# Response by Energia to SEM Committee Consultation Paper SEM-18-009

***CRM State Aid Update, 2019/20 T-1 Capacity Auction Parameters and Enduring Storage De-rating Methodology***

**19 April 2018**

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# 1. Introduction

This document sets out Energia's comments in response to the Consultation Paper on the 2019/20 T-1 Capacity Auction Parameters and De-rating Methodology dated 13 March 2018 ("the Consultation Paper")[1], including answers to the questions posed within that paper.

In support of this response, we submit a brief Memo from NERA[2] (the "NERA Memo") which reviews the Consultation Paper in the light of NERA's December 2016 report on the prospects for cost recovery under the I-SEM rules proposed at that time. The NERA Memo constitutes an integral part of this response and should therefore be fully considered by the RAs.

Energia would be happy to answer any questions about this response or to arrange a discussion with our advisors, should the RAs require any clarifications.

As a preliminary comment we note that this consultation takes place at a time when the necessary modifications to Generators' Licences have not been made, and proposed modifications are the subject of ongoing proceedings, which are directly relevant to the issues set out in the Consultation Paper. We are of the firm view that prior to any progress being made in respect of further auctions, the matter of the conditions to which Generators will be subject when participating in the I-SEM, including as regards the revenues which they can earn from all relevant markets (including for energy, system services and capacity) must be resolved. All of our comments in response to the Consultation Paper are strictly without prejudice to this fundamental position and must be read in its context.

It is also worth noting how strongly the Consultation Paper emphasises the intensity of engagement with stakeholders that was observed throughout the CRM detailed design and implementation process, stating that "[i]n order to manage the risk of unintended consequences occurring an I-SEM Rules Working Group (RWG) was established"[3]. This implies that development of the I-SEM Capacity Market was robust and subject to appropriate technical challenge, and indeed this is precisely the assumption made by the SEM Committee in defining the terms of reference for the Capacity Market Auditor and Monitor[4]. This is not a valid assumption and certainly cannot be based on the rigour of scrutiny applied through the RWG process. This is because, as explained in our response to the CMC consultation SEM-17-004[5],

[1] Consultation Paper "Capacity Remuneration Mechanism State Aid Update, 2019/20 T-1 Capacity Auction Parameters and Enduring Storage De-rating Methodology", SEM-18-009, 13 March 2018.
[2] NERA Memo to Viridian, 'Competition and Cost Recovery under the 2019/20 T-1 Capacity Auction Parameters', 19 April 2018.
[3] See for example paragraph 1.1.1 and 1.1.2 of SEM-18-009, p6.
[4] Para 3.9.6 of SEM-17-007 states that "[i]t is assumed that development of the Code was robust and subject to appropriate technical challenge".
[5] Energia's response to SEM-17-004 was submitted to the RAs on 24th February 2017.

development of the Capacity Market Code through that process was accelerated and predominantly completed over a cycle of only four Rules Working Groups in conjunction with the TSC development and a very high number of substantive I-SEM consultations running in parallel, leading to consultation overload[6]. These shortcomings of the RWG process are recognised by ESP in their Stocktake Report:

*"[T]he design has been developed in consultation with the industry, who have also been part of Rules Working Groups scrutinising that design - albeit recent workload at the Rules Working Groups has inevitably impacted the level of scrutiny of rules by participants, and hence the level of comfort that can be derived from this process …. ;"*[7]

It is unfortunate, but hardly surprising, therefore that serious 'unintended consequences' have already come to light after the first capacity auction, as acknowledged in section 7 of the Consultation Paper. This underlines the importance of independent Quality Assurance as advocated by the Electricity Association of Ireland[8] and Viridian[9], which to date has not been implemented and is long overdue.

We do not believe that it is appropriate that further auctions be progressed pending the necessary modifications to the Generation Licence conditions, and the completion of an independent Quality Assurance process.

The remainder of this response is structured as follows. Section 2 provides general comments and section 3 responds to the consultation questions[10].

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[6] This shortcoming is recognised in the ESP Stocktake Report and should be recognised by the SEM Committee.

[7] ESP Consulting, November 2016, 'I-SEM Programme: Stocktake Report', p.24

[8] See EAI letters to Chair of SEM Committee dated 8th July 2016 and 23rd August 2016.

