Bord Gáis Energy Response to I-SEM Capacity Remuneration Mechanism – Parameters Consultation

(SEM -16- 073)

21st December 2016

Introduction

Bord Gáis Energy (BGE) welcomes this opportunity to provide comments to the consultation on CRM Parameters. To date, we have supported a need to ensure that '*simplicity*' and '*transparency*' are maintained in the setting of any CRM parameter, and we continue to support this need in our response to this Consultation. Overall, we are concerned that many of the processes used to determine CRM parameters lack a clear set of principles and defined methodologies and as a result, there is a great degree of uncertainty and lack of transparency for understanding how parameters may change in future years.

We outline our detailed responses to the specific Consultation questions below but at a high level, our key positions and concerns in order of what we deem to be priority items can be summarised as follows:

1. Setting the price caps

As stated above, BGE is of the view that the process for determining any parameter used in the CRM design should be supported by a robust set of principles. The purpose of these principles should be to provide a clear methodology that gives certainty and transparency for how parameters will develop in future years. While we do not have an issue with the magnitude of the proposed price caps (i.e. €116/kW for the auction price cap and €38.90/kW for the existing capacity price cap), we are concerned that the methodologies used to derive these figures are not based on a clear set of principles, do not have defined objectives and the inputs used are not set by reference to objective factors. It is therefore not clear how they may change in future and what market based or other conditions would influence these changes. This in turn provides an uncertain environment for would-be investors.

For example, the BNE (or Net CONE hereafter) costs that have been used historically are being adapted to apply to the I-SEM design. While some changes may be necessary (i.e. moving from nameplate to de-rated capacity), by and large, the current process provides for a referenceable process which gives certainty to investors and should therefore not change (unless there are legitimate reasons to do so). We disagree with the assumptions made that certain costs (namely site procurement and electricity/water connection costs) should be omitted from the Net CONE calculations. By altering this process, the certainty that this process originally provided is being completely eradicated, since now there is no certainty around what costs are relevant and how they may change in future. Going forward, we believe that all costs should remain in place for calculating the Net CONE costs and that these are open for consultation.

We also do not agree with the process of applying multiplies of 0.5x and 1.5x Net CONE on the basis that they align with international precedent. Once again, we believe that the process for determining parameters should be supported by a defined set of principles in order to ensure certainty and transparency is present in the process in order to understand future changes and drivers. These multiples are based on a snapshot of the Net CONE and capacity level today – there is no certainty that the BNE will remain the same in the future, nor is there any certainty that capacity levels will remain as high as they are today. As a solution, we believe a principled approach should be used whereby the multiple used is referenced off the amount of surplus (or potentially deficit) capacity on the system. While a multiple of 1.5x may be suitable in today's market, where the surplus capacity decreases, it should send a signal for the multiple to increase towards 2.0x Net CONE.

2. Determining a demand curve

When designing the demand curve for the capacity market, we believe that a key principle should be to ensure an appropriate balance between the risk of security to the system and the cost/value of over-procuring capacity for the consumer. For the first transitional auction, the RAs need to be cognisant of two key points, i) the capacity requirement will be based off 2020 demand expectations (which is higher than today's levels) and ii) the RAs will allow for the procurement of additional capacity in order to resolve locational constraint issues. In other words, it is clear that the starting point for designing the demand curve is already leaning towards ensuring a high level of system security. To strike the appropriate balance between security of supply risks and value to the customer, we believe it is important that the RAs strongly consider the 'Reduced Expected Unserved Energy (EUE)' curve as a way of realising the additional costs to the consumer for every extra MW procured above the capacity requirement and in principle understanding how much extra capacity the market should be willing to over-procure. This in turn should inform the zero-crossing point in our view.

Of the three options proposed, BGE does not agree that any design fully balances the risk of system security and costs of over-procuring capacity. However, we believe a solution that would strike such a balance is akin to Option B whereby instead of an inflection point, the curve would reflect the Reduced EUE as a way of providing value to the customer. On that basis and in the interests of minimising volatility in the interim solution, we would suggest a simple linear reduction from Net CONE to a zero-crossing point at approximately 8,250MW. From a system security perspective, this approach would ensure that there is adequate generation capable of receiving a capacity contract beyond the capacity requirement. From a consumer cost perspective, the value of procuring additional capacity is captured given by showing that the zero-crossing point is in line with the reduced EUE curve.

