



DECC Consultation Co-ordinator
3 Whitehall Place
London
SW1A 2AW

10 March 2011

RWE UK response to the DECC Electricity Market Reform Consultation

RWE welcomes the opportunity to respond to this consultation. We are responding on behalf of RWE companies operating in the UK:

- RWE npower owns and operates one of the largest and most diverse portfolios of power generating plant in the UK with over 9,000 megawatts (MW) of large gas, coal and oil-fired power stations and cogeneration plant. Our retail arm, npower, is one of the UK's leading suppliers of electricity and gas with around six million customers.
- RWE npower renewables, the UK subsidiary of RWE Innogy, is one of the UK's leading renewable energy developers with an operational portfolio in the UK of 535MW and a potential UK development portfolio of over 8,500MW, including wind farms, hydro plant and biomass generation to produce sustainable electricity.
- RWE Supply & Trading is one of the leading companies in European energy trading and is responsible for all of RWE's activities on the international procurement and wholesale markets for energy.
- Our joint venture with E.ON UK, Horizon Nuclear Power, is developing up to 6GW of carbon free nuclear power.

We welcome the progress that has been made in the EMR consultation in clearly establishing the principles for market reform and setting out the direction of travel. In particular, we welcome the progress made in defining the features of the low carbon revenue support proposals to include:

- Broadening the scope of the low carbon support mechanism to include the full range of low carbon technologies;
- Keeping all generation in the market, retaining the efficiency of dispatch, maintenance and siting;
- Delivering Government objectives efficiently to minimise cost increases for consumers; and
- Bringing new investment into the market.

However there is still significant uncertainty and much now needs to be done to clarify the detail of the proposals. It is crucial that momentum is not lost and Government now needs to turn its attention to the timely delivery of a comprehensive EMR White Paper and associated legislation which is essential for investment needs. We look forward to close engagement over the coming months with the EMR delivery team to work up the necessary detail.

RWE npower

Trigonos
Windmill Hill Business Park
Whitehill Way
Swindon
Wiltshire SN5 6PB

T +44(0)1793/89 30 83
F +44(0)1793/89 29 81
I www.rwenpower.com

Registered office:
RWE Npower plc
Windmill Hill Business Park
Whitehill Way
Swindon
Wiltshire SN5 6PB

Registered in England
and Wales no. 3892782

Efficient markets need to remain at the centre of the EMR

The UK has pioneered competitive and open energy markets and these have served the UK well in terms of timely investment to deliver secure and affordable energy.

Maintaining market integrity and efficiency should be a primary goal of EMR, including ensuring full consideration of interaction of supply with demand side, to ensure that Government objectives are met in the most economically efficient manner possible and at least cost to consumers.

We welcome the commitment in the EMR consultation to retaining the exposure of all generation to the market to ensure the efficient siting, operation and maintenance of plant. It is crucial that this is delivered in the detailed design. Low carbon generation should be fully exposed to the price signals in the traded electricity market to ensure that parties have the incentives to minimise imbalance cash out. However, we note that the proposals to introduce a capacity mechanism, particularly if a broad-based capacity mechanism, could dilute and distort significantly the price signals in the market by remunerating all plant that remains on the system regardless of its characteristics with respect to the flexibility required to balance intermittent low carbon generation.

Focus on the delivery of large scale low carbon generation projects

We support the objective of levelling the playing field to ensure all low carbon technologies can contribute to the delivery of the Government's climate change and energy goals. We welcome the fact that the consultation shifts the debate towards the expansion of low carbon generation more generally and away from support for specific low carbon technologies only.

The primary issue for the EMR to address is to see investment in Round 3 offshore wind projects and the first wave of nuclear as soon as possible, as well as CCS retrofit to demonstration projects in due course. However we do not think it is sensible to try to second guess what the market will look like in 2025 and beyond. The new low carbon support mechanism (whether CfD or PFiT) should make these large scale low carbon investment projects attractive to new sources of finance by providing stable, predictable and transparent rates of return over appropriate payback periods and commensurate to the level of risk.

There is a need to ensure that whichever mechanism is implemented, it is flexible enough to accommodate the needs of both large scale and smaller scale projects, with the design of the mechanism being proportionate to the scale and complexity of the project and the risks and costs associated with different types of projects.

The reforms should be defined so as to provide the minimum set of interventions to allow investment in the first wave of investments to happen, rather than trying to encompass everything at once, which will inevitably result in unforeseen outcomes. We have concerns regarding certain elements of the package and its coherence in this regard.

Early clarification of transitional arrangements is crucial

We welcome Government's reaffirmation of its commitment to no retrospective changes to the established rights under which investment commitments have been made. This is crucial to maintain investor confidence in the UK market and to ensure that the transitional arrangements do not stifle current development or delay investment decisions.

To maintain confidence in the UK market, it is important that rights established for investment made under the RO are retained. Government are proposing certain grandfathering arrangements, which are

welcome. However, it is critical that Government provides clarification of the detail of the grandfathering provision and the future operation of the RO within the EMR White Paper, explicitly stating that grandfathering covers all the constituent elements of the current RO scheme on which investments were based (i.e. the index linked buyout price retained at current levels, the ROC multiples and the basis on which ROC values will be calculated).

We have particular concerns regarding the transitional arrangements accommodating the lead time for offshore wind. We welcome the proposed parallel running of the RO and the new low carbon support mechanism. However, the four year overlap is insufficient, leaving projects with long lead times, in particular offshore wind, in a position where they are too late to take the full benefit of the RO, but too early to have full understanding of the detail of the FiT. The most straightforward means of addressing this would be to extend the period of parallel running (i.e. extending the RO to 2020 and the RO support to 2040).

Carbon price support will not deliver new large scale low carbon investment

Carbon price support does not provide the necessary certainty for investment in new low carbon generation due to the diminishing benefits of carbon pass through as the sector decarbonises.

The EU has set emissions reduction targets through the EU ETS and this should remain the central mechanism for determining carbon prices. Introduction of a carbon price support mechanism over and above the EU ETS will materially impact on the price of UK electricity. This could have significant impact on prices for UK consumers and prices (and so competitiveness) for UK industry relative to other EU countries. It could also result in a greater level of input from overseas of power and remove any export possibilities for the UK. It could also lead to significant windfalls to existing low carbon generators (particularly existing nuclear power stations). To minimise these impacts, the tax should be set at a nominal rate to 2018 only impacting once new large scale low carbon investment comes on stream.

We are concerned that the rate of the proposed tax could be decoupled from the EU carbon allowance (EUA) price resulting in an undue impact on UK competitiveness particularly if, for example, the Commission strengthens the EU ETS or the EU moves to a 30% emissions reduction target. The method of setting the tax needs to be through a clear link to the EU ETS allowance price.

The level of the carbon price support needs to be visible when we sell future generation capability into the wholesale market. To avoid impacts on market liquidity, the tax rate should be set annually for a moving 4-year window, providing advance visibility. To this end, the carbon price support mechanism should not come into effect (even at a nominal rate) before 2015 at the earliest.

As it is a tax, it will not provide the certainty required for new investment. It will, however, increase political and regulatory uncertainty and so could curtail investment by users of energy in the UK who will be concerned at the risk of increases in the rate of the carbon tax affecting the economic returns and competitiveness of their UK business.

The case for considering a capacity mechanism as part of the EMR has not been made

The case for contemplating the introduction of a capacity mechanism at this stage has not been made and this should not therefore be a priority issue for the EMR White Paper. We have set out in our detailed consultation response why a capacity mechanism is not required and provide evidence to back this up.

Such an intervention in the market now will undermine the capability of the market to deliver an efficient combination of generation capacity and demand response at lowest cost to consumers. It simply is not

possible to define the future energy mix or response capability at the point at which a problem might arise, so any proposed solution will necessarily be speculative and more than likely inadequate or wrong.

The EMR consultation downplays the cost to the consumer of intervention in the capacity market. Experience around the world suggests that capacity mechanisms have a number of undesirable effects on the economic and efficient operation of electricity markets i.e. they undermine price signals, impact on the efficient development of demand-side response and forestall the innovative development of market-based solutions such as storage, interconnection and energy efficiency. Furthermore, there is no guarantee even with a capacity mechanism that overall security of supply will be enhanced if the subsidised capacity is of the wrong type, or in the wrong place. Our detailed response to the consultation provides evidence from other capacity mechanisms in other jurisdictions to underscore these points.

Price signals play a critical role in the successful deployment of smart metering and the participation of the demand side in the electricity trading arrangements. Any intervention that dilutes or impacts on the price signals such as a capacity mechanism will threaten the success of this policy area, which could play an increasingly important role in balancing the system going forward.

There are known issues with the present cash out arrangements that require review in the context of a consideration of capacity requirements and associated incentives. The present cash out arrangements could be improved to make them more cost reflective of some of the actions that National Grid take to balance the system. Examples of these are the methodology used to price the reserve contracts and the lack of any pricing signal when demand control is instructed. Correctly pricing these actions would produce cash out prices that would provide signals to parties to balance the system either by increasing supply or reducing demand.

Successful resolution of these issues will not only provide signals in the short term but will feed into future investment decisions on capacity and delivery of demand-side initiatives such as smart metering and associated tariffs, without the unintended and adverse effects of a capacity mechanism.

If concerns remain about the capacity margin, Government should seek to refine and build on the existing reserve market (the Short Term Operating Reserve), with adjusted cash out prices, rather than introducing a new mechanism. If designed carefully, such incremental STOR procurement to provide a pre-defined level of additional capacity could have a minimal impact on the market.

Emissions Performance Standards

The proposal for an EPS duplicates existing Government policy for new coal plant and is unlikely to provide any additional certainty or incentive for investors in low carbon generation. The introduction of an EPS opens up the risk of further intervention and may discourage investment in the new CCGT plant which will be needed to maintain security of supply during the transition to a low carbon economy.

