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RE: Response to Capacity Remuneration Mechanism Parameters Consultation Paper (SEM-16-073)

Dear Mary, Thomas,

Tynagh Energy Limited (TEL) welcomes the opportunity to respond to this Capacity Remuneration Mechanism Parameters Consultation Paper (SEM-16-073).

This response paper has been separated into two sections: Section A sets out TEL's concerns on a number of topics that have been recently consulted upon and Section B contains TEL's responses to the specific questions raised in the Consultation Paper.

Section A

TEL would like to take this opportunity to raise our concerns on two issues that have risen from recent CRM Decisions.

CRM Exposure

TEL believe that plants who have done everything in their reasonable control and are supplying DS3 services should not be penalised for incorrect forecasts on the part of the TSO. Currently a plant will be exposed to an Administrative Scarcity Price (ASP) where it has bid in Short Run Marginal Cost (SRMC) and is providing a DS3 service for system security. They could have done everything within their reasonable control to be generating, but if the event has not been foreseen by the TSO or other market participants the plant would be exposed. TEL do not believe that all plants who are simply available should be removed from an obligation. This could remove the incentive to provide greater flexibility into the market, nonetheless any plants that provides a DS3 service are providing flexibility and should not be exposed.

Grid Code Three Year Notice Period

TEL would like to take this opportunity to raise our concerns over the Grid Code Requirement for a three year termination notice of plant closure. In the CRM Locational Issues paper (SEM-16-052) the SEM Committee (SEMC) requested feedback on "*whether it is appropriate to provide assurances that generators which do not win a Reliability Option (RO) in the transitional auctions be released from their obligations to give three years notice in accordance with the Grid Code*". It was stated in the emerging thinking workshop that the "*SEMC will have appropriate regards to statutory duties and where no local security of supply issues, request for derogation would be sympathetically received but it is not purely a CRM issue*". However, the CRM Locational Issues Decision Paper (SEM-16-081) states that "*for the moment, the SEM*

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Committee does not intend to at this stage, to initiate any changes to the Grid Codes in regard to this provision". The decisions taken by the SEM Committee now require a modification to the Grid Code and it should not be left to the market participants to raise this modification. TEL believe the SEM Committee should request the TSO to take this forward as soon as possible as if a participant does not receive a RO and is therefore unable to recover their fixed costs, they should not be mandated to a three year notice period.

<u>Section B</u>

Outline of issue and proposed solution

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?

As per CRM Decision 2 (SEM-16-022), TEL believes that the Quantity of Short Term Operating Reserve (qSTR) should be defined to include primary, secondary and tertiary operating reserve plus **the ramping within one hour**. All of the available ramping within one hour should be used instead of just the replacement reserve, as units are receiving a payment on all of their ramping capacity not just the stated replacement reserve in the System Operating Constraints document.

The proposed options are a significant change from the previously outlined simple piece-wise linear ASP function as shown in Figure 2 of the consultation paper. The detailed analysis used to create the LOLP in Figure 3 is not presented in the consultation paper. Therefore, until the analysis is published TEL do not agree with a move away from the outlined curve in Figure 2. If no analysis will be provided and the SEMC wish to proceed with either option 1 or option 2, TEL would favour option 1 for the transitional auctions until all participants (including the TSO) has gained experience in I-SEM scheduling and dispatching.

3.4.1 (A) Which of 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 chose and why?

N/A.

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?

N/A.

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

N/A.

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 comments on the approach to setting the gas or oil carbon intensity factors?

N/A.

4.6.1 (C) Do you agree with the approach to setting transport adders set out in section4.4?

N/A.

4.6.1 (D) 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)?

TEL felt the decision to set the Billing Period Stop-Loss Limit at 0.5x the annual stop loss limit (CRM Decision 2 (SEM-16-022)) was reasonable. However, it was assumed at the time that the billing period coincided with the capacity billing period i.e. monthly. As per our response to the CRM Second Consultation (SEM-15-014), TEL believed "*that a stop loss limit shouldn't be so low that it limits the incentive on capacity providers to make capacity available at times of system stress. However, the penalty should not be so prohibitive that a plant is forced to close due to a single outage*". The new proposal as set out in this consultation now means that a plant could lose 1.5x its annual fee due to one ASP event lasting two hours (crossing two billing periods). Such a scenario does not benefit suppliers, generators or the RAs.

TEL agree with CRM Decision 2 (SEM-16-022) that in order "*to perform after the second billing period (billing period B+1) the limit could reduce to half its previous value and if the limit again binds then for billing period B+2 it could halve again*". TEL believe the halving of remaining stop loss limits and the alignment of the billing period to the capacity billing period (i.e. monthly) should be implemented.

If the stop loss limit must be aligned to the energy billing period, TEL recommend the billing stop-loss limit to be 0.25x the annual stop loss limit.

5.4.1 (A) 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?

N/A.

5.4.1 (B) 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.

TEL agree with the indicative schedule of termination fees however we have issues with the favoured values.

5.4.1 (C) It is appropriate to place termination fees on capacity that does 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

TEL agree with placing a termination fee on all capacity providers. However, the termination fees for existing generators must be taken into account with the Existing Capacity Price Cap (ECPC). The current indicative ECPC is €38.90/kW per annum. The proposed termination fee of €10-€30/kW per annum is far too excessive for the limited associated risk as the exposure to the consumer is reduced because the capacity can be re-auctioned in the T-1 Auction.