[9] See Viridian correspondence to the RAs dated 5th August 2016 explaining why an independent QA role for I-SEM is both necessary and beneficial and how it can be implemented in an expedient manner to meet short term and longer term objectives. Also see Viridian's follow-up correspondence dated 18th August 2016 clearly explaining why the ESP Stocktake cannot in any way be considered a form of independent QA of the I-SEM Capacity Remuneration Mechanism, if that was the intention.

[10] We have responded separately to the TSOs Consultation SEM-18-009a on Additions and Modifications to the Capacity Requirement & De-rating Factor Calculation Methodology.

# 2. General comments

In this section, we discuss areas of particular concern that should be read in conjunction with the NERA Memo, our response to the specific consultation questions in section 3[11], and previous submissions referenced where applicable.

**Cost Recovery under I-SEM**

In essence, in the Consultation Paper, the SEM Committee proposes to subject participation in the second T-1 auction to conditions which have yet to take effect by way of licence modifications and the substance of which is currently under challenge. Energia objects accordingly as a matter of principle to the proposal that participation in the second T-1 auction be subject to these conditions.

For the avoidance of doubt, Energia's objections are grounded on the fact that the restrictions to which generators would be subject, in particular generators which are highly likely to be constrained on in both the energy markets and the capacity market, go far beyond constraining market power in capacity auctions and fails to deliver competitive outcomes contrary to the stated objective of the SEMC. These restrictions have the direct and very material effect of denying generators the opportunity of recovering their total costs in the market, including making any contribution whatsoever to their costs of investment (debt and equity), thereby hindering the development of a sustainable competitive process and endangering security of supply to the detriment of consumers. This is contrary to the regulators' duty to promote competition and protect the interest of consumers and ensure that licensees can finance their activities.

We have clearly articulated these fundamental flaws and explained our objections with expert economic support provided by NERA in response to previous I-SEM consultations. In support of this response, we submit a brief Memo from NERA[12] (the "NERA Memo") which reviews the Consultation Paper in the light of NERA's December 2016 report on the prospects for cost recovery under the I-SEM rules proposed at that time. NERA conclude:

> *"Developments since December 2016 have done nothing to change our overall conclusion that the I-SEM imposed a set of bidding constraints on plants likely to be constrained on that systematically denied cost recovery and would lead to inefficient market outcomes"*.

Reflecting on the implications of their conclusions, NERA state:

[11] Some of these concerns do not fit under specific consultation questions and are therefore not addressed in section 3 of this response.
[12] NERA Memo to Viridian, 'Competition and Cost Recovery under the 2019/20 T-1 Capacity Auction Parameters', 19 April 2018.

*"The SEM Committee's revised rules do not provide sufficient incentives to deliver capacity in constrained locations. "Constrained-on" plants still cannot recover their (past or future) investment costs under the proposed pricing rules for energy and capacity, let alone any additional revenue for the value of capacity located in a constrained area. The revised rules do not therefore address the need for locational signals raised by the EC, and all of the conclusions we reached in December 2016 still apply."*

With the above in mind, we re-state our position put forward in response to the CRM Parameters consultation SEM-16-073 which remains entirely valid, namely,

*"The desire to prevent market abuse does not require a restrictive policy that defines precisely which of their costs ("NGFC") generators may include in their offer prices and, ultimately, in the prices they receive for their capacity. The SEM Committee cannot rely on "international best practice" to justify this approach, since there is no system in the world that aims (or could ever aim) to foster competition and security of supply with the combination of measures currently proposed for the I-SEM's markets in capacity and energy. As NERA confirm, 'international precedents offer no support for the specific form of capacity market price controls currently proposed for the I-SEM, because controls in other markets offers greater flexibility, rely on ex post scrutiny, and do not deny total cost recovery.' (p1)*

*On the contrary, it will be essential to allow much greater flexibility for the competitive process to work – occasionally allowing generators to bid more than NGFC, because of the necessity of recovering sunk costs. This provision may be defined by allowing for "any other costs not elsewhere specified", or better still by focusing the scrutiny of offer prices on particular cases of suspected abuse ex post, and allowing the competitive process to dictate market pricing whenever possible. Ex post regulation of this type has been effective under the BCOP in the SEM, and represents normal practice in other electricity markets. There are no grounds for adopting a different [overly restrictive], approach for the I-SEM."*[13]

The outcome of the first capacity auction, which implemented the same conditions, is that security of supply in Dublin will not be achieved and further intervention will be required, as indeed the CRU itself recognised could well be the case in its December 2017 Paper, "Regulatory Approach to Maintaining Local Security of Supply in Electricity". It is manifestly clear that the regulatory bidding restrictions and the deficiencies of the LCC Methodology implement a regime that is (1) not practical, (2) will not be stable,

[13] Energia response to SEM-16-073, p9.

and (3) generates inefficient outcomes that will hinder competition and threaten security of supply.

