DECC Consultation on Possible Models for a Capacity Mechanism

Response by E.ON

Summary

If capacity mechanisms are to incentivise efficiently the provision of generating capacity or demand side response (DSR), investors must be able to anticipate with reasonable confidence the benefits and costs arising from participation in the mechanism.

We do not think that the proposed approach to mitigating concerns raised about the targeted capacity mechanism is effective, and we do not, on balance, favour the Strategic Reserve option.

It will be extremely difficult to set and maintain the despatch price at the correct level in the Strategic Reserve. Given that the price will cap returns in the wholesale market, companies are unlikely to have confidence to invest in capacity outside the reserve until it is well established and demonstrably free from regulatory intervention.

The Strategic Reserve is not well designed to incentivise demand side response.

Given the intention to deliver a predefined capacity target in a market wide capacity market, a central body should procure the capacity through some form of auction. This central body would need to operate within clear parameters set by legislation but should be independent of Government control.

Procurement and commissioning of new or refurbished capacity could be managed with an auction at least four years before the start of the capacity contract, but a longer lead time (probably five years) is likely to reduce developer risk in terms of ensuring the capacity is available within the required timescale.

The market wide mechanism should enable DSR to participate more actively and directly in the capacity market. DSR will also be incentivised if generators are able to bid DSR to meet their contractual commitments.

We do not believe the specific reliability option proposed by DECC works effectively. If generators are unable to generate during the period when the strike price is exceeded (for

example due to plant breakdown), they face the risk of an almost unlimited and highly unpredictable liability in addition to the costs they already incur. We would favour an approach which imposed financial penalties for non-availability but capped these administratively at a level which investors could anticipate.

We believe, on balance, that a market wide mechanism is more likely to reward all capacity fairly and will provide a more reliable basis for investment, in an environment where the value of capacity will become an increasing driver of flexible plant investment, given the increasing penetration of intermittent wind in the market.

We therefore recommend that DECC develop further a reliability model. However there would have to be political and wider stakeholder acceptance of the need to pay generators for capacity to be available, as the savings to consumers from lower energy market costs, which would arise from the additional incentives provided by a capacity market, will not be as apparent to politicians and the public as the explicit capacity payments.

Targeted Capacity Mechanism

Question 1: Does this table capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?

1 The table captures our high level concerns about a targeted capacity mechanism, particularly those described under the heading ″Market Distortion″. One issue which needs further consideration, however, is the impact on the market's ability to perform its current role in plant scheduling and despatch. In a market where there will be increasing demand for flexible plant able to respond to varying output from intermittent renewable generation and demand, well functioning scheduling and despatch will become increasingly important. With a Strategic Reserve, the system operator would need to take on an additional role, which it does not currently perform, of scheduling and despatching capacity held in the reserve.

2 We do not think the proposed approach to mitigating concerns set out under 'market distortions' would be effective. In particular:

- it will be virtually impossible to set an economically ″correct″ despatch price as the ″correct″ price will continually vary with fuel prices;

- even if the "correct" price does not vary significantly, it will be extremely difficult to determine what the appropriate price level should be;
- the despatch price will in effect cap prices in the wholesale market and limit investment returns available to new capacity. Potential investors in capacity outside the reserve are unlikely to have confidence that the despatch price will allow sufficient reward until it has been demonstrated to do so over a period of years. In particular investors will want to see that neither the Government nor the regulator intervenes to reduce the despatch price. This will lead to significant delay after the introduction of a Strategic Reserve before first new build is committed outside of that reserve, or to investors factoring a very high risk premium into their investment appraisal (which may have the same effect);
- the proposed periodic review of the despatch price suggests that it could be subject to significant change either in its level or in the methodology for deriving it. This could further affect confidence in the durability of the mechanism's design and could lead to investors looking for very high rates of return for new plant construction outside the Strategic Reserve, and inside the reserve if the despatch price can be varied for existing reserve capacity already committed.

3 We do not therefore favour the Strategic Reserve option or other forms of targeted mechanism. If, however, this form of mechanism is adopted, we would want to have further discussions with Government on alternative approaches to despatching Strategic Reserve capacity into the market.

