Matt Wieckowski
Department of Energy & Climate Change
4th Floor, Area D
3 Whitehall Place
London
SW1A 2AW

4 October 2011

Dear Matt

Consultation on possible models for a Capacity Mechanism

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. We provide 50% of the UK's low carbon generation. Our interests include nuclear, coal and gas-fired electricity generation, renewables, combined heat and power plants, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including both residential and business users.

EDF Energy plans, with its partner Centrica, to build up to four new nuclear reactors, the first being at Hinkley Point. We are also actively developing our portfolio of renewable generation assets and completing construction of a 1300MW CCGT. Our final investment decisions for new nuclear generation are reliant on receiving the necessary consents and on a robust investment framework being in place.

We fully support the Government's proposals for Electricity Market Reform (EMR), as set out in the White Paper published in July. We believe that these can be developed, with all due speed, into a robust market framework that is capable of delivering the low carbon investment the country urgently requires. We agree with the Government's assessment that a capacity mechanism is needed to ensure security of supply. This is because we believe that there is a significant risk that the present energy-only market arrangements may not provide a sufficient signal for investment in reliable generation capacity or the provision of demand side response, particularly as increasing amounts of intermittent plant are added to the system. Although we recognise that a capacity mechanism is unlikely to be needed until at least 2016, we believe that it should be developed now in order to remove any uncertainty that will increase the risk associated with investment decisions in all forms of generation. It is imperative that the capacity mechanism ensures security of supply in a cost-effective manner, and in a way that does not discourage participation by new market entrants.

We believe that DECC is correct to make the distinction between diversification of supply, operational security and resource adequacy. We agree that the purpose of the capacity mechanism should be to address resource adequacy and that it should not discriminate between different sources of capacity that contribute to security of supply. It is important that market participants are clear about the role of the different mechanisms within EMR and the wider electricity market. For example, while a capacity mechanism may indirectly encourage investment in low carbon generation and assist in delivering operational flexibility, there are already tools that have either been proposed, or are already in place, to solve these issues. DECC will need to manage carefully the capacity mechanism's interaction with these other mechanisms and initiatives (such as Short-Term Operating Reserve (STOR), feed-in tariffs with a Contract for Difference (CfD), Project TransmiT, and Ofgem's forthcoming cash out review) to avoid any unintended consequences.

EDF Energy has taken the opportunity to assess the two options for a capacity mechanism outlined in the consultation document. As we will further elaborate in our response, we do not favour the proposed Strategic Reserve model, because we believe its successful operation would be heavily dependent on effective governance, and the perception of a high risk associated with further potential intervention may undermine the mechanism.

We also have serious concerns with the second option of a Reliability Market in the form proposed in the Consultation Paper. We believe this model is not compatible with existing market arrangements and creates an unacceptable basis risk by using prevailing spot energy prices to settle the value of capacity.

Our preference is for an alternative form of capacity market in which the value of capacity would remain separate from the energy market. In this capacity market, the total need for capacity would be set centrally, with a price set through annual auctions that would determine the value of capacity for all plant at least four years in advance.

We believe that the first step for any Capacity Mechanism will be for DECC to define a security of supply standard, e.g. that energy unserved must be limited to a defined number of hours. An assessment will then need to be made of the capacity required to deliver this standard, together with an assessment of the potential shortfall in capacity expected to be available. We note that these assessments are consistent with Ofgem's new responsibilities in the current Energy Bill, where it is tasked with reporting the UK's future capacity and forecasting peak demand in the future. We would therefore expect Ofgem to play an important role in the establishment and operation of the Capacity Mechanism.

EDF Energy believes that withholding capacity payments from generators that are unable to provide the contracted capacity will in itself provide generators with a very strong incentive to make plant available at the required times. We believe it may also be appropriate for generators to pay a penalty in these circumstances. As a principle we believe that any penalty must be linked to the value of capacity and not the value of energy that the plant could provide and any deviation from this is likely to create unacceptable risks for generators that could ultimately undermine the effectiveness of the capacity mechanism.

Revenues raised in penalty payments should be reimbursed to electricity suppliers and should not be redistributed amongst other generating plant. This will help reinforce the correct market signal for the value of new capacity and reduce incentives for gaming.

There will also be a number of other key issues that will need to be addressed as the details of the mechanism are developed. These include:

- Assessing the reliability of the technologies able to participate in the mechanism;
- Checking the availability of the capacity during periods of peak demand;
- Cost recovery of the mechanism;
- Solutions to deal with non-generation technologies.

We look forward to publication of DECC's technical update by the end of the year. EDF Energy would welcome the opportunity to discuss with the Government the detailed parameters required for the capacity mechanism to work, once a decision on the form of the capacity mechanism has been made.

Our detailed responses are set out in the attachment to this letter. Should you wish to discuss any of the issues raised in our response or have any queries, please contact my colleague [redacted] or myself.