3. Termination fees

Similar to our concerns relating to the processes used to determine the price caps, we are concerned that the methodology used to derive the termination fees is not clear and does not provide certainty in how they may change in future years.

We also believe that the proposed first schedule of termination fees (i.e. €10/kW) is too low and **would not** discourage speculative bidders from entering the market and thus risk skewing the capacity market price. Although we recognise that the RAs are trying to minimise barriers to new entry in this approach, we have seen in GB that their original termination fee was too low to prevent speculative bids from entering. As a result, when the market cleared at a low price, the expected return for these units did not materialise and they therefore terminated their contract with minimal risks and at a very low cost (to the speculative investor). This both skewed the market price and added to the security of supply concern in GB. For this reason, it is critical that termination fees must be set significantly higher than €10/kW to deter speculative participation and ensure the integrity of the auction outcome both for market participants and customers who are under-writing the security of supply to be provided through the mechanism. We believe a suitable approach would be to base the termination fee off the cost of procuring replacement capacity closer to the delivery date which could be set by reference to the existing capacity price cap (currently proposed as €38.90/kW). Such a process would be suitable for three reasons. Firstly, it would provide a level of transparency around the process for setting the termination fee in future years. Secondly, it would be set at an appropriate level that strikes a balance between dissuading speculative bidders from entering the market while not over-burdening genuine New Builds. Thirdly, it will ensure that the customer is not overburdened with the cost of speculative participants that exit the market.

4. ASP curve

We understand that the function of the ASP curve is to incentivise generation to be available (or demand to reduce load) during times of scarcity. However, we also recognise that there is a need to manage price volatility in the ASP design for two key reasons. First, price volatility creates a significant level of uncertainty for generators and this risk would have to be factored into their RO price. Second, a highly volatile curve would lend itself to market manipulation whereby a unit could reduce its availability by only a small amount and cause a potentially significant increase in the energy price. Therefore, we believe Option 1 (linear curve) would be more suitable as an interim solution compared to Option 2. We believe that Option 1 should be applied in the interim and reviewed again once I-SEM has been fully embedded and understood.

In conclusion, our overall largest concern is that many of the parameters proposed in this Consultation are **not supported** by a clear set of principles and as a result, there is a high level of uncertainty and lack of transparency around how these parameters may change in the future and what the drivers of change would be. While we may not disagree with many of the parameters outlined in this Consultation, we recognise that these values are based on snapshots of today's market and would not necessarily reflect a different market in the future. **Going forward, we believe all parameters must follow a clear methodology based on a set of principles and objectives to give adequate certainty and transparency to prospective investors.**

Administrative Scarcity Pricing Parameters

2.3.1: The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why?

In our response to the CRM 2 Consultation, we understood that the role of the ASP in the Balancing Market (BM) is to provide strong incentives to generate or reduce load at time of scarcity and that an exponential curve effectively hugging the X and Y axes could deliver this. In our view this solution would ensure that price volatility is minimised, which is extremely important especially in the I-SEM transitional period, while also providing the right availability signals to the market.

Of the options proposed in the Consultation and in keeping with our key principle of striking a balance between providing an incentive to generate (or reduce load) and minimising volatility, we believe that Option 1 (linear curve) would be a more suitable approach. Our analysis shows that Option 2 presents an extremely high level of volatility over the space of 0.1MW (i.e. increase from €500/MWh at 504MW to €1,950/MW at 503.9MW). This level of volatility lends itself to market manipulation whereby a unit could reduce its availability by a very small amount (0.1MW) in order to significantly increase the energy price.

Notwithstanding a preference for Option 1 over Option 2 as presented in the Consultation Paper, we still believe that the most appropriate approach for providing this incentive and minimising price volatility is the exponential curve we advocated in our CRM 2 response. We believe that this should be applied, at a minimum, on an interim basis, and reviewed again once I-SEM has been fully embedded and understood.

Cost Recovery and Charging

3.4.1-A: Which of the Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you choose and why?