4 It remains important to ensure that the cost of providing the Strategic Reserve is recovered from the market to provide incentives for capacity outside the reserve. While we agree that a legally defined change process should be implemented to limit the extent to which political factors can affect how these costs are reflected back into the market, we remain concerned that the rules will be subject to unpredictable change arising from external pressures, for example during periods of rising retail prices or if intermittent renewable plant is not adequately compensated for the higher balancing costs it is incurring. If the costs are reflected back into the market through the cash-out mechanism, it will be important to ensure that the financial impact on intermittent generators less able to

predict their load patterns are fully reflected in the level of support they are offered under the Renewables Obligation or under future Contracts for Difference (CfDs).

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

5 The lead time needs to allow for new build plant to be made commercially available from the time of the final investment decision. This lead time will depend on the type of capacity which the system operator or other body running the reserve requires to form part of the Strategic Reserve.

6 A large open-cycle gas turbine (OCGT), the type of capacity which could be constructed most rapidly, would take around three years to move from a final investment decision to commercial operation. At least four years should therefore be allowed from the point a contract is signed to the point capacity is required. Potential developers will then require sufficient time, probably around one year, to tender for equipment and construction between the issuing of an invitation to tender by the operator of the reserve and the deadline for receiving such tenders. This will require the tendering process to start significantly more than four years, probably closer to five years, before the reserve is required.

7 If new build plant other than OCGT is required then timescales need to be longer. If the Strategic Reserve is utilised to cover long periods of very low wind generation (at times of high demand) then CCGT plant is likely to be more economic than OCGT plant and this would require timescales around one year longer than stated above.

8 These timescales may act as a barrier to some DSR options, which may only be available on shorter timescales given the difficulty of estimating costs four or five years ahead. We discuss this further below.

9 Existing generation plant which may close if not entered into the Strategic Reserve will need similar notice timescales in order to maintain plant and grid connections for entry into the reserve. If not contracted on these timescales plant will probably not be maintained in suitable condition to provide reserve.

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

10 Ideally, the Strategic Reserve should consist of shorter term contracts in order that the reserve can shrink if demand falls or if the non-reserve market grows (which would be unlikely to happen in early years, but could at a later point).

11 However, as new build plant is likely to be required for the reserve, short term contracts may add to the tendered cost per MW of capacity and per MWh of energy generated. This would favour allowing the operator to strike longer term contracts.

12 To balance these two issues, the operator of the reserve should have the correct incentives to minimise cost per MW of reserve held and per MWh of energy generated in all years. This will in turn incentivise the operator not to strike unnecessarily long contracts which could in turn lead to unnecessary costs to the customer. An incentive regime for the operator is likely to lead to better outcomes than direct constraints.

Question 4: Which criteria should providers of Strategic Reserve be required to meet?

13 The required criteria on issues such as availability or flexible response should be primarily a matter for the operator of the reserve to determine, given the requirements it has for reserve capacity, and these should be factored into the tendering process so potential bidders are tendering against some common criteria.

Question 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?

14 Strategic reserve requirements have to be defined some years in advance and will relate to capacity or equivalent measures which will be needed relatively infrequently. While this should not prevent bids from DSR or storage, which should be included within the auction process, the extended timescale may make it difficult for some DSR measures to participate as the baseline demand and cost of DSR may be uncertain four or five years out and it may not always be clear that the demand will still be there to be reduced.

15 However, discussions with US aggregators of DSR have confirmed that they operate in capacity markets with contracting periods of 3 years. It is the DSR aggregators' responsibility to ensure that they have the capacity available within their portfolio. A proportion of the Strategic Reserve could therefore be reserved for DSR contracted on shorter timescales.

16 In terms of storage, the high capital cost of all storage options suggests that its role is only likely to be economic where it is used frequently, as with pumped storage currently, which would make it unsuitable for participation in the Strategic Reserve. Overall, the Strategic Reserve does not appear to be particularly well designed to incentivise either storage or DSR or to incentivise most flexible demand reduction.