Yours sincerely,

[redacted]

Corporate Policy and Regulation Director

Attachment

Consultation on possible models for a Capacity Mechanism

EDF Energy's responses to your questions

1. **Does this table [see Figure C3] capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?**

We agree that the table captures the major concerns with a targeted Capacity Mechanism. However, we believe that the mechanism, as proposed, does not fully address the 'slippery slope' problem. This is because the revenues for plant outside the Strategic Reserve will remain uncertain, and may be adversely affected by the operation of the Strategic Reserve. These revenues will be contingent on the combination of the number of hours a year that the Strategic Reserve will operate and the despatch price of the reserve.

In addition we are also concerned that this may lead to the development of a sub-optimal capacity mix, with the construction of low capital cost plants that can offer capacity into the Strategic Reserve precluding the development of more capital intensive but more efficient plant.

We believe that these problems can be minimised if the key parameters are correctly calibrated. These key parameters are the volume of reserve capacity, the despatch criteria for reserve capacity, and the impact on cashout price when the reserve is activated. However, we believe that these parameters will evolve over time as the level of intermittent capacity increases over time. This will make it extremely difficult always to set these parameters correctly and in a manner which ensures that sufficient plant is contracted in the Strategic Reserve to provide a reliable and predictable impact on wholesale prices that all market participants can rely on.

It will be important to have transparent rules in place to govern the interaction between the Strategic Reserve and the Short Term Operating Reserve (STOR). It should be made explicit that the role of the Strategic Reserve is to ensure resource adequacy, whereas STOR is required to ensure operational security of the system. STOR is a 24 hours a day, 365 days a year mechanism that deals with the effective despatch of plant that is available to ensure that demand is met. In contrast, the role of the capacity mechanism is to ensure that the System Operator has sufficient plant at its disposal to satisfy peak demand. If this interaction is not managed correctly, then market participants may not have confidence in either mechanism and this may discourage investment, leaving the system with an insufficient level of resource adequacy.

In general, the procurement and operation of the Strategic Reserve will need to be carried out in a transparent manner. A clear methodology is necessary to set the despatch price, and the impact on the cash out price should be well understood by market participants.

Although the issues raised above are soluble, the successful operation of the mechanism will be heavily dependent on effective governance to adjust the parameters of the Strategic Reserve as the future UK plant mix evolves. We believe that making the necessary changes over a period of time to ensure that the Strategic Reserve continues to operate effectively and provides a predictable and stable revenue stream for all plant will prove to be quite challenging and could create the perception of a high associated risk of further intervention, which is likely to undermine the mechanism. The difficulty in determining the required level of reliability, and estimating the proportion that is likely to be delivered by the market, should also not be underestimated. This will not only have consequences for the UK's security of supply (if the required capacity is underestimated), but also for the Government's other energy policy objectives of affordability and decarbonisation, if there is too much capacity, or if the mechanism distorts the capacity mix.

For these reasons, EDF Energy does not favour the introduction of a targeted capacity mechanism. However, despite these serious reservations we have answered the subsequent questions 2-10 on the basis that it could be made to work.

2. **How long should the lead time for Strategic Reserve capacity procurement be and why?**

We note that the approach to Strategic Reserve capacity procurement is likely to be quite different from that for procurement for a wider Capacity Market. Providers of Strategic Reserve should be able to provide reliable capacity with low capital costs and low fixed operating costs. The variable operating costs will be a less significant consideration because the Strategic Reserve will be expected to run infrequently.

This means that the potential providers of such a Strategic Reserve are likely to include assets such as new OCGT or diesel plants, existing generation assets nearing the end of their operating life, and some demand response services. In general, the lead time for procurement of these assets will be relatively short, and so the lead time for procurement of the capacity contracts could be correspondingly short. We believe that procurement could be completed around three to four years ahead of need.

However, we note that the risk identified with the Strategic Reserve is that it may fail to ensure sufficient revenue for plant outside the Strategic Reserve. It will therefore be necessary to assess the expected capacity balance over a much longer timescale (perhaps 7-10 years ahead). In the absence of clear signs that the market is likely to provide adequate capacity as a result of investment in a mix of generation assets, this would be a warning that the Strategic Reserve is failing to support the right investment climate. This would indicate a possible need to modify or replace the Strategic Reserve approach.

3. **Should the length and nature of contracts procured by the Strategic Reserve procurement function be constrained in any way?**

The contracts for new plant in the Strategic Reserve should be long enough to provide participants with a high degree of certainty on the returns to be made from their investment. For example, new generation capacity may require a contract length of 10 years, whereas a shorter contract length may be sufficient for existing plant or demand side response providers investing in new equipment.

4. **Which criteria should providers of Strategic Reserve be required to meet?**

The providers of Strategic Reserve will need to meet prevailing environmental standards and be available for despatch during periods of peak demand. The central body responsible for procuring Strategic Reserve should aim to minimise costs by awarding contracts to providers of the most economically competitive assets. By definition, capacity that is deemed to be the option of last resort is not going to run continuously and it will be important that the procurement process provides guidance on potential running patterns to ensure that the correct type of reliable capacity is brought forward.

