centrica

DECC Consultation on possible models for a Capacity Mechanism

Centrica Response

Summary

- We agree there is a need to introduce a capacity mechanism to ensure adequate security of supply given the increasing uncertainty on the framework of the UK generation portfolio due a range of factors, largely driven by Government policy.
- We do not believe the strategic reserve mechanism would be appropriate and a more market-wide mechanism would be more effective in achieving the objectives.
- However, we see significant problems with the proposed system of pure financial options as reliability contracts, and do not believe this would remove much of the perceived administrative burden.
- We believe a capacity market with central administration of forward auctions to satisfy a pre-determined de-rated capacity volume would be the most effective solution.
- Such a mechanism should be introduced as soon as possible, ie from 2013, in order to prevent unnecessary premature closures of existing thermal plant which require investment that is unjustified by prevailing poor profitability in the market.

Detailed summary

We agree there is a need for GB to introduce a capacity mechanism to ensure adequate security of supply given the increasing uncertainty on the framework of the UK generation portfolio due a range of factors, largely driven by Government policy.

We do not support a targeted mechanism

- A targeted mechanism would suppress price signals and weaken investment incentives in the 'unsupported' part of the market.
- This could, in turn, increase the need for out-of-market interventions, leading to a vicious circle, where the buyer would be forced to maintain an increasing proportion of capacity resources outside normal market conditions and the unsupported generation sector would progressively disappear.

We do not believe our concerns have been adequately addressed in the strategic reserve model.

- There is no obvious institutional arrangement to support a credible commitment to the despatch price.
- The determination of the despatch price would necessarily involve a huge degree of judgement and, therefore, a large amount of discretion on the part of the decision-maker, with significant incentives to intervene further in circumstances of sustained or regular market tightness.
- We also think that it would be difficult to estimate the required level of capacity to be procured under this scheme. This is because the administrator would need to estimate the amount of capacity that market participants would deliver without intervention, which is by nature a very uncertain parameter.

We believe a broader market wide mechanism is more appropriate, and that this should be introduced by 2013 in order to address security of supply concerns.

- These concerns arise not only from a need to ensure sufficient investment in new capacity is being made where necessary, but also recognising that the existing fleet of thermal plants across UK requires substantial investment on a regular basis to ensure continued operations.

- Prolonged poor profitability for these plants however is making this investment increasingly difficult to justify, with a consequence that there is significant risk of unnecessary early closure of this thermal plant.

However, we see significant problems with the proposed system of pure financial options as reliability contracts.

- Under BETTA there is no single spot price that can be captured by all available generators and, therefore, no obvious reference price on which to base a reliability option.
- The lack of a practical reference price combined with the range of exogenous factors that can affect availability means that generators would be exposed to a potentially uncapped liability under this system.
- An uncapped liability creates an insolvency risk which we believe would make financing more difficult for project financed generators. Increasing the risk in this way would also be expected to lead to higher costs for capacity.
- Assuming that this price issue can be resolved, an uncapped exposure to “repay” energy price spikes acts as a strong incentive on risk adverse generators to sell their output into the Reference Market. This could potentially divert liquidity away from forward markets at a time when Ofgem is precisely trying to improve churn and product availability in such markets.

A more physical capacity market with the following characteristics will better deliver the objective of ensuring that security of supply meets the defined standard.

- The capacity market should be distinctly separate from the energy market.
- The primary product should be availability not energy thus financial options on energy prices should not be considered.
    - The New England ISO reliability market and the PJM Reliability Pricing Mechanisms would seem to be good places to start when looking for a model to build from.
- It should be a market wide arrangement (the contribution of low carbon generation to security of supply would be accounted for irrespective of whether it can receive availability payments in addition to other support schemes).
- There should be central determination of capacity credits (aligned to calculation of need; derived by Government determination of the required security of supply standard).
- A primary market consisting of centrally procured auctions for annual capacity ahead of time.
    - The periodic auction would set the price of capacity with the clearing price being paid to all purchased capacity.
    - A central buyer would appear to be the most efficient solution, with outturn costs being appropriately recharged to consumers on the basis of final demand via suppliers.
    - This scheme would also support competition in the generation market by providing a simple ‘route to market’ for independent generators
    - There are advantages in having a single capacity product to ensure maximum liquidity and comparability.
- A secondary market implemented to allow re-trading of capacity obligations; this would also help demand-side response
- The arrangements need to be robust from any players exercising market power and manipulating prices to the detriment of customers.
- Non delivery penalties that are proportionate and judged against all the relevant circumstances (including level of price spikes and generator capacity income) and subject to appeal.

    - If there is a small risk of a very large penalty then credit requirements get more onerous and smaller players and demand-side response may be deterred from participating.
    - Capacity providers should not be penalised for "failing to deliver capacity" if the cause is outside their reasonable control; the determination of fault in the event of price spikes should be recognised as complex in any real world electricity system.
- The administrator, via the SO, should have the ability to instigate spot checks on generation capacity to test availability.
- There should be sufficient physical back up to underpin any contract, and this should be defined as the de-rated capacity as determined by the market regulator.
    - It is worth noting that the need to prove that sufficient physical capacity exists (or will exist) to underpin all reliability contract models removes much of the perceived benefit of adopting a pure financial form of reliability contract.
- The market design should be attractive to independent generators and to demand side participants.
- Effective competition between the widest population of "capacity" providers will mitigate market power, minimise costs to consumers and encourage innovation.

We believe the market should be functioning from 2013 and to hold annual auctions each year from that date.

- There is a real risk of early closure of existing thermal capacity across the UK due to the continued poor profitability of these plants
- If the capacity margin is adequate, the resulting clearing prices will be very low and no material cost is incurred.
- It is far better to test and refine the process and rules before they are needed in earnest.

Suggested process
a) Centrally determine the capacity credit of each generator using objective criteria that are consistent with the calculation of the capacity requirement; b) The criteria for being available should be based on physical availability at times of highest stress determined by known criteria (e.g. times of highest demand). c) Price spikes caused by within day balancing issues should be distinguished from capacity adequacy events. d) Capacity providers should not be at fault if they were available but could not physically have delivered energy for reasons beyond their reasonable control. e) Plants that are broken down on scheduled maintenance should re-trade their obligations in the secondary market. f) Part of the assessment should be whether they met their de-rated capacity factor over an appropriate reference period.

EMR capacity mechanism – 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?

The table does capture our main concerns with this approach, but we are not convinced that they have been addressed effectively in the proposed model. We continue to believe that a targeted mechanism would suppress price signals and investment incentives in the 'unsupported' part of the market, and that this could, in turn, increase the need for out-of-market interventions. This could eventually create a vicious circle where the buyer would be forced to maintain an increasing proportion of capacity resources outside normal market conditions and the unsupported generation sector would progressively disappear.

