncertainty and risk associated with this central, fundamental issue. We would welcome the opportunity to share this experience with Govt on a bi-lateral basis.

## Options to achieve the Government's objective

8. *What are your views (costs, benefits and risks) on the potential options discussed in this call for evidence that may be necessary to achieve the Government's objectives?*

Please see our detailed response contained within the attached Table, and summary contribution below.

Government state that the beneficiaries of support under EMR can achieve the "market rate" at low cost/risk. If this is the case then it is logical for govt to act as the counter-party not only for the CfD FiT, but also as the counterparty for the long term energy PPA as well, as it provides a risk free (for both parties) service to those independents seeking PPAs. The govt purchasing agency (**PPA Offtaker of First Option**) would then place this energy in the market (either through trading, if supremely confident, or through a purchase obligation on suppliers if not) and provide the necessary confidence for investors. Under this scenario it would be simpler to implement a fixed FiT of course, but the above allows the flexibility for the CfD FiT to be retained for those technologies for whom it is appropriate (e.g. nuclear and CCS). The terms of the PPA of first option would be expected to be less generous than those of a "market sourced" PPA. The logic underpinning this is that the default PPA will indeed remove risks from the holder in line with government policy ambitions and as such should allow a more favourable cost of capital to be achieved. This will be translated into a lower strike price. In order to provide an "incentive" for holders to move to a market based PPA, the strike price for these would be higher and a break clause inserted in the default PPA which allowed the holder (not govt) to move to a market based

PPA at defined points in its life. As government holds the firm view that the market conditions for PPAs should improve, it should expect those on default PPAs to move to market based ones at their earliest opportunity. Govt has argued that a fixed FiT removes any incentive to optimise availability, against market incentives. This is perfectly logical where an operator has a *choice* of when they are going to generate. In the case of variable renewables, the incentive is to maximise production, as variable costs are always so far below market price. The scheduling and optimisation of "maintenance" is beside the point as this is primarily based on availability of required access windows (offshore) and minimum loss of resource (onshore) rather than "price".

Provide an effective **supplier "pull"**. Government has so far not properly considered the idea of a more sophisticated allocation of the costs of support on suppliers, ruling it either too complex or inappropriate. However, without it there is no incentive on suppliers to act in a *differential* manner. Allocation of the costs of support COULD be allocated according to the carbon intensity of the supplier's portfolio (gCo2/kWh), with the "darkest" bearing the most cost. With proper design, this could provide an effective incentive to move towards a lower carbon portfolio. In the ultimate, where all generation is low carbon, the costs of support will have declined to zero. Work would need to be done (as per the RO) to ensure that the costs/rate of desired de-carbonisation/burden on customers were all considered on a holistic basis. The Committee on Climate Change has recommended to government a binding 2030 emissions performance target of 50gCO2/kWh for the power sector as a whole, which would rule out the development of coal and gas plants without carbon capture technology.

9. *What are your views of the potential for market distortions and possible impact on the wider market?*

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, as is the case in GB, regulatory intervention is the only effective route to resolution.

We would advocate wholesale reform but acknowledge that in the short term this is unlikely to be deliverable (although it should be adopted as a medium term objective). In the near term we need an Offtaker of First Option, preferably as the counterparty for both the CfD and the PPA. This should be coupled with a cashout reform process which is expanded in scope to properly acknowledge the changing future generation/demand mix and addresses the need to incentivise and provide flexibility and balancing services on a competitive basis against known, stable and predictable costs.

10. *Can you identify and explain any other viable options (voluntary, competition based, regulatory or otherwise) that should be considered?*

Please see our contribution to the various themes in Table 1.

# Annex 1 - PPA Background

The state of the PPA market can better be understood by considering the drivers behind the need to offer PPAs.

A large integrated utility will be constantly reviewing the "make or buy" decision for its plant portfolio over all timescales. In the short term, this will be in the form of exercising the *option* to generate conferred by existing plant or the *option* (when it becomes available) to purchase at below current in-house marginal production cost, from the market.