Existing plant should be allowed to compete in these tenders, as it may be more cost-effective to pay for an existing generating plant to remain in service than to build a new peaking asset, even after taking into account the extra costs likely to be incurred because of flexibility constraints. However, there may need to be controls to prevent plant "flipping" in and out of the Strategic Reserve. For example, it might be expected that existing older plant entering the Strategic Reserve would close rather than return to the market when they were no longer required in the Strategic Reserve.

We believe that consideration will also be given to how the reliability of Strategic Reserve can be assured. If the plant is called only very infrequently, there may be a high risk of failure when it is called. A regime of periodic test operation may be required to manage this risk, which should be done in a manner designed to have minimal impact on the normal operation of the market.

Providers of Strategic Reserve should face a penalty for non-availability if they fail to provide the contracted capacity when instructed to do so.

5. **How can a Strategic Reserve be designed to encourage the cost-effective participation of DSR, storage and other forms of non-generation technologies and approaches?**

The Strategic Reserve should be designed to procure capacity from the most cost-effective sources, irrespective of whether they are generation assets, Demand Side Response (DSR), storage or other solutions. However, in order to do this, it is important to investigate the key parameters of the various possible solutions:

- Lead times for construction and development
- Likely levels of capacity available
- Ramping rates for delivery of capacity
- Period for which the provision of capacity can be sustained
- Fixed capital and operating costs and variable operating costs
- Reliability
- Operational constraints.

The procurement criteria and process should be designed to ensure that specific sources of capacity are not automatically excluded because they fail to meet a single standardised approach to provision of capacity. The test should be whether they will make a cost-effective contribution to a portfolio of Strategic Reserve assets that will provide the required level of capacity.

However, a critical requirement for the participation of DSR in a targeted Capacity Mechanism is that the DSR is actively provided in response to the requirements of the Strategic Reserve Operator in such a manner that it can be properly evidenced, quantified and verified.

6. Government prefers the form of economic despatch described here. Which of the proposed despatch models do you prefer and why?

In our response to the original Electricity Market Reform consultation, we indicated a preference for last resort despatch at a high "reserve activation price" to minimise any distortion of the market, and this preference still holds. However, it is important to recognise that the Strategic Reserve will have been developed for it to be operational when dealing with scarcity. It should therefore be deployed only when the pre-determined threshold level of scarcity is reached. This scarcity should be signalled to the market through the balancing mechanism, and included in the cash out calculation for the appropriate half-hour balancing period.

There is an important relationship between the despatch price and the size of the Strategic Reserve. The Strategic Reserve could be kept very small with the expectation that it would operate very infrequently and only at a very high price. The impact might be highly variable from one year to the next, but in most years it would have only a minimal impact compared with the existing energy-only market. Alternatively, the Strategic Reserve could be much larger and would be expected to operate more frequently but at a lower price. The impact of this mechanism compared with the existing energy-only market would be much greater but would be expected to be more consistent.

The despatch price could be regarded as having a capacity and an energy component; the energy component represents the fuel and other variable operating costs of the plant in the Strategic Reserve. In principle, the capacity component multiplied by the expected number of running hours per year should be equivalent to the annualised cost of a peaking plant. One estimate of this annualised cost could be taken from the Irish capacity mechanism for 2011 at €79 equivalent to £68/kW (at an exchange rate of £1 = €1.15).

We have carried out some modelling of the volumes of Strategic Reserve capacity that might be required. As examples (based on the above numbers and rounded to the nearest £100/MWh), for a future system with approximately 35GW of installed wind generation capacity:

- A minimal Strategic Reserve expected to operate for around 10 hours per annum on average might require around 2-3GW of plant, and should have a despatch price of around £6,800/MWh for capacity, plus fuel and other variable operating costs of around £200/MWh.
- A larger Strategic Reserve expected to operate for around 60 hours per annum on average might require around 8GW of plant and should have a despatch price of around £1,100/MWh for capacity, plus fuel and other variable operating costs of around £200/MWh.
- A Strategic Reserve expected to operate for around 120 hours per annum might require around 10GW of plant and should have a despatch price of around £600/MWh for capacity, plus fuel and other variable operating costs of around £200/MWh.

Of these three examples, the minimal Strategic Reserve would operate infrequently and set very high prices when triggered but would otherwise have relatively little impact compared to the current energy-only market. However, it would create unacceptable risks for generators as they could face extremely high penalties if their plant fails at the time when the Strategic Reserve is activated.

In contrast, the largest example is reaching the practical limit at which we believe a Strategic Reserve remains manageable but would be required to give generators that are not contracted in the Strategic Reserve the necessary confidence of a stable and predictable revenue stream.

We would also question the assertion that the targeted mechanism will "constitute a cap on market prices" (page 165) for two reasons.

Firstly, this does not take into account any possible effect on interconnector flows during a Europe-wide scarcity event. The GB market must retain the capability to increase market prices above the despatch price, so that the GB market can retain indigenous power supplies and/or import additional power supplies up to the point where it is no longer willing to pay a higher price than neighbouring markets. If this is not allowed then this will simply mean that the GB market would have paid for Strategic Reserve without benefiting from the additional security of supply.

