Electric Ireland Response:

Capacity Remuneration Mechanism Detailed Design

Capacity Requirement and De-Rating Consultation Paper

SEM-16-051

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Respondent's Details

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General Comments

Electric Ireland (EI) welcomes the opportunity to respond to this Capacity Remuneration Mechanism (CRM) Capacity Requirement and De-Rating Consultation. Consistent with our previous responses, Electric Ireland views these consultation proposals from the perspective of a standalone supplier and as a representative of the consumer. In our response we have focussed mainly on the de-rating of DSUs and of the interconnectors.

EI broadly supports the methodologies proposed but make some suggestions for improvements.

Some of the key points for Electric Ireland and our customers are discussed below:

Governance of Inputs and Methodologies

The methodologies as presented are still in a development phase requiring refinement and over time likely to require further development to reflect I-SEM experience and market changes e.g. the enduring IDM cross-border solution and the establishment of a regional (cross-border) balancing market. Many of the results are highly sensitive to e.g. outage data inputs which have been extracted from historic SEM (and GB) records. Consequently it will be important to establish robust rules and governance arrangements to enable these data inputs to be derived and methodologies to be developed and refined in an appropriate and equitable manner.

At the minimum this would mean an established timetable for review, consultation, and decision on these important matters which will have significant commercial impact on both industry participants and consumers.

DSU De-Rating Factors and Tolerance Bands

A main concern is in relation to the indicative values and methodology for determining DSU de-rating factors. EI believes that the proposed methodology underestimates DSU de-rating factor values and that this may be a result of the way the historical outage data is treated. Given that a DSU arises from a portfolio of customer assets, forced outages are likely to be only partial and consequently a two-state on / off model of availability is not appropriate for DSUs.

Fundamentally, pure demand reduction and back-up generation are very different and so there is likely to be 'legitimate technical variation' between units within a combined DSU-AGU technology group. Consequently EI believes that non-zero tolerance bands are required for DSUs to reflect such differences.

Interconnector De-Rating Factors

The proposed interconnector de-rating methodology is based on the likelihood of physical scarcity in the I-SEM and GB markets. No real account is taken of the possibility that imperfect market arrangements sit over this physical situation and which may fail to deliver the flows and contributions to I-SEM system security implied by the analysis. Imperfections include: the interim IDM arrangements where only periodic cross-border trades can occur; the initial BM arrangements which do not contemplate cross border flows; uncertainties about the enduring regional balancing market where differences in scarcity prices may trump physical considerations; and the limitations and nature of SO-SO trades about which little is known. Consequently a much more conservative approach to interconnector de-rating is required than that proposed.

Whether or not to include the long Moyle partial outage and the recently announced significant EWIC outage within the inputs to the analysis is likely to have a critical effect on the resultant outputs. EI believes that both should be included. It is essential that interconnectors are treated equally to other units and that robust governance rules provide a framework for answering such questions.

Furthermore, many sensitivities are carried out to reflect the many assumptions that need to be made in order to derive interconnector de-rating factors. Given the material risk to security of supply and that high interconnector de-rating factor values would exacerbate the ‘hole in the hedge’, EI believes a prudent approach is required given the level of uncertainty and that the lowest values produced from the sensitivities should be adopted as the final de-rating factors for each of the interconnectors. In addition it will be necessary to set out what are appropriate sensitivities.

Section 2:- Capacity Requirement and De-Rating Factor Methodology

2.2.1 A: Capacity Requirement Determination

EI generally supports the proposed methodology but suggests a number of improvements below.

EI acknowledges the intention to remove TSO discretion from the methodology by randomly selecting Capacity Adequate Portfolios (CAPS) from the currently installed capacity assets. However there is a possibility that there is a bias in the types of technologies which opt out from the CRM in the qualification phase e.g. possibly a significant proportion of wind may opt out. Consequently a very different subset may go forward to participate within the auctions. There is no guarantee that such a subset will be adequately reflected by the randomly selected CAPS.

In effect, any technologies opting out of the auctions are definitively assumed to contribute to the overall capacity requirement at their relevant de-rating factors but from outside of the CRM. The remaining capacity requirement to be applied to the auctions needs to be sourced from potentially a very different mix of capacity providers.

