Integrated Single Electricity Market (I-SEM)

Capacity Remuneration Mechanism Parameters
Consultation Paper SEM-16-073

A Submission by EirGrid and SONI

21st December 2016

EIRGRID SONI

Contents

1 EXECUTIVE SUMMARY

EirGrid and SONI welcome the SEM Committee's consultation on the I-SEM Capacity Market Parameters. The values at which these parameters are set are an important component of the overall Capacity Market design.

Regarding the basis for the reserve scarcity price curve, we favour Option 1 as it avoids at step change in the price which likely to result in reduced volatility in the administered scarcity price.

We would support the SEM Committee's view that Option 3 (A broader based Supplier Charge, with Supplier charges focused on a broader day-time period from 7am to 11pm in all quarters) is the most appropriate charging base at this time and also that this be kept under review to ensure that the most efficient signals are being provided to the market.

On the subject of interest rates, we set out the approach as we understand it as described in the draft of the Trading and Settlement Code currently under consultation.

The Capacity Market strike price is critical value that sets the strength of the performance incentives on Generator Units and the level of protection from high prices provided to Supplier Units. As System Operators, our main interest in this regard relates to ensuring strong (but not excessive) performance standards on Generator Units. We support the setting of the DSU component of the strike price formula to €500/MWh as it strikes a balance between retaining performance incentives for generator units and incentives for supplier units to actively manage trade in the ex-ante markets. The proposals in relation to the dynamic components of the strike price appear reasonable in that the Directed Contract process is a well established process and the sources used in this process have been subject to considerable scrutiny for a number of years by both the RAs and the industry.

Regarding the fuel price indices to be used, for which the System Operators are tasked with proposing to the RAs, due to the proprietary nature of this type of information, their presence in the formula may mean that it is not possible to publish the strike price. As this would have fairly significant implications for market participants' ability to evaluate their exposure to the Capacity Market (especially market participants that do not use the indices in question), we propose a possible mitigation which uses the formula as described but would see the RAs fix the value for the capacity year for each auction based on the System Operators proposals. Due to the relative values of the various components of the strike price formula, this is likely to yield the same strike price value. The key difference is that the actual value of the strike price could be included in the Capacity Auction Information Pack for each auction.

It is important that the performance incentives and fees relating to the delivery of new capacity strike a balance of ensuring that new capacity is delivered on time while not acting as a barrier to entry.

Regarding the shape of the demand curve for the first transitional auction we believe that Option A is appropriate. We agree that a more gently sloped demand curve will help to reduce price volatility for the transitional auctions. We also agree that a zero crossing point of 15-20%

in excess of the Capacity Requirement is more appropriate for a small system with limited interconnection.

In relation to secondary trading, the governance for setting the FPFCQSF is set out in the CMC and we suggest that no further decisions are required in this regard. As the products for secondary trading have yet to be defined and may be auctioned more than once, it is important that the setting of FPFCQSF uses the most up-to-date forecast information.

Finally, EirGrid and SONI would like to reaffirm our commitment to working with both the industry and the Regulatory Authorities (RAs) in the development of effective and appropriate I-SEM arrangements.

2 INTRODUCTION

2.1 EIRGRID AND SONI

EirGrid holds licences as independent electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale trading system in Ireland, and is the owner of the System Operator Northern Ireland (SONI Ltd), the licensed TSO and MO in Northern Ireland. The Single Electricity Market Operator (SEMO) is part of the EirGrid Group, and operates the Single Electricity Market on the island of Ireland.

Both EirGrid, and its subsidiary SONI, have been certified by the European Commission as independent TSOs, and are licenced as the transmission system and market operators, for Ireland and Northern Ireland respectively. EirGrid also owns and operates the East West Interconnector, while SONI acts as Interconnector Administrator for both of the interconnectors that connect the island of Ireland and GB.

EirGrid and SONI, both as TSOs and MOs, are committed to delivering high quality services to all customers, including generators, suppliers and consumers across the high voltage electricity system and via the efficient operation of the wholesale power market. EirGrid and SONI therefore have a keen interest in ensuring that the market design is workable, will facilitate security of supply and compliance with the duties mandated to us and will provide the optimum outcome for customers.

