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Dear [redacted]

Electricity Market Reform – Consultation on possible models for a Capacity Mechanism

Thank you for the opportunity to provide comments on the possible models for a capacity mechanism.

This response is provided on behalf of National Grid which owns and operates the high voltage electricity transmission system in England and Wales and, as National Electricity Transmission System Operator (NETSO), operates the Scottish high voltage and offshore transmission system. National Grid also owns and operates the gas transmission system throughout Great Britain and through our low pressure gas distribution business we distribute gas in the heart of England to approximately eleven million offices, schools and homes. In addition, National Grid owns and operates significant electricity and gas assets in the US, operating in the states of New England and New York.

In the UK, our primary duties under the Electricity and Gas Acts are to develop and maintain efficient coordinated and economical systems and also facilitate competition in the generation and supply of electricity and the supply of gas. Our activities include the residual balancing in close to real time of the electricity and gas markets.

Through our subsidiaries, National Grid also owns and maintains around 18 million domestic and commercial meters, the electricity Interconnector between England and France, the electricity Interconnector between England and the Netherlands and a Liquefied Natural Gas importation terminal at the Isle of Grain. We have also formed National Grid Carbon Limited which is a wholly owned subsidiary advancing the transportation and storage elements of the Carbon Capture and Storage (CCS) supply chain.

In recent years, the existing market structure has provided sufficient generation capacity to maintain security of supply, with generators taking the view that the revenue earned by flexible, non-baseload plant justifies the retention of the plant.

This role has predominately been filled by older plant but, forward looking, it is more likely that new plant will be required to offset the intermittent nature of renewable generation. Whilst older, less efficient plant is still likely to fall down the merit order and provide reserve or capacity margin to the market, new plant will also be needed to replace the emissions directives (Large Combustion Plant Directive and Industrial Emissions Directive) led closures.

Supporters of a capacity mechanism argue that new plant will not be built and/or existing plant will be closed absent some form of regular payment to cover fixed costs. Others argue that the existing market structure will deliver sufficient generation capability because customers' needs will remain paramount and suppliers will want to avoid exposure to potentially high imbalance prices. It can also be argued that low utilisation fossil plant may not be the cheapest way to provide this element of security of supply. Increased interconnection, demand side management and energy storage may all have a part to play and undue encouragement of fossil plant in this role could distort the market and discourage development of these alternative resources.

National Grid's view is that all of these arguments have merit and so it is difficult to come down firmly on one side or the other. We are sensitive to the need to avoid imposing further (possibly unnecessary) costs on customers and it would be preferable to be able to observe the development of the market and act if it was clearly necessary. However, we are of the view that due to the timescales needed to put a capacity mechanism in place, this is not a realistic option and we would not advocate taking undue risks with security of supply.

In light of this, we would support the introduction of a capacity mechanism, provided that it is clearly focused on maintaining security of supply at minimal cost to end consumers. A market wide mechanism is more likely to achieve this than a strategic reserve mechanism due to likely market distortions, as detailed further in our response to the consultation questions, which will inevitably lead to significant inefficiencies. A financial based capacity mechanism is attractive as it builds on the present market principles and, in its purest form, allows the market to deliver without the need for any further intervention, for example, physical checks that capacity is in place and reliable. However, such a mechanism raises issues such as the potential for new capacity to locate behind constraints, longer-term market liquidity issues as a result of encouraging all players to trade in the short-term market, the attractiveness of the mechanism for baseload players due to the need to trade in the short-term market and the effectiveness of a financial based capacity mechanism in a vertically integrated market (penalty payments circulate from generator arm to supplier arm). Therefore, we feel that a market wide physical capacity mechanism is likely to be the most appropriate design.

In addition to the introduction of a capacity mechanism, it is important that attention is paid to several aspects of market design. These include imbalance charges that more fully reflect the actual cost of balancing, and arrangements to actively promote and fully integrate further demand side management (for example, supplier allocation of half hourly domestic demand commensurate with smart meter roll out), energy storage and more interconnection where this is economic.