In our response to the CRM 1 Consultation, we highlighted that a flat fee should be applied for setting capacity charges across all Trading Periods on the basis that it places all suppliers on a level playing field regarding their customer portfolio. A flat fee also importantly recognises that all consumers benefit from the security of supply that capacity mechanisms provide and therefore the cost recovery approach should be designed to ensure all consumers pay for this benefit. On that basis, of the Options proposed in this Consultation, BGE believes that Option 3 (7am to 11pm in all quarters) would be the most appropriate solution.

Furthermore, it is clear that the focus on peak hours in Options 1 and 2 would significantly increase the capacity price at those times and that this would be only paid by a subset of electricity consumers (namely residential consumers). Although we understand that the RAs are trying to incentivise consumers to reduce load at peak hours, we believe it would be unfair to do so by levying higher capacity costs on them, especially when they do not have the appropriate infrastructure in place to best manage consumption (i.e. smart meters and time of use tariffs).

Similarly, in the UK, the RAs have applied capacity charges on the basis of 'Triads' (targeting the three highest periods in the Winter). This has encouraged larger consumers to power up on-site generators (e.g. diesel generators) at times when they expect these Triad periods to occur. Not only has this burdened smaller consumers with higher costs, it results in less accurate demand forecasts during these times which in turn increases the cost of balancing the system – again, placing an even higher cost on these consumers. Therefore based on the above arguments, we believe Options 1 and 2 would not be appropriate for capacity charging.

3.4.1-B: Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?

We believe that LIBOR and LIBID would be appropriate interest rates to use for setting the surplus premium interest rate (SPR) and deficit premium interest rate (DPR) respectively.

Reliability Option Parameters

4.6.1-A: Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?

In line with our overarching concerns, we believe that the process for determining the DSU floor price should be supported by a key set of principles and a clear methodology in order to provide transparency and clarity in how it will change in the future. While we do not object to the proposed floor price of €500/MWh to be applied in today's market, there has been no process used to determine the value. Therefore it is unclear to us how it will change over time as the market changes or what the market drivers for change may be.

4.6.1-B: On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comment on the approach to setting the gas or oil carbon intensity factors?

BGE agrees that the proposed carbon intensity factors are appropriate, assuming the gas/oil index choices will be NBP and Low Sulphur Fuel Oil. These are consistent with figures used by the RAs in the past (i.e. Directed Contracts). To ensure that our underlying assumptions are correct, we request that the RAs confirm in their Decision that this is what they will be in future for gas/oil indices.

4.6.1-C: Do you agree with the approach to setting transport adders set out in section 4.4?

While we agree with the figures presented in the Consultation paper for transportation costs of gas and oil, it is not clear how they will be applied to the costs of gas/oil. For clarity, we request that the RAs specify how transportation costs will be built into the Strike price model. We assume that the costs of gas presented reflect the cost of transporting has from NBP to Moffat (£/therm) and then from Moffat to RoI (€/therm) but we would prefer if the RAs could explicitly outline this in their Strike Price model.

4.6.1-D: Do you agree that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?

BGE is of the view that when determining appropriate stop-loss limits, there should be careful consideration given to balancing the protection of generators from RO risks and the protection of suppliers from an increased hole in the hedge. It is not clear what analysis was carried on this balance when proposing a Billing Period Stop-Loss Limit of 0.5x the Annual Stop-Loss Limit, especially given that the Billing Period has moved from monthly to weekly since the initial proposals were made.

From a market's perspective, we believe that 0.5x the Annual Stop-Loss Limit is too high given that a generator could reach its annual stop-loss limit within two weeks (or potentially two days). In such as case, a generator would no longer be incentivised to provide the reliable capacity that they contracted for. We believe the principles should ensure that generators are incentivised for as long as possible to make themselves available. This would be achieved by applying a multiple of lower than 0.5x the Annual Stop-Loss Limit.

However, from a supplier's perspective, we understand that the lower the stop-loss limit in a given Billing Period, the higher the hole in the hedge will likely be. Therefore we also believe that the stop-loss limit should not be too low to ensure that suppliers are not overly exposed to high hole in the hedge scenarios.

In efforts to strike a balance between the generator and supplier risks outlined above, we believe a suitable Billing Period Stop-Loss Limit would be 0.375x Annual Stop-Loss Limit. This would reflect the billing period being reduced to be in line with the Energy Settlement timetable and ensure that generators will be available over longer periods of time. Although this may increase the hole in the hedge for suppliers in certain Billing Periods, overall it will be reduced over the course of the year.