New plant investment will also be considered against the prospects for fixed and variable costs, over the lifetime of the asset (and of course the prospects for revenue). Depending on the contracting strategies adopted, fuel costs may range from largely fixed (long term nuclear fuel contract) to largely variable (shorter term gas purchases).

Other things being equal, unless a long term purchase contract offers a price so low as to be virtually risk free, together with (if possible) flexibility with regard to the offtake volume terms, a utility will always choose to invest in its own assets, or seize short term purchase opportunities as they arise. Revenues from the generation and supply margins (either current or forecast) should allow asset investment/renewal to take place at the "right time" to ensure no pressures on either portfolio capacity or the balance sheet.

The above assumes that there is little or no risk to the final volume/price forecasts that the integrated utility has for its supply business (the "hedge" has a high degree of certainty).

## Drivers for Change

Why would an integrated utility offer to purchase power from a third party, rather than generate itself?

In the short term (3-5 years) to cover a "capacity gap" created by the need to replace a significant proportion of its asset portfolio (investment "hump").

In the short term (3-5) years to cover a "capacity gap" created by a sustained and significant increase in its supply business numbers (provide energy until assets can be built out to capture the generation as well as supply margins).

In the long term (15-20 years) to comply with a disruptive change to the energy landscape, whereby its existing generation portfolio is either under threat or being forced into retirement through government policy, requiring a level of sustained internal investment spend that the business cannot resource.

## The Landscape before EMR

It is easy to think of the Renewables Obligation and the EU 2020 renewable target as being part of the same initiative. For the government, the imperative is to meet the target, for the supply businesses, the target is not *directly* relevant, what is relevant is *minimising the costs* (both in the short and longer term) imposed by government on the industry by its mechanisms to incentivise progress towards the target. Whilst one does indeed facilitate the other, the fact is that in the minds of asset portfolio planners, prior to the introduction of EMR the RO would still have been in place as a policy instrument, post 2020 and this major change in strategic assumption needs to be taken into account. The *Renewables* Obligation would have been seen as the main policy instrument to achieve the decarbonisation of the electricity sector through the 2020's as advocated by the Committee on Climate Change. Business forecasts would have projections of costs for the supply businesses through the 2020s which would have been monotonically increasing, as the RO ramped up. Under these circumstances, it would always have been cheaper to possess ROCs than pay the buyout penalty. Demand would be increasing (pre-financial crisis forecasts) and old fossil plant would be decommissioned (or forcibly retired due to EU regulations). Given an expectation of a much longer term and a much greater volume where potential penalties for non-compliance were in play, it made sense to enter into long term PPAs, which would hedge out *longer term* supply business *obligations* and allow *own* asset investment decisions to be made at a much more *considered* pace over a longer timeframe.

## EMR, Uncertainty in the Policy Landscape and the Financial Crisis

The investment figures required for transmission and generation to make the required changes in the energy landscape are widely accepted. There are also accepted views on the ability (or not) of the utilities to fund the changes in the generation mix. Since the financial crisis, not only has their ability to invest in *"own"assets* been reduced, but the treatment by companies and rating agencies of *long term commitments* (e.g. PPAs) on the balance sheet has been subject to revision. There is an argument that with much reduced balance sheet strength, opportunities for any deployment of remaining balance sheet capacity place investing in long term PPAs much lower down the priority list than they did before.

Demand forecasts have dropped significantly, both over the short and medium term. Government now believe that there is unlikely to be a significant "capacity squeeze" in 2015/2016. The option of relying on "mothballed" first generation CCGTs to bridge any gap that might unexpectedly arise is being actively investigated. Increasing interconnection (East West, Brit Ned etc) also plays its part in reducing the potential capacity required to meet any tightening of the margin.

Lower demand forecast out into the future means *less* renewable capacity is required to meet the 2020 target. The RO is now "self adjusting" (in contrast to the fixed percentage targets of its early years which were responsible for the damage to its reputation) and the target for future years will reflect current and anticipated build rates, which will be conditioned by expectations of price and volumes available in the market (which is now smaller).