We are pleased that Government has recognised and attempted to ameliorate this risk. The principles of no retrospective introduction of an EPS for existing plant and grandfathering of the EPS level for new investments will be crucial to maintaining confidence in the UK as a place to invest and should be enshrined in primary legislation.

We need clarity on circumstances under which existing plant will be subject to an EPS in the event of significant life extension or upgrade. However, the EPS requirements must not undermine the ability of plant to invest in the upgrades necessary to facilitate plant changing its role over its lifetime to meet potential gaps in the market (i.e. for flexible back up plant) at a relatively lower cost than replacement new plant. An EPS should thus apply for the full plant life and not be triggered by a significant life extension or upgrade, unless it is demonstrable that any revised standard can be met through best

available techniques as set at the European level (akin to the BAT Reference Review process for setting emission limit values).

Low carbon support mechanism

We welcome the proposals to support the full range of low carbon generation technologies as part of a package of measures designed to meet the Government's targets for decarbonisation. This will allow government objectives and targets to be met more cost effectively.

The priority is the need for a mechanism to underpin large scale low carbon investment to ensure Round 3 wind, the first wave of new nuclear and CCS retrofit of demonstration projects and deliver stable and predictable returns commensurate with risk.

We believe a 'Low Carbon Obligation' based on the ROC approach would have been the simplest way of achieving this with minimum disruption to the delivery of investments and the market. The Government has decided against this approach seeing greater potential merit in a more targeted revenue support mechanism. This should be designed to deliver more certain returns to attract capital from new investors who are not used to taking electricity market price risk. The scale of the investment required in the UK by 2025, higher than the other EU countries, means that one crucial measure of the effect of the EMR will be its success in attracting new investment.

A contractual revenue support mechanism is best suited to satisfying the requirement of investors for stable, predictable and transparent returns commensurate with risk, independent of whether a CfD, PFiT or variant is chosen. Both a CfD and a contractual PFiT could be designed to deliver investment in large scale low carbon generation. As currently framed in the consultation, however, the CfD appears to most closely offer the regulatory certainty that investors are seeking subject to resolving some of the complex issues associated with implementing this approach (such as defining the strike and indexed power price, the level of support and contract duration).

Government has focused on the cost of capital as a reason for preferring CfD, believing this will be attractive to investors and reduce costs to the consumer, compared with a PFiT which fits better with the market. However, the cost of capital will be fundamentally dependent on how risks are shared between developers and government and we believe that some form of contractual framework will be needed to allocate risk, independent of whether a CfD, PFiT or variant is chosen.

For portfolio generators, exposure of their low carbon generation portfolio to the carbon price provides an important hedge against the impact of rising carbon prices on their fossil generation portfolio and is a significant consideration in any low carbon investment decision. A two-way CfD, as proposed in the consultation, would remove exposure to the carbon price and Government needs consider the implications for investment in low carbon generation.

Government should not underestimate the complexities of any contractual relationship to deliver low carbon. It is critical that the key delivery elements of the Government's proposals are defined as soon as practicable (such as the cost recovery mechanism and defining the contractual counterparty).

Auctions are not feasible for Round 3 projects and the first wave of new nuclear

In theory, auctions can work well where there are a significant number of credible bidders, the requirements are well specified and understood by the bidders and the costs known.

Round 3 offshore wind and new nuclear projects do not meet these criteria and hence we do not believe that an auction would be a feasible mechanism for setting the level of support for these projects.

- Nuclear and Round 3 sites have already been auctioned and awarded, reducing the number of credible participants in any subsequent allocation process. Another auction will increase uncertainty, stifle early stage development and introduce delay in delivery of these projects.
- With limited experience of delivering such complex technical projects in the UK, there is incomplete information about the costs of deploying these projects. An auction process introduces the prospect that the least realistic bidder might win low carbon support, which in turn could lead to the non-delivery of projects (the ‘winners curse’ as demonstrated by the NFFO auctions, where only 30% of projects were built).
- Being in a position to bid is itself very costly. With a high level of risks and uncertainties surrounding Round 3 offshore wind projects and the first wave of new nuclear, developers will need to go some way down the development cycle before they can bid into an auction. Too few credible participants mean that the auction would not deliver a competitive price.

For these reasons an administered process involving appropriate contractual arrangements and structures will be the only way of satisfying investor requirements, while seeking to ensure projects deliver value for money.

Treatment of Combined Heat and Power (CHP)

The proposals in the EMR threaten to undermine both existing and future investment in new high efficiency gas CHP unless emissions associated with heat production are removed from the calculations for both the carbon tax and the EPS levels.

Treatment of biomass

The treatment of biomass emissions under the proposed EPS should be consistent with the EU ETS monitoring, reporting and verification guidelines, which currently zero-rates emissions from biomass fuel when calculating plant carbon-dioxide emissions.

EMR must avoid unintended consequences on company balance sheets

Any market reform must take care not to unduly increase the liabilities on utility balance sheets which would result in reduced capital for investment and raising of investment hurdle rates. This would extend to any guarantee requirements placed on a CfD as this would utilise capacity within corporate credit headroom for credit rating evaluation purposes. Consequently, reducing the level of capital that could be raised, resulting in a longer lead time to deliver the low carbon generation required to meet Government’s targets.

The way forward

The issues raised by the consultation are many and complex, as well as highly interactive. To maintain progress and avoid a hiatus in investment, the EMR White Paper needs to focus on a minimum set of interventions which will deliver the required investment and at lowest cost to the consumer.

A sense of urgency is required in terms of need for action and timely outcome to the EMR. We need clarity this year and detail by the end of 2012. We are concerned about reports that the White paper has slipped from May to July this year and could be delayed to Autumn. Furthermore, the legislative timetable has now slipped to May 2012 for the introduction of the Bill.

The Government's rejection of extending the ROC mechanism to all low carbon generation will itself result in a delay in the clarity and certainty of the mechanism that investors require. We are also concerned about potential scope creep of the EMR to include network issues and liquidity. These are being considered elsewhere and would add further to the complexity of the market reforms and could undermine progress. We also believe that there is the potential for unintended outcomes.

We look forward to working with Government on the detail of the proposals to deliver an EMR White Paper which is sufficiently comprehensive and detailed in its thinking to lead to a decision. Focusing on delivering an appropriate minimum set of interventions, together with parallel tracking of the legislation and the setting up of the institutional arrangements and implementation detail, will be necessary if Government is to make timely progress to facilitate early investment in either Round 3 wind or first wave new nuclear projects.

Yours sincerely,

John McElroy
Head of Policy and Public Affairs

RWE UK response to detailed EMR questions

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

It is worth noting that the present market arrangements have delivered on security of supply, low prices and reducing emissions as described on page 22 of the consultation document and in particular:

- delivered the almost 30GW of gas generation currently in operation and maintained an adequate capacity margin;
- resulted in electricity prices which have been comparatively low and fairly responsive to movements in fuel costs;
- supported the deployment of increasing amounts of renewables from 3.1GW in 2002 to 8GW in 2009; and
- reduced greenhouse gas emissions by more than 25% compared to 1990 levels.

The existing arrangements have already evolved to meet challenges along the way and there is a very strong case for a minimalist approach to reform which would address the issues relating to high capital cost, low carbon generation (i.e. offshore wind and nuclear), and leave the rest of the market arrangements as they are today.

For example, the current renewables support mechanism is fully compatible with the existing trading arrangements. We believe a further evolution of the RO into a 'Low Carbon Obligation' could have helped to move the UK towards its decarbonisation objectives with minimum disruption to the delivery of investments and the market. The Government has decided against this approach seeing greater potential merit in a more targeted revenue support mechanism to attract new investors.

We recognise that the scale of the investment challenge facing the energy sector is huge. Significant capital investment in new electricity generation capacity will be required over the next two decades to deliver the Government's decarbonisation and renewable energy aspirations. The EMR estimates a capital requirement of £70-75 billion in low carbon generation by 2020 alone, and high rates of capital investment in generation infrastructure will need to be sustained into the 2020s.

The scale of investment required to deliver the Government's low carbon ambitions is indeed difficult, if not impossible, to fund from utility balance sheets alone. UK Government is keen to make investment in low carbon attractive to a wider range of investors to address this restriction.

Ensuring the right market structure is the crucial first step in delivering future investment. To make the investment more attractive to new investors, who are not used to taking electricity market price risk, there are two key issues:

- that the returns are stable and predictable and commensurate with the risks that are being taken, and
- that the investment can be compared to other opportunities investors have to deploy similar amounts of capital in large infrastructure investments.

In this context, a contractual revenue support mechanism is most likely to satisfy the requirement of investors and lenders for firm returns from the low carbon support mechanism, that are protected from regulatory risk, independent of whether a CfD, PFIT or variant is chosen.

Another key element to investor confidence will be the track record of the first few projects in being delivered on time and to budget. As confidence grows in low carbon investment a greater range of investors is likely to be attracted.

However, it is unclear whether these investors will be keen to take construction risk as well and so such investors may delay their participation until post construction refinancing. Therefore other sources of finance may be required during construction. One such source would be the Green Investment Bank if it was able to invest alongside project developers during construction on a like for like 'pari passu' basis.

2. Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

As noted above, existing market arrangements have delivered on security of supply and just as importantly they have had to evolve to meet new challenges along the way. Some argue that the scale and pace of change now required is such that the present market arrangements cannot deliver security of supply in the future. We go on to argue that this is not the case, there is no reason that the present arrangements cannot evolve to deliver government objectives in the future.

In relation to the particular question of security of supply, the case for the consideration of any form of capacity mechanism as part of EMR has not been made. Other than the proposed Significant Code Review (of cash out methodology) we do not consider any further intervention to be required. We have the following comments on the discussion in the consultation document.