Consequently EI believes that the capacity requirement analysis needs to be re-run following qualification with units randomly drawn from the subset participating in the auctions. This would be short of the full analysis since it would be necessary to keep the de-rating factors constant at the pre-qualification values.

The proposed methodology draws heavily on the annual Generation Capacity Statement (GCS) for the generation of demand scenarios which in turn are a strong determinant of the capacity requirement. It is appropriate therefore to consider whether the development of the high and low scenarios within the GCS are sufficiently robust and whether the process leading to publication is also fit for this (capacity requirement) purpose. Considerations should include:

- the spread between high and low demand scenarios: whether this is reasonably consistent between years and whether these reliably capture actual system demand (growth) over both year-ahead and 4-year-ahead timeframes;
- whether forecast GDP remains the best predictor of system peak demand;
- whether forecasts for calendar years, with their ambiguity about system peaks at the beginning or end of the year, should be moved to a 'tariff year' basis to be consistent with the CRM delivery years;
- whether the current schedule for production of the GCS is appropriate in the context of providing a basis for annual T-1 and (eventually) T-4 auctions.

All of these aspects should be set out in the governance arrangements.

Pairing wind scenarios with demand scenarios (and netting them off) acknowledges that there is a relationship between both and daylight / solar gain[1]. However this may underestimate the possibility of little or no wind at peak demand e.g. under winter high pressure weather conditions and so underestimate the possibility of scarcity in these conditions. EI notes that the interconnector de-rating method carries out a specific sensitivity to evaluate this possibility. EI recommends that, at a minimum, the paired demand and wind profiles are examined to ensure that such conditions are appropriately represented within the scenarios.

While some steps have been taken (e.g. inclusion of the reserve requirement), there is a need to ensure consistency between the assumptions and approaches used in the CRM and those in the GB Capacity Market.

[11] There is perhaps a clearer relationship between onshore wind output and solar gain than for offshore wind.

This is important in the context of the proposed move to an enduring CRM cross-border participation model where it will be critical to align the incentives on capacity providers in both GB and I-SEM. This is also likely to improve compliance with any future ENTSO-E guidelines on capacity adequacy across Europe. EI believe that more can be done in this respect to build on the significant analysis already done by GB.

2.2.1 B Treatment of Operational Reserves

EI believes that it is reasonable to include a provision for reserve in the capacity requirement methodology based on the largest single infeed. This provides better parity with the GB market so that, notwithstanding the decision to assume a lower security standard, consumers don't suffer an even greater level of supply disruption than their neighbours (post transition).

The possibility that customers pay twice for operational reserves through the CRM and DS3 markets should be mitigated since CRM bids should be on the basis of 'missing money' taking into account revenues from the ancillary services market. Consumers will rely on sufficient competition within the auctions to incentivise bidding on this basis. During the next two years ancillary services revenues will be well known via the DS3 interim tariff arrangements. Appropriate coordination of DS3 and CRM auctions will be required beyond this period to ensure that ancillary service revenues are factored into CRM bids.

2.2.1 C Technology Groupings

EI acknowledges that broad groupings have the effect of averaging out the unavailabilities of individual units arguably producing more robust, representative, and stable de-rating values for the group as a whole. However this requires that members of the group are sufficiently similar.

EI maintains that there is 'legitimate technical variation' between members of the combined DSU-AGU technology grouping since there is a fundamental difference between pure demand reduction and back-up generation in terms of their technical characteristics. Each DSU will comprise a portfolio of customer assets each with a different mix of demand reduction and back-up generation. There is also significant variation in the potential types of pure demand reduction varying from automated interruption of e.g. refrigeration to manual switching down / off of industrial processes with very different technical characteristics.