Secondly, in the absence of any specific capacity-related remuneration for plants outside the Strategic Reserve, these plants are rewarded for providing capacity by high prices in the energy market at times of system stress. The operation of the Strategic Reserve will be a major factor in setting the energy prices at such times; it therefore effectively becomes the mechanism that provides the right incentives for investment in capacity outside the

Strategic Reserve. The precise impact of the Strategic Reserve on energy prices will depend on the detailed rules of the cash out mechanism. If it sets prices too high, it will lead to excessive costs to customers but, if it sets prices too low, it will discourage necessary investment in "market" capacity.

For both of these reasons, we believe that, although the operation of the Strategic Reserve will clearly affect market prices at times of system stress, the idea that it would set a cap on prices underplays the importance of high market prices at these times in ensuring security of supply. At times, it might effectively set a floor, rather than a cap, on market prices.

7. **How would the Strategic Reserve methodology and despatch price best be kept independent from short-term pressures?**

The reserve despatch price, and the number of half-hours this price is visible to the market (i.e. when the strategic reserve is despatched at this price) is critical to ensuring that non-reserve plant receive sufficient revenue with the required certainty to remain on the system. Any unexpected change, or outside intervention, will impact investor confidence and have a detrimental impact on the Government's security of supply objectives. Therefore, the rules governing the Strategic Reserve must be robust, transparent, stable and well documented. These rules must include a rigorous change management process, with an appropriate level of checks and reviews, to ensure that the methodology and reserve despatch price are not subjected to short-term pressures. The methodology for calculating the reserve despatch price must be clearly defined and include appropriate indexing against fuel costs to ensure it is beyond reproach.

8. **Do you agree that a Strategic Reserve should be periodically reviewed? If so, who would be best placed to carry out the review and how often should it be reviewed?**

The Strategic Reserve should be periodically reviewed in order to provide long term assurance for participants, and to ensure that the system is fit for purpose. We believe that this role can be carried out by Ofgem, in line with its proposed responsibilities for conducting capacity and demand assessments. It is crucial that any recommended changes and/or remedies are subject to a full consultation with market participants. We believe that there would be merit in having the first review after three years but appreciate that this would most likely have to focus on planning and procurement rather than the operation of the Strategic Reserve. This is because the utilisation of the Strategic Reserve may vary from year to year, and it will take time before appropriate conclusions can be drawn from this.

9. **Into which market should Strategic Reserve be sold and why?**

The Strategic Reserve should be despatched into the Balancing Mechanism under clearly defined criteria based on a threshold level of capacity scarcity. This will allow the despatch decision to taken as close to real time as possible, when it is more certain that the system requires the Strategic Reserve to be despatched. The reserve despatch price should then feed into the calculation of the cash out price for the relevant half-hour period.

We do not believe it is necessary to offer the Strategic Reserve in a forward market .This is because the market would have already taken a view on the likelihood of the Strategic Reserve being despatched when determining the day-ahead and other forward market prices. We recognise that some capacity may require a notice period to be available but this does not require it to be offered in the forward market. The arrangements for such notice and any payments made in respect of it (e.g. "warming contracts") would form part of the capacity provider's contract and would be taken into consideration in the original procurement decision.

10. Do you have any comments on the functional arrangements proposed for managing a Strategic Reserve?

We agree with the six broad functional groupings proposed for managing a Strategic Reserve.

11. Given the design proposed here and your answers to the above questions, do you think a Strategic Reserve is a workable model of Capacity Mechanism for the GB market?

EDF Energy believes that the Strategic Reserve could, in theory, be a workable solution for the GB market. It would however require the establishment of robust and transparent rules to ensure that the value of the capacity is fully reflected in the energy market, and that all capacity contributing to peak demand (i.e. generating when the Strategic Reserve is activated) benefits from the impact that this will have on wholesale prices. In practice, it would be very challenging to achieve this, and this could create the perception of a high associated risk of further intervention, which is likely to undermine the mechanism.

We believe that a simpler mechanism, such as a universal capacity market with a centrally co-ordinated auction, would be a more suitable solution for the GB market. We explain this further in our response to Question 25.

12. How and by whom should capacity in a GB market be bought and why?

We believe that there is a choice between:

- a centrally co-ordinated procurement approach, where all capacity is procured by a single Agency and the costs are recovered from customers through suppliers, and
- a "supplier-led" approach, where suppliers are obliged to procure capacity directly to meet the requirements of their customers (whether through a single auction or through bilateral contracting).

There are some arguments in favour of the "supplier-led" approach. This places the responsibility on suppliers to manage their own capacity requirements, and to minimise the costs of doing so. This may be seen by some as a more "market-based" solution, because it will involve a greater number of buyers in the process, but we do not believe that this approach will lead to better price discovery compared with procurement by a single body through an auction.. However, we believe it has some significant disadvantages which outweigh the possible advantages:

- The "supplier-led" approach would rely on the collective ability of suppliers to forecast and to procure capacity requirements with a long enough lead time for new plant build. We have serious doubts as to whether this would be an effective approach.
- A "supplier-led" market in capacity might not be liquid enough to provide clear price signals for the construction of new capacity.
- Although large and established suppliers might be able to manage the obligation effectively, it may create a barrier to entry into the supply market.
- Suppliers would need to procure capacity with a much longer lead time than most of their supply contract volume. This has two consequences. Firstly, it will lead to a lack of accountability for the procurement of adequate capacity. Secondly, it will require the development of an active secondary market in capacity to enable suppliers to manage their exposure to capacity obligations as they gain or lose customers.
- Verification that suppliers have complied with the obligation will be difficult and this could undermine the actual security of supply that is achieved.