The peak wholesale electricity price may not rise high enough (low peak prices) – it is widely known that there were a number of compromises in the design of the present cash out arrangements. Ofgem has signalled its intention to carry out a significant code review into the present cash out arrangements. This review is the place reforms should be assessed to ensure that the correct market signals for capacity are provided. When these issues are resolved, the GB trading arrangements will give robust incentives on companies to remain in balance with the reserves maintained by National Grid then providing a sufficient safety net for unexpected variations within settlement periods. As wind penetration increases, market prices will provide the incentive for investment in further flexible generation which will be able to benefit from the changing profile of hourly prices.

We do not accept the arguments, made by some, that occasional incidences of price spikes in the balancing market are unacceptable. Indeed, we believe it is an important part of delivering an efficient level of capacity and demand response. The NETA/BETTA market has already been working for 10 years and numerous price spike incidents have occurred during this time without a requirement for intervention. In fact most of the political scrutiny of price levels is around the *average* level of customers' bills rather than prices in the balancing mechanism in particular half-hourly periods. In general, commentators and observers of the industry and the media recognise the difference between balancing prices (which end-users do not see) and consumers' bills. Likewise most well-informed industry experts recognise that adopting policies that suppress normal price signals will result in higher overall bills since capacity would be delivered through an administrative process that is inefficient (as demonstrated in the pre-NETA market).

Management of peak price uncertainty – The current market arrangements allow for efficient hedging of peak price volatility and encourage efficient investment. However, forward prices are only one of the signals that investors model when making investment decisions. Investors also model the potential 'extrinsic' value that results from investing in plant flexibility (including the rents that can be obtained from providing services to National Grid in the balancing system). Strategic considerations, such as the way a

company wishes to position itself in retail markets, are also important. Finally the risk appetite of the companies and their balance sheet structures will affect decision making.

We would observe that the inherent uncertainties in the sector have not deterred investment so far in CCGT's and upgrading of existing plant that ensures it can provide the flexibility that the system requires. If anything, higher penetration of renewables makes the returns from investment in flexible generation less uncertain, since flexible capacity will be needed more frequently.

Policy Uncertainty – There is no doubt that EMR introduces a significant degree of policy uncertainty. However, it is for the government to determine energy policy and decide on EMR as soon as possible. The overall direction of policy with respect to renewable penetration and decarbonisation has been clear since the 2020 renewables and 2050 decarbonisation targets were adopted. A commitment to some 10GW of new capacity has been made in this context. As far as RWE investments are concerned, the increasing need for flexible operation from 2015 onwards has been explicitly taken into account in plant specifications.

Investment cycles in generating capacity – There has been a steady flow of investment in new generation over the last decade with more due on stream in the next few years. This suggests that investors take a more considered view of a package of investment signals than the consultation suggests and take a relatively long term strategic approach.

Low levels of liquidity in electricity wholesale markets - We support the work of Ofgem in considering the issue of liquidity under the current market design. However, we do not believe the case for radical change has been made. We are working hard to improve liquidity in the electricity market by supporting developments such as the N2EX exchange, which are now established in the GB power market. Traded volumes have grown consistently since May 2010. In November 2010, N2EX announced that the day ahead auction would form the index for a series of cleared financial contracts on UK power and these are now appearing on the NASDAQ system. N2EX also recently launched an OTC spot market for companies who don't have the appetite to clear through the auction. We believe that, in time, financial contracts will attract new entrants to trading forward power, and will increase spot/auction volumes as financial hedges are converted to physical. Increased interconnection with the Netherlands (recently) and with Ireland (next year) will also increase the linkage of the UK market to neighbouring markets and increase the number of market participants and traded volumes. We are pleased that Ofgem has recognised that the industry is making efforts to improve liquidity and expect that the spring review will confirm that progress is being made.

We believe that the market modelling by Redpoint on behalf of DECC for the EMR has a number of shortcomings which means that investment is underestimated. In particular it does not appear to correctly capture the following factors affecting price determination and consequently investment decisions:

- allocation of the costs of 'unit commitment' (i.e. start costs) in bidding behaviour,
- incorporation of the opportunity costs of companies offering into day-ahead markets (i.e. the forgone possibilities to offer the plant into intraday, balancing and reserve markets),
- the option value of highly flexible plant (this will be increased by improving price signals in balancing markets and renewable penetration),
- strategic behaviour by companies in formulating their investment strategies and the feedback effect on the size and efficiency of retail supply businesses,
- future possibilities for companies to reduce fixed costs on existing stations through the application of new technology or different working practices,
- the role that planned (eg, Britned and Eastwest) and new interconnection could play in increasing system resilience and reserve capacity, and

- developments of new technologies and practices which lead to the increased impact of demand side participation.

We, therefore, believe that current market arrangements are the best way of ameliorating security of supply risks.

Feed-in Tariffs

- 3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?**
- 4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?**
- 5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?**

We have answered questions 3, 4 and 5 together in the following sections.

We welcome proposals to support low carbon generation

In the EMR consultation document, the Government has set an implicit target to 'decarbonise' the electricity industry by 2030. This requires the rate of investment in low carbon generation to increase significantly over the next two decades. As noted in Question 1 above, the scale of investment required will be difficult to fund from utility balance sheets alone. Consequently, we believe that support for low carbon will be important to attract the new sources of finance needed to deliver investment in the large scale low carbon generation projects in the period to 2025 (limited to Round 3 offshore wind, the first wave of new nuclear and CCS retrofit to demonstration projects).

Efficient wholesale markets

The UK has pioneered competitive and open energy markets and these have served the UK well in terms of timely investment to deliver secure and affordable energy. The current market design has served the UK well in the last 20 years bringing forward significant investment in renewables, biomass, CCGT, flue gas desulphurisation and peaking plant.

Maintaining market integrity and efficiency should be a primary goal of EMR, including ensuring full consideration of interaction of supply with demand side, to ensure that government's objectives are met in the most economically efficient manner possible and at least cost to consumers.

Specific measures to support investment in Round 3 offshore wind projects and the first wave of new nuclear and attract new sources of finance

The most efficient mechanism to deliver the investment in low carbon generation required to meet the UK Government's decarbonisation targets would be a clear market price signal from the EU ETS. However for various reasons this carbon price signal has yet to be delivered.

We support the objective of levelling the playing field to ensure all low carbon technologies can contribute to the delivery of Government's climate change and energy goals. However, we believe that the primary issue for the EMR to address is to see investment in Round 3 offshore wind projects and the first wave of nuclear as soon as possible. We do not think it is sensible to try to second guess what the

market will look like in 2025 and beyond and so the market interventions should focus on making these large scale low carbon investment projects (limited to Round 3 wind, 1st wave of new nuclear and CCS retrofit to demonstration projects) attractive to new investors.

The reforms also need to make investment in the first wave of low carbon generation attractive to new sources of finance as utility balance sheets alone are unable to deliver this level of investment in the period to 2025. This may mean the revenue support mechanism will need to go beyond that which utilities require. In particular greater revenue and regulatory certainty may be required by investors and lenders less comfortable with long term electricity market price risk. This will be particularly necessary until the first wave of projects are proven in commercial operation and refinancing can take place to release finance from investors willing to take development and construction risk for the next wave of projects.

A contractual revenue support mechanism is best suited to satisfying the requirement of investors for stable, predictable and transparent returns commensurate with risk, independent of whether a CfD, PFiT or variant is chosen. Both a CfD and a contractual PFiT could be designed to deliver investment in large scale low carbon generation. As currently framed in the consultation however, a CfD appears to most closely offer the regulatory certainty our investors are seeking and may be able to access new sources of finance.

The Government has focused on the cost of capital as a reason for preferring CfD, believing this will be attractive to investors and reduce costs to the consumer, compared with a PFiT which fits better with the market. However, the cost of capital will be fundamentally dependent on how risks are shared between developers and government and some form of contractual relationship will be needed to allocate risk independent of whether a CfD or PFiT is chosen.

We would note that for portfolio generators such as RWE, exposure of their low carbon generation portfolio to the carbon price provides an important hedge against the impact of rising carbon prices on its fossil generation portfolio and is a significant consideration in any low carbon investment decision. A two-way CfD, as proposed in the consultation, would remove exposure to the carbon price and hence this carbon hedge investment incentive. Investors are likely to require a higher rate of return on projects as a consequence.

It is important to remember that Round 3 wind and nuclear projects are capital intensive projects with a longer period between investment decision and first revenue generation. For example, a nuclear project may cost around £10bn and take 7 years from investment decision to commissioning of the first unit. This means developers will have invested an average of £5bn for 7 years before starting to see any return. Developers would be expected to be rewarded appropriately for deploying scarce capital in this way versus other investment opportunities (such as CCGT) which provide a much quicker return on investment.

Government should not underestimate the complexities of any contractual framework to deliver low carbon, which depending on whether a CfD or PFiT is chosen will have to address issues such as contract duration, level and stability of strike price and indexed power price, definition of fixed and capital costs earning streams required to set the strike price, process for setting the strike price, performance criteria, arrangements for ensuring project delivery, arrangements for protection from regulatory risks during construction and operation, project stages and changes to contract parameters and the recovery of costs associated with administration and support.

The robustness of the CfD or PFiT contracts over the duration they could reasonably be expected to extend will be key to investor confidence – the contracts will need to be in place before investment

decisions, through 8-9 years of construction until all units at a site are commissioned and then for at least the first 20 years of operation.

With regard to the CfD mechanism, the methodology by which the reference price is set would need to be very carefully considered. We believe it is impractical to set technology specific index power prices and the utilisation of a market price should be considered. The technology specific risks, including generation profile, should then be included in the setting of the strike price. The design equally needs to evaluate the duration of the index price setting period and whether the price is to be set on a forward price or post delivery model.