The combined group is likely to consist of a moderate number of DSUs with very limited running hours and a small number of AGUs with greater run hours. Splitting the categories might be unsatisfactory for both categories on the basis of lack of statistical robustness. However the RAs have only presented average outage rates for each group and have not presented any indication of the spread of outage rates between units within the group so it is difficult, without attempting to replicate the TSO's analysis, to judge whether the combined grouping is appropriate or not. Some indication can be inferred from the plots of outage rates for the combined DSU-AGU group over years which vary much more than other technology groups. In addition the difference between capacity-weighted and output-weighted averages also suggest a significant variation between units with different load factors within the group. EI requests that the RAs publish statistics on the spread of outage rates within groups and for DSUs and AGUs separately to justify their decision on this matter.

Whether or not the RAs decide to keep this combined grouping in order to provide some stability of de-rating factors, EI believes that non-zero tolerance bands are required for this group to mitigate the differing commercial risks of holding ROs arising from such legitimate technical differences.

2.2.1 D Marginal Derating Curves

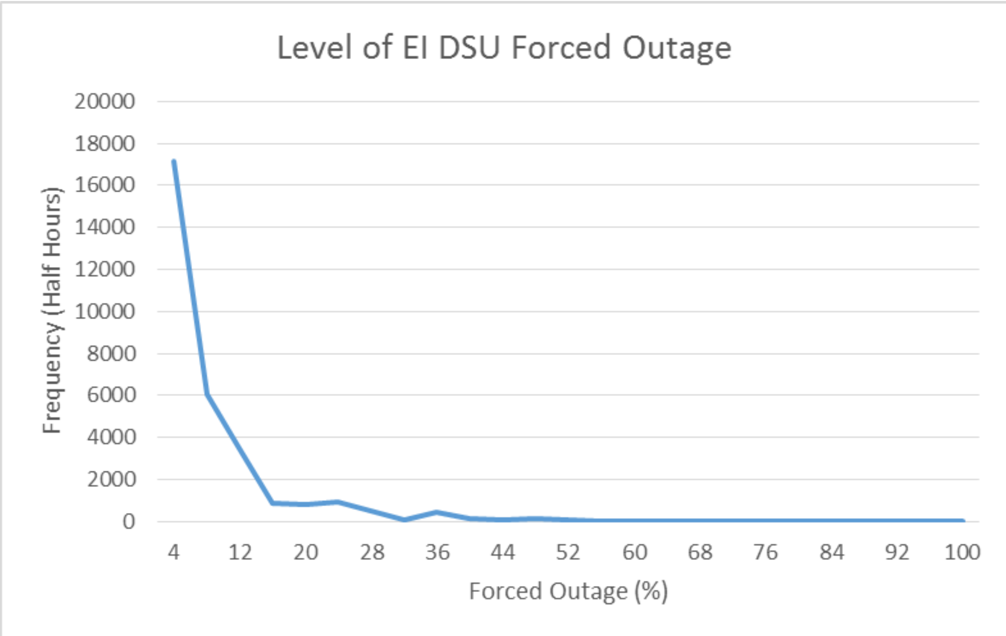
In this section EI confines its comments to the marginal de-rating curves for DSUs but goes on to consider how the 'nameplate' capacity for DSUs might be determined.

EI believes that the proposed methodology underestimates the de-rating factors for DSUs.

The biggest driver in the calculation of de-rating factors is likely to be the *forced* outage data inputs (since scheduled outages are timed, in the methodology, to avoid peak demand periods). EI believes that it is important to interpret the DSU historical data carefully in order to derive representative outage data inputs for the calculation.

Since DSUs operate on the basis of a portfolio of consumer assets, it is perhaps unlikely that all of them are able to respond to a dispatch instruction. Equally it is highly unlikely that none of them will respond. There is a parallel with the proposed treatment of Capacity Aggregation Units (CAUs) where de-rating factors are applied to individual units and then aggregated. This avoids the effect of lower de-rating factor values with increasing size which is warranted since a single large unit may be all on or all off with a significant impact while loss of all of the units in the CAU is extremely unlikely and the more likely loss of some has a much lower impact. This diversity benefit doesn't appear to be equally reflected in the treatment of DSUs which comprising a portfolio of consumer assets are similarly unlikely to be all 'off' (full DSU outage).