For all of the above reasons, we believe that a supplier obligation would lead to significant additional cost, complexity and risk to suppliers in managing a relatively small component of the customer bill. This in turn would lead to increased costs for customers.

EDF Energy would favour a centrally co-ordinated procurement approach, where capacity would be procured by a central Agency through a transparent auction process, all providers being paid the auction clearing price. We would expect Ofgem to provide its assessment of future firm capacity and projected demand to the Secretary of State (as provided for in the Energy Bill 2011). This would be followed by a public consultation with market participants. We would then expect the Secretary of State to publish a 'requisition' for capacity (both new and existing). A new central Agency would then be tasked with running the auctions and procuring the capacity required.

13. What contract durations would you recommend for a Capacity Market?

We believe there are two basic options for the procurement approach for capacity:

- The "bespoke" approach – the Agency identifies potential capacity providers and designs the auction process to make it attractive for these providers to participate, having regard to the specific attributes, revenue requirements and risk profiles of their assets.

- The "standardised" approach – the Agency procures a single capacity through a single contract form; potential providers of capacity have to assess their ability to provide this standard product.

The standard product may be termed a "MWyear":

- A contract offered to provide an average of x MW of available capacity over the "peak" periods (with "peak" to be defined).
- Contracts to have a duration of one year only and to be sold by auction four years ahead.
- Our initial view is that the natural "contract year" would be April – March but this point should be given further consideration at the detailed design stage.

Although the bespoke approach looks at first sight to have many advantages in securing the most cost-effective solutions to provision of capacity, it would also introduce significant extra complexity into the market. While capacity providers may initially view the bespoke approach as providing certainty for specific sources of capacity (e.g. by providing a long contract duration to support a specific investment), we believe that, in the long run, the standardised approach should be more stable and will offer greater certainty.

There is a risk that the prices from standard one year contracts might vary significantly from year to year, perhaps reflecting the full value of new entrant capacity in some years and dropping close to zero in other years. Further consideration should be given to whether the standardised approach would require a mechanism to stabilise prices from year to year.

If the more complex "bespoke" approach were adopted, then the key factors driving contract duration would be:

- The period needed to recover a sufficient part of the investment in new capacity or in extending the life of existing capacity. It will also be important to recognise that the significance of capacity revenue in an investment decision will vary markedly between different types of assets.
- The existence of other regulatory or contractual obligations on capacity providers.

Considering these two factors in turn:

Period to recover investment costs

  - For new assets, this might suggest contract duration of up to, say, 10 years to ensure recovery of a substantial proportion of the initial investment.
  - For an existing generation asset, the contract duration might need to take account of major expenditures on maintenance or refurbishment. For example, a coal plant may typically require major maintenance outages on a four year cycle.

Other regulatory or contractual obligations

- For demand side response, a shorter contract duration might allow customers to offer a demand side response service without compromising their ability to manage their business operations.
- Contract durations may need to be linked to limitations on existing fossil plant arising from measures such as the Industrial Emissions Directive.

Under the "bespoke" approach, the Agency might run three auctions: (see also our response to Question 14):

- To procure x GW of capacity on a 10 year contracts starting 3-6 years ahead (which might be met by new assets)
- To procure y GW of capacity on a 4 year contract starting next year (which might be met by existing generation assets)
- To procure z GW of capacity on a 2 year contract starting this year (which might be met by demand side response or by existing generation assets)

We believe that it will be difficult to make transparent decisions that reflect the trade off between price and term of the different options that could be available in a bespoke approach. In light of the above, our preference would be for the standardised approach. However, we recognise that this is an important decision, and it may be advisable to defer a final answer on this until later in the process of designing the new mechanism.

14. How long should the lead time for capacity procurement be? Should there be special arrangements for plant with long construction times?

As noted in the answer to Question 2, the procurement approach for a Capacity Market will be very different from that suitable for a Strategic Reserve. The Capacity Market has to work for a wide range of different capacity providers, with varying lead times for asset development and construction.

There are two possible approaches to the lead time for capacity procurement which correspond to the "bespoke" and "standardised" approaches outlined in our answer to Question 13.

Under the "bespoke" approach, capacity would be procured in tranches:

- A long term capacity assessment (5-10 years) could give an early indication of capacity requirements, leading to some early procurement.
- Four years ahead will normally be adequate to construct a CCGT on a consented site.
- Shorter term contracting (1-3 years) could be used to fine-tune capacity requirements and would be adequate for OCGT plant and may be more suitable for procurement of demand side response.

- The contract duration for new plant would be long enough to make a significant contribution to the payback of investment costs, and could be shorter for existing plant.