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

17 The Government's preferred form of economic despatch is really a form of last resort despatch, but with a price lower than the value of lost load (VoLL). If the Government pursues the targeted approach, despite our reservations about its credibility, we would want to explore alternative despatch options with Government consistent with our recommendations in response to DECC's earlier consultation on EMR (see para 54 of our response).

18 Reserve capacity should be available both inside and outside the balancing market, but the despatch price within the balancing market should be higher in order to reflect the significant additional costs of making the plant available on short timescales (through warming or capital investment in more flexible response) which will help disincentivise participants from entering the balancing market knowingly out-of-balance.

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

19 The Strategic Reserve methodology and despatch price would best be kept independent from short-term pressures through a legally defined change process with defined timescales as outlined by DECC, and by ensuring that the operator of the reserve was able to operate within a statutory framework which preserved its independence while

providing the right incentives in terms of policy goals, but did not leave it open to regular Government or regulatory intervention or direction.

20 Whilst this seems the only viable approach, it will not necessarily be believed in by the market until it has been seen to operate efficiently without major changes for some years. Until the system has been seen to work by investors, regulators and the public, concerns will remain that it will be undermined by politically driven (including potential legislative) change.

21 The need for this type of approach and the unavoidable potential for changes in the despatch price and the cost recovery arrangements to undermine investments outside the Strategic Reserve are significant weaknesses of this mechanism.

Question 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?

22 It is always necessary to review the operation of any newly implemented measure to ensure it is delivering against its design objective. However, this review should be driven by experience of operation of the Strategic Reserve and a clearly identified need for change not to some predetermined timetable which will create the impression that significant change is probable. Investments made on the basis of rules subsequently changed should be protected through appropriate grandfathering provisions.

23 Who is best placed to carry out reviews when they are required will depend on what aspects require to be reviewed and who is responsible for operating the reserve and any regulatory arrangements covering it. We would suggest that the review is either initiated by the operator of the reserve where relatively minor changes are required or by Ofgem if more significant changes are needed including to the role of the operator itself. If the mechanism is clearly failing in its objective and experience suggests a change of policy or legislation is required, then this would be a matter for Government.

24 Any review process has to be carried out in a transparent way and the results of the review process implemented in a way which maintains consistency in the system's operation (assuming it is broadly functioning correctly). Radical change will undermine investor confidence.

Question 9: Into which market should Strategic Reserve be sold and why?

25 The Strategic Reserve should be sold into any market requiring it at the relevant despatch price and where the reserve capacity is required in order for supply to meet demand, in order to minimise overall costs to the consumer. This suggests that it would not be appropriate to reserve despatch of the Strategic Reserve capacity for the balancing mechanism. Provided plant is only available in advance at the despatch price, this should not distort the market to any greater extent than otherwise.

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

26 The functions outlined by DECC seem appropriate. It would seem sensible for these functions to be integrated into the bodies already performing similar functions in today's market.

Question 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?

27 We do not think that the Strategic Reserve as proposed by DECC will function efficiently given the difficulty in setting the despatch price at the correct level. Because new plant outside the reserve is only rewarded indirectly, we question whether investors will have confidence in the mechanism and any design modification arrangements until they have accumulated some years' experience of its operation. This could lead to investors deferring investment decisions for plant outside the reserve which may simply lead to more plant being contracted within the reserve. Given the large requirement for new capacity in the UK to replace existing closing coal, oil and some gas plant and the other uncertainties affecting plant returns, including the pace and impact of intermittent renewable plant investment, Government may prefer an approach which provides investors with more assurance of predictable rewards. We also believe that the Strategic Reserve is not well designed to incentivise DSR.

Market-wide mechanism: Capacity Market

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

28 Our understanding is that Government wants a pre-set capacity target to be in place which will be determined by Government on the basis of advice from Ofgem who will have consulted other stakeholders. This is the premise of the relevant provisions in the Energy Bill 2010-11. Given that this is the preferred approach, the most appropriate approach would be for a central body to procure the capacity through some form of auction. This central body would need to operate within clear parameters set by legislation but should be independent of Government control. Suppliers have very little certainty of their market share four years in advance and so are not well placed to act as purchasers against a fixed capacity requirement.

