TYNAGH ENERGY
L I M I T E D

Thomas Quinn
Commission for Energy Regulation
The Exchange
Belgard Square North
Tallaght
Dublin 24

Natalie Dowey
Utility Regulator
Queens House
14 Queens Street
Belfast
BT1 6ED

Ref: TEL/CJD/16/019

8th February 2016

RE: Response to Capacity Remuneration Mechanism Detailed Design Second Consultation

Dear Natalie, Thomas,

Tynagh Energy Limited (TEL) welcomes the opportunity to respond to this Capacity Remuneration Mechanism Detailed Design Second Consultation (SEM-15-014).

The response has been separated into two sections: Section A describes TEL's views on the CRM 2 Consultation Paper and Section B answers the questions raised in the Consultation.

<u>Section A</u>

1. Cross Border Participation

TEL believe that the interconnector and provider led approaches are the only potential viable options. However, the interconnector led approach has a fundamental problem in that there are restrictions on the interconnector owners taking an interest in generation and this limits the ability of an interconnector to contract up-stream generators to cover risks that are outside its control. Considering one of the fundamentals of the CRM is to ensure security of supply for the consumer, this makes the interconnector led approach undesirable.

Whereas, the Provider Led approach should ensure consumers receive the benefits of interconnected capacity while providing system security and enhancing competition in the CRM. Furthermore, the Provider Led approach is in line with the European Commission in terms of removing discrimination against foreign sources of reliability. TEL believes the Provider Led approach would be the option that would contribute most to security of supply.

The de-rating methodology for the non I-SEM participants needs to be further discussed and analysed. In the document three factors are highlighted for de-rating non I-SEM participants: technology de-rating factor, non I-SEM losses factor and an interconnector constraint. The record of involvement of non-local participants in other CRMs must be taken into account, not just for the double payment but also in terms of security of supply issues. Redpoint (2013)[1] highlights that "France (along with Ireland) is the market that shows the greatest extent of correlation with GB at times of system stress". This correlation will see a significant reduction of capacity provided to Ireland at times of greatest need. In order to reduce security of supply

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

concerns TEL would recommend that GB capacity market participants should only be allowed bid in their excess (not already contracted) capacity and that this excess capacity should be de-rated.

For the interconnector constraint/de-rating, TEL agrees with point 2.2.3 that “at least initially, historic interconnector flows may not be a good indicator of those in the future”.
The scarcity event referred to repeatedly in the workshops is an extremely cold day. The trouble is that an extremely cold day in Ireland will also probably be a cold day in GB and France. This will see a need for participants in GB to provide capacity in their market. It is unlikely that historic interconnector flows can be used to model the GB response in this scenario, as the current ex post market in Ireland leads to inefficient IC flows that should be corrected by I-SEM. Therefore there is a need for an ex-ante approach performing the fundamental modelling of the European Power system under a number of scenarios. TEL would recommend further discussion on the scenarios to be applied before any modelling is performed.

As highlighted in the consultation paper, the provider led approach is one of the strongest approaches in terms of competition, security of supply and equity. However, as outlined above, there needs to be a realistic de-rating applied to any cross border plant.

2. Secondary Trading

TEL consider that a mandatory centralised secondary trading market place is essential to reduce the RO exposure when a plant is on temporary or forced outage. The introduction of a mandatory market place will reduce the possibility of market power abuse occurring by forcing portfolio providers to trade rather than internally transfer RO’s between their assets. This increase in transparency should result in lower costs to consumers and improved risk hedging for all market participants.

However, we have concerns over the level of liquidity in the market with the current suggested de-ratings. For example, a day with moderate system demand (4,000 MW) and reasonably high wind generation (2,500 MW) may require only 1,500 MW of thermal generation. Assuming the majority of this 1,500 MW consists of generation from coal or peat units the current GB de-rating factors[2] would not result in enough spare capacity (Nameplate capacity – de-rated capacity) from scheduled units (coal and peat) to cover the RO capacity of most CCGT plants in the I-SEM. In this scenario, if a third of that wind is 1 hour late, there could be a scarcity event and any generators that are on an outage will have been unable to cover their position. These generators may be exposed to significant penalties. A possible solution to the probable lack of liquidity in the secondary market place would be to have lower de-rating factors than that which are typically used in GB.

3. Detailed Reliability Option Design

TEL agree 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. Therefore TEL would suggest a monthly stop loss of 150% of the monthly capacity revenue. This value should be regularly reviewed either annually or biennially. But if the reason that a plant fails to deliver on its RO obligation is due to an inappropriate TSO instruction, then the TSO should be liable for the penalty.