The only possible conclusion is that a different approach as described above is required to meet the SEM Committee's usual I-SEM assessment criteria, and to comply with the regulatory authorities' statutory duties.

It is also worth briefly reflecting on the State aid decision that was published since and that has been assessed by NERA in their Memo as follows:

> *"The EC noted the importance of locational signals for incentivising generation and transmission capacity in areas of constraints. The EC therefore raised concerns about the I-SEM, specifically that the market does not send locational signals to remunerate plant in temporarily constrained areas, and that 'locationally important plants appear to not be able to monetise their locational value in the energy-only market'. These concerns echo our conclusions that the proposed pricing rules for existing capacity in constrained locations do not reflect competitive market pricing…and that they will diminish the efficiency of outcomes…."* [NERA Memo, p10]

We note further that State aid approval was given by the European Commission based on submissions from the Irish authorities to the effect that "*the combined effect of the price controls in both the CRM and the I-SEM will not affect the ability of the CRM to secure a sufficient amount of capacity in the necessary locations".* However it is apparent from the Commission's decision that the Commission understood, among others, that transmission constraints are temporary and would be resolved by 2024 and that I-SEM market reforms would afford additional revenues to plant behind the constraints. Clearly that is not the case. Not only will the constraints not be resolved by 2024 but the design of the restrictions in the CRM for generators subject to the USPC is that any additional revenues earned in other markets reduced the revenues which may be earned on the capacity market, so that generators required at certain locations and subject to the USPC simply cannot earn sufficient revenues from their participation in I-SEM to continue to provide the capacity that is needed at those locations. Furthermore, the European Commission appeared to have taken comfort from the Irish authorities' indication that local security of supply requirements could be addressed by targeted contracting mechanisms although details had not been designed. We note that the CRU's December 2017 paper has provided little if any clarity as regards such details, in particular in terms of the conditions to be attached to such a contract. It remains entirely unclear accordingly that such a mechanism is available to, and can, ensure that locational value of plant is rewarded.

### Locational Capacity Constraints (LCC) Methodology

The overall approach to the LCC methodology remains a significant concern. While it is understood that the LCC methodology only purports to address a sub-set of local constraint requirements (i.e. network power-flow limitations), this leaves a substantive gap in terms of the additional requirements to deliver security in the Dublin and east-coast areas (voltage, system stability etc.).

While the Consultation Paper alludes to market reforms to improve locational signals stressed by the EC as important, such as reforms to the ancillary service market as well as other potential reforms (section 2.2.5), no further clarity is available on these issues at present. For the period that the gap continues and as long as regulatory restrictions in the capacity market prevent cost recovery as discussed above, there is a substantial and imminent risk to security of supply as the available mechanisms do not collectively address the security requirements.

### Dublin Demand

We have previously raised concern about the lack of information on how regional demands are apportioned, in particular that the LCC Methodology may not properly take account of the likely high demand growth in Dublin, including large Data Centre load which are expected to locate in the Dublin area. Our concerns about this are exacerbated by the statement in Section 5.2.4 of the current Consultation Paper where it is noted that:

*"Indicative analysis by the TSOs with updated demand assumptions for 2021/22 show a slightly smaller load forecast in Dublin applicable for the CY2019/20 compared to CY2018/19…"*

While it is understood that this is only "indicative", it is extremely concerning and reinforces points made in response to previous consultations, regarding lack of transparency in how locational demand was allocated and thus does not facilitate necessary industry input and feedback to mitigate the risk of unintended consequences.

It is hardly credible, in light of various statements and publications by the CRU and EirGrid, that the demand for Dublin could be less in the 2019/20 auction than for the 2018/19 auction. The increase in Data Centre demands has been referred to in many publications, as well as the extent to which this interest is concentrated in the Dublin area (ref. EirGrid's "Tomorrow's Energy Scenarios Locations Consultation").