29 Because the problem of capacity resource adequacy (the target of any capacity mechanism) is intrinsically related and will overlap with the problem of providing sufficient shorter-term reserve, we believe a capacity mechanism is most sensibly administered by the same body as the reserve mechanism, i.e. the system operator.

30 There is then a question about the need for business separation between National Grid's current role as system operator and its asset ownership (which could be advantaged or disadvantaged by capacity build). However, we do not feel this problem is sufficiently significant to avoid giving this responsibility to National Grid, subject to appropriate arrangements enforcing separation and ensuring independent operation of the capacity market.

31 Contracts would need to be entered into at least four years before they are called upon, in order to give time for new build to take place (see our responses to Q2 and Q14).

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

32 Our preference is that all plant providing the same capacity value should be rewarded at the same price and with the same contract duration. We would be concerned as investors if the mechanism were designed to reward new and existing capacity differently

or if it differentiated between different types of capacity, for example in terms of its environmental impact, which should be driven by other mechanisms. A specific concern we have is that existing capacity will not receive its full capacity value if new capacity benefits from long term contracts. New capacity will bid in the auction for the year it wishes a long term contract to begin but it will not need to bid in later auctions at its capacity cost as it will already have secured its contracted revenue for the following years. This effect will become accentuated as more and more new plant with capacity on longer-term contracts enters the market. We see no reason why investors in new plant cannot invest against the expectation of a capacity price delivered by annual auctions which offer one year contracts, particularly as capacity will only be part of that plant's income.

33 We recognise, however, that there may be a need for transitional arrangements allowing longer term contracts for new capacity (and existing capacity requiring significant capital investment) because there may be limited early confidence in a new capacity market, but any longer contracts offered must be available to such plant only for a pre-set and strictly limited number of years.

Question 14: How long should the lead time for capacity procurement be? Should there be special arrangements for plants with long construction times?

34 At present the only new plant types likely to be built as a result of capacity payments are either CCGTs or OCGTs (other potential generation types would all receive CfDs), although in principle the unabated proportion of a new coal plant could be entered into a capacity auction with the abated proportion covered by a CfD. Whether developers would want to invest in unabated coal if a CfD were available for abated coal plant is unclear. Also new coal plant even without CCS will have a higher capital cost than CCGTs or OCGTs so may not be a credible competitor for investment based on capacity rewards.

35 Both CCGT and OCGT (and major refurbishments or life extensions of existing plants) could be managed with an auction at least four years before the start of the capacity contract, but a longer lead time (around five years) is likely to reduce developer risk in terms of ensuring the capacity is available within the required timescale and so will reduce costs, although capacity requirements will be more uncertain five years out. A lead time of under four years would require investors to commit to building a new plant before securing capacity payments for it. This is unlikely to happen as competitive pressure will force prices

down once sufficient plant has been committed for build. Developers will not commit to a project before securing the capacity payments for fear of not being successful in the ensuing auction because other developers will have made similar commitments and the total build committed crashes the capacity market. Hence a shorter lead time could lead to continued supply shortages.

36 If lead times for new plant increase, for example through imposing CCS obligations on CCGTs, or if other plant types with longer lead times become available then the lead time for contracts would need to be extended.

37 Although there is currently a significant volume of consented CCGT plant, this is not the case for OCGT capacity and at some point the availability of consented CCGT projects may diminish. As no investor is likely to be in a position to bid (on a conditional basis) an unconsented project into an auction and deliver it within a four or five year timescale, it will be essential to ensure that the planning regime enables investors to bring forward sufficient consented capacity to predictable timescales and at reasonable cost for participation in the auction.`

38 We would recommend that all capacity should be contracted on the same lead times. Otherwise, the operator of the mechanism may contract for longer term capacity only to find that capacity contracted to meet shorter timescales is sufficient to meet the longer term requirements. This implies that the auction should be able to accommodate the longest lead time plant.