The design of the institutional arrangements to implement the EMR will require careful consideration by Government once the likely package of reforms has been determined in the White Paper. However, there are a number of key principles which need to be considered in the design of the arrangements:

- the reforms should be implemented by a single body within government to ensure they are implemented in a joined up manner avoiding any unintended consequences;
- the counterparty to any new low carbon support mechanism contracts needs to be credit worthy (supported by a government guarantee);
- the organisation will need to have a clear remit and autonomy from DECC and Treasury to be able to enter into a CfD or PFiT contract with developers in a timely manner; and
- the organisation will need to be appropriately resourced for the magnitude and commercial complexity of the contracts it will be negotiating, including specific project financing expertise to ensure that the resulting contracts are bankable.

We have provided comments in response to Question 7 regarding the relative level of returns and factors influencing these rates. We remain concerned that this consultation and reviews into market liquidity may have unintended consequences on balance sheets of the utilities, namely increasing liabilities which result in reduced capital for inward investment and raising of hurdle rates. This would extend to any guarantee requirements placed on a CfD as this would utilise capacity within corporate credit headroom for credit rating evaluation purposes. Consequently reducing the level of capital that could be raised, resulting in a longer lead time to deliver the low carbon generation required to meet generation targets.

The low carbon support mechanism should build on the achievements of the RO

We have previously supported a development of the Renewables Obligation into a 'Low Carbon Obligation' since this support mechanism is well understood and helped to support investment. The Government believes that an RO or LCO approach has issues associated with economic efficiency and affordability which would be further aggravated by a carbon floor. Consequently, it is currently proposing that the RO be phased out to over a period to 2017.

The continuation of the RO through a transition period is both welcomed and essential to enable continued investment. However, the proposed arrangements will be insufficient to facilitate investment in offshore wind in the medium term. We believe there is a strong case for extending the period of parallel running of the RO from 2017 to 2020 and the RO support until 2040. If this is not possible, then alternative mitigation measures are required to limit any hiatus and damage to the supply chain (see Question 36).

It is important that rights established for investment made under the RO are maintained. Government are proposing certain grandfathering arrangements, which are welcome but these need to be defined in detail. Investment decisions were based upon the RO as a market mechanism with a recycle element and Government must explicitly state that grandfathering covers all the constituent elements of the

current RO scheme (i.e. the index linked buyout price retained at the current level, headroom, recycling and the ROC band).

The low carbon support mechanism should be compatible with other initiatives and facilitate the normal operation of the traded electricity market

We believe that the low carbon support mechanism should enable the traded electricity market established under the NETA and BETTA arrangements to be maintained as far as possible.

Both the CFD and PFIT models would retain a level of exposure to the power price and its associated volatility, and should encourage low carbon projects to trade in the electricity market (though the incentive properties of the proposals differ).

It is also important that the low carbon support mechanism is compatible with other initiatives such as the carbon price support mechanism which will have a significant impact on power prices.

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

We believe that low carbon generation should be fully exposed to the price signals available in the traded electricity market. This serves two purposes: first, it enables parties to hedge efficiently to minimise risk; and second, it ensures that parties have the incentives to balance output through exposure to the cash out prices derived from the balancing mechanism.

Under the current ROC scheme, the revenue maximising strategy is to forecast output as accurately as possible, to sell firm output in the forward market as efficiently as possible and to minimise exposure to imbalance cash out. These outcomes result in the lowest cost for the system operator in managing low carbon output and are economic and efficient for the market as a whole. The proposed low carbon support mechanisms may have a significant effect in diluting or distorting the price signal.

Price signals are also important to ensure back up generation is available. All of the low carbon support mechanisms (ROC, PFIT and CFD) have the effect of displacing fossil-fuelled power stations in the merit order. Over time this will result in a greater divergence between low power price periods and high power price periods, which is an inevitable outcome of the policy intervention to support low carbon generation. The key issue is the extent to which the required backup fossil generation can recover fixed and capital costs in the high power price (no wind) periods. This will require efficient price signals, which should not be undermined by other subsidies or artificial interventions or restrictions on the resulting prices.

Efficient price signals will encourage demand side participation and deliver efficient hedging of high priced periods by the market (essentially buying forwards predictable generation), efficient market entry (for example by mid merit capacity) and efficient exit. It will also ensure that the costs of balancing the system are optimised by the market. In addition, the price signals will ensure that capacity is maintained on the system without the need for any additional capacity support. We note that capacity support, particularly a broad-based capacity mechanism, could dilute and distort significantly the price signals in the market by remunerating all plant that remains on the system (available) regardless of its characteristics with respect to required flexibility.

7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

We believe that the Government's evaluation of the cost of capital for low carbon generators has a number of headline errors in the evaluation of the technology status, namely that onshore wind should be 'Established' not 'Emerging' and all offshore wind should be classified as 'Emerging' not 'Mature'. These evaluation points combined with other factors result in a substantial challenge to the hurdle rates and perceived discount rates relative to the baseline.

Discount rates and any relative increase or decrease to the baseline needs to take account of wider economic factors and investors risk appetite associated with these factors, which include:

- the length of time capital is locked in during the high risk construction and early generation phases,
- the level of absolute investment required for the transition to a low carbon generation mix,
- the finite amount of and competition for these sources of capital,
- the effect the transition has itself on the wholesale power price over the longer term, and
- the level of absolute exposure equity and debt providers are prepared to take in the electricity sector at these rates.

We believe that a Premium FiT is likely to increase rather than maintain the hurdle rate on the assumption that there is increased long term volatility in power price from increased or earlier penetration of large scale wind. Appropriate hurdle rates for a CfD will be dependent on capital availability factors, the contractual structure, and the appropriate sharing of risk especially in the construction and early generation phase, and finally on the credit rating of the CfD counterparty.

8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

Please see our comments above.

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

There are divergent opinions across the industry regarding the relative merits of the two proposed models, which is apparent from the views expressed in the trade association responses. This is reflective of how the models impact on different types of market player, technologies and scale of project.

For Government to achieve its carbon reduction objectives, it is essential that the model adopted is attractive to the widest range of investors and effectively supports all low carbon generation. This is unlikely to be achieved via a one size fits all policy. This has already been recognised by Government with the introduction of a full FiT tariff for micro-renewables, to protect small scale investors from market risks and transactional costs.

Ideally, the new low carbon support mechanism (whether CfD or PFiT) should be designed to specifically make large scale and first-of-a-kind low carbon investment projects (i.e. Round 3 offshore wind, the first wave of new nuclear and CCS retrofit to demonstration projects) attractive to new investors.

However, there is a need to ensure that whichever mechanism is implemented, it is flexible enough to accommodate the needs of both large scale and smaller scale projects, with the design of the mechanism being proportionate to the scale and complexity of the project and the risks and costs associated with different types of projects.

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Both the premium FIT and the CfD models expose parties to the power price to some extent. Consequently there is an incentive on parties to ensure that revenue can be maximised by efficient energy forward sales (hedging) and efficient management of imbalance. These incentives to trade efficiently will further help drive increased liquidity in general.

Under the FIT proposal, the incentive on parties to trade forward will depend on the level of the premium and its duration. If the premium is set at a high level, parties will receive the majority of remuneration through the subsidy mechanism, and the incentive to trade forwards will be reduced.

Under the CfD model, the incentive to trade is established through exposure to the indexed power price. Of course the key question is how the power price is established, maintained and managed. If the index is set ex ante then parties have an incentive to match or beat the power price. However, there are a number of questions that require resolution, including the way the index is set, its stability over time and the period in which it is applied. Some weighted average of the day-ahead market price could be suitable. This would allow a reasonable balance between incentives to optimise production and the certainty that investors need.

Clearly in terms of establishing a robust power price index, there must be sufficient assurance that the power price is economic and efficient. This will require confidence that there is a sufficient volume of trades that underpin the price index. This in turn will require confidence that the index is not capable of price manipulation.

In essence the index represents the efficient level of forward trade achieved by parties in the market place. The only index that can perform this function is, potentially, the day ahead-price obtained through the power exchanges or the market index price established ex post in the cash out mechanism (which represents the short term cost of energy trades) or some form of power price index derived from a power exchange (such as the monthly N2EX price). The appropriate index may differ for different technologies.

Establishing the power index arrangements is critical to the efficient hedging strategy of parties under a CfD. Price setting for the index power price is not achievable on a technology specific basis, meaning that the strike price set within the CfD will need to reflect the project specific criteria considered for the largest and first-of-a-kind schemes. This should reflect not only the cost bases but also form a representation of the achievable wholesale prices for that technology and/or project, as each project represents a large investment with individual project characteristics.

11. Should the FIT be paid on availability or output?

It is imperative that the FIT or CfD is paid on output rather than availability. This will ensure that parties develop the sites that are most likely to deliver the Government's decarbonisation targets by optimising the delivered output to the market.

We would be extremely concerned if FITs or CfDs were paid on availability. We believe that such an arrangement would result in the development of projects at sites where the renewable resource is suboptimal in order to maximise rents through the availability payments.

Emissions Performance Standards

12. Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

The proposal for an Emissions Performance Standard (EPS) is unlikely to provide any additional certainty for investors in low carbon generation. We note that the proposed EPS aims to provide a 'regulatory backstop' to prevent new coal-fired generation being built without installation of carbon capture and storage. However, in practice the EPS duplicates existing Government policy for new coal-fired power generation. The consultation itself notes that the proposed EPS has limited interaction with the other mechanisms. It is difficult to see how the EPS will provide any additional certainty or incentive in delivering the investment needed to achieve climate change goals.

We concur with government's conclusions on the security of supply implications of introducing an EPS and recognise that the proposal has attempted to ameliorate these risks through e.g. grandfathering at consent and setting the EPS as an annual limit.

13. Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

Setting an EPS for a coal fired power station (or mandating for CCS through the consenting process) before CCS is technically and commercially proven and the technology has been demonstrated, is premature.