Consequently, other than a forced outage of the DSU control centre (a very low likelihood), any forced outage of the consumer assets is likely only to be partial. This is reflected in the operation of EI's DSU where at the dayahead stage the availability of the DSU may be redeclared down but not to zero to reflect advance knowledge of the unavailability of a customer assets. The chart below shows forced outage levels for EI's DSU for the period Jan 2015 to September 2016 inclusive.



Due to the very few occasions that DSUs have been called in the study period, there is only a limited basis on which to calculate forced outage rates directly. EI have therefore taken the approach of treating redeclarations at the day-ahead stage as scheduled outages (where there is time to find alternatives at an economic cost) and redeclarations within day as forced outages (where it may be costly to find replacement capacity). Arguably this approach provides a reasonable proxy for true (partial) non-delivery forced outages in the circumstances.

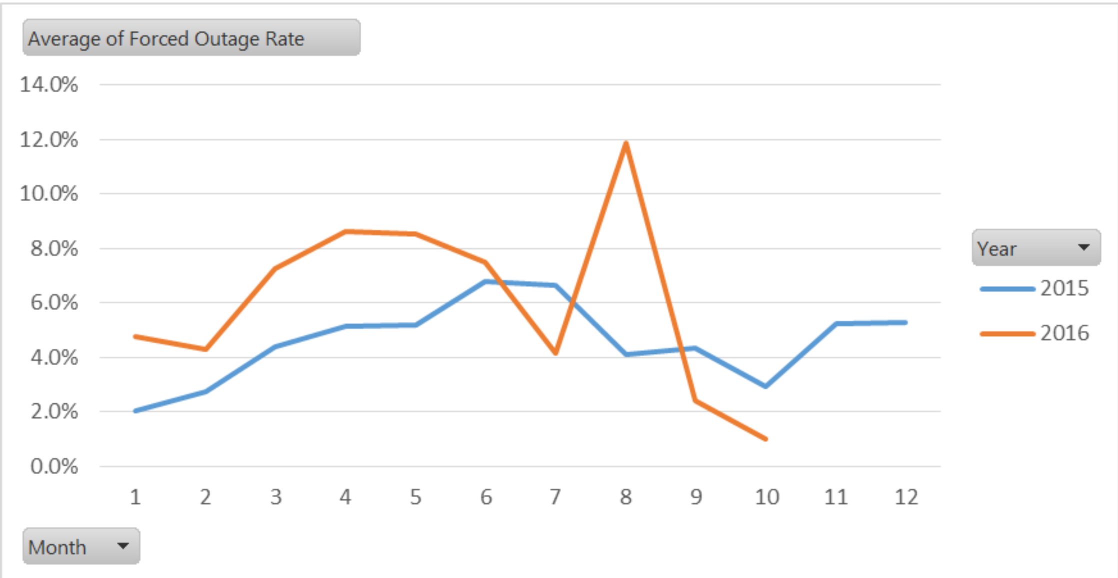
The percentage forced outage level in each half hour is calculated as:

100 x {DA available capacity – actual availability} / {DA available capacity}

It is clear from the chart that the forced outage level is almost always only partial and very rarely full. This strongly indicates that a two-state on / off model is inappropriate for DSUs. If all, or a large number, of the instances of within-day redeclarations within the historical data are treated as full forced outages, this would significantly exaggerate the forced outage rate and correspondingly underestimate the de-rating factor value. EI's calculation of the forced outage rate for its DSU is 6.1% compared to the group value of 24.7% - a large discrepancy!

It is unclear how the TSOs have identified forced outages for DSUs in the historical data and this has not been set out in the consultation. No assistance is provided by the monthly availability statistics reports since these only cover thermal plant and not DSUs. EI recommends that forced outage rates for DSUs should be calculated in the manner described above (i.e. monthly percentages reflecting partial outages) and that the RAs publish details of the methodology used to determine scheduled and forced outage statistics from the historic data. EI requests that this is made clear in the justification of the RA decision on this matter and this provides a specific example of an instance requiring rules for the interpretation of the historical data.