The latest all-island Ten Year Transmission Forecast Statement (TYTFS) published by EirGrid on 12th October 2017 signals a clear need for additional generation in the Dublin area, which seems completely at odds with the indicative results of the LCC Methodology[14].

*A key driver for electricity demand in Ireland for the next number of years is the connection of large data centres. A significant proportion of this extra data centre load will materialise in the Dublin region. Given the lead times associated with transmission reinforcements, generation capacity or equivalent may need to be available in the Dublin region to accommodate this additional demand in the short-term.*

We therefore reiterate our request that the TSOs make available the **specific** demand distribution used in the CRM calculations, so as to remove ambiguity in how data centre demands are treated in the locational distribution and facilitate necessary industry input and feedback. This could be in a similar format to that used in the TYTFS Appendix C. At a minimum, the TSOs should provide as a matter of urgency, Winter Peak demand used in the CRM model for

- All-Island
- Ireland
- Dublin area
- Each transmission station within the Dublin area

This should be provided for both CY2018/19 and for CY2019/20 (as soon as available). **The data should be made available in time for comment**, and not provided only after modelling and results are completed.

**Demand Side Units (DSUs)**

The Consultation Paper acknowledges the significant amount of new DSU capacity that was awarded in the first T-1 auction (held in December 2017) for CY2018/19 and highlights the imbalance between the one-year Reliability Option that was awarded from the auction and the 18 month long stop date, which therefore puts the long stop date after the end of the period for which it is contracted to deliver capacity. This is a significant oversight which gives rise to inappropriate incentives and has the potential to put security of supply at risk particularly in the Dublin locational constrained area where the contribution from new DSU capacity is highly consequential[15]. In addition, it is

[14] It is also acknowledged by the CRU with reference to the TYTFS that *"...the particular growth in the establishment of new data centres, which tend to have large demand loads, and relatively short construction lead times...can create challenges for network planning".* See CRU Information Paper (CRU/17/346) on maintaining local security of supply, published 18th December 2017, p1.

[15] It is stated in paragraph 7.1.6 of the Consultation Paper that "[t]he SEM Committee does not believe that there is any risk to security of supply in CY2018/19 since the CY2018/19 T-1 auction ended up awarding over 1,000 de-rated MW of Reliability Options in excess of the adjusted Capacity Requirement of which only 174 de-rated MW was new capacity." However, new DSU capacity in excess of 70MW was awarded ROs to meet the 1,300MW requirement in the Dublin LCC area which clearly has the potential to be significant.

acknowledged that DSUs have limitations in reducing their demand and thus providing capacity and as such a review of their de-rating factors is discussed in the Consultation Paper and the accompanying TSO de-rating methodology paper.

Despite these significant (but not unexpected) findings and acknowledgments, there is no proposal to change any of the T&Cs applicable to those who were awarded contracts in the T-1 auction for CY2018/19 and remarkably there is no proposal to run an emergency in-year auction for capacity that qualified for the CY2018/19 auction but lost. Nonetheless, these are remedies which are contemplated for CY2019/20 in the Consultation Paper. It is entirely unsatisfactory that such risks and remedies are not being considered for CY2018/19, especially without valid justification. This should be given immediate attention by the CRU and TSOs in the context of the Dublin requirements with a view to running an emergency in-year auction for capacity that qualified for the CY2018/19 auction but lost (subject to any caps including in particular USPCs being set at a level which allows the appropriate remuneration of selected generators, including constrained-on generators, so that they can earn a reasonable return and finance their generation activities).

**De-rating Tolerance Bands**

Energia maintains (for reasons outlined in response to SEM-17-027) that meaningful tolerance bands for de-rating factors should be re-instated as provided for in Decision Paper SEM-15-103. In the confidential annex of our response to SEM-17-027, we provided supporting evidence that there is “legitimate technical variation” to justify a meaningful (positive) tolerance band for Gas Turbines in particular. In the light of this evidence we have previously called for greater transparency around the process to understand the basis for a zero tolerance band. Without this necessary transparency the purported rationale for a zero tolerance band for Gas Turbines is not justified.