New Build, Termination Fees and Performance Bonds

5.4.1-A: Do you agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?

BGE is concerned that the approach for setting the New Capacity Investment Rate Threshold is arbitrarily set and is not supported by a clear set criteria or principles. As per our overarching concerns, we believe that the processes used for determining any CRM parameters should be supported by clear principles in order to provide transparency and clarity for managing future changes. BGE has two key issues with the process used for determining this threshold, namely:

1. Removal of key investment costs from the Net CONE

As an initial step, the RAs identify that the costs of the Net CONE (historically known as the BNE) would equate to approximately €619/kW of de-rated capacity. However as part of this, the RAs have assumed that costs such as site procurement and electricity/water connection would not have to be incurred by an investor when building a unit and therefore deem them appropriate to omit from Net CONE calculations. The process to date for calculating the BNE for capacity payments has been to include all associated investment costs to building a unit on a green field site. It is not clear why an assumption is now being made that a new entrant would be on a brown field site and that it would be as part of an existing site/project. There are no signals in the market to indicate that this is to be the case.

We therefore believe that all relevant investment costs (which have been used in BNE calculations to date, including site specific costs and sunk costs) should be included when calculating the Net CONE costs.

2. Using a factor of the Net CONE to identify the investment rate threshold

Given that the first step identified the Net CONE costs to be €619/kW, the RAs then set a 'discount factor' of 50% to approximately align the investment rate threshold with international precedent. We do not believe that this is an appropriate method for setting a key parameter of the CRM as; a) it does not reflect the actual costs related to either building new capacity or retrofitting existing units; b) it does not differentiate between different costs in different jurisdictions (which the RAs refer to in the Consultation around the Existing Capacity Price Cap and Net Going Forward Costs (NGFC)), and c) it does not provide a guiding principle as to what the discount factor may be in future years i.e. is international precedent the guide for the threshold or a discount factor related to the Net CONE calculation for the market.

Given that the RAs are determining a single investment rate threshold for both new and refurbished units, we believe a more suitable approach would be to apply a methodology akin to setting the Strike Price, whereby the minimum value is selected between the costs of building New Capacity and the costs of upgrading an existing unit. In equation form, this would be:

$$Investment\ Rate\ Threshold = min[Cost\ of\ New\ Build, Cost\ of\ Extensive\ Refurbishment]$$

Although we recognise more work would be needed to develop a costing methodology for 'extensive refurbishment', an equation as per the above would ensure that all relevant costs are appropriately captured when determining the investment rate threshold while following a consistent set of principles. To be clear on refurbishment costs, we believe that only those who make significant upgrades (i.e. extensive refurbishments/overhauls) should be entitled to compete for a long-term contract – it should not be available to existing units who make systematic/recurring upgrades in order to maintain their efficiency levels – which is incentivised through the de-rating methodology.

5.4.1-B: Do you think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.

BGE believes that termination fees should progressively rise for New Builds as the Delivery Date approaches and we therefore agree with the proposed schedule outlining when termination fees should increase. Understanding the basis for the threshold, how it acts as an incentive and protects the customer from the risk of speculative bids or poor market development/ practice, we are concerned that the methodology behind setting the termination fee and the level of the connection fee are not appropriate to deliver these collective objectives.

As per our overarching concern with a number of parameters set out in this Consultation, we are concerned that there is not a clear process outlining how the termination fee should be set and how it should change with the market and market dynamics.

We also believe that the proposed first schedule of termination fees (i.e. €10/kW) is too low and **would not** discourage speculative bidders from entering the market, which could in turn risk skewing the capacity market price. Although we recognise that the RAs are trying to minimise barriers to new entry in this approach, we have seen in GB that their original termination fee was too low to prevent speculative bids from entering. As a result, when the market cleared at a low price, the expected return for these units did not materialise and they therefore terminated their contract with minimal risks and costs. This both skewed the market price and added to the security of supply concerns in GB.