The White Paper suggests that this distortion could be minimised by withholding the Strategic Reserve from the market until prices rise to high levels (potentially up to the VoLL under the 'last resort despatch' model). We think that there are some fundamental economic and institutional issues that would affect the credibility (and hence the effectiveness) of this approach.

Firstly, there would be a natural temptation for the decision-maker to lower the despatch price when confronted with frequent price spikes. In an environment with low load factors for thermal generation, prices would have to rise to very high levels at times of scarcity to support new investment (potentially close to VoLL or £10,000 / MWh). Prices at these levels are untested and could have adverse consequences for small, out-of-balance participants (e.g. wind generators, small suppliers). This market environment could also make it more difficult for the regulator to monitor the market and distinguish between 'good' price spikes (reflecting economic scarcity) and 'bad' price spikes (resulting from abuse of market power). The combination of these factors would create huge pressures on the decision maker to use the Strategic Reserve to mitigate price spikes.

Secondly, there is no obvious institutional arrangement to support a credible commitment to the despatch price. The White Paper suggests that the despatch price would be subject to a 'defined change process', which we assume means some form of independent, evidence-based review. However this type of process can only be an effective guarantee against short-term pressures if there is an objective basis to inform the decision. In reality, the assessment of the VoLL and the determination of the despatch price would involve a huge degree of judgement and, therefore, a large amount of discretion on the part of the decision-maker. The lack of a clear standard for the decision would also affect the effectiveness of traditional appeal mechanisms (e.g. a judicial review or a reference to competition authorities). Suppose that there is a proposal to reduce the despatch price from, say, £2000 to £200; it is not obvious how Ofgem could decide whether this decision would or would not be in the best interests of consumers, or how an appeal court could decide whether it would or would not be unreasonable.

For low-carbon generation, the government has recognised that legally binding contracts were the only type of institutional arrangement that could credibly reduce the scope for ex post opportunism. This approach cannot be applied under the Strategic Reserve model, since the parties potentially affected by decisions are in effect outside the scheme. In other words, the government cannot enter into contracts with unsupported generators that would protect them against the effect of lowering the despatch price.

Recent developments in the oil market illustrate the effect of short-term pressures on this type of instrument. On June 23rd the International Energy Agency (IEA) authorised the release of 60 million barrels of oil to mitigate the effects of the Libyan crisis on oil prices. This was despite the fact that the reserve was originally designed to cover supply gaps, and not to influence the basic price of crude.

Similarly, in Sweden market participants and regulators have repeatedly highlighted the risk of market distortions associated with the use of peak load reserves. For example:

– the **Energy Markets Inspectorate** (EMI) has argued that the reserves would not provide a sustainable solution to the issue of capacity adequacy and should be replaced by a more market-based solution;[1]

  > *'The main argument against having the Government responsible for the peak load reserve is that investments in peak-load production will only be carried out if they can be financed within the framework governing the procurement of the reserve. This leads to a continued need for a larger power reserve. State responsibility for the power reserve therefore does not give rise to a stable long-term handling of the problems related to peak load shortages.'*

– for similar reasons, **NordREG**, the regional association of energy regulators, has argued that non-market interventions such as the peak load reserve can have adverse consequences on market dynamics and should only be prolonged if security of supply cannot be achieved through other means;[2]

– **Nord Pool Spot** has expressed concerns that the deployment of the reserve to mitigate 'unreasonably high price' would dampen investment incentives for commercial developers. Similarly to the EMI, Nord Pool has argued that the long-term objective should be to phase out the reserves and establish a more market-based approach to capacity adequacy. In the shorter term, Nord Pool is recommending that the dispatch price be set sufficiently high to cover the total costs of the reserve (fixed and variable).[3]

Overall, we continue to believe that the targeted approach would undermine the effective operations of the market and that it cannot provide a sustainable solution to the issue of capacity adequacy.

We have tried to answer the next questions constructively even though we do not support this option.

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

We think that the lead time should be at least 4 years. The Strategic Reserve is likely to comprise primarily of thermal plants, which tend to have relatively short construction times. However, the business case of these plants will be wholly contingent on the revenues from the capacity mechanism (unlike that of the plants participating into a market-wide mechanism). As such it will be critical for the developers to obtain a firm contractual commitment on Strategic Reserve revenues before finalising their investment decision and financing arrangements.

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[1] Energy Market Inspectorate (2006), 'Price formation and competition in the Swedish electricity market'.
[2] NordREG (2009), 'Peak load arrangements – assessment of Nordel guidelines'.
[3] Nord Pool Spot (2010), 'Handling the peak load reserves on the sport market'.

We also think that it would be difficult to estimate the required level of capacity to be procured under this scheme. In principle, the administrator of the reserve would need to estimate the amount of capacity that market participants would deliver *without intervention*. In practice, market participants will incorporate expectations of government intervention in their investment decision, and the exercise becomes partly circular. This uncertainty creates an additional source of uncertainty in the calibration of the scheme. Against this backdrop, there is a high probability that the decision-maker will seek to err on the side of caution by procuring a larger amount of capacity compared to its central estimate of the requirement, and that the costs of the scheme will be larger than expected under an assumption of perfect foresight.

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

We do not support the adoption of the Strategic Reserve model as it would introduce significant distortions in the market. If the government were to implement this model, we think that it should be defined very clearly as a temporary solution to address the uncertainty surrounding the resilience of the system during the transition to a low-carbon power sector. The implication is that the length of the contracts should not exceed 4 to 5 years to avoid 'locking in' long-term commitments. This duration would be sufficient to support existing plants that would otherwise retire, and it could potentially also support new build (it is the duration applied to contracts for new capacity in New England).

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

We expect the main criteria to be the following.

– **Technical criteria**—We think that the definition and weighting of the technical criteria should be informed by the preliminary assessment of the problem. If the analysis indicates that supply gaps will be difficult to predict but will only last for a short period of time, then ramping rates are critical. If the risk relates to longer supply gaps, then the length of sustained running should be given more weight. We understand that the Strategic Reserve would be designed primarily to address longer supply gaps, which would seem to imply a stronger weighting for length of running.

– **Location—**If project TransmiT were to remove or dampen locational signals in TNUoS charges, then there might be a case for reflecting the costs and benefits of different locations for the system in the procurement criteria.

– **Creditworthiness**—We also think that the administrator of the reserve will have to consider the issue of credit and counterparty risk carefully (especially for long contract durations).

– **Project advancement—**The administrator might require that new plants can only bid if they have met certain project milestones (eg consent). For such projects, the tendering specifications would also need to specify a penalty for non delivery.

Finally, the tendering process might also need to articulate the trade-off between the cost and the 'quality' of different resources. For example, if the initial stages of the procurement process indicate that purchasing a reserve with the desired specifications would be very costly, but that procuring a reserve with slightly lower specifications would lead to large cost savings, there might be merit in going for the latter option. There is an inherent trade off between the costs and benefits of providing a certain level of resilience in the system, and this could be reflected in the procurement process.

