– 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 CO_2 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 techiques 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.

<u>Options for market efficiency and security of supply</u>

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

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2 [redacted]

- 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 be 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.