For this reason, we believe that it is critical that termination fees must be set significantly higher than €10/kW to deter speculative participation and ensure the integrity of the auction outcome both for market participants and customers who are under-writing the security of supply to be provided through the mechanism. We believe a suitable approach would be to base the termination fee off the cost of procuring replacement capacity closer to the delivery date which could be set by reference to the existing capacity price cap (currently proposed as €38.90/kW). Such a process would be suitable for three reasons. Firstly, it would provide a level of transparency around the process for setting the termination fee in future years. Secondly, it would be set at an appropriate level that strikes a balance between dissuading speculative bidders from entering the market while not over-burdening genuine New Builds with providing high upfront costs. Thirdly, it would ensure that customers are not disproportionately burdened with the cost of filling the gap left by capacity which exits the market.

5.4.1-C: Is it appropriate to place termination fees on capacity which does not meet the definition of New Build, and if so, at what level, including:
a. Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;
b. Unproven DSUs;
c. Any other capacity provider which has not already demonstrated its ability to physically deliver; or even
d. All existing capacity

We recognise that existing units are different to New Builds in the sense that they must post collateral to cover their RO payback risk under the Trading and Settlement Code (TSC). However, this would not cover a unit who is terminated mid-year and who under the current CMC rules would not be liable for any subsequent RO paybacks. We are concerned that an existing unit could use the termination provisions within the CMC as a means of opting out of the CRM. Therefore we believe that an existing unit should be liable for all RO paybacks for a given contract year even if it is terminated from the market during the year. Their obligation to payback could be managed through the TSC where the TSOs could retain the collateral needed and draw down on it as and when difference payments occur. We believe that such an approach would be appropriate for all four options outlined in this question.

5.4.1-D: Should Performance Bonds be required for 100% of termination fees, and should this vary by type of capacity?

BGE believes that Performance Bonds should be required for 100% of termination fees for **new capacity**. As we have explained in our answer above, instead of a termination fee for existing units, a form of penalty should apply if they terminate their contract whereby they are made liable to make difference payments until the end of their originally anticipated contract. Payments can be made from the collateral that existing units must post when they sign up to a RO contract.

Auction Parameters

Net CONE

6.6.1: Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10? If not, explain why.

BGE understands that by moving to I-SEM, there is a need to change some of the fundamental steps to accommodate changes in the market design and that therefore adjustments will have to be made to existing approaches going forward. However, as outlined in more detail below, we are concerned that some of these changes are moving away from the original process in an inconsistent way and we therefore urge the RAs to reconsider their assumptions or provide supporting rationale and evidence where necessary. We discuss our positions/concerns on each element of the Net CONE calculation in more detail below.

Outage rates

To date, the Net CONE (or BNE in historical calculations) has used a forced outage rate of 5.91% which reflects the expected outage rate of that particular unit. Recognising that the capacity market is moving to a de-rated capacity environment for a cluster of units within a given technology class, this involves the calculation of an average forced outage rate for this cluster of units within the technology class with the purpose of providing a de-rating factor for that cluster of units. However, this does not change the forced outage probability of the specific unit that is the Net CONE being used for the purpose of deriving the price caps. We do not believe that using the average forced outage rate for a cluster of units is an appropriate reference point for a very specific unit type. While it would be appropriate for estimating its capacity market revenues (since a de-rating factor will apply to those revenues directly), it is not appropriate to use them when estimating the energy market availability. Therefore we do not believe it is appropriate to change the outage rate of the Net CONE from its current level. The real forced outage probability of the specific unit in this instance is more relevant for calculating Net CONE costs and we therefore believe it should remain at 5.91%.

Impact on RO difference payments

We believe the assumption around the 4-hours of partial ASP events is too arbitrary and should not be applied to the RO payback calculation. While we recognise (but do not agree) that the RAs apply an 8-hour loss of load expectation (LOLE) for setting the capacity requirement in line with the systems' overall security standard, this is already significantly above the level of scarcity events that occur on the system. Assuming an additional 4-hours of partial ASP would also occur is therefore in our view further over-estimating the level of scarcity on the system and in turn the revenues that will be earned by market participants. We therefore believe that the 8-hour Full ASP assumption alone is enough to capture any and all expected RO payback periods.