TEL agrees with a number of RO design features highlighted in the consultation such as: 1. Indexation, 2. commissioning phase project enforcement, and 3., modelling of the impact of a shortage of capacity caused by non-delivery by a new project needs to be performed”.

---

[2] http://www.raeng.org.uk/publications/reports/gb-electricity-capacity-margin

4. Administered Scarcity Pricing

TEL agrees with point 5.3.10 that administered scarcity pricing should not apply when there is sufficient capacity and it cannot start/ramp-up fast enough leading to a short term reduction in operating reserve. However, the RAs stated in SEM-15-103 and at the workshop in Dundalk (20/01/2016) that the ASP will apply. Further clarification is required from the RAs on the application of ASP when sufficient capacity is available but inefficient TSO scheduling results in a load shedding event.

The split market option for the market reference price ensures that the capacity provider will pay difference payments on the difference between the price in the market (Day-Ahead Market/Intra Day Market/Balancing Market) they were scheduled and the CRM strike price. If there is a scarcity event in both markets and the price goes to FASP, those providers who have sold in the DAM and not turned up will face a lesser penalty than those who have not provided at the Balancing Market. This will see a reduced risk for baseload plant over mid merit and is inequitable. Therefore to ensure equality for market participants across all three markets the Euphemia cap option should be applied to the Full Administered Scarcity Price.

While other markets are not limited to the EUPHEMIA price, these markets have not opted for the Split Market Reference Price. If the potential price is higher for those participants in the balancing market, then it will once again add greater risk to mid merit plant. These plants are essential to the operation of the system especially when there is a high level of installed wind capacity.

5. Transition

The "do nothing" option is undesirable as it does not provide security of supply, competition or stability to the period between the SEM and I-SEM. The lack of transparency and opportunity for market power abuse within option 2 (auction as a block) means option 1 (auction separately) is the only viable option available.

<u>Section B</u>

i. *Which of the approaches to the treatment of cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based" or "Availability Based" variant).*

   The European Economic Advisory Group (EEAG) requirements for capacity markets state that, where physically possible, operators located in other member states should be eligible to participate. Designing a capacity market that precluded participation therefore would seem contrary to this. This would therefore rule out option 1 and 2. Of the remaining options, TEL believe that the Provider led option is the most suitable. However, this is heavily dependent on how the de-rating of non I-SEM units and the interconnectors is calculated.

ii. *Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future?*

   The de-rating methodology for the non I-SEM participants needs to be further discussed and analysed. In the document three factors are highlighted for de-rating non I-SEM participants: technology de-rating factor, non I-SEM losses factor and an interconnector constraint. The record of involvement of non-local participants in other CRMs must be taken into account, not just for the double payment but also in terms of security of supply issues. Redpoint (2013)[3] highlights that “France (along with Ireland) is the market that shows the greatest extent of correlation with GB at times of system stress”. This correlation will see a significant reduction of capacity provided to Ireland at times of greatest need. In order to reduce security of supply concerns TEL would recommend that GB capacity market participants should only be allowed bid in their excess (not already contracted) capacity and that this excess capacity should be de-rated.

For the interconnector constraint/de-rating, TEL agrees with point 2.2.3 that “at least initially, historic interconnector flows may not be a good indicator of those in the future”. The scarcity event referred to repeatedly in the workshops is an extremely cold day. The trouble is that an extremely cold day in Ireland will also probably be a cold day in GB and France. This will see a need for participants in GB to provide capacity in their market. It is unlikely that historic interconnector flows can be used to model the GB response in this scenario, as the current ex post market in Ireland leads to inefficient IC flows that should be corrected by I-SEM. Therefore there is a need for an ex-ante approach performing the fundamental modelling of the European Power system under a number of scenarios. TEL would recommend further discussion on the scenarios to be applied before any modelling is performed.

iii. *If there is a preference for the “Interconnector led performance based” approach there will be a need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were:*
   - *Balance interconnector utilisation;*
   - *Pro-rata to interconnector metered flow; and*
   - *Complex power flow modelling*

   N/A

iv. *If there is a preference for the “FTR led” approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?*
   N/A

v. *If there is a preference for the “Performance based Provider Led” approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades?*
   - *As traded*
   - *Pro rata to Reliability Option (in which case – do you prefer “gross” or “net”)*
   - *Ignore – all in Balancing Market*