39 Unlike the Strategic Reserve, these longer timescales may be less of an issue for DSR. Although some DSR options may have difficulty in bidding into the capacity auction on such a long timescale for the reasons we set out in response to question 5, we think market participants will under this option also be incentivised to develop DSR as a means of meeting their capacity obligations in the reliability market. It would also be possible for the capacity mechanism to accommodate shorter term auctions both for DSR, as discussed for the Strategic Reserve, and potentially for additional generating capacity (mainly from existing plants) as more accurate capacity requirements are made closer to the delivery point.

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

40 We believe that a secondary market is highly desirable. There should be no restrictions on what capacity or DSR is made available to meet contract commitments, which would allow a secondary market in provision of capacity or DSR to develop as a means of ensuring participants are able to meet their obligations at least cost, although the market for generating capacity may not be highly liquid given that most generating capacity will be made available by its operator to meet that operator's commitments and avoid penalties and would not be released to third parties.

41 We agree that such a secondary market in provision of reliable capacity would encourage DSR to be offered which had not been available on the timescale of the initial auction. The secondary market would allow generators to make available DSR where it is cheaper or where the generator's plant is unavailable.

Question 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?

42 The principal advantage of a centrally administered approach is that it will prevent gaming whereby generators or providers of DSR could promise additional capacity or demand reduction in the hope of not being required to generate or reduce demand at outturn. If availability is to be measured administratively, this would also have to be against a centrally determined measure of the plant's capacity. A disadvantage is that an administrative determination may remove some incentives to increase the reliability of plant after the determination has been made. It may also be difficult to establish administratively how to de-rate wind and other intermittent generation and this would remove the incentive for the market to find an answer.

43 We believe that it will be necessary to determine both availability and penalties for non-availability administratively if the market based criteria (i.e. a "reliability option") proves impractical, which we believe it is (see our response to question 17).

44 It is important that any penalties are capped in order not to introduce unmanageable risk to capacity or DSR providers. In the absence of such a cap, capacity providers have a potentially extremely large liability should their plant fail or if DSR is not deliverable.

45 However, there needs to be sufficiently strong incentives to deter operators bidding capacity into the mechanism which is not reliable. The penalty needs to be a function of the benefit they are receiving through their regular capacity income but set at a level which does not substantially inflate the capacity fee generators will require. We discuss this further in response to the following question.

Question 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?

46 We do not believe the reliability option proposed by DECC works effectively. In order for the CfD strike price to have an impact (i.e. cap price at some point and to compensate suppliers for the payment of the option fee), there must be some probability that the wholesale market price will exceed the strike price. This might occur, for example, if a large part of the wholesale market price reflected scarcity of available capacity to meet demand which could not be factored into indexation of a strike price tied to fuel costs. It might also occur if indexation of the strike price to fuel costs failed to reflect short term increases in fuel costs.

47 However, if generators are unable to generate during the period when the strike price is exceeded (for example due to plant breakdown), they face a virtually unlimited and highly unpredictable liability in that they would be obliged to repay the value of electricity they should have supplied at the difference between the strike price and the reference price, in addition to having to meet any contractual commitments arising from having sold the power in the forward market, and additional balancing market costs.

48 Currently, generators face the risk that, if their plant breaks down when market prices (or, more accurately, spreads) are very high, they will have to buy out their commitments in the market. Furthermore, under such circumstances, the fact that their plant is unavailable may itself push prices higher. With the proposed reliability option,

generators face the risk of the strike price being triggered and paying out on the option (whether or not the plant is running). These two risks are not independent, as breaking down during a period of high prices may be enough to raise prices to the point where the strike price is triggered.

49 While it might be possible to mitigate some of this exposure by making available plant not contracted within the capacity market (if this were available and participation is not compulsory) or through accessing DSR, the option payment would need to be very high to compensate for this potential exposure, as such significant downsides pose higher risks to businesses than losses of potential upside (because the former poses a greater risk of cash flow problems and even bankruptcy).

50 Because the introduction of the capacity mechanism is designed to ensure that there is enough plant available on the system to cope with expected breakdowns, there is limited benefit in imposing potentially extremely high penalties on those plants which do breakdown. We would therefore favour an approach which imposed financial penalties for non-availability but capped these administratively at a level which investors could anticipate. Penalties should be a multiple of the capacity fee for the relevant period to provide sufficiently strong incentives, taking account of the cost of having to buy power from the market to meet contractual commitments and balancing market costs.