DECC should also clarify the conditions under which existing plants could bid to operate under the reserve (and withdraw their capacity from the commercial segment of the market).

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?

We are sceptical with respect to the ability of this model to support effective participation by non-generation resources.

– **DSR**—We think that the Strategic Reserve model would make it more difficult to provide a level-playing field between DSR and generation. For this model to work, the administrator of the reserve must have confidence that the resources can be dispatched when the price rise above the trigger level, but equally market participants must have sufficient assurance that the capacity will *not* be despatched until that point is reached. It is not obvious how DSR resources can provide this guarantee.

  Suppose for example that a large supermarket with coolers and freezers installs load management equipment and bids the resulting demand response in the Strategic Reserve. The supermarket would have a natural incentive to use its new system to reduce consumption when prices rise even if they do not rise up to the despatch price. It is not obvious how the administrator of the reserve would ensure compliance in this context: would the supermarket be penalised for *not* consuming the expected amount of electricity at times of high demand?

– **Interconnectors—**The same issue would apply to interconnectors. It is difficult to envisage a situation where the administrator of the Strategic Reserve would sponsor the construction of an interconnector to improve system resilience, and then only allow power to flow to GB when the price hits the trigger level (apart from anything else, this would conflict with EU rules for the management of cross-border capacity).

– **Storage**—For storage, the capacity mechanism would need to harness the potential for the technology to provide both ‘positive reserves’ (ie addressing supply gaps and price spikes) and ‘negative reserves’ (ie addressing supply surpluses and negative prices). It is not clear that the Strategic Reserve could achieve this. In practice it could mean setting a ‘negative despatch price’ (ie, the price at which the storage operator would start to inject energy) as well as a positive despatch price (ie, the price at which the operator would start to withdraw energy), but there would also need to be some rules regulating the baseline volume that would allow the operator to provide a suitable volume of both types of reserves on request. The design issues involved in setting these parameters would be particularly complex.

Overall, we think that a market-wide mechanism would be a better platform to establish effective competition between generation and non-generation technologies (see our answer to question 22). We also think that DSR are a more natural provider of STOR, given their very fast reactivity (and in practice we do observe that the few aggregators that are starting operations in GB seem to be targeting that market).

Similarly, we do not see how this model would support participation by providers of capacity outside GB. Presumably, if there are suitable market arrangements in place to ensure that power flows follow price differentials (such as market coupling), then the interconnectors will be used at full capacity when the GB price rise to the despatch level.[4] The despatching of a reserve plant in the adjacent country would not make any difference to the supply situation in GB.

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

As explained in our answer to question 1, we do not believe that the 'last-resort despatch' option is sustainable in political terms as there would be strong pressures to use the reserve to mitigate price spikes.

We think that the 'economic despatch' option would lead to significant market distortions even if it is slightly less prone to ad hoc regulatory intervention. Importantly, we are sceptical with respect to the notion that the scheme specifications can somehow be 'fine-tuned' to remove these distortions (paragraph C2.25 in the consultation paper).

Specifically, the consultation paper states that under this model prices would rise to lower levels (because of the cap) but more often (because there would be less unsupported capacity in the market). The consultation further argues that in principle there is a despatch price and reserve volume at which the second effect offsets the first, and the revenues of unsupported plants are unchanged. We think that it is likely that the second effect would only partially offset the first, and that the revenues of unsupported plants *would* be lower. The scheme would affect the revenues earned at times of peak demand, which are normally captured by all generators, not just peaking plants. As such it is conceivable that it would affect the economics of baseload and mid-merit projects as well.

If reserve plants are despatched on a quasi-commercial basis, then as the despatch price gets closer to the marginal cost of the plants, the state-supported reserve plants would start to 'compete' with the unsupported plants to capture scarcity prices. Such a situation may carry a risk of non-compliance with State Aid rules.

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

In general we are deeply sceptical with respect to the possibility of insuring this regime against short-term pressures (see our answer to question 1). If, however, the government were to pursue this option we think that institutional arrangements should be sufficiently robust to isolate the despatch price from short-term pressures.

If the decision is conferred to an independent body, it is fundamental that the organisation be required to give due consideration to the effect of its decisions on past & future investments, and has the necessary expertise to understand and evaluate these effects.

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?

As explained in our answer to Question 3, we oppose this model and we think that if DECC were to take it forward it should be designed very clearly as a temporary solution. The implication is that instead of a system of periodical reviews focused on the *parameters* of the

[4] That is, unless there is a region-wide shock to demand or supply and prices are even higher in adjacent countries. But in that context there is no guarantee that the despatching of reserve plants in adjacent countries would change interconnectors flow and contribute to meeting demand in GB.

system (ie, the volume, type, and despatch price of the reserve), there should be a backstop date at which the *need* for the scheme is reassessed.

The default assumption at this review should be that the scheme is terminated. If there are continued concerns about security of supply, then the reviewer should be required to consider alternatives to the Strategic Reserve (eg market-wide mechanism).

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

We agree that selling the Strategic Reserve into the Balancing Mechanism would be the most straightforward option, but we are also concerned about the risks associated with this solution. If the reserve is deployed close or during real time (ie, in the Balancing Mechanism or the within-day market) then it will overlap with STOR contracts. If this is the case then the SO might decide to reduce the size of STOR, which would, in turn, reduce the amount of revenues available to generators under this scheme. In other words, the strategic reserve could start to 'bleed' into the market for STOR just as it would bleed into the general wholesale market, and would thus start to undermine security of supply.

Selling the Strategic Reserve into the day-ahead market could mitigate this issue, but only partially. Suppose that the system is stretched but that prices do not reach the trigger level in the day-ahead market; if the situation deteriorates closer to real time and a risk of disruption emerges (for example because STOR plants are insufficient to cope with the gap) it is difficult to imagine that the administrator of the reserve would continue to withhold the reserve.

A possible approach to this question would be to divide the Strategic Reserve into different 'tiers' that would be despatched into different markets. This division could be based on the technical performance of the resources, with the least reactive resources despatched in the day-ahead market, and the most reactive resources despatched closer to real time. However, this approach would not really resolve the issue of the 'boundary' with STOR (indeed, the 'reactive' tier of the Strategic Reserve would compete with STOR), and it might introduce further complexities in the administration of the reserve.

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

We believe that there would be merit in locating the procurement function in the organisation responsible for contracting the FiT-CfDs, as there would probably be economies of scope between the two functions. The critical requirement for this organisation will be its creditworthiness, and we will comment on this aspect in the separate consultation relating to the institutional aspects of the FiT-CfDs scheme.

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?

We do not believe a Strategic Reserve option is an appropriate model for dealing with the issues here.