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

TEL believe the Performance Bond should be linked to the revenue that participant will receive from the auction instead of the termination fee. It would be perverse for the participant to post credit for more than they would receive in the year. TEL suggest that the Performance Bond should be 50% of the annual fee.

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.

TEL believe the forced outages for energy and ancillary services should not be combined into a single value.

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

N/A.

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 service markets),0] + Expected Reliability Option difference payments

TEL fundamentally agree with this methodology. However, TEL would emphasise that plants that are behind a constraint will do better under I-SEM than under SEM. As such IMR estimations for these plant need to be based on I-SEM forecast rather than SEM historicals. Equally those plant that are likely to be constrained on are far less likely to be exposed at a time of an ASP than plant that are not behind a constraint.

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

No, as the data inputs do not take into account all of the NGFCs. The SEMC needs to examine why costs are higher in Ireland compared to other countries. We have in the past outlined that significant annual fixed costs for an Irish CCGT would approximately be:

Annual Gas Capacity (assuming 15 million KWh Entry and Exit)	€12 Million
TUoS Charges	€3.5 Million
Insurance	€2 Million
Fixed O&M	€5 Million
Rates	€2 Million

These costs are far higher than the costs that units in other countries are exposed to. The regulators have set these extremely high Gas Transportation and System Charges and need to consider these in this consultation.

That is €24.5 million in fixed costs before looking at other significant non fuel related costs that might vary with CCGT's in Ireland (e.g. staffing).

Perhaps just as important is the size of units and generation sites in Ireland, in GB and in the US, many sites host a number of units. In some GB and US sites, there may be four to eight units. In Ireland there is usually one or in some cases two. This is hugely significant in terms of costs per kw.

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.

No, this seems to be based on the assumption that fixed costs are fundamentally the same as non-fuel related costs – variable O&M in the generator reporting. This is not the case as Annual Gas Transportation Capacity is seen as a fuel related cost whereas it is definitely a fixed cost.

As the rules and regulation have emerged for I-SEM, it is clear that there has been a significant emphasis placed on reducing opportunities for generators to meet their fixed costs. As shown above (answer to 6.6.4), CCGT's in Ireland will have fixed costs in the region of €20-25 Million. This will not be met by 0.5x Net Cone. The RA's have proposed that plants will be limited in only bidding a very restricted (not including variable O&M) SRMC into the Balancing Market. As all markets will be bid in the expectation of the Balancing Market outturn price, then SRMC is likely to be the dominant price in the market. While very efficient baseload plant will still earn IMR, mid merit plant will not. This may see plants that have already been successful in the CRM auction forced to leave the market early. TEL would strongly suggest that the RA's at least in the short term keep the ECPC at a level that allows controlled exit in the Irish market.

TEL would suggest that the Existing Capacity Price Cap should be set at a minimum of 0.75 x Net CONE.

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?*

TEL agree with the RA's that NFOC are not a good approximation of fixed costs. As detailed above in answers 6.6.4 and 6.6.5, TEL believe that NFOC does not include Annual fixed costs, and as such is likely to considerably underestimate the fixed cost of running a plant in Ireland. Of the significant costs, (i) Annual Gas Capacity should be covered by capacity payments, otherwise more plants will be forced to bid in daily gas capacity therefore increasing the SMP significantly; (ii) TUoS charges are more likely to increase for plants with more wind on the system; (iii) Rates and Insurance are outside a generators control and are unlikely to change with I-SEM (though we suspect that Irish rates are higher than GB and US); and lastly (iv) Operating and Maintenance contracts.

O&M contracts in Ireland are based on European model staffing levels. We believe that the costs for these will be reasonably consistent across Europe per similar plant. However, the issue is that plants in Ireland are on smaller sites with less MW than standard international systems

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 explained above in the answers to the previous three questions, costs in Ireland are largely outside of a generators control. The high costs that networks charge for Gas Transportation and for System Charges are set by the RAs and are beyond the generators control. As stated above the only one of the significant costs that generators could potentially reduce is O&M contracts. These contracts are standard across Europe and are likely to be multiyear in length and will not be changed easily.

TEL have performed an analysis on the transportation costs for a plant in Ireland and three plants in GB (Great Yarmouth, Sutton Bridge and Langage Power Station). The total TO gas transportation capacity costs and SO commodity charge for a GB plant ranges from 1.02868 p/therm (Great Yarmouth) to 2.29182 p/therm (Langage power station). The total for similar charges to an Irish plant is 7.12933 p/therm. This analysis shows a power plant in Ireland has somewhere in the range of three to seven times the costs for gas transportation capacity costs compared to a GB plant.

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?

TEL believe that option A should be implemented for the transitional auctions. However, once market participants and the Capacity Market Operator have gained experience in the auction format a consultation on the parameters of option C should be performed.

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

See answer for question 6.6.8.

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?

TEL believes that more consultation is required on this as there are outstanding questions that need to be addressed i.e. how will the lumpiness issue be addressed in the locational requirements zones? The lack of a local demand curve could potentially provide units with market power (in the locational zone) with greater market power through the flexibility/inflexibility of their bids.

7.2.1 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?

N/A.

7.2.2 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?

TEL do not agree that capacity providers should be able to trade against their load following margin in calendar year +2.

Should you have any queries, please do not hesitate to contact me.

Yours sincerely,

Paraic Higgins
I-SEM Analyst