Regarding DSUs, the SEMC decided to establish a negative tolerance band (100%) to provide flexibility for DSU aggregators to qualify the capacity which they can reliably deliver from their portfolio. Under this regime the SEMC recognised the risk that DSU aggregators may systematically over-state their reliable capacity and decided to deal with this through the Qualification Process by requiring DSUs to submit evidence that the unit can deliver the capacity being qualified. Unless the maximum de-rating attainable is conservative (which it patently is not), such a regime is highly reliant on (and thus vulnerable to) the robustness of the qualification process and the scrutiny of evidence submitted by aggregators. Detailed evidence should be required and scrutinised to ensure that DSUs are appropriately vetted in the interests of preventing ‘ghost capacity’, promoting competition and protecting security of supply. Historic performance should be taken into account for existing DSUs and this should have a temporal element (such as the ability to perform reliably for a certain number of hours over a consecutive number of days) and the Business Plan requirements for new DSUs should be robust[16].

**Comparisons with GB Capacity Market**

The Consultation Paper refers to the approach taken in the GB Capacity Market to help justify the SEM Committee's minded to position to keep the Existing Capacity Price Cap consistent with the level previously set i.e. €41.06/kW/year (paras 4.5.5 and 4.5.6). A similar comparison was made with the GB Capacity Market when the SEM Committee argued in its Decision Paper on CRM parameters in 2017 that its proposals did not discriminate against existing plant[17]. In doing so, it relied on precedent from the British market even though markedly differing arrangements for mitigating market power exist for new and existing plant. The SEM Committee's analysis on these points is misleading. In Great Britain, the regulator collects information on costs from all generators that want to bid above the price taker threshold, but only investigates bid prices on a case by case basis when auction outcomes require it. In the GB capacity market State aid decision, one of the grounds upon which the European Commission concluded that the measure does not unduly discriminate against existing generation is that existing plant are not prevented under the scheme from earning a rate of return deemed necessary, since this may be included in their submitted justification for needing a higher level of payment[18]. In contrast to the GB scheme, the inflexible bid cap (or any USPC approved based on the inflexible definition of NGFC) under the I-SEM CRM does in fact prevent the recovery of total costs and earning any rate of return.

In Great Britain, therefore, there is no presumption than that price caps must be imposed on certain generators, unlike under the proposed rules of the I-SEM. Comparing Great Britain with the I-SEM therefore highlights the prejudicial nature of the proposed CRM rules for the I-SEM (which provide the basis for undue discrimination).

**Other Comments**

Consistent with our position that generators which are constrained-on under the CRM must be able to finance their generation activities and cannot therefore be subject to generation conditions such that they are deprived of the possibility to recover their total costs and earn a return, below is a non-

[16] We explain later in this response (see section 3) why it is inappropriate and imprudent for DSUs to be de-rated on the same basis as storage units. A more severe de-rating is required for DSUs that takes into account their specific characteristics which make them fundamentally different from storage units. The same unique characteristics need to be recognised during the qualification process.

[17] SEM Committee (2017), "Capacity Remuneration Mechanism - Parameters and Auction Timings: Decision Paper", (SEM-17-022), para 6.3.69.

[18] See European Commission, State Aid SA.3598 (2014/N-2) – United Kingdom Electricity market reform – Capacity Market, para. 139.

exhaustive list of issues arising in connection with the manner in which a USPC is set[19]:

- A USPC must allow justifiable additional costs actually faced by investors to allow a reasonable rate of return
- 10% allowance to cover estimation uncertainty surrounding NGFC is inadequate
    - It does not allow sunk cost recovery
    - It does not take into account forecast horizons (which differ by capacity auction)
    - The inclusion of Reliability Option Difference Payments within this allowance prevents cost recovery even of NGFC as strictly defined by the RAs
    - NGFC estimates should be *risk-adjusted* as per the GB capacity market
- If shared costs are disallowed in a USPC application, contingent bidding should be implemented in the auctions such that bids can be made contingent on linked units clearing

[19] Some of these topics, which were never consulted upon, feature in Information Paper SEM-17-090, published November 2017.

# 3. Response to specific consultation questions

**Section 3: Auction Timings**

***1) Do you have any comments on the indicative auction timetable set out in this section?***

At the outset, we wish to recall our fundamental objection to the implementation of the CRM at a time when necessary licence conditions have not come into effect and proposed licence conditions are the subject of ongoing proceedings.