We have addressed the detailed response to the consultation questions in the Appendix to this letter. If you wish to discuss this further, or have any queries regarding this response, please contact me or [redacted]

Yours sincerely

[By e-mail]

[redacted]

UK Director of Regulation

Appendix

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?

Whilst the table in Figure C3 goes some way to address concerns with the interaction between the market and a targeted capacity mechanism for strategic reserve, we have concerns that the anticipated low utilisation and high fixed utilisation price could cause issues regarding the reliability of the strategic reserve and provide the possibility of significant windfall gains when it does run. With respect to the windfall gains, this could be resolved with some form of contract for difference, with a utilisation reference price linked to cost-reflective operational running costs. This mechanism would mean that the dispatch price becomes merely a trigger for utilisation, with payment based on the contract for difference and the difference being re-circulated to the industry by some mechanism, for example, via Balancing Services Use of System (BSUoS) charges.

There is also a risk that generators will prefer to receive a capacity payment and in order to achieve this may identify their plant as closing which in turn will signal a need for the central body to procure additional capacity. Should the generator successfully achieve a contract for strategic reserve this will remove this capacity from the market, with suppliers being required to pay energy prices for this capacity at a level higher than the highest long-run marginal cost plant. Should the generator that signalled closure fail to achieve a contract for strategic reserve, then their incentives to continue operation remain unchanged (since the dispatch price for strategic reserve will be set above the highest priced marginal plant) and therefore could result in the over procurement of strategic reserve.

If the strategic reserve is allowed into the wholesale market at despatch price that is a more reflective of actual utilisation cost, it competes at an unfair advantage to non-strategic reserve[1] and hence is likely to lead to an ever increasing need for strategic reserve.

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

The lead time for strategic reserve procurement should be sufficient to allow new generation to be built or for demand-side alternatives to be developed and proven as being capable of delivering reliable strategic reserve. For new generator build, the time required would depend on the type of plant required to meet the specific technical requirements of strategic reserve, the need to gain the necessary consents, and the need to prove that they are capable of delivering a service. For demand-side, the time would depend on the implementation of a suitable despatch mechanism (smart meters or other communication mechanisms) and need to prove that they are capable of delivering a service.

Typically, we would expect new generation build to require a longer lead time, with this being a minimum of four years.

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[1] This is because plant in the capacity mechanism is receiving a subsidy against its fixed costs of operation and then competing in the same market as plant which is not in receipt of such a subsidy.

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

It would seem inefficient to procure all capacity on a long-term basis but necessary for plant with large capital costs. There a risk that one or two new plants might be able to meet an ongoing strategic reserve requirement, thereby foreclosing the market for the duration of their contracts (e.g. 20 years). However, making contract durations shorter, and then allowing the plant to operate in the marketplace, could introduce project risk that might make the building of the plant less likely.

The length and nature of contracts procured by the strategic reserve procurement function should be left flexible with the correct incentives placed on the procurement function to ensure an economic and efficient outcome.

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

The specific requirements should be decided by the strategic reserve procurement function based upon the information from the annual report on security of electricity supply. On the assumption that National Grid's procurement of existing Balancing Services deal with issues such as the short term effects of wind intermittency[2], ramp rate characteristics would be less of an issue, with the focus instead on the duration for which the strategic reserve could run.

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?

The capacity product will need to be structured along the lines of a "Capacity Duration Curve", therefore some capacity will only be needed at peak times for short periods, which may be well suited to demand side response. Demand side providers could also offer a sustained running period, by allowing an aggregator to offer a number of demand side providers in succession to achieve this aim.

Storage providers are likely to have some flexibility in how they deliver capacity, for example, batteries could provide power for short duration or sustained release for a number of hours, potentially at different prices.