While CCS technology is a potential for future low carbon generation of electricity the full chain has not yet been demonstrated and is not likely to be commercially viable for a number of years. It is far from clear what warranties on performance standards vendors will be able to offer and how these might impact on the cost of CCS.

The operating pattern of a generation unit fitted with CCS is very difficult to predict at the demonstration stage. Hence, it is very difficult to set a meaningful EPS until it is clear that the unit with CCS fitted is fully operational and meeting CO₂ removal efficiencies.

While setting the EPS as an annual limit may be seen to ameliorate these performance risks to some degree, the introduction of an EPS does nothing to improve the bankability of investing in new coal-fired plant. A more considered policy with Government, for example, underwriting some of the risk if CCS were not feasible technically or economically, would be more likely to encourage the UK to develop CCS expertise.

If an EPS is to be introduced, it should be set as an annual limit and at a level consistent with existing coal policy (600g/KWh) to avoid further undermining the case for investment in CCS demonstration.

However, even at this level, the EPS could further deter investment in new high efficient gas CHP, unless emissions associated with heat production are removed from the EPS levels.

In contrast to CCGT, where the incentive is to maximise the electrical efficiency of the plant, with CHP the aim is to maximise the overall efficiency (electricity and heat) of the plant. Good Quality CHP is defined under EU legislation as upward of 75% electrical + heat efficient (compared with 59% electrical efficiency of a new CCGT plant). However, the electrical efficiency of a Good Quality CHP plant is driven by how much heat load there is and is extremely variable (from 16-30%). Currently the incentive – rightly

– is to match heat load to demand. The EPS, as currently framed will serve to penalise larger heat loads, perversely incentivising new CHP plant to maximise its electrical efficiency potentially to the detriment of overall plant efficiency. It is likely that this would deter investment in new high efficient gas CHP, unless emissions associated with heat production are removed from the EPS levels.

14. Do you agree that the EPS should be aimed at new plant, and ‘grandfathered’ at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

If an EPS is to be introduced, then the principles of no retrospective introduction of an EPS for existing plant and grandfathering of the EPS level for new investments will be crucial to maintaining confidence in the UK as a place to invest. This is particularly relevant for new CCGT investment, which has an important role to play in maintaining security of supply in the transition to a low carbon economy.

Regulatory changes that could potentially impact on the return on an investment, such as the potential introduction of an EPS for gas-fired power stations or changes to the level at which the EPS is set over time, will impact on investors’ decisions to invest in new power plant capacity in the UK.

Plant typically changes its role though its lifetime (e.g. from baseload to flexible mid merit to peaking). The EPS requirements must not impact on this progression or on the investment in upgrades necessary to facilitate this changing role.

15. Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

The extension of the EPS to cover existing plant in the event they undergo significant life extensions or upgrades would introduce policy uncertainty and could deter future investment in CCGT plant, with attendant security of supply implications.

As noted in Question 14 above, the EPS requirements must not undermine the ability of plant to invest in the upgrades necessary to facilitate plant changing its role over its lifetime to meet potential gaps in the market (i.e. for flexible back up plant) at relatively lower cost than if new plant is built.

An EPS should apply for the full plant life and not be triggered by a significant life extension or upgrade, unless it is demonstrable that any revised standard can be met through best available techniques (defined for CO₂ emissions through a process similar to the BREF Review and set at the European level).

16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

Periodic review of the EPS could undermine new investment in CCGT in particular unless, as outlined above, the EPS applies to new plant only and is only triggered for significant life extensions/upgrades of existing plant where it has been demonstrated that any revised standard can be met through best available techniques defined at the European level.

17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

The treatment of biomass emissions should be consistent with the EU ETS monitoring, reporting and verification guidelines, which currently zero-rates emissions from biomass fuel when calculating plant carbon-dioxide emissions.

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

We agree with the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls. In particular, the annual limit is crucial to safeguarding the ability for plant to change its operating behaviour over its life and to ensuring the continued investment in peaking or back-up plant necessary to meet demand as more intermittent generation comes on to the system.

Options for market efficiency and security of supply

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

We note the assessment of the pros and cons associated with a capacity mechanism in the EMR consultation. We believe that the discussion in the document leads to the conclusion that there is no case to consider policy intervention in this area as part of EMR .

RWE rejects the argument that the cost of intervention is low relative to the welfare effects of a prolonged shortage of electricity. We believe that an administrative process for determining the amount and characteristics of generation capacity are more, not less, likely to result in security of supply difficulties and will lead to poor value for money for customers. Any 'inefficient' capacity held outside the market will introduce a de facto cap into the short run market signals, distort market prices and chill investment in incremental capacity. Consequently 'inefficient' capacity has the potential to impact on security of supply and lead to a 'slippery slope' whereby all other capacity will require support given the inefficient pricing signals.

Examples from other jurisdictions demonstrate that capacity mechanisms have only been introduced as a result of other shortcomings in market design such as; the existence of price caps, lack of intraday markets, compulsory participation in centralised day ahead exchanges, restrictions on the freedom of operation of generation plant, insufficient interconnection; and finally, lack of scope for demand participation in energy market and insufficient real time metering.

The current trading arrangements in the GB electricity market have largely avoided the above issues and do not include a specific capacity mechanism. Instead, capacity is remunerated through two key mechanisms:

- sales of energy in the forward electricity market in response to price signals associated with the cost of meeting the electricity imbalance on the total system; and
- contracts with the system operator for balancing energy which in the case of short term operating reserve include a specific payment for 'capacity' through availability payments.

The electricity trading arrangements have been remarkably successful and resilient in operation. The vast majority of demand and generation is efficiently hedged in forward markets such that the residual imbalance represents only a relatively small element of the market. From 2005 to 2010, the average

residual imbalance was only 0.87%¹. In other words, more than 99% of electricity was traded in forwards markets (defined as notified contracts).

As well as the balancing market there are, in any case, specific payments for availability of short term operating reserves. This ensures that there is sufficient capacity to deliver the real time supply/demand requirements of the system operator, including a specific allowance for reserve to be available to meet peak demands. The current arrangements therefore ensure that there is enough capacity in the market to ensure that the supply/demand balance is maintained.

Strengthening of existing price signals should therefore be the first port of call when seeking to improve incentives to balance supply and demand. In this context, there are a number of known issues associated with the current trading arrangements that require review in the context of a consideration of capacity requirements and associated incentives. The present cash out arrangements could be improved to make them more cost reflective of some of the actions that National Grid take to balance the system. Examples of these are the methodology used to price the reserve contracts and the lack of any pricing signal when demand control is instructed. Correctly pricing these actions would produce cash out prices that would provide signals to parties to balance the system either by increasing supply or reducing demand.

Successful resolution of these issues will not only provide signals in the short term but will feed into future investment decisions on capacity and delivery of demand-side initiatives such as smart metering and associated tariffs, without the unintended and adverse effects of a capacity mechanism.

In addition, price signals play a critical role in the successful deployment of smart metering and the participation of the demand side in the electricity trading arrangements. Any intervention that dilutes or impacts on the price signals such as a capacity mechanism will threaten the success of this policy area, which will play an increasingly important role in balancing the system going forward.

In developing the thinking on a capacity mechanism it is important that the specific objectives of such an arrangement are considered carefully. The Government appear to be concerned about the impact of intermittent renewable generation in general on the market; the “two weeks in winter” issue. We believe, however, that this perceived problem is spurious for a number of reasons.

- There will, by 2020, be much greater scope for demand response from customers as smart meters allow all customers to see – and respond to - market price signals directly. Customers, or their suppliers, will be able to sell back power into spot markets at high prices by moderating their demand. This will in all likelihood be much cheaper than paying for spare unused capacity.
- It will, in any case, be in the interest of generators to continue to retain some ramping capability to respond to incidences of low wind/high demand. Companies already have to do this in order to manage the possibility of unplanned outages at their existing stations.
- Greater price variability increases the option value of flexible plant and the returns available from life extensions and new investments. The opportunities for running flexible plant will actually be much greater than the ‘two weeks’ identified. They will also have considerable opportunities to serve load in periods when other fossil stations are not flexible enough to respond. In addition, flexible stations also will have opportunities for revenues as a result of transmission constraints.

¹ Daily aggregated Net Imbalance Volume as a percentage of daily aggregate demand from 1st Jan 2005 to 31st March 2010. Note also Standard Deviation: 1.2%, Maximum: 5.2%, Minimum -3.3%. Data derived from Elexon reports.

- Investing in flexible plant does not necessarily mean new power stations. Existing stations can have their lives extended by investing in flexibility and moving into a new market, as has been the case with existing plant on the system. There is also a market for the purchase\sale of existing units. Costs can also be reduced by co-locating OCGTs at existing sites or making better use of the substantial amount of diesel generation retained by e.g. hospitals, water companies and other industrial customers. Flexible capacity can potentially be retained much more cheaply than assumed in much of the modelling analysis.
- The constraint in the UK is on the capacity to meet the peak demand rather than the duration of the peak and if sufficient capacity is installed to meet the peak hour or two, it will also be sufficient to meet an extended peak of “two weeks”. (This can be contrasted with an energy constrained system such as Norway where the security constraint is on the stored potential of hydro energy and the peak duration would be far more relevant.)

We, therefore, believe that the price signals available under the current market design are sufficient to provide the required incentive to maintain capacity in the GB electricity market regardless of the level of renewable penetration. Indeed, the increased volatility of hourly prices that will result from increased renewables encourages the required flexible plant to be developed. This is already happening. The new capacity being installed is already relatively flexible plant.

In the debate over capacity and security of supply, wider concerns about import dependence or volatile primary fuel prices have also been raised as concerns. It should be noted that capacity mechanisms alone do not and cannot specifically address these issues.