Strictly without prejudice to this, with reference to the indicative auction timetable set out in the Consultation Paper, Energia is the view that each of the transitional auctions should be completed before holding the first T-4 auction. We regard this as a key requirement that should be applied in order to provide greater certainty for participants. This position was stated in our response to the CMC consultation SEM-17-004 and was a view strongly shared by EAI. We note that the SEM Committee have acknowledged in this Consultation Paper that this is indeed a widespread preference. However, it is the SEM Committee's position that this is not desirable as it would reduce the lead time to less than 3½ years and thus reduce the capability of some new entrants to compete. We have considered this and the need to align CRM and DS3 to facilitate new entry. Accordingly, we have suggested below a pragmatic solution as reflected in an amended auction timetable. This takes into account the need to align the first T-4 capacity auction with the DS3 cycle where we understand that parties participating in the DS3 volume capped auction are not expected to be contracted until May 2019. This also takes into consideration the desire to avoid auctions in September which carries unnecessary risk of resourcing pinch-points over July and August, the preference being to defer such auctions until October.

We recommend that the first T-4 auction for CY 2022/23 be replaced with an additional transitional auction to be held at the same time as the remaining two transitional auctions for CY 2020/21 and CY 2021/22. This allows for all transitional auctions to be completed before holding the first T-4 auction for CY 2023/24. This proposal is reflected in the revised auction timetable below:

In respect of the three transitional auctions that are scheduled for December 2019 in our amended timetable, we would recommend that the USPC process for these auctions be combined to minimise the burden on market participants and the RAs but that the actual auction dates be staggered sufficiently so that market participants receive at least their provisional results from the previous auction before entering the following auction. We believe that this amended auction timetable would receive widespread support among market participants who have previously (under the auspices of EAI) outlined their strong preference for the transitional auctions to be completed before the first T-4 auction.

**Table 1: revised auction timetable proposed**

| CY | CY Start | T-4 | Time between CY and Auction Date | T-1 | Time between CY and Auction Date |
|---|---|---|---|---|---|
| 2018/19 | 22/05/2018 | N/A | N/A | Dec-17 | 5 Months |
| 2019/20 | 01/10/2019 | N/A | N/A | Dec-18 | 9 Months |
| 2020/21 | 01/10/2020 | N/A | N/A | Dec-19* | 10 Months |
| 2021/22 | 01/10/2021 | N/A | N/A | Dec-19* | 1 Year 10 Months |
| 2022/23 | 01/10/2022 | N/A | N/A | Dec-19* | 2 Years 10 Months |
| 2023/24 | 01/10/2023 | Mar-20 | 3 Years 7 Months | Mar-23** | 7 Months |
| 2024/25 | 01/10/2024 | Oct-20 | 4 Years | Mar-24** | 7 Months |
| 2025/26 | 01/10/2025 | Oct-21 | 4 Years | Mar-25** | 7 Months |

** Auctions should be sufficiently staggered to allow participants to receive at least provisional results from previous T-1 auction before the subsequent auction takes place*

***T-1 auction to procure residual capacity withheld from corresponding T-4 auction*

## Section 4: Capacity Year 2019/20 T-1 Parameters

***1) Do you agree with the SEM Committee's minded to position to keep the parameters (excluding capacity requirement and de-rating factors) for the CY2019/20 capacity auction consistent with the CY2018/19 parameters?***

No. See general comments, the accompanying NERA Memo and our position in respect of each parameter set out previously in response to the CRM Parameters consultation SEM-16-073.

## Section 6: De-rating Factors

***1) Do you agree with the proposed modification to the treatment of outages for small and embedded capacity in GB in the interconnector de-rating methodology?***

No comment.

***2) Do you agree with the use of a least-worst regrets approach to the choice of GB generation scenario used to set EMDF?***

Yes, we agree with the proposed approach.

***3) Do you agree with the approach that the EMDF need only be determined for the GB market for CY2019/20 in the absence of interconnection with other markets?***

Yes, we agree with the proposed approach.

**General comment on Interconnector de-rating**

Under the I-SEM capacity market design, interconnectors that secure capacity contracts effectively displace domestic alternatives. They therefore displace one form of "capacity" with another rather than adding an additional layer of security. Given that the availability of interconnectors is influenced by very different factors than domestic generation, this replacement may actually reduce overall system resilience, at a very high cost.