The procurement mechanism and contracts will need to be flexible in order to accommodate DSR, storage and other forms of non-generation technologies and approaches. Our experience of the procurement of existing balancing services is that it is necessary to keep the procurement and terms under review as new technologies emerge. It will also be important to place the correct incentives on the procurement function to ensure the most effective approach.

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

'Economic despatch' appears to be the "least-worst" method, but the level at which the despatch price should be set and the extent to which participants in the market price just below that price (and its corresponding impact) are likely to be difficult to determine.

[2] E.g. an unforecast drop in wind output

A single despatch price would not allow for differentiation between different providers without some form of additional mechanism (for example, a 'rota') to ensure equitable despatch. A potential solution here is to require providers to submit a utilisation price as part of the procurement process. As highlighted in our response to question 1, this utilisation price could be linked to cost reflective operational running costs and form part of a contract for difference to the despatch price.

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

Keeping the despatch price independent of short-term pressures requires it to be set at or above the theoretical level described in paragraph C2.25 of the consultation; the methodology for updating the despatch price needs to be set to promote this. However, given the linkage between price and volume of strategic reserve, this is likely to be challenging due to the need for detailed knowledge of the load duration curve.

The methodology for the despatch price could be contained within an industry code (for example, the Balancing & Settlement Code) and therefore subject to appropriate industry governance in order to amend it.

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?

Whilst it would be sensible to periodically review strategic reserve to consider the impact of it on the market, there needs to be protection offered to any existing providers, especially those who are committing to significant investment. Ofgem would seem best placed to conduct such a review with the criteria being set by DECC, when and if strategic reserve is implemented.

Since the lead time for strategic reserve capacity procurement needs to be at least four years any review should be at least the same timescales.

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

If the strategic reserve is sold into the BM, the SO would despatch the reserve (subject to any rules on choice of provider if there is a common despatch price, etc) and the costs would feed into cash-out in accordance with relevant rules. Costs would also be factored into BSUoS charges and smeared across market participants, thus not weakening the incentive to balance portfolios.

In order for the strategic reserve to be dispatched in BM timescales, the provider would need to be able to meet the necessary dynamic parameters to allow such dispatch (for example, minimum notice time and run up rates). This may not be efficient for all generators to meet such dynamic parameters, as a capacity requirement should be relatively foreseeable in timescales further out than those applicable to the BM. However, this issue could be overcome by using tools such as Pre Gate Balancing Transactions to circumvent restrictions from dynamic parameters.

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

The functional arrangements appear appropriate. It may be efficient for certain functions to be delivered by the same entity, for example; the despatch function, the procurement function and payment function. Due to the synergies with other activities, it would seem efficient for the System Operator to carry out at least the despatch function. Furthermore, due to the need to ensure there are no locational issues with any capacity provided, for example avoid capacity being located behind a constraint, this would require, as a minimum, input from the System Operator on procurement decisions.

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?

Strategic reserve is probably a workable model for a capacity mechanism for the GB market. However, for the reasons detailed above it is likely to lead to market distortion and significant inefficiencies as a result.

Market-wide Capacity Mechanism

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

The PJM based model whereby there is a supplier obligation with the ability for a supplier to 'self supply' appears to have a number of favourable attributes. The ability to self supply allows parties to limit their exposure to high auction prices, whilst the fall back of a central auction provides an easier route for new entrants. The self supply option may also help to encourage more innovative products from suppliers, for example, from demand side. Whilst the PJM model does appear to have a number of favourable attributes, such as self supply, it should be noted there are a number of differences between the PJM market and the GB market which would require careful assessment in the design of the capacity mechanism.

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

For new plant, the contract duration would probably need to equate to a substantial proportion of the anticipated life of the asset (as it the case elsewhere, e.g. in Ireland). The alternative would potentially leave the provider facing market exposure to recover fixed cost elements, which may simply result in the provider trying to the recover these costs over a shorter period.

For existing plant, the contract duration could in theory be shorter. Such shorter durations might also favour demand-side capacity provision where the underlying capacity might be more dynamic in nature.