Under the "standardised" approach, all capacity would be procured with the same lead time, for which we believe four years would be a reasonable period. This would provide indirect rather than direct support for new investment decisions. For example, an investor in a new CCGT would not know the income they expect to receive from capacity payments but they would be able to use market prices for capacity to inform their investment decision. As with Question 13, we recognise that there are arguments in favour of either approach but on balance, we recommend the standardised approach.

If the standardised approach is adopted, then there may well be a temptation to introduce bespoke elements to it. These temptations should be resisted; otherwise the benefits of standardisation are likely to be eroded very quickly.

15. Should there be a secondary market for capacity? Should there be any restrictions on participants or products traded?

A secondary market for trading will be essential if suppliers are obliged to purchase sufficient capacity certificates, or reliability contracts, to meet their customer demand (during, for example, the 200 peak hours of overall system demand). This is because the customer portfolios of suppliers will change from the time that the capacity certificates/reliability contracts are procured to the time of delivery.

We believe that a secondary market for capacity would also be necessary under a central procurement approach. This would enable capacity providers to manage the under or overprovision of capacity (including, for example, the consequences of project delay or unexpected availability), and thus promote the overall efficiency of the system. It would also provide portfolio players with a means of meeting capacity requirements out of their portfolio, and not just from individual assets.

16. What are the advantages and disadvantages of making a central, administrative determination of (i) the capacity that can be offered into the market by each generator; (ii) the criteria for being available; and (iii) the penalties for non-availability? In outline, how would you suggest making these determinations?

(i) Central determination of capacity that can be offered into the market by each generator

Advantages:

- The central determination of each generator's capacity should be consistent with the initial assessment of the market's capacity requirement.

- Capacity offerings will be independently assessed using a consistent set of criteria and provide an independent assurance of the level of capacity available in the market.

- This will also help ensure that the capacity remains rooted and linked to physical capacity, and reduces the risk of diluting the signal for physical capacity in a financial derivatives-based market.

Disadvantages:

- Capacity values determined centrally may not match an individual generator's self assessment of capacity and hence may not be an accurate assessment of capacity. However, generators would be able to explain to the Agency where they believed that there was a material error in the central assessment of capacity In any case generators would be able to reflect and correct for any over or under valuation in the expected performance in the price that they offer for their capacity in an auction.

(ii) Criteria for being available

Advantages:

- Selection criteria should be standardised and based on the expected contribution that all technologies can expect to make to providing firm capacity at any particular time. This will reduce opportunities to game the system, and the availability criteria should match the criteria that Ofgem will develop to assess the level of capacity that is available.

Disadvantages:

- No significant disadvantage noted.

(iii) Penalties for non-availability

Advantages:

- For avoidance of doubt, it should be made clear that only capacity that is physically available during the specified periods over which the capacity payment will be paid will qualify to receive the capacity payment. This in itself will provide generators with a very strong incentive to make capacity available at the required times.

- We believe it may also be appropriate for generators to pay a penalty in the event that contracted capacity is not made available at the required times. This may be set as a percentage of the capacity payment that the generator would have expected to earn if it were able to make its capacity available.

- We believe it would be necessary to understand the details of the operation of the capacity mechanism before determining the precise level of the penalty. However as a principle we believe that it must be linked to the value of capacity and not to the value of energy that the plant could provide.

- Revenues raised in penalty payments should be reimbursed to electricity suppliers and should not be redistributed amongst other generating plant. This will help reinforce the correct market signal for the value of new capacity and reduce incentives for gaming.

Disadvantages:

- A disadvantage of a penalty payment only arises if the penalty is badly designed or set at an inappropriate level. If the level is set too high, this may discourage generators from participating in the mechanism and they may remove capacity from the system, if there is a risk that the potential liability arising from the penalty will exceed the revenue they expect to receive from it. Such a situation is likely to arise if the penalty for unavailable **capacity** is somehow linked to wholesale **energy** costs.

- It is important to have clarity and understanding on the constitution of both these components. So, while there are many factors that will influence the energy price, such as the cost of fuel and details of the running pattern of the plant, none of these have a direct influence in maintaining the capability of a generating asset. Under the current trading arrangements, we would expect the bulk of the revenue earned by most generators to come from energy payments and a relatively modest proportion from the capacity mechanism. Therefore, linking a penalty to energy payments or wholesale power prices is likely to create a significant disincentive to participating in the capacity mechanism.

17. How should the reference market for reliability contracts be determined and what would be an appropriate reference market if it is set by the regulator? How could any adverse effects of choosing a particular option be mitigated?

EDF Energy does not support the Reliability Contract proposal in its current form because of the potential distortions caused by the interaction between the energy market and the capacity market. We do not believe that Reliability Contracts are compatible with the current BETTA market arrangements.

The Reliability Contract as proposed in the Consultation Paper takes the form of a derivative contract, being an option against the price at which power is sold by a generator to a supplier.