Such a scheme would be 'workable' in the sense that it could be implemented alongside the current market structure, and that it could potentially provide a short-term 'fix' to potential capacity shortfalls. However, we do not think that it represents a sustainable solution to the issue of capacity adequacy. We believe it is much more difficult to accurately assess how much capacity should be held in a Strategic Reserve, and consequently there is a significant risk of failing to deliver the intended level of security of supply. We continue to believe that this scheme would weaken investment incentives in the generation market and this would, in turn, require further intervention. We note that DECC's impact assessment assumes away these distortions, and it is therefore questionable whether it represents an accurate estimate of the welfare impact of this option.

The decarbonisation agenda will fundamentally transform the economics of the plants that are needed for security of supply, and we argue that this warrants a more coherent, market-wide mechanism.

Question 12: How and by whom should capacity in a Capacity Market be bought and why?

We support the use of a periodic auction to set the price of capacity with the clearing price being paid to all purchased capacity. We believe the conditions exist to make this one instance where auctions can be the most effective form of price discovery. It should also help ensure that all generators are offering capacity on equivalent terms.

A central buyer would appear to be the most efficient solution with outturn costs being appropriately recharged on the basis of final demand. This would be via suppliers, directly to self supplied load and to interconnector export parties. Having an obligation on suppliers would incur extra costs associated with retrading capacity obligations between suppliers. This would be necessary because customers will switch supplier in the competitive retail sector between the time of the original purchase and the point of energy supply. As such, this scheme would support competition and customer switching in the retail market.

A single tender process should give better price discovery than multiple smaller ones and a central determination of the capacity requirement should be more consistent that each supplier determining their own needs.

It will be necessary to give suppliers and other consumers regular forecasts of their likely liability for capacity costs so that the appropriate costs can be built into customer contracts and tariffs.

This scheme would also support competition in the generation market by providing a simple 'route to market' for independent generators. A credit worthy central buyer would be helpful for new entrant generators seeking to build new capacity under capacity contracts.

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

There are significant advantages in having a single capacity product. If the market is split up into contracts of different duration them liquidity will be split. It will also be hard to compare prices for contracts with different durations. For existing plants, one year contracts would seem to be appropriate.

However, we also recognise that new marginal capacity that could be dependent on capacity payments for the bulk of its income may be difficult for independent generators to offer without longer term contracts. Long contracts have the disadvantage of removing that capacity from subsequent auctions and reducing the price competition.

We understand that in PJM, the SO can only use contracts of 15 years if the normal auction fails to clear the necessary amount of capacity (or if there are particular locational constraints).

Question 14: How long should the lead time for capacity procurement be?

We think either option a) or option b) in the consultation would be most appropriate, either shorter than or around the shortest construction time which we would expect to be 2-3 years ahead of delivery. In addition to investment in new plant that may be required, it must be recognised that there is a significant requirement of investment in existing thermal plant across the UK to ensure its continued operations. Much of this plant is facing prolonged periods of poor profitability[5] which will mean this investment is not justified, with the consequence that we face a heightened risk of premature and unnecessary closure.

For new investments, it would seem prudent to set minimum development hurdles that prospective projects would have to cross before being allowed to participate in auctions. Such criteria could include obtaining all major consents and having a firm construction cost and timetable.

It could be appropriate to allow some new plants with long construction times extra lee way if the value of the capacity delivered is of material benefit to the system. It is not obvious what such plant would be apart from hydro or some forms of storage.

The complexities associated with very long lead times for large new capacity such as nuclear or large offshore wind farms (or large tidal schemes) will need careful consideration both in the assessment of capacity needs and in how it participates in the capacity auction results so that construction delays do not cause discrepancies. These plants will almost certainly hold CfDs and the question of a specific lead time for these plants is only worth considering if they are allowed to fully participate in the capacity mechanism.

A key factor will be the penalties associated with late delivery of capacity.

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

A secondary market would be beneficial under all market designs. It should facilitate DSR participation and give generators the ability to re-trade out of capacity obligations for maintenance, outages etc. There does not seem any reason to restrict the products traded as long as they are consistent with the primary obligation of the contract seller. Consideration needs to be given to whether primary participants can assign their obligations or merely subcontract them in which case they would still be responsible for the final delivery obligation. Credit issues may also need to be consistent.

Q16 Advantages and disadvantages of making a central, administratively determination of:

1) **capacity that can be offered into the market by each generator**
2) **criteria for being available;**

[5] For example, see Credit Suisse report on UK Utilities of 8 April 2011

3) penalties for non-availability?

It is of fundamental importance that there is complete consistency between the assumptions made in determining the required level of capacity (as per C3.11 and 3.12) and the capacity credit used in the procurement process. Otherwise the process will be inconsistent and will not deliver the expected level of security of supply.

We agree that not all generation capacity (or demand side response) is equivalent but given the link to the determination of need, it would seem that these rules must be set and administered centrally. They should be based on objective technical analysis and probabilistic assessment of the capacity factor achievable at the desired level of security of supply.

The test for contracted capacity being available (either generation or demand side) and the penalty for non-availability are strongly linked with the nature of the capacity contract - e.g. whether it's a financial option or a physical capacity supply contract.

We believe that a pure "fully firm financial option" style obligation would create a number of significant issues. It could be counterproductive if capacity providers face penalties in financial reliability options that are the entire market exposure above a determined strike price and not linked to their option fee income in the period. This structure effectively creates an uncapped capacity contract exposure which would be a very difficult market risk for providers to assess and would inevitably lead to onerous credit obligations and potentially requiring significant collateral to be provided. An uncapped liability creates an insolvency risk and we believe it would not be bankable for project financed generators. As such it would be a barrier to entry for smaller independent generators. Increasing the risk in this way would also be expected to lead to higher costs for capacity.

Such a mechanism may have unintended consequences, and is too blunt an instrument to apply to a complex energy issue. This can be illustrated by considering the causes of high spot prices that could trigger large payment obligations for the capacity seller under a financial option contract.

Whilst very high electricity prices are indicative of a period of system stress they may not be the only relevant criteria.

The following list gives some examples of circumstances that could give rise to very high electricity spot prices:

- major coincident plant failures,
- transmission failures,
- low wind + high demand,
- major gas supply failure,
- very high fuel/carbon prices,
- high coincident interconnector demand caused by Europe issue,
- short notice i/c reversal,
- within day wind gusts causing loss of wind generation,
- "type faults" on certain classes of generation;
- wide scale coincident technology changes e.g. FGD, SCR.

Some good design principles for capacity mechanisms would be:

a) that capacity providers should not be penalised for "failing to deliver capacity" if the cause is outside their reasonable control. This might apply during force majeure type events such as disruption to the gas supply arrangements (for gas fuelled generators). It is our understanding that fuel diversity risk is not intended to reside at generator level.

b) That if generators are not disincentivised to contract in the forward market, for example if generators have sold their output in the forward market, they should not be made to payback the spot price they have not received.