The de-rating methodology for the non I-SEM participants needs to be further discussed and analysed. In the document three factors are highlighted for de-rating non I-SEM participants: technology de-rating factor, non I-SEM losses factor and an interconnector constraint. The record of involvement of non-local participants in other CRMs must be taken into account, not just for the double payment but also in terms of security of supply issues. Redpoint (2013)[4] highlights that “France (along with Ireland) is the market that shows the greatest extent of correlation with GB at times of system stress”. This correlation

[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

will see a significant reduction of capacity provided to Ireland at times of greatest need. In order to reduce security of supply concerns TEL would recommend that GB capacity market participants should only be allowed bid in their excess (not already contracted) capacity and that this excess capacity should be de-rated.

vi. *If there is a preference for the "Hybrid" approach:*
   - *Should this be paired with the "Delivery Based" or "Availability Based" provider led approach?*
   - *Should Interconnector participation be mandated or voluntary?*

   N/A

Section C

i. *Do respondents agree that direct secondary trading of Reliability Options should be permitted?*

TEL agree that direct secondary trading of reliability options should be permitted. Point 3.2.2 thoroughly highlights the reasons for RO holders to secondary trade.

ii. *Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?*

The mandatory centralised market is TEL's preferred option. Out of all of the options the mandatory centralised market provides competition, stability, efficiency, equity and transparency to the secondary trading of ROs. The improve transparency of the mandatory centralised market reduces the potential for market power abuse of the CRM. TEL are of the opinion that the platform should be ready at I-SEM go live.

iii. *Do respondents believe that "back-to-back" trading to lay-off exposure to difference payments should be permitted?*

Only those participants who are physically backed should be allowed to participate, anything else may give an illusion of security of supply.

iv. *With respect to the creation of a centralised Reliability Option secondary market platform:*
   - *Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform;*

The total cost of developing a centrally organised platform would have to be determined before TEL could provide an answer to the question. However, TEL do believe that a secondary market platform is required for the I-SEM. The risks to any market participant are likely to be extremely high, especially after the first plant retirements. These risks will drive the need for a secondary market.

   - *Do respondents think that capacity providers should be allowed to acquire Reliability Option volume in excess of their de-rated capacity (plus the tolerance margin), and if yes, how the limit on Reliability Option volume for the net primary and secondary volume should be structured?*

If capacity providers are unable to acquire reliability option volumes in excess of their de-rated capacity then there could be very little volume available to trade in the future if plants (outside the CRM) are shut down. TEL think the de-rating methodology needs to be published before the secondary volumes may be determined. Plants should not be allowed trade beyond their nameplate capacity.

- *What limits should be placed on secondary trading timeframes, including: the timing of secondary trade execution - how soon after the auction should they be allowed, and how late in relation to real time delivery should they be allowed; and the length of the Reliability Option contract which can be traded?*

TEL believe that ex-post trading would confer an unfair advantage on portfolio generators. In the interests of Market Power all trading should be performed on the mandatory ex ante market.

- *Should the Capacity Market Delivery Body maintain the processes and capability to undertake pre-qualification throughout the year, and what service standards are required for processing new applications?*

TEL think the capacity market delivery body should maintain the processes and capability to undertake pre-qualification throughout the year. Any new applications should have to go through the same qualification process as the CRM pre-qualification.

- *Should a secondary acquirer of a Reliability Option start from a zero position against each "stop-loss" limit, or should the loss transfer?*

The secondary acquirer should start from a zero position. This facilitates a more liquid secondary market.

Section D

Reliability option contract length questions

1. Principle of Longer Term Reliability Options:

i. *Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options?*
Yes.

ii. *Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year?*
N/A.

iii. *Do respondents believe that longer term Reliability Options should only be available to new-build plant, or should also be available to existing plant where significant investment is being made to enhance or maintain its capability to provide capacity?*
Longer term RO's should be available to existing plant where significant investment has been made in line with DS3 decision.

2. Classification of plant as new, upgrade or existing

i. *Do respondents have a view on which approach should be used to classify capacity providers as "new", "upgrade" or "existing"?*

We would have a preference for Option 2 – Tangible Facts. This is the most transparent and objective approach. A system should allow participants to answer predetermined criteria.

ii. *Do respondents prefer the approach of classifying providers as "new", "upgrade" or "existing", please indicate your view of the criteria, evidence and thresholds that should be used to inform this classification.*

We do not see a need to differentiate between New and Upgrade. There is no distinction for the DS3 line of consultations. The CRM should operate along similar lines.