The extent to which interconnection could be relied upon in an all-island stress event is statistically more complex to calculate than for domestic generators, for which historic data gives a relatively reliable indication of availability. If, for example, an I-SEM stress event was triggered by cold weather and low wind speed, there is a higher than average probability that GB would also be experiencing cold weather and low wind speed, potentially leading to higher prices in GB and no interconnector flows to I-SEM at the very time they were most needed.

Over the longer term, changes in energy policy or other unanticipated events (including post BREXIT conditions) could also result in I-SEM being less able to rely on GB for imports during scarcity events. This would result in a pressing need to rapidly replace domestic capacity as the de-rating factors applied to interconnectors are revised downwards. Forcing the TSO to act as a distressed buyer of capacity will not deliver optimal outcomes for consumers over the long term.

While none of these events can be predicted with any certainty, it is the mere possibility of their occurrence that makes the estimation of interconnector de-rating factors a difficult and risky endeavour in a way that is not the case for domestic generation. A conservative approach to de-rating interconnectors is therefore warranted, especially when, as acknowledged by ESP at the workshop on 29 September 2016, the methodology employed *"relies on a range of estimations, simplifications and a view of the future"*[20].

***4) Do you have any response to the storage related questions raised by the TSOs in their paper, which are listed in paragraph 6.3.3 above?***

[20] SEM-16-058b, „CRM Workshop – Interconnector De-rating Methodology", 29 September 2016, slide 16.

There was insufficient time within the consultation period to give detailed consideration to the proposed methodology for de-rating of storage units. We must therefore reserve our position to give detailed comments at a future stage. We have however given detailed consideration to the application of storage de-rating factors to DSUs as discussed in response to the question below.

5) ***Do you have any response to the other energy and run-hour limited generation related questions raised by the TSOs in their paper which are listed in paragraph 6.3.5 above.***

Energia does not support the proposed approach for de-rating DSUs on the same basis as storage units with limited Maximum Down Time. DSUs are not as reliable as other storage technologies in terms of providing capacity and in general are unable to do so for similar periods of time on multiple occasions, their de-rating should therefore be higher (lower effective capacity) than currently proposed. For reasons explained below we conclude that there is no justification for applying the same assumptions to DSUs as storage units when calculating their de-rating factors.

**Storage and DSUs are not comparable technologies**

The TSO paper proposes that DSUs should be de-rated in an equivalent manner to “other” storage technologies, based on using the same outage rates, and interpreting the maximum down time for a DSU (i.e. the maximum period for which a DSU can remain offline) as equivalent to the storage volume. However storage units and DSUs are fundamentally different in nature which deems this an inappropriate mechanism for calculation of DSU de-rating factors.

When Storage is depleted it can be recharged and used again, so it can deliver repeatedly, limited only by its storage/recharge characteristics. Thus, in a period of tight capacity margins, a storage unit will contribute for as many days, or weeks, required of it. DSUs however, whilst able to contribute when required in terms of short-term response, are unlikely to be able to contribute day after day, in the same way as Storage units. It is likely that the adverse impacts they would suffer from repeated use will mean that they will at some point cease to respond to enduring capacity shortfalls.

As such there is no justification for applying the same assumptions to DSUs as storage units when calculating their de-rating factor.

**Concerns over the reliability of DSUs for provision of capacity**

Historically, DSUs tend to be used as a backup or emergency resource and are only called upon to reduce demand during a small number and short duration of stress events. Whilst a storage unit would always be expected to be ready for use if such a stress event occurs, a DSU may only be made ready to deploy once the relevant person within the DSU knows that a stress event is likely or already in progress. If the stress event was not foreseen in time it is feasible that the DSU may not be able to respond. This feature of DSU operation would make the likelihood of non-delivery higher for DSUs than for storage and therefore requiring a higher de-rating factor (lower effective capacity). This is likely to be a particular problem where the risk of RO events is perceived as low.

Furthermore, when DSUs are given repeated instructions to reduce demand it is more likely that they will fail to do so as required, this is known as ‘response fatigue’. This is particularly true if they have already received numerous dispatch calls over a short period of time. In such a scenario, it is more likely that DSUs will offer less capacity to reduce demand, especially if participants can manually override a request for a demand reduction or refuse to provide capacity when required.