Similarly, in the case of a financial contract with some form of market reference price generators should not be liable if they could not reasonably have been expected to have "captured" the revenue through energy sales into the relevant market. For instance, a short duration event happening with no notice, will generate a spike in the BM and possibly for some hours following. However, these could be inaccessible to generators that are available but not generating if they have start times and/or ramp rates that preclude generation within that time scale. Such events, happening within operational time frames are really STOR events rather than "capacity adequacy" events and could be considered inapplicable even though they caused a high spot price.

Designing these aspects of the capacity market requires careful consideration of the intended risk allocation between parties. The assessment of performance needs to be considered over a reasonable time period – availability during one half hour price spike should not be the sole measure of annual performance.

We believe that a more administrative assessment of whether the resource was "at fault" or not when unavailable would reflect a better sharing of the risk. In other markets that have capacity mechanisms, we believe that the penalty for non-delievery is more a reduction in the capacity fee than the full mark to market impact of the capacity reduction. We understand that in New England ISO, the generator penalty is capped at the monthly capacity fee.[6] The size of the potential risks under the contract will have a material impact on how generators price their bids into the procurement auction.

We believe that a balanced approach is to

a) Centrally determine the capacity credit of each generator using objective criteria that are consistent with the calculation of the capacity requirement;
b) The criteria for being available should be based on physical availability at times of highest stress determined by known criteria (e.g. times of highest demand).
c) Price spikes caused by within day balancing issues should be distinguished from capacity adequacy events.
d) Capacity providers should not be at fault if they were available but could not physically have delivered energy for reasons beyond their reasonable control
e) Plants that are broken down on on scheduled maintenance should re-trade their obligations in the secondary market.
f) Part of the assessment should be whether they met their de-rated capacity factor over an appropriate reference period.
g) The penalty within a month should be proportionate to the market cost of replacing that capacity but capped at the monthly capacity fee unless certain extreme market conditions are met.

[6] See for instance NE-ISO's training material on the calculation of the Peak Energy Rent available at http://www.iso-ne.com/support/training/courses/fcm/day_4_fcm101.pdf

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 adverse effects of choosing a particular option be mitigated?

We believe that a form of reliability contract that is a pure financial option is incompatible with the current BETTA market arrangements. See Appendix A for detailed explanation. Any contract that settles by reference to an energy price is an energy contract. As such it would constrain the ability of generators with these reliability contracts from offering conventional energy contracts via the existing wholesale markets, and could therefore divert liquidity entirely to the chosen reliability reference market.

Whilst it is valid to use spot energy price spikes as a "flag" that security of supply is at risk. It is very different to use such energy prices in a financial option contract. The generators ability to "access" the reference price is a fundamental criteria for financial contracts as it determines the generators ability to hedge its exposure.

Or if they choose not to hedge, they should know the size of their financial exposure in advance of the contract delivery period. This does impose some practical constraints; we agree that there could be implications for liquidity and that contracted plants will likely not sell into markets before the reference market.

In the BETTA electricity market there is no single "spot market" price that is readily available to all generators. Nor do we think there is any evidence that generators carry out "strategic bidding" to influence market prices as suggested in paragraph C3.48 Generators are "paid as bid" in the forward markets that exist for contracts for delivery at various times into the future. There is no daily auction or pool that sets a single price for all generators.

The only possible "real time market" is that in the Balancing Mechanism (BM). However this is a dual price cashout mechanism and not a market. In it generators only get paid if the System Operator accepts their offer and they only get their price not the marginal price. This individual offer price goes into the calculation of the system buy price, but is unlikely to equal it. Moreover, active participation in the BM entails many complex requirements in terms of communication systems and despatch mechanism.[7] Thus the BM "spot" price fails the test of being a readily accessible price for all generators who might need to access it.

Other possible market prices are within day (prior to Gate Closure), or day ahead or further forward in time such as week ahead or month ahead as noted in the consultation but some of these may be liquidity constrained. If the market is too far from real time, there is a risk that it will not send the right signal when issues arise in real time. In each of these forward markets, generators can only access the price by selling the relevant forward contract. Having sold one forward contract, for example annual base load, the generator cannot access high prices that may temporarily arise in the forward market for another time period. We therefore do not believe that netting off volumes of energy contracts that generators have sold prior to Gate Closure from their "reliability" obligation is a workable solution. Generators will either have sold forward "energy" contracts into the reference market and "captured" the price, or they will not, in which case they cannot generate (without creating an imbalance) and even if they did they would not be paid the reference price. This seems to be a fundamental problem with trying to implement financial option contracts within the current GB design, which could only be resolved by a wholesale change to the market arrangements to some form of mandatory day ahead auction or Pool market. However, we do not believe such a change is the desired or appropriate action in the UK market at this time, and would not advocate such a change.

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[77] These requirements are summarised in National Grid's ongoing consultation 'Managing intermittent and inflexible generation in the balancing mechanism', September 20th.

The interaction of capacity contracts and STOR contracts needs to be clearly established so that it is clear which “events” or price signals each is responding to. If STOR is meant to cover operation issues (within day) and the capacity market the generation adequacy risk, then this needs to inform the selection of the reference market, although as we have shown above there are fundamental issues which will be difficult to resolve.

If within day risks are the province of STOR, then capacity contracts should not reference any market closer to real time than “day ahead”. On a day ahead basis, prices would spike in situations such as when the system was stressed due to high demand and low wind, or major and persistent plant outages. In these situations, capacity contracted plant would have both the incentive and ability to respond: the high day ahead price would forewarn the generator that the contract would be exercised, and the generator would be able to hedge this by selling uncontracted output into the day ahead market. They would also then self dispatch to run during the relevant period to meet their energy commitments and have sufficient notice to allow for start times and ramping times. There would be transitional issues because some generators may have sold into the day ahead market prior to prices spiking which would need proper consideration.

If suppliers were the buyers of the reliability contracts that had physical delivery obligations, then these become in effect tolling contracts, which are again a form of energy supply contract. The suppliers would dispatch the plant to run when they wanted but in accordance with start times and ramp rates specified in the contracts. This in effect transfers the despatch decision from the generator to the supplier. Depending upon the individual supplier’s hedge position and hence exposure to short term prices, it may not have the desired effect of maximising the generation capacity running at times of system stress. Bilateral contracts do not appear to be a robust solution to the security of supply problem that is being addressed.

Question18: For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

Subject to our reservations above on option contracts, the nature of the strike price depends on a number of issues.

The consultation suggests that it should be a “boundary price” between normal and scarcity conditions and be set materially above normal prices but below VOLL and the implied “cost” of voltage reductions. This is in fact a very wide range from say £200 to £10,000.

The higher the strike price the more value a bidding generator would attach to energy profit that it is allowed to keep under the option and therefore the lower his auction bid price should be and vice versa.

If it is over say £1000/MWh –then it is so far above generators potential SRMCs that it may as well be fixed for a year rather than indexed. If it is much lower, then it may be better to index it to the relevant fuel and carbon costs so that it effectively represents a clean spark or dark spread.