In this form, reliability contracts subject generators earning capacity revenue to a double exposure against the power/energy price, effectively penalising them twice for non-availability. Firstly, there is the energy cash out penalty if they are unable to generate and meet their position. Secondly, they will also then face a liability under the option contract (whether generating or not) – creating basis risk against wholesale market revenue. The logic of requiring generators to pay the price of energy to compensate for the value of capacity is flawed. The potential liability under such an arrangement will discourage long term contracting, and will have an impact on forward curve liquidity and the relationship with the proposed CfD reference price. This will also undermine current initiatives by DECC and Ofgem to increase liquidity and extend the length of traded market liquidity. The fundamental problem with this approach is that the value of capacity is distorted by being settled against an energy price - the spot price of gas or coal has no correlation with the fixed costs of providing capacity.

18. For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

Given our response to question 17, we do not have any comment to make on this, as we believe the concept of penalising capacity on the basis of prevailing energy prices is fundamentally flawed.

19. For a Reliability Market, what level of physical back up (if any) should be required for reliability contracts and how should it be monitored?

We believe that only owners (or managers) of physical capacity should be able to offer capacity into a capacity market. This would need to be periodically verified to ensure that this capacity was at, or under, the maximum capacity the facility could physically achieve. We do not believe it is prudent to rely on financial options to provide security of supply.

Similarly any demand side response would have to be verified and payments linked to specified demand reductions that can be achieved on specific request at a particular time. It will be important to separate such demand reduction from any other unspecified load reduction that occurs spontaneously in response to high prices. We do not believe that such unsolicited and non-firm demand response should qualify for any direct payment from the capacity mechanism.

20. Do you agree that a vertically integrated market potentially raises issues for the effectiveness of a Reliability Market? If so, how should these issues be addressed?

We do not believe that vertical integration makes any fundamental difference to the operation of a reliability market. There may be a perception that, because vertically integrated companies will be interested parties on both sides of a reliability contract, this will somehow diminish or distort the value of the contract. However, as with the energy market, it should be recognised that these companies are also likely to carry an exposure on both sides of the contract, and it is in their interests to ensure that a reliability market is able to operate effectively without distortion.

The real concern about the effectiveness of a reliability market comes from the structure of the GB market that is based on the physical forward contracting for energy, which makes the proposals, as currently presented, unworkable. We believe that the proposal we have put forward in our response to question 25 addresses these shortcomings.

21. What could we do to mitigate interactions between a Capacity Market (especially if a Reliability Market) and Feed-in Tariff with Contract for Difference without diluting the effectiveness of either?

Feed-in Tariff with Contract for Difference (CfDs) aims to provide sufficient revenue certainty for low carbon generation. Capacity revenue should not be considered as additional revenue. The market value of any capacity revenue earned by CfD plant should be netted off the flow of money under CfDs, to avoid a double payment. For example, a CfD generator would earn energy revenues (expected either from production or availability against the energy reference price) and capacity revenues (from the capacity market) during a particular period. These two revenue streams should be combined when calculating whether the generator receives money from, or pays out, to the CfD Agency. The size and likelihood of any penalty for non-availability would need to be considered when assessing the CfD strike price. We believe that there may be grounds to consider capping the penalties that a generator may be liable for if not available.

22. How can a Capacity Market be designed to encourage the cost-effective participation of DSR, storage and other non-generation technologies and approaches?

DSR, storage and other non-generation technologies and approaches should be included in the capacity/reliability market to the extent to which they can provide reliable capacity. This must be properly evidenced and quantified, either by direct measurement or by reliable estimation. Ensuring that the price signal is robust and reliable will encourage DSR. If given a sufficient lead time, it may be possible for suppliers or aggregators to sell a DSR product to the central Agency, and then subsequently contract with customers to provide this service.

The inclusion of interconnection capacity in a Capacity Market is a complex issue and will need to be assessed further. It is important that any decision made does not adversely impact interconnector energy flows (which are driven by price arbitrage), and that any mechanism is compatible with future European arrangements such as market coupling.

23. Do you have any comments on the functional arrangements proposed for managing a Capacity Market?

The rules governing the Capacity Market must be robust, transparent, stable and well documented. These rules must include a rigorous change management process with an appropriate level of checks and reviews to ensure that the market is resistant to short-term pressures for interventions.

We would envisage DECC defining a security of supply standard; e.g. the energy unserved must be limited to a set number of hours. In line with its proposed new powers, we would expect Ofgem to be responsible for conducting capacity and peak demand assessments. There would also be a role for a new Central Agency with the responsibility for the actual capacity procurement.

24. Do you think that a trigger should be set for the introduction of a Capacity Market? If so, how do you think the trigger should be established, and how should it be activated?

As outlined in our response to the Electricity Market Reform consultation, it is our belief that, without capacity payments, the economics of new low load factor capacity will depend on very infrequent occasions of very high prices. The uncertainties over the magnitude of these peak prices, their frequency, and their acceptability leads us to believe that, if a capacity mechanism is not introduced, the market would reach an equilibrium with a lower standard of security of supply than we currently have. This problem is unlikely to materialise until at least 2016, maybe later. However, we believe it is important to address this issue now to remove an uncertainty that will increase the risk associated with investment decisions in all forms of generation.