20. Do you agree with the Government’s preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

We believe that the current market mechanisms based on efficient and economic price signals together with specific support for reserve services is capable of delivering the required capacity on the GB electricity system. As noted above, the cash out and reserve procurement arrangements are capable of enhancement to meet the challenges associated with increase connection of power stations with variable output. Consequently we do not believe that an additional policy intervention is required and that this would not be in the interests of consumers.

National Grid already has a range of tools that could be used to ensure that there is sufficient capacity to meet margin requirements through, for example, the procurement of additional short term reserve. It is important that if this mechanism were to be implemented, the effects in electricity cash out are considered carefully. Cash out prices need to adjust to reflect the marginal cost of the targeted capacity and provide economic and efficient price signals (and to minimise the requirement for the additional capacity).

21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

Experience around the world has indicated that capacity mechanisms have a number of undesirable effects on the economic and efficient operation of electricity markets.

- They are often expensive for consumers (e.g. capacity payments to generators in PJM capacity market run to several billion US dollars).

- The additional capacity procured undermines the pricing signals in an energy only market (e.g. Spain where the extent of the payment is having to be extended as a result of low electricity prices).
- Rent seeking behaviour by market participants will result in the slippery slope problem, whereby parties will seek additional revenues from the capacity mechanism to provide the required “missing money” that occurs as a result of lower forward energy prices and diluted price signals.
- The capacity mechanism results in either inefficient entry by over rewarding capacity or inefficient exit, by forcing closure of capacity that does not receive capacity payments.
- The capacity mechanism itself may distort the energy price as parties withhold or deploy capacity in response to the capacity signals, rather than the energy market signals: (e.g. PJM: where reports of “profiteering” of generators has resulted in the New Jersey legislature launching a tender for 2000MW of additional capacity)².
- There is no guarantee that even with a capacity mechanism that overall security of supply will be enhanced. In France there is discussion of what penalty regime to put in place on suppliers that fail to meet the capacity obligation – in effect a shadow balancing market.

We believe that a capacity mechanism would have the effect of undermining the economic and efficient operation of the current electricity market.

Furthermore, capacity mechanisms have required significant market intervention to design and redesign the support mechanism to meet the centrally administered targets for investment. This has been the experience in US Markets where constant modifications have been required to manage the capacity mechanism and they are now under challenge from state legislatures. It is worth noting that some of these changes have been to restore the signals of an energy only market.

22. Do you agree with Government’s preference for the design of a capacity mechanism:

- **a central body holding the responsibility;**
- **volume based, not price based; and**
- **a targeted mechanism, rather than market-wide.**

We do not agree that a capacity mechanism is required in the GB electricity market. Given the concerns expressed above we do not see the role for such a mechanism where capacity is currently delivered by forward energy sales and contracts for balancing services with the system operator. Any capacity mechanism will either distort the forward market signals or the procurement of balancing services

If concerns around a capacity margin remain, then a mechanism, based on procurement of incremental Short Term Operating Reserve (STOR), with adjusted cash out prices could have the least impact on the market. Such a mechanism could be procured by a central body based on volume and targeted rather than market wide. The detailed design requires consideration, but could be based on the following:

- The capacity margin should relate to the level of generating capacity relative to the actual peak demand for electricity. A specific parameter could be defined as the required capacity margin of a specific period as follows:
 - generating capacity must exceed a percentage of peak demand on the transmission system (the “margin”);
 - an annual margin could be established by the System Operator and/or Ofgem forecasting the expected level of capacity and the demand (as required under the 2011 Energy Bill);
 - the Annual Margin is forecast for the year ahead based on the data notified by generators under the Grid Code (OC2 data) and the forecast level of demand (this data is already published); and

² Reuters, NJ Gov. Christie signs bill to get more power plants built, January 31 2011.

- the within year margin is updated using data notified by generators under the Grid Code (OC2 data) and the forecast level of demand (this data is already published).
- In the event that the margin forecast indicates a potential shortfall, then some form of procurement process is required to deliver the required capacity. Given the specific requirement identified in the consultation (i.e. impact of intermittent generation), incremental STOR could be procured by National Grid as System Operator. An additional obligation could be placed on National Grid as System Operator to ensure that any capacity margin shortfall identified through the ongoing monitoring process is addressed. In this context the following elements are required:
 - a licence obligation on National Grid to address any margin shortfall through the procurement of additional STOR;
 - the licence obligation would require National Grid to develop an appropriate methodology to determine the incremental STOR capacity (Targeted Capacity Mechanism STOR requirement) required to meet the margin shortfall identified by Ofgem/DECC;
 - the System Operator would be capable of recovering the incremental costs associated with the additional STOR requirement through balancing Services Use of System (BSUoS) charges; and
 - incentive arrangements may also be required on the System Operator to enable it to fulfil its role as administrator of this Targeted Capacity Mechanism.
- The incremental STOR capacity procured by the System Operator to meet the margin requirement would form part of the overall STOR holding. Consequently, the capacity would be capable of dispatch to meet the overall reserve requirements in the same way as any other STOR capacity. The incremental margin capacity would be contracted on the same terms as the current STOR capacity.
- Adjustment to cash out is required to ensure that the marginal opportunity costs of the contracted STOR capacity is appropriately reflected in market price signals.

We expect that efficient price signals from the market will deliver the required margin. Consequently, we expect that typically there would not be a normal requirement to procure this additional targeted capacity unless there were extreme circumstances such as unforeseeable events.

Any broad-based mechanism would undermine the economic and efficient operation of the electricity trading arrangements. The PJM and other capacity market models from the US (e.g. California and New England) are not suitable for the UK or other European markets. In particular;

- the share of wind generation in PJM is small (less than 3%),
- PJM is a much more fragmented transmission system with incomplete unbundling between generation businesses and transmission system owners which distorts proper incentives,
- there is no intraday market and compulsory participation in day-ahead markets i.e. before wind output can be predictably forecast, and
- there is no scope for the demand side to participate in the day-ahead market (unlike in GB).

We also consider broad based mechanisms to be questionable with respect to the requirements of EU Directive 2009/714 and 2005/89.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

The current market design provides incentives on all market participants to deliver capacity including demand side response, storage, interconnection and energy efficiency. In particular we note that

imbalance signals create strong incentives on market participants to deliver innovative solutions to imbalance risks. We would expect, for example that increasing costs of imbalance for intermittent low carbon generation sources will enhance incentives to invest in technologies that enable output to be more appropriately shaped through for example, demand side, storage or interconnection with Norway utilising pumped storage capability. We believe that any capacity mechanism will stifle this innovation.

As noted above we believe that efficient price signals are required to ensure that the economic and efficient level of supply and demand response, interconnection, storage and energy efficiency is available in the GB electricity market. A capacity mechanism will undermine these price signals. This has a particular consequence for the technologies under consideration, and in particular to participation of customers with smart meters and operation of interconnection.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- **Last-resort dispatch; or**
- **Economic dispatch.**

As outlined in Question 22 above, we do not believe that the case has been made for considering a capacity mechanism in the GB electricity market at this stage. If concerns remain about the capacity margin, a refinement of the existing STOR mechanism, with the procurement of incremental STOR with adjusted cash out prices, could have the least impact on the market. If the capacity is procured as part of the STOR arrangements, then the capacity could be dispatched on an economic basis from the perspective of the system operator, subject to adjustment of cash out prices.

A last resort arrangement would require definition of the circumstances under which the capacity would be utilised. To minimise market impact, such circumstances would be very limited, resulting in capacity that is withheld from the market for considerable periods of time, with a consequent cost to customers. Even if the utilisation periods can be adequately defined, the effect of the capacity holding would be to result in costs for market participants that are potentially lower than the cost of each participant ensuring that they maintain or obtain their own additional capacity through whatever source (including demand side response, imports, storage). Last resort capacity therefore may undermine the efficient market response.

25. Do you think there should be a locational element to capacity pricing?

We believe that it is essential that there are appropriate cost reflective locational signals as part of the overall regulatory arrangements. There is no point in providing incentives to construct additional capacity on the system in locations that are, for example, impacted by significant constraints on the system or which would provoke expensive additional network investment. We believe that the locational aspects of capacity will be increasingly important on a transmission system that may be subject to increasing constraints as a consequence of the transmission design criteria (SQSS) and connect and manage arrangements.

Analysis of packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

We believe that cost-efficiency should be at the centre of any market reform and to this end, the EMR's primary focus should be to:

- Get Round 3 offshore wind projects, the first wave of new nuclear and CCS retrofit of demonstration projects away, rather than to second guess what the market will look like in 2025 or beyond; and
- Maintain market integrity and efficiency, including ensuring full consideration of interaction of supply with demand side, to ensure that the Government's objectives are met in the most economically efficient manner possible and at least cost to consumers.

In order to achieve this, the EMR should seek to avoid unnecessary duplication and policy redundancy and to introduce the minimum set of interventions necessary to deliver the required investment. In this regard, we have some concerns about the coherence and aggregate impact of the government's preferred package. In particular:

- As noted in Question 27 below, **the importance of the carbon price support mechanism will be dependent on the choice of low carbon support mechanism (ie whether CfD or FIT).** The EU has set emissions reductions targets through the EU ETS and this should remain the central mechanism for determining carbon prices. Introduction of additional measures in the UK should not be seen to undermine the EU ETS. We are concerned that the rate of the proposed tax on the carbon content of fossil fuels supplied to generation could be decoupled from the EU carbon allowance (EUA) price resulting in an undue impact on UK competitiveness if, for example, the Commission strengthens the EU ETS or the EU moves to a 30% emissions reduction target. Consequently, the carbon tax needs to be linked to the EUA price.