EirGrid and SONI have duties under licence to advise the CER and UR respectively on matters relating to the current and expected future reliability of the electricity supply. We have also been allocated responsibility for administering the Capacity Market Code through recent modifications to our TSO licences. This response is on behalf of EirGrid and SONI in their roles as TSOs and MO for Ireland and Northern Ireland, including as operators of the Capacity Market.

3 EIRGRID AND SONI VIEWS ON THE CONSULTATION TOPICS

In the following section, EirGrid and SONI provide their comments on the topics discussed in the consultation paper and put forward its views on the consultation paper proposals and questions.

3.1 ADMINISTRATIVE SCARCITY PRICING PARAMETERS

Q: The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1, Option 2 or some intermediate option for the shape ans slope of the ASP function, and why?

In trying to follow the notional loss of load probability (LOLP) curve more closely, option two introduces a large step change in the price where the short term reserve falls below the requirement; however, it is important to bear in mind that this notional LOLP curve is a construct based on all available capacity and does not necessarily reflect the actual loss of load probability (and associated cost) that would be present on a particular day.

On the other hand, option one in not trying to follow the notional LOLP curve by adopting a straight-line avoids the step change present in option two which likely to result in reduced volatility in the administered scarcity price. On this basis, we would favour option 1.

3.2 COST RECOVERY AND CHARGING

Q: Which of Options 1 to 3 do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you choose ad why?

In order to promote efficient responses from the market, it is important to concentrate the recovery of the cost around the times that contribute most to those costs. In this regard, periods of higher LOLP tend to require higher levels of capacity to maintain the security standard and they tend to drive the costs of capacity to greater extent than periods of lower LOLP. On this basis, it makes sense to focus cost recovery around times of highest LOLP as this is likely to promote reductions in demand in these periods and thus reductions in the LOLP and in the need for greater levels of capacity to satisfy the security standard. Nevertheless, based on the analysis set out in the consultation document, higher demand (and LOLPs) over the winter quarters and over the peak tend to be driven primarily by residential customers. As these customers are not yet adequately equipped to respond to these market signals (e.g. through the presence of time-of-use metering, tariffs, etc.), it may not be possible at this stage for these customers to respond and thus they would bear a disproportionate cost that they may not yet be at a stage to manage.

In addition to considerations of market efficiency above, it is also important to highlight that the Supplier Capacity Charge Price, at which the charging base will be charged per MWh of consumption in order to recover the cost of capacity payments, may also be impacted disproportionately by the proposed options. As this price will be based on a forecast of the charging base, the process to setting the price will need to take in consideration the degree of forecast error in the demand forecast used. In order to ensure there is sufficient cash flow to fund the capacity market, it may be necessary to reflect this forecast error in the price. While this forecast error would tend to be relatively low in relation all demand, it is likely that the error would increase the smaller the subset of demand considered.

For example, if we consider a demand forecast error that is driven solely by an error in winter peak hours of 5%, based on the figures set out in Table 1 of the consultation paper, this would represent a forecast error of 45%, 25% and 7% in relation to charging base options 1, 2 and 3 respectively. While all errors are not driven by the peak and ultimately this would subject to a more detailed calculation to determine any proposed values, this calculation serves to illustrate the potential for greater forecast error against a smaller charging base and the potential for higher prices as a result to account for these forecast errors.

Finally, as the analysis set out in the consultation indicates, the loss of load probability tends to be driven primarily by relatively well established patterns of consumption (i.e. day vs. night). Nonetheless, the impact of variable renewables on the distribution of LOLP over the year is increasing and, as the paper concludes, it is difficult to identify a clear pattern beyond the day night pattern that would justify opting for a more concentrated charging base.

On the basis of the above factors, we would support the SEM Committee's view that Option 3 is the most appropriate charging base at this time and also that this be kept under review to ensure that the most efficient signals are being provided to the market.