Name-plate vs de-rated capacity

We agree with the proposal to calculate all costs with respect to the de-rated capacity as opposed to the nameplate capacity. Unlike our concerns related to outage rates, the de-rated capacity value is a true reflection of what the BNE could earn capacity payments on. This would not be inconsistent with applying the original BNE forced outage rate.

Auction Price Cap

6.6.2: Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?

We understand that given the level of surplus capacity in the market today, the RAs wish to set the auction price cap on the lower end of the proposed range (i.e. 1.5x to 2.0x Net CONE). However, this surplus may not exist indefinitely and therefore a higher multiple may be needed to incentivise investment in new capacity. We would like to see a methodology/process introduced as part of this process which clearly outlines how the multiple for setting the auction price cap is set. For example an appropriate approach may be to base the auction price cap off the expected level of surplus capacity on the system. For example, at today's capacity margin levels the appropriate price cap may be 1.5x Net CONE. As the capacity margin becomes tighter, there could be a sliding scale moving from 1.5x to 2.0x Net CONE, where the price cap at zero capacity margin would be 2.0x Net CONE. As this is a consultation on the methodology to derive the specific auction parameters, we believe that these principles and rationale should be set out and determined at this stage to give transparency to the market and clarity to would be investors.

Given the unanticipated energy price swings seen from time to time, we also believe that there should be a level of control put in place to limit the amount of volatility on the price cap when IMR and DS3 values are unexpectedly large. We have seen in other markets (i.e. PJM) that the Gross CONE (i.e. total costs of the CONE having not deducted IMR and Ancillary revenues) is used as a way of controlling such large unexpected energy swings whereby the Gross CONE will be used to set the price cap if the multiple of the Net CONE results in a value less than the Gross CONE. We believe that a similar approach should be used in the Irish market in order to provide stability to the price cap in the event that IMR and DS3 revenues are unexpectedly high.

Existing Capacity Price Cap

6.6.3: Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs (NGFC) at: Max[(Fixed operating costs – gross infra-marginal rent from the energy and ancillary serves markets),0} + Expected Reliability Option difference payments

While the approach for estimating a generator's Net Going Forward Costs (NGFC) seems reasonable at this time, the RAs should share the dissemination of data with parties on a bi-lateral basis to ensure accuracy in their interpretation and analysis.

6.6.4: Do you agree with the proposed process and data inputs to calculate NGFCs as set out in 6.3?

Similar to our response to 6.6.3 above, while the process seems reasonable at this time, we believe the RAs should discuss the data they use and how they interpret the information with generators on a bi-lateral basis to ensure efficiency and accuracy in their analysis.

6.6.5: Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.

Similar to our response on the auction price cap and our overarching concerns, while the value seems appropriate in today's market, the method used to derive it is not supported by any clear principles and it is therefore unclear how it will be set/ changed in the future. Firstly, it is unclear why the existing capacity price cap is calculated as 0.5x Net CONE given the in-depth analysis on the Net Going Forward Costs of generators. By setting the price cap by reference to the Net CONE, it effectively renders the extensive exercise of determining NFGC to be pointless.

In addition to this, there is no correlation between the Net CONE and the NGFC of units and so if one value changes, the other will not necessarily respond in the same way. This creates major uncertainty (and major divergence) for future price caps for existing capacity.

On the basis of the above arguments, we believe that the Existing Capacity Price Cap should be determined solely off the NGFCs of generators.

6.6.6: Do you think that the NFOC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or do you think that the NFOC contain material variable cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap?

Yes, we believe that the costs reported by generators should be used as a proxy for determining the NGFCs for setting the existing capacity price cap. For efficiency and ensuring consistency in their data interpretation and analysis, the RAs should share the dissemination of data with parties on a bi-lateral basis when calculating the NGFC for setting the existing capacity price cap.

6.6.7: Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.