3. Maximum available Reliability Option lengths

i. *Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant?*

We believe that this should mirror the contract lengths available under DS3.

ii. *How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section.*

TEL view the generic economic life (e.g. 15 years) as the most suitable for attracting new investment into the market, similar to the approach implemented in the DS3 programme.

<u>Stop-loss limits questions</u>

i. *Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits applying over that I-SEM Capacity Year?*

We believe that there should be a monthly stop loss equivalent to 1.5 times your monthly capacity revenue. However any plant that did not supply for six separate scarcity events where they had been given their grid code notification period should lose 1.2 times their annual capacity revenue and their contract.

ii. *Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?*

There should be a limit per month.

iii. *Which approach do respondents favour for the definition of the Per Day/event limit?*

We believe that there should be a monthly stop loss equivalent to 1.5 times your monthly capacity revenue. However any plant that did not supply for six separate scarcity events where they had been given their grid code notification period should lose 1.2 times their annual capacity revenue and their contract.

iv. *Please provide views on the appropriate levels for the each of the proposed stop loss limits.*

We believe that there should be a monthly stop loss equivalent to 1.5 times your monthly capacity revenue. However any plant that did not supply for six separate scarcity events where they had been given their grid code notification period should lose 1.2 times their annual capacity revenue and their contract.

<u>Commissioning Window and Implementation Agreements questions</u>

i. *Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?*

This is dependent on the nature of the transition window. Existing plants should be able to bid into an annual auction.

ii. *Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer-running capacity projects to be completed?*

The long stop date should be consistent with the DS3 programme.

iii. *Are the proposed milestones reasonable?*
N/A

iv. *Are there any other milestones, especially prior to Substantial Financial Commitment, which could be used to add security to the delivery of new capacity?*
N/A

v. *What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?*
N/A

vi. *Is six-monthly reporting appropriate?*
Yes

vii. *Do any (or all) of the reports need to be independently verified?*
Yes.

viii. *Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?*
Yes.

ix. *Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?*

Yes.

x. *Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?*

Any failure should be reviewed at that time. However, if a milestone is agreed in advance and it is not met, then it should be within the market's powers (subject to this review) to terminate the option.

xi. *Is it appropriate to partially terminate a Reliability Option if it can achieve 'Minimum Completion? What level should be set for Minimum Completion?*
No.

xii. *If a Reliability Option is terminated under the terms of the Implementation Agreement, should this project be 'sterilised' for a period of time following the termination and be unable to participate in capacity auctions?*
Yes.

xiii. *Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?*
Yes.

xiv. *Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?*
N/A

xv. *Do respondents agree with the principle that the level of performance bond should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?*

The level of the performance bond for new entrants should rise over time to reflect the increased costs to the market.

xvi. *At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?*
N/A

xvii. *Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?*
N/A

xviii. *How should the level of the performance bond change over time? Should this have any link to the milestones?*

N/A

xix. *Do you consider that the Time To First Delivery (/Time to LSD) proposed here for the CRM should also apply equally to the delivery of System Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis / what rationale should they differ?*
Yes.

Section E

i. *Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)?*
   - *a) VoLL;*
   - *b) EU Consistent (e.g. with GB);*
   - *c) Euphemia Cap; or*
   - *d) Existing SEM PCAP*

EUPHEMIA cap, it is the only option that can be consistent with the Split Market Reference Price.

ii. *Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out . If not please explain why, and your proposed alternative definition.*

iii. *Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.*
N/A

iii. *If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.*

The Full ASP should be set at the EUPHEMIA cap from the first day. It should remain at this cap as any other level would discriminate against those plants that are more likely to be scheduled in the BM market.

v. *If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.*

The Full ASP should be set at the EUPHEMIA cap from the first day. It should remain at this cap as any other level would discriminate against those plants that are more likely to be scheduled in the BM market.

vi. *Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?*
Yes, yes.

vii. *What should the value of X in Figure 12 be?*
N/A

viii. *How far in advance of the start of the Capacity Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?*
N/A

ix. *Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?*
N/A

<u>Section F</u>

i. *Which of the suggested options (annual auction, block auction, do nothing) do you prefer?*

Annual Auction, as outlined in Section A.

ii. *If you prefer the do-nothing auction, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?*
N/A

iii. *Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?*
N/A

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

Yours sincerely,

Cormac Daly
Risk and Regulatory Manager