Q: 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 would like to highlight that the terms set out in the consultation, which may have formed part of the RAs initial considerations, do not feature in the final draft of the Trading and Settlement Code, which is currently the subject of a public consultation. The application of interest in relation to the socialisation fund are dealt with in the TSC in the following paragraphs:

- G.1.6.10, which states that all capacity and trading payments and charges co-mingle on SEM Clearing Accounts and SEM Clearing Deposit Accounts (while being deemed to be segregated);
- G.1.4.5, which states that any interest in these accounts accrues and belongs to the Market Operator, which is then considered under price control processes (through proposals of Market Operator charges). These processes are outside the scope of the Trading and Settlement Code.

We suggest that any decision in relation to this matter is undertaken by the RAs as part of the review of the Market Operator and TSO revenue review process.

3.3 RELIABILITY OPTION PARAMETERS

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

The Capacity Market strike price is critical value that sets the strength of the performance incentives on Generator Units and the level of protection from high prices provided to Supplier Units. The greater the strike price, the lesser the performance incentives on Generator Units, the lesser the protection from high energy prices provided to Supplier Units. The lesser the strike price, the lesser the risk on Generator Units, the lesser the incentive on Supplier Units to actively trade in the ex-ante market timeframe.

As System Operators, our main interest in this regard relates to ensuring strong (but not excessive) performance standards on Generator Units but also to ensure that incentives remain for Supplier Units to actively trade their customers' demand in the day-ahead and intraday timeframes to ensure that the system does not face excessive imbalance quantities close to the real time operation of the system. On this basis, the proposed value would appear to strike a balance between these objectives; however, we would suggest that this value is kept under review in particular in relation to the liquidity of hedging arrangements and the ability of suppliers to manage their risk up to the value of €500/MWh.

Q: On the assumption that the gas index will be a reference price related to gas obtained from the GB systems, do you agree with the carbon intensity factor? Do you have any other comments on the approach to setting the gas or oil carbon intensity factors? Do you agree with the approach to setting transport adders set out in section 4.4?

The RAs have set out in their third Capacity Market decision that the System Operators shall propose and the RAs shall approve the appropriate fuel indices for use in the strike price formula.

We agree with the RAs proposals to adopt the indices similar to those used in the Directed Contracts process as the source of fuel prices for the Capacity Market strike price calculation. This process has been running since the beginning of the SEM and benefitted from feedback from industry on the appropriate indices to reflect the cost of the various fuels in the I-SEM. On this basis, we agree broadly with the values set out in the consultation for the carbon intensity of gas and heavy fuel oil and agree also that the final values be decided alongside the decision in relation to the fuel price indices.

Regarding the proposals in relation transport adders, again we agree that values used in the Directed Contracts process should be used and that the higher of the values for transport to Ireland and Northern Ireland be used.

In relation to the choice of fuel indices, it has come to our attention that in order to give effect to the decision, the System Operator will need to propose and source price indices that are likely to be proprietary in nature (in particular in relation to Heavy Fuel Oil, where we are not aware of any suitably reliable source that is publically available). This is likely to prevent the System Operators from publishing the strike price.

In this instance, all participants will only be able to calculate the value of the strike price by obtaining access to these proprietary data sources directly. While the cost of obtaining access to these data relative to the cost of administering the capacity market are relatively modest, if all participants need to source the data, the cost to the market as a whole may become significant. In addition, as these commodity prices will only be available for near term, it is will not be possible for generators or suppliers to calculate their exposure to the capacity market and to hedge this until this index information becomes available. This is likely to impact on forwards liquidity and should be considered in any further developments in this area. While we continue to consider ways of mitigating this impact, it may be unavoidable if the current monthly calculation is required.

One possible approach to mitigating this impact would be to use the strike price formula as set out in the third Capacity Market decision to calculate the strike price and then fix it on an annual basis prior to the publishing of the Capacity Auction Information Pack. Currently, the proposed DSU floor price of €500/MWh is significantly higher than the value of the dynamic components of the strike price formula e.g. the price of HFO would have to more than double before the cost of the 15% efficient HFO unit even begins to approach this level. As the price could be calculated ex ante, it could employ publically available data sources that best represent those indices set out in the formula at the time of calculation. Adopting this approach would ensure that the strike price can be published prior to each auction (including for T-4 auctions) and it would be is clear to all the risks / protection that are provided by the Capacity Market.

Q: Do you 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)?