The planning assumptions used 4 years ago assumed that LCPD plant would largely "retire" at the end of its LCPD regime in 2015, giving rise to a capacity "squeeze". Whilst some capacity will retire, at least 3 GW is planning to "return" as either dedicated biomass or co-firing plant.

In energy terms 3 GW co-fired coal is roughly equal to 9 GW of wind. This means fewer requirements for new plant to meet the *national energy balance* and an increased supply of ROCs over and above past forecasts.

It was noted above that the expectation for the RO would legitimately have been an *increasing* target through the 2020s. With the closure to new entry in 2017 AND the beginning of "dropout" from the RO (projects commissioned in 2002 will cease to be eligible for support in 2022), the level of the RO will *decline.* Business planners will now have a reducing requirement for ROCs, incentivising the use of shorter term purchasing strategies.

Those participants in the market who are able to offer PPAs on a speculative basis (i.e. not implicitly hedged by a supply business) will be looking for shorter term deals AND considering the maximisation of value through trading power and ROCs independently, rather than as a "package". This means that increasingly there will be free or unallocated ROCs available on a shorter term basis, in turn allowing utilities the *option* of short term ROC purchases or paying the buyout price.

EMR has had implications significantly beyond the debate on whether CfDs will "work" or not:

- Decarbonisation will not be based on a "renewables" strategy throughout the 2020s, but a *low carbon* one. Renewables no longer have an exclusive place in the "solution strategy"
- The use of financial *penalties* to incentivise changes to the plant portfolio will disappear with the demise of the RO
- Decarbonisation will be based on a *voluntary* decision by companies/investors, based on the attractiveness of new low carbon plant investment, versus remaining with existing assets part way through their lives, or investment in conventional plant against predicted costs of operation.
- The capacity mechanism is proving to be an unresolved source of uncertainty and differential damage for renewables. Govt originally justified its consideration on the basis that "the lights might go out" in the short term (2015-2017). This probability is receding for the reasons detailed above. However, any mechanism will be a "win/win" for the utilities. It will inevitably remove value from the energy market and redistribute it into the capacity market. Variable renewables obviously cannot feature to any extent in the capacity mechanism. Qualifying plant will either be existing (mothballed) capacity or "dual purpose" capacity. Both of these will be able to take a share of the <u>energy</u> market as well as the capacity market (maximising the return on investment). This will further reduce the opportunity for renewable energy deployment.
- The design of the mechanism will be heavily influenced by the utilities and will reward capacity and (possibly) energy as noted above. What it will not do, unless the terms of reference are revised, is deal with the more important question for variable renewables – that of ensuring that sufficient *flexibility* is present on the system to deal with increased variability. The current plant mix of the Big 6 is reaching the limits of its capability to cost effectively balance additional variable generation. This will be exacerbated by the retirement of coal plant and its (partial) return as biomass fuelled generation – which will not wish to flex to the same degree. No investment in additional

flexibility will be made until utilities have assurances that it will be paid for (backed by government "guarantee")

- The carbon floor price will either be absorbed and passed on to consumers (via an increased price for electricity), or ameliorated to ensure that prices do not rise unacceptably/economic competitiveness is not compromised. It is unlikely to provide a sufficient incentive to decarbonise at the rate needed to accommodate the renewable industry ambitions for new capacity.
- Suppliers will have no incentive to exert "supplier pull" regarding changes to the generation mix. Current proposals assume that the costs of the CfD support scheme will be levied according to market share only. Thus two suppliers with equal market share, one backed by gas, one by renewable, will pay exactly the same support levy into the CfD system

One of the objectives of EMR is to ensure that low carbon generation achieves "parity" in the market with other generation technologies – by tailoring support to achieve overall "market rates" for new capacity. Parity is NOT SUFFICIENT for investors to make a *positive* choice, particularly given the long term nature of such investments, which rely heavily on a government policy framework which will continue to have significant uncertainty present in both the generation and supply sides of the industry (see below).