For gas plants acting as peaking plants with low load factors, which may only run during price spikes, they will not be able to hedge their fuel costs at the time of entering the auction because they will not know when they will be running.

For long term contracts for new build, it would seem inappropriate to offer different indexation to different types of generation because it makes comparison impossible. If it was clear that there was only one fuel (such as gas or oil) that would be used by all new capacity then it might be appropriate to offer some linked indexation. Again this is dependent upon the contract duration. For a short duration, it may not be necessary.

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?

As the consultation document recognises, there are difficulties with all options here, particularly the first two.

Option a) no physical backup

The key question is whether it is appropriate to rely on pure financial contracts to deliver physical security of supply? As noted in the consultation, there is no "need" for financial reliability contracts to have physical backup. However, to rely solely on the financial penalty (which may be perceived differently) being sufficient to ensure physical security of supply would be unreliable and has a number of consequences. Firstly it makes the issue of credit support for the contract holder of paramount importance, but where it is also very difficult to pre-estimate the maximum liability under the contract – which would essentially be uncapped. This could have the unintended consequences of precluding small generators and many demand side players from participating.

The more the contract is financial, the harder it is to stop it being assignable and tradeable, leading to further risks around insolvency and remoteness.

Also, if events trigger large and severe financial consequences, then it becomes highly likely that any generator faced with large payouts will examine all legal and commercial opportunities for minimising their exposure – leading to potentially protracted arbitration and legal disputes.

If such arrangements also mean that new plants cannot have different contract durations from existing plants then this is likely to lead to suboptimal outcomes and become another barrier to new entrant generators.

Option b) name plate capacity

Allowing generators to sell reliability up to their name plate capacity would cause significant problems, particularly with regard to intermittent generation technologies and DSR, and result in a similar situation to option a). It would rely solely on the financial penalty as the lever for generators to restrict the amount of capacity they contract, and as laid out above, we believe this has substantial difficulties. Like the option above, this would also effectively delink the calculation from capacity need (with its assumptions on derated capacity) from the procurement of that capacity. This would make it almost impossible to confirm that the "right" amount of capacity had been purchased in the tender to deliver the desired security of supply.

Option c) regulatory de-rated capacity. This is what other markets have adopted and seems the best way of delivering physical plant/ demand side response to comply with the Security of supply standard. We disagree that there would be a large additional regulatory burden because Ofgem will already be making similar calculations when carrying out its annual security of supply report for the Secretary of State.

We believe option c) is the only workable solution as relying on financial mechanisms raises very significant issues and also depends upon getting the VOLL value accurate – something which is almost impossible to achieve.

It should be noted that with the introduction of the need to prove that sufficient physical capacity exists (or will exist) to underpin all reliability contract models, much of the perceived benefit of adopting a pure financial form of reliability contract is removed compared to a more pragmatic centrally-administered New England ISO arrangement.

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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?

The analysis is incorrect in regard to vertical integration (VI). If the model for reliability contracts is as set out in Figure C.12 then all the purchased contract volume goes via a central auction. In a supplier obligation model, the costs of these would presumably be allocated out on some basis linked to metered sales. However, unless the whole procurement/contracting was delegated to suppliers (which would be inefficient as discussed above) the contracts could not be viewed as “internal”. In addition, most of the VI companies run and account for their generation and supply business as separate entities which makes netting of profits unlikely. Thus concerns over VI generators having internal contracts are invalid.

The concept of “ensuring the option payments ... flow to customers” is flawed. Unless suppliers routinely price into their tariffs the extreme price spikes that would trigger the option payments then there is no need to “pay customers”. In fact the opposite is true; the suppliers need to retain the option payments to offset their spot market liability such that their supply tariffs do not become loss making. Under pure financial option contracts the receipts will be netted off the fixed costs of the contracts as part of the contract administration and cost recovery from suppliers and the demand side.

The only circumstances where the former could arise is if large customers are on some form of “spot” market price contract where the spot market used is the same as that for the reliability contracts.

As described above, the major problem for implementing financial options as a reliability market appears to be the bilateral nature of UK market rather than VI.

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?

Some of the concerns noted in this section are caused by the reliability contract being structured as an energy price option and they highlight the need for clear rules on interaction between the two markets. The CFD interaction then is additional on that.

In general, there need to be clear rules as to how energy contract sales (normal bilateral or exchange contracts) interact with reliability contract obligations if it is indeed possible as discussed above. The impact assessment suggests one option is that there would be a netting off of energy contract volumes from reliability contract volumes. Thus only capacity uncontracted at Gate Closure would be performance measured under the reliability contract. However, this is unworkable as described in Appendix A.

Regarding CFD and Capacity Market interaction, we suggest that some clear principles are agreed. The most important should be that there is no “double dipping”. If CFD qualifying capacity wishes (or has to) participate in the capacity market then any benefit should either be taken into account when setting the CFD strike price or substantially refunded via the CFD. Given the potential variability of capacity market revenues over the life of the CFD, the latter option may be easier to implement. Alternatively all low carbon plant could be excluded from the capacity market and the requirement adjusted down appropriately. This approach would probably be the simplest to administer, and it would be consistent with the notion that there does not need to be two sets of overlapping investment incentive schemes (the CfDS and the Capacity Mechanism) for low carbon generation.

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?

In order to facilitate the widest range of participation in the capacity market we believe it is important that:

- Financial penalties for non delivery are commensurate with the rewards – if there is a small risk of a very large penalty then credit requirements get more onerous and smaller players and DSR may be deterred from participating.
- There should be a robust secondary market where the capacity obligation can be re-traded and broken down into shorter time periods.
- If the financial option (reliability contract) is chosen, then this may deter DSR because it would require them to buy their power on the matching “market index” which may expose them too excessive volatility in contradiction of their normal procurement and risk management strategies.
- DSR and storage should be allowed to participate in the annual auction process on the same terms as generators.
- Interconnectors should be encouraged to participate on the same terms

We note that Ofgem has highlighted the risk of a separate ‘missing money’ problem for interconnectors as part of the development of its policy for interconnectors. That is, the developers of cross-border capacity might be subject to an incentive to ‘under-size’ their assets to ensure that they do not completely remove the congestion rent between two markets. We believe that allowing interconnectors to participate in the capacity market would go some way towards removing this incentive.

At any rate, we think that a market-wide mechanism would be better suited to creating a level playing field between generation and non-generation technologies than a targeted mechanism.

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

The discussion of functional arrangements is sensible and it is clearly difficult to be specific until further details of the specific mechanisms are clear. Efficiency and cost effectiveness with the minimum of bureaucracy would be obvious goals.

A key input to the determination of the capacity requirement, in addition to those listed, is the desired security of supply standard. There are a number of ways of defining this, one of which is in terms of an annual volume of unserved energy. i.e. that only in 1 year in 100 would unserved energy exceed XGWh. Another cruder measure is in terms of derated plant margin. However it would be useful to have a number of additional dimensions around this such as the desired maximum duration of any single outage event etc. We assume that there would be a process whereby the Secretary of State would determine what this security standard should be.