The effect may be masked where DSUs are part of a large portfolio of resources (as for the system as a whole). DSUs will tend to be the last resources deployed, and as such, comparatively unlikely to be called upon repeatedly for extended periods. However in the case of a more limited resource pool, such as in a locational constrained area, it is much more likely that a capacity shortfall will, when it does occur, remain for an extended period. In this case DSUs will be called upon repeatedly. Placing reliance on them to be able to deliver repeatedly over sustained periods of operation has to be regarded with considerable scepticism. DSU Aggregators to date for example have typically marketed DSU as having “minimal impact” on the customer’s business, and emphasise that it is likely to be called only very occasionally (e.g. five times per year). Analysis indicates that DSUs (up to now) are typically called upon for less than 0.1% the time.

**Financial Incentives / Penalties are not equivalent for DSU and Storage**

It is possible a DSU may face financial incentives not to dispatch during a system stress event, given the cost for reducing demand can vary from one stress event to another and the cost to each individual DSU may differ. As such, a scenario may arise where incurring a penalty through the CRM (or contract with the aggregator) may be more attractive than stopping production. This same argument does not apply to Storage units with awarded capacity that, like conventional generation, faces a simple incentive to generate during periods of system stress.

If the demand-side service is provided to the CRM by someone who does not directly control the consumption of the capacity provider (e.g. a DSU aggregator) their capacity is subject to the additional risk that the parties responsible for providing the capacity fail to comply with the agreement with the CRM participant. In addition there may not be sufficient financial incentives or penalties for failure to provide capacity given that the licence provisions apply only to the DSU aggregator and do not extend to the actual unit supplying the capacity. Also, in the case of a locational supply issue, whilst there may be an incentive for a capacity provider to enter into a secondary trade with another source to deliver its capacity if it cannot provide it, there is no incentive for the capacity provider to source an alternative within the same locational area.

**The proposed approach overstates the benefits of DSU to system adequacy**

The TSO consultation paper recognises that the approach proposed for calculating de-rating factors for Storage units will over-state the benefit of new storage to system adequacy. The paper suggests that the approach is defensible, “where there is only a small increase in the level of storage in a given auction”, and further states that “if the TSOs become aware of significant quantities of new storage generation looking to connect to the system then this approach may need to be reviewed”.

If the same approach is applied to DSUs, it will similarly overstate the benefit of DSUs. The stated argument for Storage does not hold up in the context of DSUs. There is already a significant quantity of DSUs, so that the effect here cannot be dismissed as insignificant. As such, this approach will over-reward DSUs through inappropriate de-rating factors.

**<u>Section 7: Long-Stop Date and Termination of New Capacity</u>**

1) ***Do you agree with our revised proposals for Long Stop Dates and Substantial Financial Completion dates as set out in the section, and summarised in Table 4?***

The revised proposals are clearly an improvement and address (at least partially) the issue of an 18-month long-stop date for a 12-month auction period.

The assertion (section 7.1.5) that “applying the 18-month deadline for Substantive Financial Completion to a T-4 auction is appropriate”, is questionable. The absence of new capacity (that have been awarded an RO for up to 10 years) for such an extended period (at least 18 months) could result in significant capacity deficits. Further, the supposition that it “allows the TSOs opportunity to remedy non-delivery”, is not reasonable; if actions are only commenced by the TSOs when the 18-month deadline is reached, mitigating actions are unlikely to deliver within the required timescales.

The statement in section 7.1.6 that “The SEM Committee does not believe that there is any risk to security of supply in CY2018/19 since the CY2018/19 T-1 auction ended up awarding over 1,000 de-rated MW of Reliability Options in excess of the adjusted Capacity Requirement”, may be reasonable in the context of the capacity requirements for the system as a whole. However it patently does not hold up in the context of the Dublin locational constrained area, where “new DSUs” are a substantial part of the local portfolio and there is not a significant over-provision of Reliability Options to fall back on. This should be given immediate attention by the CRU and TSOs in the context of the Dublin requirements with a view to running an emergency in-year auction for capacity that qualified for the CY2018/19 auction but lost (subject to any caps including in particular USPCs being set at a level which allows the appropriate remuneration of selected generators, including constrained-on generators, so that they can earn a reasonable return and finance their generation activities).