A carbon floor price should only be introduced on the timescales where it could have an impact on the revenue flows to new low carbon investments. Any benefits of certainty in the price of carbon are likely to be over the period from 2020-2030 (particularly until future carbon targets are agreed at EU level) and there are likely to be very limited benefits for investment decisions if introduced earlier than 2018. In particular, there is a danger that if it is introduced at a rate that results in higher electricity prices in the short-term it risks resulting in windfalls for existing low carbon generators and being seen simply as a further revenue raising measure for the Government which unduly impacts on UK competitiveness.

- **The case for considering a capacity mechanism as part of the EMR has not been made.** As outlined above, we believe that the current market mechanisms based on efficient and economic price signals together with specific support for reserve services is capable of delivering the required capacity on the GB electricity system. Current cash out and reserve procurement arrangements are capable of enhancement to meet the challenges associated with increased connection of power stations with variable output.
- **The proposal for an EPS duplicates existing coal policy and is unlikely to provide any additional certainty or incentive for investors in low carbon generation.** The proposed EPS aims to provide a 'regulatory backstop' to prevent new coal-fired generation being built without installation of carbon capture and storage, but in practice it will duplicate current Government policy on new coal-fired power generation.
- We believe that the introduction of an EPS is both premature and unnecessary, and serves to undermine the development of CCS expertise in the UK. A moratorium on unabated new coal (either through a requirement for CCS demonstration or an EPS) will have the impact of stopping the development of CCS on new coal in the UK. A more considered policy with Government, for example, underwriting some of the risk if CCS were not feasible technically or economically, would be more likely to encourage the UK to develop CCS expertise.

In summary, the Government's sole focus in EMR should be on the method of low carbon support. The other three elements of the package are either unnecessary or likely to introduce undue complication or distortion both into the central low-carbon support mechanism and the market more widely.

27. What are your views on the alternative packages that Government has described?

We agree with the EMR conclusions that certainty on carbon price will not, on its own, be sufficient to guarantee the investment needed in the electricity sector for a number of reasons:

- The future carbon price is clearly an important factor when considering investment in both low carbon generation and other investments in our generating portfolio. For a portfolio generator, exposure of low carbon generation to the carbon price provides an important hedge against the impacts of rising carbon prices on the profitability of our fossil plant. However, it is only one of the factors taken into account. Other factors include the impact of future fuel and commodity prices on the potential returns for investors, exchange rates and, given the international nature of RWE's investments, the level of political risk associated with investment in any particular country.
- Taxes are subject to change by future governments and hence a carbon price support mechanism does not provide certainty of level of support, a risk which will be factored into investment decisions.
- The future level of the carbon price will have diminishing importance in setting future electricity prices as the sector decarbonises.
- Even if the carbon tax and pass through were known, setting a carbon price support trajectory out to 2030 does not create sufficient visibility for nuclear investment in particular which has a 40 year life and will be commissioned in the early 2020s.

As outlined above, maintaining market integrity is crucial to ensuring the efficient operation of the market, delivering government objectives at lowest cost to the consumer. A fixed FiT ring-fences low carbon generators from the market, unavoidably reducing economic and dispatch efficiency. In particular:

- Ring-fencing different generators from the market could lead to market power problems and reduce liquidity, meaning a less competitive market overall.
- Removing low carbon generation from the market removes exposure to the carbon price and hence the rationale for introducing carbon price support to incentivise investment in low carbon technologies.
- A fixed FiT combined with total priority in dispatch will lead to more extreme volatility in prices, especially negative. A fixed FiT can create unnecessary costs to consumers, as the generator typically has no responsibility for ensuring that output follows demand and can promote bad projects at great cost to consumers ie solar in Germany, where the most recent data shows that solar PV takes 24% of the support provided by fixed FiTs, but produces only 6% of the electricity.

Furthermore, the introduction of a fixed FiT would represent a radical reform to the current market arrangements, which could exacerbate the hiatus in renewables investment, stretching the gap to the 2020 renewables target. There was a two-year delay in development when the RO was introduced as a replacement for Non-Fossil Fuel Obligation (NFFO).

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

We note that Ofgem started Project TransmiT in September 2010 which, whilst broad at the start, is now focussing on electricity charging and connection arrangements. Meeting the Government's targets for renewables and decarbonising the electricity industry will require not only a huge investment in low carbon generation technologies but also a significant investment in networks. It will be equally important that this investment is carried out efficiently. This will be best achieved with the present locational TNUoS methodology. We believe that the present methodology is robust to delivering the government

targets and that a move to uniform TNUoS would lead to a significant increase in costs without any discernable benefits.

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

The importance of the carbon price support mechanism will be dependent on the choice of low carbon support mechanism. If the low carbon support mechanism is a PFiT, then investors will need confidence that a long-term carbon price trajectory will remain in place. However, if the low carbon support mechanism is a two-way CfD, then the carbon price trajectory is no longer relevant to investors, but can become a significant issue for Government as this could impact on the amount of risk on the Government balance sheet. Hence, there will be a strong incentive for Government to set a high target carbon price to minimise their liabilities.

The interaction of the carbon price floor with the choice of low carbon support mechanism is important, particularly in setting the trajectory and rate of increase for the level of carbon price support. An important factor in determining the balance between carbon price support and other EMR mechanisms should be the impact on overall prices to customers.

The carbon floor, the proposed CfD or PFiT and, potentially, capacity payments, all have implications for the Government's balance sheet and could interact with counter-balancing effects on the Government's balance sheet. These policy interventions interact in the following way:

- The carbon price support provides a revenue stream to the Treasury in the form of a tax;
- The tax revenues from the carbon price support will offset the potential liabilities for the Government that arise through the low carbon support mechanism.
- The low carbon support mechanism will provide an incentive to invest in renewables projects which have low operating costs;
- Output from low carbon generation will depress power prices in periods when all these schemes are competing to sell output and displace fossil plant;
- Fossil plant will need to earn its revenues in the "residual" periods (for example when there is no wind);
- The residual periods will potentially result in high and volatile prices, and increase the risk of regulatory intervention to cap prices;
- The risk of failing to earn adequate returns for fossil plant will increase the demands for capacity payments;
- Any capacity payments will need to be provided by a central agency that procures "capacity";
- The capacity may result in liabilities for the agency which could be regarded as a tax resulting in a liability on the Government's balance sheet
- The capacity liability may offset the tax revenues from the carbon support increasing the required level of the tax

In other words: The carbon price support mitigates the Government balance sheet risk of the low carbon support. However, the carbon tax will also increase the marginal costs of fossil plant and displace them in the merit order leaving increased exposure to volatile prices. This increases the demand for broad-based capacity payments, which may be regarded as a liability on the Government's balance sheet, offsetting the Treasury tax revenues from the carbon tax. In addition, the incremental capacity that is retained on the system may depress power prices increasing the costs to Government of the low carbon support mechanism.

Implementation issues

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

The package of proposals that form the electricity market reform are interrelated and have certain dependencies. It is important that these are recognised and understood prior to implementation. In particular:

- The carbon price support proposals interact explicitly with the low carbon support mechanism since the direction of travel for the carbon floor will influence the electricity prices while the carbon tax will influence the electricity price achieved by low carbon projects;
- The capacity mechanism is also likely to interact with any low carbon support mechanism. Any mechanism which suppresses the electricity wholesale price by encouraging inflexible capacity to remain on the system will increase the risks to investors in low carbon generation.
- The carbon price support proposal impacts on the efficient functioning of the electricity market by attempting to internalise the cost of carbon over and above the EUETS – this will impact on price signals for entry and exit with a knock on effect on the amount of capacity available on the system;
- Any capacity mechanism will influence power station remuneration, the merit order and power prices and may distort the operation of the market.

The interaction between the proposals creates significant implications for implementation since it is essential for normal market operation that the interventions are coherent, credible and durable. It is unclear as to whether the institutional arrangements are capable of recognising the interactions, or whether the organisational implications have been fully recognised. In particular we note that the split of responsibilities between Government departments is unhelpful in the development of a coordinated market intervention.

We believe that some form of overarching implementation and institutional framework is established for the implementation and ongoing administration of the various policy interventions implied in the package of proposals.

As noted elsewhere we believe that there is an alternative approach for electricity market reform that is based on the implementation of a specific support mechanism for low carbon generation investments without the need for carbon price support, a capacity mechanism or the EPS. In essence the Government targets for decarbonisation can be achieved through this route provided that there are sufficient market signals for the efficient and economic operation of the GB electricity system. This will require cash out reform, full implementation of the smart metering programme and more effective demand side participation in the electricity market.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

- **Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?**
- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**
- **How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?**
- **Are there other models government should consider?**

- **Should prices be set for individual projects or for technologies**
- **Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?**
- **Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?**

We appreciate that government is seeking to ensure that the cheapest technology or project within a technology category is deployed first. In theory, auctions can work well where there are a significant number of bidders, the requirements are well specified and understood by the bidders and the costs known. However, in the context of the first wave of new nuclear build and Round 3 wind, inefficient outcomes such as over- or under-recovery of costs by winning bidders is likely in the event of an auction process to determine the level of low carbon support for a number of reasons:

- Nuclear and Round 3 sites have already been auctioned and awarded, reducing the number of credible participants in any subsequent allocation process. Another auction will increase uncertainty, stifle early stage development and introduce delay in delivery of these projects.
- With limited experience of delivering such complex technical projects in the UK, there is incomplete information about the costs of deploying these projects. An auction process introduces the prospect that the least realistic bidder might win low carbon support, which in turn could lead to the non-delivery of projects (the ‘winners curse’ as demonstrated by the NFFO auctions, where only 30% of projects were built).
- Being in a position to bid is itself very costly (resulting in unopposed bids e.g. the 1991 ITV franchise auctions). With a high level of risks and uncertainties surrounding Round 3 offshore wind projects and the first wave of new nuclear, developers will need to go some way down the development cycle before they can bid into an auction. If these costs are not underwritten, there is a risk that companies will not bid.