51 If introduced despite all of the above, half hourly day ahead prices appear the most logical reference price as short time granularity (a half hour) is required if peaks are to be captured and this is the most liquid market for such products.

52 A further issue is the compatibility of this approach with BETTA, a voluntary bilaterally traded market, as opposed to a pool system where existing examples of reliability markets exist. It will not be in the interests of any seller to sell in the day ahead market for more than the strike price because they would not realise the additional income under their reliability contract. Should the cost of generation exceed the strike price, sellers would seek to sell their energy in to the balancing mechanism, creating liquidity problems for the bilateral market. The only way of resolving this is to introduce compulsory selling, at which point the market becomes similar in nature to a pool.

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

53 As discussed, we do not believe the proposed reliability option works effectively. If introduced despite this, indexation, probably on a daily basis, to the short-run marginal cost of peaking plant (either gas or oil fired OCGT) , plus a fixed fee to cover its fixed costs, would be most appropriate as this capacity is likely to set the price during periods of capacity scarcity.

Question 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?

54 Requiring physical backup to reliability contracts entered into following an auction should in principle encourage the adequate provision of physical capacity, but companies should be able subsequently to meet their obligations with alternative sources of capacity or with DSR.

Question 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?

55 With a central buyer, the provision of capacity and the recovery of costs from suppliers by the system operator are separated so no issues should arise from vertical integration. The impact on suppliers and new entry in the retail market should be considered as part of the cost recovery arrangements.

Question 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?

56 CfD plant should not see substantial additional benefit from the existence of a capacity mechanism as the CfD should be the main driver of the investment but we believe CfD supported capacity should receive capacity income to ensure the CfD reference price includes capacity as well as energy market income. CfD plant should therefore receive capacity income, but should pass through this income to the CfD counterparty to avoid double subsidies. To incentivise the proper functioning of the capacity system, the CfD plant

could be allowed to keep a small percentage (for example less than 1%) of the capacity income.

57 To be eligible for capacity income it should therefore participate in the auction process (we assume this is required to be eligible for payments). However, there might need to be constraints on its bidding behaviour to avoid participants using it to influence the clearing price.

58 In order not to increase risk, and therefore costs for CfD plant, penalties paid under the capacity mechanism should also be passed through to the CfD counterparty (at the same percentage as benefits, if not all income is passed through).

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

59 It is important that these options are incentivised by capacity market design whether directly or indirectly. Given that the capacity market will reward all capacity and DSR directly, the market wide mechanism should enable DSR to participate more actively and directly in the capacity market than would be the case with the Strategic Reserve. We would expect DSR providing equivalent value to generating capacity to be rewarded and penalised at the same level, although different rules would need to be developed.

60 DSR will also be incentivised if generators are able to bid DSR to meet their contractual commitments, where this is cheaper than capacity or where their plant is unavailable, or to bid a combination of DSR and, possibly, less reliable generation to deliver an overall product which meets the required criteria. It would also be possible for the capacity mechanism to accommodate shorter term auctions for DSR as discussed for the Strategic Reserve.

61 Experience in the USA has demonstrated that a considerable amount of DSR is despatched manually with active engagement of the end customer. They are willing to participate and do seek to ensure their reduction in load is delivered for the required demand reduction period. If the financial reward is high enough then participants are also willing to take quite extreme measures including for extended periods of time. From a DSR perspective therefore the capacity auction needs to be managed in a way that allows active participation by loads that are reduced for shorter periods of time, but also allows, in

extreme conditions, sufficient financial reward to enable very occasional, but longer term load reduction events, that would otherwise have to be met through OCGTs or other peaking plant that would run very infrequently. This will in practice depend on the capacity or DSR requirements identified by the system operator prior to the auction and ensuring that DSR is able to compete where it can meet the requirements specified.