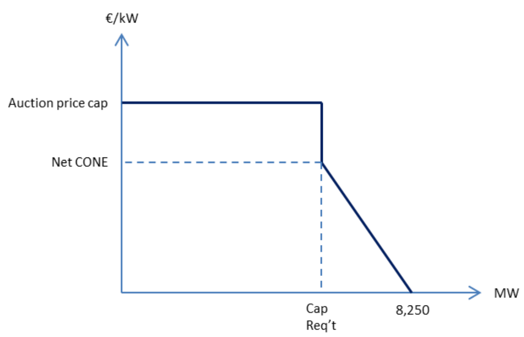
As a first point, we believe that it is up to the capacity market to force generators to find alternative ways to lower their costs. It should not be something for the RAs to force on the basis of international precedent. Notwithstanding the above, the costs incurred by generators in Ireland can differ greatly from their counterparts in the UK. For example, the cost of gas capacity and transportation costs for a generator in Ireland are typically significantly higher than those costs in the UK. Similarly, Operation and Maintenance (O&M) costs, penalties and Government rates are typically all higher in Ireland compared to the UK.

Demand curve parameters

6.6.8: Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?

When designing the demand curve for the capacity market, we believe that a key principle should be to ensure an appropriate balance between the risk of security to the system and the price for over-procuring capacity for the consumer. For the first transitional auction, the RAs need to be cognisant of two key points, i) the capacity requirement will be based off 2020 demand expectations (which is higher than today's levels) and ii) the RAs will allow for the procurement of additional capacity in order to resolve locational constraint issues. In other words, it is clear that the starting point for designing the demand curve is already leaning towards ensuring a high level of system security. To strike an appropriate balance between providing an appropriate level of security of supply while also ensuring value to the customer who will ultimately underpin this investment, we believe it is important that the RAs strongly consider the 'Reduced Expected Unserved Energy (EUE)' curve as a key input into understanding how much extra capacity the market should be willing to over-procure. This in turn should inform the zero-crossing point in our view.

Of the three options proposed, BGE does not agree that any design fully balances the risk of system security and costs of over-procuring capacity. However, we believe a solution that would strike such a balance is akin to Option B whereby instead of an inflection point, the curve would reflect the Reduced EUE as a way of providing value to the customer. On that basis and in the interests of minimising volatility in the interim solution, we would suggest a simple linear reduction from Net CONE to a zero-crossing point at approximately 8,250MW. From a system security perspective, this approach would ensure that there is adequate generation capable of receiving a capacity contract beyond the capacity requirement. From a consumer cost perspective, the value of procuring additional capacity is captured given by showing that the zero-crossing point is in line with the reduced EUE curve. We illustrate our proposal in the Figure 1 below.



6.6.9: Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?

As per our answer to question 6.6.8 above, we believe that the shape of the demand curve for the first transitional auction should extend from Net CONE to a zero-crossing point at approximately 8,250MW. This solution would be akin to Option B but would also realise the costs to the consumer by reflecting the Reduced EUE curve whereby the value to the consumer is effectively zero at 8,250MW.

Locational parameters

6.6.10: If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?

In order to minimise disturbances to the capacity market and to limit to costs of over-procuring capacity, we believe that locational constraints should be defined as a single capacity requirement rather than on a demand curve basis. Designing a demand curve for each jurisdiction requiring localised capacity would potentially increase the amount of capacity being procured in these areas and as a result, would take away from the all-island capacity market and also potentially allow for market manipulation. Therefore BGE agrees with the RAs that the cost/risk of implementing local demand curves outweighs the benefits and instead a minimum capacity requirement should be applied.

Load Following for Secondary Trading

Question: Do you have any comments on the approach to setting the load following parameters set out in the section?

We agree with the approach and principles outlined by the RAs for determining load following factors for secondary trading. To improve liquidity in the secondary capacity market, we believe the load following factors should be developed on the following basis:

- Factors are determined ex-ante year ahead and open for consultation alongside all other parameters.
- Factors can be adjusted on a monthly basis to reflect changes to demand forecasts. We believe monthly changes provide an appropriate balance between unexpected large changes (if the granularity is longer than one month) and being administratively burdensome (if the granularity is less than one month).
- As per the above, we believe that the factors should be shaped on a monthly basis (as outlined in the Consultation). However we believe that days of the month should be shaped on a weekday/weekend basis (using a daily average shape for each period).
- Forecast elements should be built into the factor, namely a forecast for economic parameters that influence demand and a forecasted season average used to adjust for weather parameters.

Question: Do you think that capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage?

Given the difficulty of predicting demand and weather patterns, particularly for over one year in advance, we believe that secondary trading should be limited to one year ahead. We believe this this solution still provides adequate liquidity to the secondary trading market while also providing a clear and transparent process.