The mix of long and short term contracts should be left to the procurement function with correct incentives to encourage the most efficient approach.

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

To ensure efficient procurement it would seem appropriate that the majority of capacity procurement should be between the shortest and longest construction time of new plant, including consenting. However, it would also seem sensible to procure additional residual amounts closer to real time as demand-side projects become

more certain and indeed some amounts further out to account for long construction times.

The lead time for procurement should be left to the procurement function with correct incentives to ensure the most effective approach.

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

A secondary market is essential to allow participants to adjust their position. This will help physical providers of capacity balance their obligations with, for example, the need to undertake maintenance or manage plant failures. Furthermore, a secondary market might offer a route by which more innovative forms of capacity with more restricted availability, such as DSR, could develop.

Whilst the inclusion of financial participants into a secondary capacity market might encourage innovation (more so than a physical market), there will still need to be some form of comfort that capacity will actually be delivered. The mix of physical and financial markets does present a risk that the same capacity could be offered twice.

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?

A central determination of the capacity that can be offered into the market by each generator (i.e. the de-rated capacity) allows for an industry wide consultation with a central determination taking account of cost and risk. The alternative approach is for market participants to make such a determination themselves (a clear requirement of a pure financial market) which ultimately should lead to a similar outcome with the diversification of players risk/reward appetite.

The market approach does assume the arrangements correctly penalise for non-availability, with less optimal outcomes if such penalties fail to do this. A central approach also potentially has the drawback of treating all generation types the same. For example, a generator with a portfolio of wind spread across all of GB and offshore could have a higher de-rated capacity than a wind generator limited to one location.

Our experience of STOR provides a basis for the criteria of determining availability and penalties for non-availability, and is not dissimilar to the approach taken by PJM for their capacity market. As highlighted in the consultation, the challenges are around specifying when availability is required, setting an appropriate penalty level and resolving disagreements over unavailability. A financial market removes a number of these issues since physical assessments are not required.

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?

The reference price needs to be set relatively close to real time to reflect the scarcity of capacity, for example due to winter high pressure conditions (low wind, cold weather), which would need to be reflected in the reference price. However, setting

the reference price close to real time would require participants to sell their energy in the reference market to hedge against the risk of the paybacks.

In order for a reliability market to work, all capacity providers would need to offer their capacity (whether it is de-rated wind capacity or flexible generation), otherwise it would lead to a risk of over procurement. For baseload generators, the need to sell their energy in the reference market (i.e. close to real time) is likely to be unattractive, and would have a significant impact on market liquidity for longer-term energy contracts which would limit the options for suppliers to hedge their costs.

Finding a reference price that would work for all types of generation appears difficult for a financial market where the reference price is the instrument to ensure capacity is delivered. In a physical market this is not an issue since capacity is physically demonstrated and penalties can be tailored to the removal of capacity payment income (in most instances), rather than real time energy price exposure.

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

Setting a strike price that reflects the boundary between normal operation and market scarcity is challenging and complicated. The need to index the price would depend on the length of the contract, but it would seem necessary to have some form of indexation to keep the strike price relevant for more than a year. It will also be necessary to set the strike price above a providers operational running costs in order to avoid exposing a provider to paybacks when they are simply not in merit to run.

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?

At present, generators build capacity based upon signals from the energy market with peak generation capacity responding to the potential for peak prices and suppliers' needs to hedge such prices. A reliability market essentially caps the energy price and moves the peak prices to a firm income stream. Therefore building on the present market principles it may be argued there is no need for physical checks.

However, physical requirements to demonstrate capacity provide greater certainty that the capacity requirement is being met and removes the risk of speculative traders selling capacity without making the necessary investments. This is perhaps an important concept since the purpose of the capacity mechanism is to provide certainty of security of supply. Furthermore, if the procurement function is aware of the location of the capacity then the location could be taken account of as part of the assessment. This would remove the risk of capacity being built in areas of the system that may be congested at times the capacity is required.