It is important that a Capacity Market is introduced as soon as practically possible, so that economic signals for any need for new capacity are fed back to the market in the most efficient and timely manner. We believe a realistic timetable would require gaining clarity on the details of the capacity mechanism next year, with the first capacity auctions ideally in 2013, or 2014 at the latest. By 2014, auctions could be held covering the years 2016/17/18, thus putting the Capacity Market into operation by 2016. Although capacity prices may be low in 2016, we would expect them to rise by 2019/2020. It would be inappropriate to wait until this date to introduce the mechanism, because investment decisions need to be made now. This is particularly pertinent for plant subject to environmental legislation (such as the IED), and which are due to make investment decisions (particularly coal plant) in 2012/2013 with regard to their method of compliance. Certainty over the capacity mechanism will result in more informed asset lifetime planning decisions by the operators of such existing plant.

25. What is the most appropriate design of Capacity Market for GB and why?

EDF Energy favours an alternative form of Capacity Market which we believe will be more compatible with the existing GB market and the other elements of Electricity Market Reform.

The core requirements of defining future need and confirming the veracity of qualifying capacity would remain as currently proposed.

The mechanism itself would consist of a centrally co-ordinated approach, where the total need for capacity would be set centrally, looking at a single year in the future (say four years in advance). A centralised auction would be held to satisfy the demand for the required capacity. Both generators and providers of demand side response would be able to sell capacity certificates through a competitive process and the clearing price of the auction would set the value of capacity for that year.

The auction clearing price would be paid to all participants. All providers of capacity that contribute to system security would be eligible to participate, and this capacity would be audited. The certification would reflect different levels of availability; e.g. wind would need to have its capacity credit assessed. Availability would need to be checked over a defined number of hours reflecting highest demand, e.g. the top 200 hours. Capacity owners would face a penalty if not available when called upon. It is important that this penalty should be set at a level that incentivises availability but, at the same time, should not be set too high, to prevent capacity owners withdrawing capacity in fear of the penalty.

The Central Agency would be responsible for recovering the costs through a levy on suppliers as a function of their share of demand over the 200 hours of highest demand. The suppliers would in turn recover this amount from customers. We believe that this time duration represents a compromise. If the number of hours is too long, then it will not promote enough peak demand reduction and will reduce the incentive to be available when most likely to be needed. Conversely, if the number of hours is too short then this will make it too difficult for capacity providers to predict the peak hours, and will place too great a risk on them if they are not available during this period.

The benefit of this mechanism is that the capacity market and the energy market would remain separate to avoid distorting each other.

DECC has left open the question of whether the CfDs for baseload generation will be on a capacity or energy basis. In the event that the CfD is based on output only, then it would be appropriate for the generator to retain the revenue from the capacity market. Conversely if the CfD is on a capacity basis, then it would be appropriate for the generator to pass through any additional revenue received from the capacity mechanism to the CfD counterparty. In such instances the total revenue earned (i.e. energy and capacity) would be netted against the CfD strike price.

We do not believe it would be necessary or desirable to introduce specific licence conditions to prescribe or regulate generator pricing. The existing controls in place to deal with market abuse should prove to be sufficient to prevent or deal with any anomalies.

26. What are your views on the costs and benefits of a Capacity Mechanism to industry and consumers?

As outlined in our response to Electricity Market Reform consultation and question 24, it is our belief that, without capacity payments, the economics of new low load factor capacity will depend on very infrequent occasions of very high prices. The uncertainties over the magnitude of these peak prices, their frequency, and their acceptability lead us to believe that, if a capacity mechanism is not introduced, then the market would reach an equilibrium with a lower standard of security of supply than we currently have. This problem is unlikely to materialise until at least 2016, maybe later. However, we believe it is important to address this issue now, to remove an uncertainty that will increase the risk associated with investment decisions in all forms of generation. It is important that a Capacity Market is introduced as soon as practically possible, so that economic signals for any need for new capacity are fed back to the market in the most efficient manner.

Introducing a capacity mechanism along the lines we have proposed in our response to Question 25 will also provide a robust and reliable signal for DSR.

The costs of the capacity mechanism would be offset against the damage caused by a reduced security of supply, and should be considered in establishing the desired/prescribed level of security of supply.

In an ideal world, all electricity end-users would be able to signal their economic willingness to pay to avoid a blackout (e.g. Value of Lost Load). The introduction of smart meters may change this in future, by enabling more sophisticated approaches to the management of capacity. However, this can only be considered once the roll out of smart meters to a significant number of end-users has been achieved.

Therefore, an approach is needed to manage the security of supply requirements of the GB market that can be developed now. It is our belief that this task should be undertaken by a central body, which has the responsibility for forecasting the future capacity requirements and signalling this back to the market. It is important that the costs associated with a capacity mechanism should be targeted toward end-users benefiting most from the increased security of supply. We feel that costs should be billed to suppliers based on their customer demand during periods of peak demand, when the system is most stressed.

27. Which Capacity Mechanism should the Government choose for the GB market and why?

Please see our response to Question 25.

EDF Energy
October 2011