It is important that the correct reliability signals are provided to participants in the Capacity Market and setting the Billing Period Stop-Loss Limit to 0.5 times the Annual Stop-Loss Limit would appear to be a reasonable trade-off between the competing incentives.

3.4 NEW BUILD, TERMINATION AND PERFORMANCE BONDS

Q: 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.

The full termination fee should apply before the start of the Capacity Year as this would better reflect (and offset) the costs associated with the non-deliver of this capacity. This is especially the case given that the Capacity Year starts in a period that demand is high.

Q: Do you think it is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level?

The position in the Capacity Market Code reflects the decisions as at the completion of CRM3. The Capacity Market Code differentiates between capacity that was commissioned as at the time of Qualification (Existing Capacity) and capacity that was not commissioned (New Capacity). New Build as described in the CRM consultation is taken to be any New Capacity in the Capacity Market Code. New Build may, or may not, be eligible for award of capacity for more than one year, but this is based on its costs, not whether it is New Capacity. The Capacity Market Code requires all New Capacity to put up Performance Security as security against the project failing to commission within the time limits specified in the Capacity Market Code. The termination fee applied when capacity is terminated is funded by the Performance Security.

There is no requirement under the Capacity Market Code for Existing Capacity to post Performance Security or to pay a termination fee. The capacity is in existence so the risks are less. Further, the Capacity Market Code does not allow voluntary de-registration of capacity that has been awarded capacity. If Existing Capacity cannot deliver on its obligations then its options are to modify its position via secondary trade or to accept exposure to difference charges until stop loss limits remove its exposure.

Q: Do you think performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?

In order to ensure that the termination fee is recoverable, it is essential that the performance security should cover 100% of the termination fee for each unit. This is the position reflected in the draft Capacity Market Code.

3.5 AUCTION PARAMETERS

Q: Do you agree with the proposed adjustments to the BNE calculation approach? If not, explain why.

It is stated that the TSOs' proposed I-SEM CRM de-rating factor for the reference BNE plant is 95%. It needs to be highlighted that this value is taken from the indicative results of the de-rating factor analysis for the purpose of that consultation document and should not be considered to be the TSOs proposed value for setting the outage rate for the BNE reference plant. It is unclear if the intention is to update this value for each auction.

It is agreed that adjustments to the BNE calculation to account for de-rated capacity, ASP and expected difference payments would better reflect the I-SEM trading arrangements.

Q: Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs (NGFC)?

As stated in the Executive Summary of CRM Decision 3, the existing unit will apply to the CRM Delivery Body for an exemption from the Price-taker Offer Cap, but that it will be the role of the

Regulatory Authorities to review this application and make a recommendation to the SEM Committee.

Q: 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?

If we consider an all-island capacity requirement of 7500MW, 10% beyond the capacity requirement represents an additional 750MW de-rated capacity, which represents approx. two 400MW CCGTs. In GB, for example, 10% of the capacity requirement of approx. 50,000MW represents approx. 5000MW of de-rated capacity, which equates to fourteen 400MW CCGTs. Needless to say, the additional reliability from fourteen units far exceeds the additional reliability from two units. In general, the additional reliability from capacity beyond the capacity requirement decreases as the size of the system decreases. This is captured to an extent in the marginal de-rating process; however, this process does not capture the need to ensure that the capacity is sufficiently uniformly distributed to avoid transmission constraints. This is particularly the case during outage season where parts of the network are switched out to facilitate capital works and maintenance on both generation and transmission plant.

If we were to represent current customers willingness to pay for reliability through the current Capacity Payment Mechanism on the same axes as being presented in the consultation (and focus on the area around the capacity requirement, which is set out in the consultation at approx. 7500MW), we would see the demand curve sloping from the a price of 1.5 times Net CONE (€116.72/kW) at two thirds of the capacity requirement (5,000MW) to Net CONE (€77.81/kW) at the capacity requirement (7500MW), gradually downwards to a price of two thirds of Net CONE (€51.87/kW) where the capacity reaches 150% of the capacity requirement (11,250MW). All three of the above points on the curve yield the same overall cost reflecting the fixed nature of the Annual Capacity Payment Sum (ACPS). In other words, the ACPS is set based on the capacity requirement times Net CONE; however, it is paid out based on eligible availability which currently exceeds the capacity requirement, which implies a lower effect capacity price. The slope of this demand curve is significantly shallower than the proposed options i.e. at 9000MW, the price would be €64.84/kW instead of the zero under all the options proposed. As such, all of the options represent a large increase in the elasticity of the demand relative to today’s arrangements.