It fails to provide any strong incentive for customers/suppliers (in the broadest sense) to:

- Retire *existing* capacity with significant remaining life and known costs (which can be passed on to the market), in favour of new low carbon capacity
- Choose low carbon capacity in preference to other technology choices (e.g. gas) for new investment. Gas will achieve "market" rates because it sets the market price. It also provides the opportunity to **beat** the market as operation can be value weighted.

**Supply** is often overlooked in the debates on energy *policy,* with the focus usually being only on *price*. The ability of the large utilities to offer long term contracts of any sort (assuming other issues are resolved) is directly related to their long term view of their associated supply businesses, their volume, make up and shape. Most of the industrial and commercial sector are now "active" in the market and require competitive quotes. However, some 80% of the domestic market can be "relied upon" by the utilities as relatively "firm". It is this *stability* which allows consideration of long term power purchases

Every intervention in supply (and there are many) is underpinned by the drive to *increase* competition, ease of market entry etc. This is often accompanied by the spectre of radical reform of the supply market. Against this background of uncertainty and perceived erosion of the de facto "franchise", utility business planners will have a decreasing view of what constitutes "firm volume" in the portfolio for the years ahead. In turn, this will be reflected in their willingness to countenance any purchase agreements which have a long term tenor.

Data previously provided by external sources suggests that the utilities do not require any additional ROCs to cover their "de facto franchise" obligations and can/will focus on shorter term hedging strategies.

## Conclusions

It can be argued that the requirement to use or offer long term PPAs to potential competitors and facilitate their entry into the market is not a "natural" feature of a steady state market, characterised by vertically integrated utilities that can self fund the necessary asset portfolio to meet their objectives. A mixture of own generation and a strategic short/medium term marginal trading capability is the natural profit maximising strategy for a utility.

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The drivers which facilitated the provision of PPAs on reasonable terms are no longer in place.

- Compliance with/costs associated with the RO is now a "solved" issue within utility medium term plans. The RO is a declining business consideration.

- Reduced demand and plant conversion/commissioning mean that the lights will "stay on" for the next 10 years plus. Major capacity decisions can wait – there is no incentive to act in the short term, based on partial and uncertain policy landscapes.

- New gas capacity is *not* prevented from entering the market, merely waiting to ensure that a sufficient revenue stream is available, once the current policy uncertainty subsides.

- In the absence of any strong *differential incentives to decarbonise*, investment in new capacity will be based purely on overall economics. Existing plant life extension and "do nothing" are potentially valid options under EMR as it is currently constituted.

**Solutions to Achieve Government Policy Objectives**

Government believe that the beneficiaries of support under EMR can achieve the "market rate" at low cost/risk. It follows that government could therefore act as the counter-party not only for the CfD FiT, but also as the counterparty for the long term energy PPA as well, as it provides a risk free service to those independents seeking PPAs. The govt purchasing agency (**PPA Offtaker of First Option**) would then place this energy in the market (either through trading or through a purchase obligation on suppliers) and provide the necessary confidence for investors. This provides benefits equivalent to a fixed FiT, but allows the flexibility for the CfD FiT to be retained for those technologies for whom it is appropriate (e.g. nuclear and CCS). The terms of the PPA of first option would be expected to be less generous than those of a "market sourced" PPA. The logic underpinning this is that the default PPA will indeed remove risks from the holder in line with government policy ambitions and as such should allow a more favourable cost of capital to be achieved. This will be translated into a lower strike price. In order to provide an "incentive" for holders to move to a market based PPA, the strike price for these would be higher and a break clause inserted in the default PPA which allowed the holder (not govt) to move to a market based PPA at defined points in its life. As government holds the firm view that the market conditions for PPAs should improve, it should expect those on default PPAs to move to market based ones at their earliest opportunity. Govt has argued that a fixed FiT removes any incentive to optimise availability, against market incentives. This is perfectly logical where an operator has a *choice* of when they are going to generate. In the case of variable renewables, the incentive is to maximise production, as variable costs are always so far below market price. The scheduling and optimisation of "maintenance" is beside the point as this is primarily based on availability of required access windows (offshore) and minimum loss of resource (onshore) rather than "price".

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