Whilst there are major issues on the CfD FITs associated with the identity and credit rating of the contract counterparty we percieve these issues to be much less material for annual capacity contracts.

There probably would be cost and organisational benefits in combining the functions of CfD administration with that of capacity contract administrations.

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?

We believe that the capacity market arrangements should de defined and the framework implemented as soon as reasonably practical, ideally by 2013. Defining the detailed rules and building the necessary software always takes longer than expected. The future levels of plant build and closure over the next 5-10 years are quite uncertain so it will be hard to predict exactly when the capacity market will be needed to deliver “additional” capacity. A better approach is to have it functioning from 2013 and to hold annual auctions each year from that date. If the capacity margin is adequate, the resulting clearing prices will be very low and no material cost is incurred. It is far better to test and refine the process and rules before they are needed in earnest. International experience shows that most capacity markets have seen design changes and rule changes implemented in the first few years following the market creation.

Establishing clear visibility of the process and the start of a price track record will be important for achieving investor confidence.

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

- Our preliminary thinking is that a more physical capacity market with the following characteristics will better deliver the objective of ensuring that security of supply meets the defined standard.
- The capacity market should be distinctly separate from the energy market
- The primary product should be availability not energy thus financial options on energy prices should not be considered.
- The New England ISO reliability market and the PJM Reliability Pricing Mechanisms would seem to be good places to start when looking for a model to build from.

- It should be a market wide arrangement (possibly excluding low carbon generation subject to separate support).
- There should be central determination of capacity credits (aligned to calculation of need).
- A primary market consisting of centrally procured auctions for annual capacity ahead of time.
- A secondary market implemented to allow re-trading of capacity obligations
- The arrangements need to be robust from any players exercising market power and manipulating prices to the detriment of customers.
- Non delivery penalties that are proportionate and judged against all the relevant circumstances (including level of price spikes and generator capacity income) and subject to appeal.
- The administrator, via the SO, should have the ability to instigate spot checks on generation capacity to test availability.
- The market design should be attractive to independent generators and to demand side participants.
- Effective competition between the widest population of “capacity” providers will mitigate market power, minimise costs to consumers and encourage innovation.

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

Assessing and benefits to consumers relies on being able to accurately reflect a true value of VoLL, which is very problematic and as the consultation document notes has been estimated to be between £10,000 and £30,000/MWh but also varies considerably between customer groups. The cost will be very dependent upon the amount of “spare” capacity that is determined to be needed which is in turn dependent upon the security of supply standard adopted by DECC. The incremental unit cost of providing each extra increment of security will be high but the total costs appear small in the context of the electricity market as a whole.

Delivering the Government’s renewable energy targets requires substantial addition of intermittent generation to the system. This will reduce security of supply and will require additional investment to offset this additional risk. Counter against the cost of achieving the low carbon policy objectives, the relatively small incremental cost for the country as a whole of a market wide capacity mechanism seems good value. Given the very reliable electricity system that has existed since privatisation, consumers have become used to a very high standard of generation security. Failure to maintain that security will attract much more criticism than the relatively small additional costs of avoiding problems.

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

We agree there is a need for GB to introduce a capacity mechanism to ensure adequate security of supply given the increasing uncertainty on the framework of the UK generation portfolio due a range of factors.

As outlined above, we do not believe the strategic reserve mechanism would be appropriate and a more market-wide mechanism would be more effective in achieving the objectives. However, we see significant problems with the proposed system of financial options as reliability contracts, and do not believe this would remove much of the perceived administrative burden. We believe a capacity market with central administration of forward auctions to satisfy a pre-determined de-rated capacity volume would be the most effective solution.

The determination of fault in the event of price spikes should be recognised as complex in any real world electricity system and the importance of fairness recognised in assessing penalties. Penalties should not be uncapped nor disproportionate or they will increase the cost of providing the capacity.

Such a market should be introduced as early as practically possible, in order to identify and resolve any early stage implementation issues prior to being needed in earnest. Whilst the capacity margin is adequate, the clearing price from a capacity market auction would be low and therefore incur little cost but the value of demonstrating the concept would be very important for building confidence of investors.

ANNEX

Are Financial Options a viable form of Reliability Contract in a capacity market in the current BETTA market arrangements?

Introduction

In the White paper and consultation document, one market wide capacity mechanism described is a Reliability Market. This is described as "under this approach, a financial incentive – such as a financial call option – is put in place to incentivise availability and provide penalties for unavailability" (P181 para c3.8). The aim of a capacity market is to ensure security of supply via delivering resource adequacy.

We are aware that New England ISO use Reliability Contracts as the basis for their capacity market but we do not believe these are financial options in the sense that is used in the above description and in this note.

The purpose of this note is to examine whether Reliability Contracts that are pure financial options could work as a way of rewarding and penalising capacity under the current BETTA GB electricity market arrangements.

Definitions:

- **Financial Option**: this is a fully firm financial instrument that obliges the seller to pay the difference between a market reference price and the strike price for the contract volume whenever the reference price exceeds the strike price. There is no force majeure or other exceptions to the payment obligation.
- **Imbalance Volume**; is the difference between what a generator / supplier actual metered volumes were and the sum of all their forward sales or purchases. The Imbalance Volume is adjusted to take account of changes instructed by the System Operator via the Balancing Mechanism.
- **Balancing Mechanism (BM):** Is a dual price cash out mechanism, comprising a System Sell Price (SSP) and a System Buy Price (SBP). In general, in any period one cashout price will be derived from Exchange traded data (market prices), the other from the price of the actions instructed by the System Operator (SO) in the Balancing Mechanism to balance the system. This price is an average of the last [500MWh] of accepted prices and thus not a truly marginal price. Generators/ Demand Side that have volumes accepted by the SO in the BM are paid the relevant submitted price not either of the cashout prices.
- **Imbalance Cost**: this is the cost charged to (or payment made to) a generator or suppliers for their imbalance volume. The principle is that imbalances which reduce the system imbalance are charged/paid at market and those that make it worse get a penal price.
- **Gate Closure**: is a rolling deadline ahead of real time. It is the time one hour ahead of the start of each half hour settlement period and is when the SO takes over responsibility for balancing the system in real time. All generators and demand must notify Elexon prior to Gate Closure of their bilateral contracted energy volumes aggregated by counterparty for the period falling one hour after Gate Closure. [8]

[8] APX closes 15mins before Gate Closure to allow time for the Exchange to notify positions to Elexon

Context

Under BETTA, generators trade into the forward markets the energy volumes they wish to sell. These are bilateral trades that are settled at a mutually agreed price. Generators either have to physically produce the volumes they have sold or buy the volumes from other generators. Suppliers buy contracts in the forward markets for the energy volumes they forecast that their customers will use. Any difference between forward contract volumes and actual outturn generation volumes gives rise to an Imbalance Volume and associated Imbalance Cost. Revenues collected from imbalance cash out are redistributed to all participants in proportion to their energy volumes via the RCRC payment. There is no Pool arrangement nor near real time auction where all generators are paid a marginal clearing price.