A further benefit of having a physical requirement is the potential synergy with STOR. This would allow a party to offer their generation or demand product either for STOR or capacity, allowing the procurement function to make an efficient assessment and remove the need for the provider of having to choose one or the other. For a reliability market with no physical checks, it would be possible for a provider to also offer a STOR product at the same time as a capacity product, although they would risk being financially penalised if they chose to do so and both were called. However, given the different roles of the products some may feel this was a risk worth taking.

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?

We would agree that that a vertically integrated market raises an issue over the effectiveness of a Reliability Market, as contract paybacks would simply be a transfer of money within the same company (generator arm to supplier arm) leading to incentives to ensure capacity is in place being diminished. Physical demonstration requirements would help to mitigate this risk by giving greater certainty that capacity is actually in place.

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?

Under a purely financial based Reliability Market it would not appear possible to prohibit any party from participating since there is no physical check.

Whilst the risk of double payment is an issue, there may be parties receiving a FIT CfD that could tailor their plant to offer additional capacity (e.g. CCS) and therefore simply prohibiting their participation in the capacity mechanism may be inefficient. It may be possible to design the FIT and capacity mechanisms such that 'baseload' capacity resulting from the FIT cannot receive income from the capacity mechanism but the provider can receive capacity income for any flexible capacity element.

In any market wide capacity mechanism it will be important to either design a mechanism such that all capacity can participate (whether it is de-rated wind or peaking generation), or the procurement function is able to account for all capacity, otherwise it raises a significant risk of over-procurement. For example, if a mechanism either prohibits participation from a certain group or discourages participation for any reason, it will still be necessary for the procurement function to have sufficient information about the capacity such that it can make an informed decision on its contribution to fulfilling the total requirement.

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?

See response to question 5.

In a similar manner to which there is a risk of carbon leakage resulting from a Carbon Floor Price, there is a similar risk from implementing a capacity mechanism. Capacity payments risk diluting the energy price in GB at times of system stress, since parties will be receiving a capacity payment which would remove the need to recover fixed costs via energy prices. This may in turn, see increased exports on interconnectors than would otherwise occur, in particular to markets without a capacity mechanism (since they are likely to have peakier prices). This would be a lower risk if all European markets are harmonised with the same rules however, this may not be the case even with a 2014 target for creating a single EU-wide market for gas and power, as the decision to put in place a capacity mechanism is a member state decision.

More generally, interconnectors have the potential to share significant levels of capacity between member states which may remove any concerns of a capacity deficit or conversely may exacerbate them. However, in order to have greater

certainty on the potential availability of this capacity, there is a need for a co-ordinated approach to capacity levels (in particular the calculation of capacity levels) at a European level.

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

See response to question 10.

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?

On the basis a conclusion has been made that a capacity market is required, then not immediately implementing a mechanism may lead to uncertainty and investment hiatus, promoting the need to implement it. As such, we feel that once a mechanism has been chosen it should be implemented in reasonable timescales such that no such hiatus it created, leading to the very event the mechanism is intended to prevent.

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

Based upon our responses to the earlier questions we feel a market wide physical capacity mechanism is the most appropriate design. The PJM model appears to have a number of favourable attributes, although it should be noted there are a number of differences between the PJM market and the GB market which would require careful assessment in the design of the capacity mechanism, for example, locational signals.

Capacity Mechanism Assessment

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

Not unsurprisingly, the NPV of any model is highly dependent on the value of VoLL, which itself is difficult to estimate. Furthermore, the NPV assumes no significant market distortions from the implementation of the capacity mechanism which, particularly for the strategic reserve model, appears unlikely. The choice of whether to have a capacity mechanism and then the choice of which one is likely to be a more qualitative than quantitative decision.

A capacity mechanism may also not achieve the most efficient outcome when compared to the existing fully market based solution, however, it does bring greater certainty that sufficient capacity will be available.

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

See response to question 25.