Too few credible participants mean that the auction would not deliver a competitive price. In contrast, the potential for an open-book process that the contractual element of the CfD offers could provide advantages of greater price transparency for government.

Even an efficient auction will result in some element of surplus for the winning bidder(s) based on the difference between the winner’s valuation and the second placed bidder. Auction design cannot prevent this outcome (revenue equivalence theory). Unattractive auction designs will cause participants to change their bidding behaviour or not participate at all.

The range of technologies and indeed projects required to deliver government’s objectives can not be achieved via technology neutral price setting which will lead to a limited technology mix. Price setting must be achieved on a technology specific basis, with project specific criteria considered for the largest and first-of-a-kind schemes. For a CfD contract the price setting would need to reflect not only the cost bases but also form a representation of the achievable wholesale prices for that technology and/or project, as each project represents a large investment with individual project characteristics.

32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

The electricity market reform package will require a substantial intervention by the Government in the operation of the electricity market. This will require that institutions are established for each area of policy intervention. Each institution will have different roles:

- A capability to monitor, review and assess the Carbon Price Support mechanism (presumably in the Treasury);
- A capability to establish and maintain a level of support for low carbon generation (a central low carbon support agency);
- A capability to establish and maintain any capacity mechanism (a capacity mechanism agency);
- A capability to establish and maintain the Emissions Performance Standard (presumably within DECC).

As outlined in Questions 3-5, the design of the institutional arrangements to implement the EMR will require careful consideration by Government once the likely package of reforms has been determined in the White Paper. However, there are a number of key principles which need to be considered in the design of the arrangements for implementing the FiT (whether CfD or PFiT):

- the reforms should be implemented by a single body within government to ensure they are implemented in a joined up manner avoiding any unintended consequences;
- the counterparty to any new low carbon support mechanism contracts needs to be credit worthy (supported by a government guarantee);
- the organisation will need to have a clear remit and autonomy from DECC and Treasury to be able to enter into a CfD or PFiT contract with developers in a timely manner; and
- the organisation will need to be appropriately resourced for the magnitude and commercial complexity of the contracts it will be negotiating, including specific project financing expertise to ensure that the result contracts are bankable.

The institutional framework for any capacity mechanism will depend on the nature of the support that is envisaged. A limited, targeted capacity obligation could be discharged by the system operator. A broad-based capacity mechanism implies greater market intervention and may require a significant change to the GB electricity trading arrangements, particularly if any of the US models of capacity support were to be developed.

33. Do you have view on how market distortion and any other unintended consequences of a FiT or a targeted capacity mechanism can be minimised?

The key issue for the low carbon support mechanism and a capacity mechanism is the extent to which the revenue from this support mechanism distorts behaviour of the relevant units in the merit order dispatch. Since both mechanisms will, to a greater or lesser extent, provide a generating unit with a revenue stream that recovers fixed operating costs, the prices that are required to be achieved in the forward market or through the balancing mechanism will be lower than competing generating units that do not receive the subsidy.

The extent of any market distortion depends on the level of support and the technologies under consideration. A low carbon support mechanism which supports low operating cost power stations may have limited impact provided that all similar technologies receive a broadly similar level of support.

A capacity mechanism that enables more general support to available capacity will introduce a significant distortion to the current electricity trading arrangements. Such a mechanism will result in lower wholesale prices and reduce the remuneration required through the balancing mechanism. Consequently the incentives on parties to balance will be diminished and distorted. This has the potential to increase the costs of the system operator in balancing the system and suggests that the overall cost of the policy intervention will be higher when compared with enhancement of the existing reserve market or sharpening of the existing incentives in the market.

A market wide mechanism would over-compensate inflexible generation and under-compensate flexible generation by suppressing the required variation in prices. It would also offer rent-seeking opportunities for certain power stations, and these effects are difficult to mitigate. Experience in other markets around the world suggests that it is difficult to design a mechanism that does not have a distortive effect on the wholesale electricity market.

The potential impact of incremental STOR capacity can be minimised by ensuring that the costs of utilisation in the balancing mechanism are appropriately reflected into cash out (as outlined in Question 22 above). This would ensure that the 'missing money' created by the capacity payments is reflected in the market signals in the balancing mechanism. These market signals should result in efficient balancing and energy procurement and, of course, significantly reduce the need for the capacity mechanism in the first place. Unfortunately, the adjustment to cash out price envisaged cannot address the potential distortive effects of a broad based capacity mechanism on the GB merit order or on efficient entry or exit signals.

Transitional arrangements

34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

The two key factors to be addressed in the transition to the new low carbon support scheme are:

- protection for existing investment, ensuring no retrospective changes to income structures or levels for current projects
- processes to avoid an investment hiatus, that will impact both the supply chain and Government's targets.

We welcome Government's intent to address both these issues and believe that with some modification, as set out below, Government's proposals have the potential to achieve both.

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

It is critical that Government provides detailed clarification of all aspects of the grandfathering provision and the future operation of the RO within the White Paper, including:

- retaining the index linked buyout at current levels,
- the ROC multiples,
- the basis on which ROC values will be calculated (see response to Question 38).

Projects are already being put on hold awaiting the outcome of the banding review. Government has taken measures to address this, by bringing forward the banding announcement, but unless these projects have visibility of the future RO arrangements investment decisions will continue to be delayed.

The announcement of EMR creates a hiatus as projects with investment decisions prior to 2013 may halt progress to see the detail of the FiT scheme, to enable comparison with the RO. This can be avoided by enabling projects which commit to investment before details of the FiT are established but are not yet accredited under the RO, to opt into the FiT scheme once there is granularity of detail regarding the scheme. This would not have an adverse impact on ROC forecasting as the decision is made pre accreditation.

As the new low carbon support mechanism is intended to be more attractive to finance community, Government should also consider allowing existing RO to transfer as this could help leverage external finance against built projects.

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition to introduce the new feed-in tariff for low carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:

- **All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;**
- **All new renewable electricity capacity accrediting after the introduction of the low-carbon support mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.**

We believe that the period of parallel operation of the RO and the new low carbon support mechanism is essential as the FiT level will be established before the investment decision, whilst the ROC level is only fixed at accreditation post first generation.

It is also welcomed, as it as it maintains investment during the consultation and period of FiT establishment, then allows for market learning, ensuring that there is opportunity to resolve any issues with the new mechanism whilst enabling projects to progress under the RO.

However, even if there is no delay in the parliamentary process, the four year overlap is insufficient leaving projects with long lead times, in particular offshore wind farms, in a position where they are too late to take the full benefit of the RO but too early to have full understanding of the granular detail of the FiT.

For an offshore wind project with a first generation date of 2015/16, the basis for the investment decision would have to be established two to three years earlier in 2012/13, potentially longer if the project is funded by external investors rather than equity. Yet the later turbines will not be commissioned until 2018/19, therefore two years ROC revenues are lost for the later phases of the project.

The most straightforward means of addressing this would be to extend the RO to 2020 and the RO support until 2040. The FiT will require a price setting process and this can be used to inform the ROC banding out to 2020. However, if this is not politically acceptable, there are other mitigation measures that could be applied:

- Different phases of the wind farm could be accredited under different regimes. However, at the point of the investment decision, details of the FiT regime would be unknown, creating significant extra risk to the project finance which would be reflected in the cost of capital. This could be addressed via a read across formula which secures the value of the FiT based upon the ROC price value that the project would have received under the current arrangements i.e. the ROC value at the point of first accreditation. Note, this option would create additional costs to the projects if separate metering was required, as the electrical designs are mainly fixed.
- The ROC values or multiple could be adjusted to provide the equivalent of the full 20 year support within the constrained timeline. This would not create an increased cost to the consumer as the total ROC support for the project would remain the same and it would not impact on forecasting as Government intends to introduce a fixed ROC price.

Alternatively the post-2013 ROC banding for larger projects should reflect the revenue lost post 2037.

37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies, should we:

- **Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?**
- **Carry out an “early review” if evidence is provided of significant change in costs or other criteria as in legislation?**
- **Should we move them out of the “vintaged” RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?**

These should be moved into the new FIT scheme, makes forecasting of the number of ROCs easier, with periodic reviews if evidence is provided of significant change in costs.

38. Which option for calculating the Obligation post 2017 do you favour?

- **Continue using both target and headroom**
- **Use Calculation B (Headroom) only from 2017**
- **Fix the price of a ROC for existing and new generation**

Investment decisions were based upon the RO as a market mechanism with a recycle element. Fixed ROC values represent a fundamental change in the nature of the RO and would remove the positive impact of a variable recycle price for renewable generators in low wind years. This must be recognised in the grandfathering provision.

The proposal to fix ROCs has been introduced in response to concerns that ROC headroom would not be maintained out to 2037, as the pool of ROC accredited projects reduced. DECC officials have quoted anecdotal reports that ROC prices are being reduced to reflect this. This is not our experience. However, Government’s consultation on a proposal to fix the ROC price has itself created uncertainty, which will now be factored into future ROC valuations.

Once again, Government must announce in the White Paper its decision regarding the options for calculating the obligation for the full period from 2017 to 2037, including the formula that will be used to fix ROC values at a fixed or headroom level.

We believe that Option B the headroom calculation should be the basis of future obligation setting for three reasons:

- this will minimise the impact on PPAs,
- it retains the supplier obligation which promotes the market for intermittent renewable power, and
- if the ROC price is fixed, this will create a volume risk for renewable generators. To create the required cash flow from consumers to generators, the supplier obligation is set in advance of ROC generation, based upon forecast volumes. The variations between actual and forecast ROC are managed via the outturn ROC price. If the ROC price was fixed, then the price and the supplier obligation set a required ROC volume; leaving generators facing the ‘cliff edge’ scenario. Under a fixed ROC scenario, this can only be addressed if Ofgem as the purchaser was obliged to buy all ROC generation, leaving Government with the ROC balancing risk.