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

62 The division of functions set out in the consultation seems reasonable. In our view the system operator is the body best placed to operate a capacity market as with the Strategic Reserve. However, its high level design needs to be determined by Government, including the measure of capacity requirement which the mechanism is designed to achieve as this is a political trade off between supply security and cost. Once this design is established, we would expect the system operator to facilitate development of the rules in more detail in discussion with Government, Ofgem, industry participants, academic experts and other stakeholders, but with Government approving the final package as consistent with its high level goals.

63 Settlement could be managed by the same entity responsible for settlement of other industry commercial mechanisms, including the balancing mechanism, the new CfDs, provided it could demonstrate it can manage all these functions efficiently and without imposing costs on participants in the other mechanisms it manages.

64 Oversight of the mechanism would be a matter for the system operator (in terms of administrative compliance with the rules) but Ofgem would also have a role in terms of market conduct and compliance with licence conditions. Changes to the capacity market rules would, we would expect, be subject to similar arrangements to existing industry codes.

Question 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?

65 No. In our view, new generating capacity could be required around 2017, although this date is of course subject to uncertainty, notably in respect of demand growth and

whether additional coal-fired plant closures might result from the carbon price support mechanism. With a four year lead time, this would require contracting in 2013 which is as soon as it appears a mechanism could be implemented under the timetable set out in the White Paper. If possible the mechanism should be implemented earlier to ensure it is fully functional by the time capacity is required.

66 We do not believe there will be any significant new investment in the market until a capacity mechanism is introduced. Should this take place after 2013 , there is a risk of a capacity shortage occurring in 2017.

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

67 Given that DECC wants the total capacity need to be centrally set, we would be happy to take forward a reliability market but not the specific reliability option outlined by DECC in the consultation, because it exposes investors to excessive and unpredictable risk.

Capacity Mechanism Assessment

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

68 The cost and benefits are extremely difficult to quantify as it requires an understanding of the costs arising from leaving the energy market in its current state. In an energy only market, a number of studies have shown that wholesale prices would need to move to extremely high levels during periods of shortage to reward capacity and to maintain security of supply. Were an energy only market to be retained and, if it were successful in securing sufficient capacity through such high prices, overall costs could be similar but prices would be more volatile, particularly for large industrial consumers. Were an energy only market not be able to deliver sufficient investment, prices could rise to very high levels for extended periods and the level of energy unserved could rise significantly.

69 In our view, the volume of intermittent wind generation together with base load nuclear generation based on CfDs planned for the UK, which is a market with limited interconnection to other systems (compared to for example Central Europe), makes it particularly difficult for the wholesale market in its current form to support sufficient investment to deliver sufficient capacity in the UK. A capacity mechanism is therefore

necessary and should reduce the total cost to the consumer of the power price they pay including the cost of energy unserved.

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

70 In our response to the EMR consultation, we said that the most efficient approach to incentivising the provision of capacity at least cost is to create a market-based mechanism where all generation (or DSR) providing firm capacity (or an equivalent reduction in demand) is rewarded at the same value, given that it is offering an identical product. This is consistent with the way an energy only market would function. It would therefore create a market clearing price for capacity or demand reduction, which all capacity or demand reduction would earn at that point in time. Any capacity mechanism also needs to be robustly designed and stable providing reliable incentives that investors can respond to.

71 While both a Strategic Reserve or a market-wide mechanism can be designed with these principles in mind, we believe a market wide mechanism is more likely to reward all capacity fairly and will provide a more reliable basis for investment in an environment where the value of capacity will become an increasing driver of flexible plant investment, given the increasing penetration of intermittent wind in the market. However there has to be political and wider stakeholder acceptance of the need to pay generators for capacity to be available in addition to their energy income, as the benefits to consumers from foregone energy income, which will arise from the additional incentives provided by a capacity market, will not be as apparent to politicians and the public as the explicit capacity payments.

72 As we have made clear, it is essential that the financial impact (including potential losses) of a capacity market is reasonably predictable for investors. The specific reliability market design put forward by DECC does not meet this criterion because generators would have a virtually unlimited and unpredictable exposure to the reference price rising above the strike price. We have suggested ways of resolving this issue, and subject to that, we would favour taking forward a reliability market model.

E.ON
October 2011