Options as Reliability Contracts

The general concept of Reliability Contracts is that generators exchange a volatile energy revenue from price spikes for a fixed annual fee. The contract then obliges them to repay money received from the market during any price spikes. Customers, who bear the cost of the fixed payments avoid volatile energy price spikes in exchange for an “insurance premium” and achieve a desired level of security of supply. It is assumed that all “security of supply” events would give rise to high “spot” prices in the electricity wholesale market which signals that more generation is needed or demand needs to be reduced.

The occurrence of price spikes above a predetermined strike price (set at a level above normal market price levels) is then used to identify when generators should “pay back” excess rents that they have collected. Under BETTA, these price spikes would presumably occur first in the BM (the real time “market”) and then in the prompt half hour market (once the triggering event had happened) and would persist into the day ahead forward market for some period depending on the nature of the event.

The “advantage” of using a pure financial option is that it would be simple to administer with a clean price trigger and payment mechanism. The exposure to the option payments would act as a continuing incentive on generators to be available and to generate at such times of high prices.

In a firm financial option a “spot” energy price would be chosen as the Market Reference Price (MRP). Under such a contract the generator would makes a difference payment of:

Contract payment = contract volume * (Market Reference Price – strike price) whenever the MRP> strike price.

Risk adverse generators may want to hedge their financial exposure under such option contracts. They can do so be selling their physical generation volumes at the MRP used in the contract. They thus know they will have the revenue to make the option payment [9]. For the Reliability Contract to respond to security of supply events and “signal” a need for maximum generation by all generators we assume that the MRP would have to be a price close to real time. However, the fundamental problem is that under BETTA there is no combination of MRP and reliable hedging strategy for the generator that would reasonably ensure that the generator had the revenue to make the option payments.

[9] This is true unless the generator is unable to generate because of maintenance or breakdown.

Which spot price to use for the MRP?

The MRP could not be either of the prices in the BM because these are not accessible to all (or even any) generators because the BM is not a marginal price energy market. The next most prompt price would be a forward half hour for the current day for which Gate Closure had not occurred. However, there would be significant concerns about how liquid the within day half hour market was or how desirable it would be for the system operator to have large volumes traded very close to real time.[10]

A more liquid market price could be the day-ahead base load market. However, this is not ideal because it is not a single period price set at one time. The forward day-ahead baseload contract is available to trade for all of the previous day. The price of this contract will vary across the day. If there is a sudden supply event, the price prior to the triggering event will be "normal", but following it, will be at some much higher price depending on the market's perception of the duration of the event. Clearly, only generators who had not sold forward prior to the "event" would be able to "capture" the higher prices to fund their option payments. This would have the affect of encouraging generators to delay selling forward until the last moment, causing further liquidity concerns. Only if the period of high prices persists will generators be able to capture these prices through their forward sales[11].

Thus there is no obvious "spot" price that currently exists within the BETTA arrangements that meets the desired criteria of being accessible to all generators and also a near real time price.

Impact on Liquidity

Assuming that this price issue can be resolved, then an uncapped exposure to "repay" energy price spikes acts as a strong incentive on risk adverse generators to sell their output into the Reference Market. This is likely to have a significant consequence for market liquidity in general because it will divert large amounts of generator forward selling activity away from its current spread across various forward timescales to be largely focussed on the Reference Market.

To summarise, the first conclusion is that there is no obvious market price to use as a Reference Price.

The second conclusion is that which ever price is chosen will impact on market liquidity. This would distort and shorten the liquidity in the traded energy market which is contrary to current DECC and Ofgem initiatives to increase liquidity and extend the length of traded market liquidity.

Netting contract positions

One solution that has been proposed for this liquidity issue is to recognise other energy sales contracts that generators may have entered into and net these volumes off the option contract volume[12]. This would preserve the ability of generators to sell their output into any forward market they chose. Thus, if a generator had forward sold its entire volume into the month ahead market it would have no exposure under the option contract. In fact, netting off

[10] The closer to real time the MRP becomes, the greater the physical capabilities of the generation unit limit the ability of the generator to respond to unexpected price signals. Such limitations include start up time and ramp rates. A pure financial option would make no distinctions for plant characteristics.

[11] provided there are buyers willing to pay such high prices

[12] This presumes a complicated system of tagging traded contracts to physical generators such that the net position of individual generation assets can be determine.

might encourage forward trading of other markets because it would enable generators to net off all contractual liability under the option contract. The generator retains the incentive they currently have to generate the volumes needed to match the forward sales because failing to do so exposes him to an unpredictable (and very expensive if an emergency occurs) cash out cost in the BM. If the generator knows he will be unavailable then he has to incur the cost of buying the replacement power at then prevailing market prices.

In principle, a netting off approach works because generators are incentivised to deliver what they have already promised (by way of forward sales) which will always help security of supply. Also, any capacity that has not been forward sold (and thus netted off) would remain exposed to the Reliability Contract payment obligation which in theory acts to encourage that "spare" capacity to remain available should it be needed.

However, the nature of the BETTA market arrangements makes this unworkable. This is because generators can only "capture" any market price by selling forward contracts for future delivery of energy prior to Gate Closure. Generation output is sold forward and unused generation capacity is offered into the BM. Thus even energy sold into the Reference Market used by the option contract would be a "forward contract" eligible to be netted off. Thus a blanket netting off would not work because there would then be no generation capacity left to which the Option contract could be reasonably applied.

Any generation capacity covered by the Option Contract that had not been forward sold for the settlement period an hour after Gate Closure is effectively sterilised at Gate Closure when all forward markets applying to that settlement period close. Beyond Gate Closure, the BM is the only "market" into which such spare capacity can be "sold". As noted above the BM does not meet the necessary criteria to be used as a Reference Market for this contract.

Generation capacity is not allowed to self-dispatch to a higher output level in real time than is consistent with its notification at Gate Closure. If it did it would result in an imbalance cost. A generator's only access to real time prices is if it has an offer accepted in the BM[13]. One reason for generation offers not being accepted in the BM would be that the units start times or ramp times, or even location, did not meet the SOs requirements.

Thus the third conclusion is that if netting off is used to get around the concentration of liquidity identified above then this would mean that there would be no "uncontracted" capacity left that could reasonably be expected to respond to emergencies except through the BM which is not a valid energy market.

Thus the nature of BETTA, with its pay as bid forward contracts, self dispatch and dual price cashout Balancing Mechanism appear to be incompatible with Reliability Contracts structured as pure financial options.

This is not to say that Reliability Contracts as used in the New England ISO could not be made to work in the UK

[13] In which case it would be paid its offer price.