Based on the above, considering the small size of our system, the limited levels of interconnection and the relatively large size of generators relative to the size of the system, we believe that a demand curve with a zero crossing point at 20% more accurately reflects the value of additional capacity on a smaller system. Furthermore, we believe that Option A is the most appropriate curve for the first transitional auction as it represents a smoother transition from the current CPM to the proposed Capacity Market.

It is important to ensure that the demand curve that ultimately features in the auction is consistent with any Local Capacity Constraints that are also being included. The situation may arise whereby the presence of shallower demand curve results in greater levels of capacity being scheduled in the unconstrained auction. If further capacity was required to satisfy Local Capacity Constraints, it may result in more capacity clearing than was originally envisaged. On the other hand, if a steeper demand curve was chosen and the auction scheduled satisfied the Local Capacity Constraints, it may be the case that insufficient capacity is cleared to provide for a system that is otherwise constrained. Any choice in this regard would represent a trade off between risks associated with less capacity clearing and the costs associated with greater levels of capacity.

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

As we are making significant changes to the SEM market arrangements, we would urge the RAs to adopt a cautious approach in the initial years to ensure that any exit of capacity from the market occurs in an orderly fashion and that we always have sufficient capacity to ensure that we can continue to transform the power system to facilitate new demand and generation customers and deliver against policy objectives in relation to renewables, reliability and the internal market in electricity.

While the transitional auctions may benefit from a demand curve that reflects a smoother transition from the current arrangements to the new Capacity Market, the more information that is available on the likely evolution of the shape of the demand curves the better as this will enable capacity providers to assess the future demand for capacity e.g. it may be worth opting for option A for the first T-1 auction but adopting a curve closer to option C for the following year and so on. Again, the interaction between the demand curve and the Local Capacity Constraints is important here.

Q: 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?

At this stage, we believe that Local Capacity Constraints should be based on minimum requirements as opposed to local demand curves and that the elasticity of demand should be reflected in the combined demand curve for Ireland and Northern Ireland. This does not preclude the introduction of such local demand curves at a later date if deemed appropriate; however, for the transitional period, we believe that one demand curve is sufficient.

3.6 LOAD FOLLOWING FOR SECONDARY TRADING

Q: Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?

It is stated in 7.1.3 that the Product Forecast Capacity Quantity Scaling Factor (FPFCQSF) has replaced the profiling factor for the load-following capacity obligation parameter. However, the FPFCQSF is a parameter only associated with a product in secondary trade. It may be some conservative estimate of the profiling factor but it is not intended to replace any parameter required under the TSC. For a given interval in time (e.g. 3 AM) there could a range of products applied with different durations. All of these products will have different values of FPFCSQSF representing some conservative estimate of the load following factors applicable over the hours those products apply to.

We are concerned that the proposed approach would artificially constrain secondary trading in the Capacity Market. The granularity of the Product Forecast Capacity Quantity Scaling Factor (FPFCQSF) is linked to the granularity of the product being traded e.g. for a weekly product, this value may be based on the latest forecast of the peak for that period. As such, it should not in our view be rigidly defined to correspond to a particular period or time of the year as the granularity, timing and frequency of secondary trading products has yet to be defined. It would be important to allow the values to be recalculated before each auction based on the most recent forecasts. For example, for a week in July, when it is first secondary traded, say in Jan, the FPFCQSF would be based on the peak demand for the week in July as forecast in Jan. When the product is traded again in June, the forecast from June would be used. In this way, the likelihood allowing Capacity Market Units from trading above their de-rated capacity is minimised.

It is already stated in the draft Capacity Market Code that the TSOs will derive the factor for a product, and we believe that calculation of such a value should come under the governance of the Capacity Market Codes. In our view, no other explicit governance for this methodology is needed.

Q: 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?

See above.