EI's DSU has been registered since April 2014 and during the period from January 2015 to September 2016 there have been 3 occasions when dispatch instructions have been issued (either as a test or as a market requirement). The average forced outage rate over this period was 6.1%, calculated as a percentage reduction in capacity delivered from the prevailing redeclared available capacity for each half hour and then averaged for each month and across the whole period. The corresponding scheduled outage rate is 13.4%. The monthly average forced outage rates are shown in the chart below.



These forced outage statistics for EI's DSU are significantly less than the DSU-AGU forced outage rate input value of 24.7% used in the analysis which would translate into to a much higher value for the de-rating factor than indicated for the group (since forced outage rates rather than scheduled outage rates drive this). This is further support for the assertion of legitimate technical variation within the DSU-AGU group. EI's scheduled outage rate of 13.4% is higher than the group value of 4.5% used in the analysis but EI's combined value of 19.5% is significantly lower than the group value of 29.2% indicating either anomalies in the treatment of data or significant variation within the group.

The important related topic which has not yet been properly developed is how to determine the 'nameplate' capacity for DSUs. DSUs are likely to recruit consumers constantly throughout the year and not just in time for CRM auctions. Furthermore since demand response would likely participate in CRM, DS3, and energy markets, there is unlikely to be a single time for new registration / qualification to all these markets. Consequently a different approach is necessary for DSUs than for other technologies in order to enable effective participation which provides some flexibility for including new consumer assets.

As an example, the GB capacity market provides such flexibility through the concepts of 'proven' and 'non-proven' capacity bids. In the first GB T-4 capacity auction this year, the vast majority of the total demand side response that pre-qualified (97%) and that was successful in the auction (95%) was 'unproven'. Requirements for 'proven' capacity should be based on existing SEM arrangements.

CRM qualification and T-1 auctions will necessarily occur several months in advance of the delivery year. It would hinder the development of the important demand side market if DSU nameplate capacity was very strictly determined at the time of CRM qualification and no provisions were made to allow later inclusion of further consumer assets, subject to verification, but before the start of the delivery year.

2.2.1 E Effective Interconnector Capacity

EI believes that the proposed methodology provides a starting point given the lack of valid historical flow data. However there are a number of deficiencies and anomalies that need to be addressed:

- The proposed interconnector de-rating methodology is based on the likelihood of physical scarcity in the I-SEM and GB markets. No real account is taken of the possibility that imperfect market arrangements sit over this physical situation and which may fail to deliver the flows and contributions to I-SEM system security implied by the analysis. Imperfections include: the interim IDM arrangements where only periodic cross-border trades can occur; the initial BM arrangements which do not contemplate cross border flows; uncertainties about the enduring regional balancing market where differences in scarcity prices may trump physical considerations; the limitations and nature of SO-SO trades about which little is known; and differential treatments of carbon taxes and renewable incentive schemes contributing price distortions. Consequently a much more conservative approach to interconnector de-rating is required than that proposed.
- whether or not to include the long Moyle partial outage and the recently announced significant EWIC outage within the inputs to the analysis is likely to have a critical effect on the resultant outputs. It is essential that interconnectors are treated equally to other units and that robust governance rules provide a framework for answering such questions.
- the main de-rating methodology 'pairs' wind profiles with demand profiles but the interconnector methodology develops independent demand and wind scenarios (although a sensitivity is carried out for low wind at peak)
- the main de-rating methodology uses several historic load duration profiles to develop demand scenarios (because the shape can materially influence the LOLE) but the interconnector methodology only uses an average monthly demand profile which would smooth out the shape and likely underestimate the likelihood of scarcity

The analysis carries out a number of sensitivities in the light of the many uncertainties involved and the number of assumptions that have to be made. These largely show modest sensitivities to the conditions examined. However, a prudent approach needs to be taken to interconnector de-rating factors given the important detrimental impact on the hole in the hedge. Consequently EI recommends that the final de-rating factors should be the minimum of the resultant values from all the sensitivities. In addition the nature and extent of the required sensitivities needs to be set out as part of the governance arrangements – crucially these need to include examinations of the impact of imperfect market and pricing arrangements.

2.2.1 F Interconnector De-Rating Factors

See answer above.

Section 3:- Tolerance Bands

Assessment of Options

3.2.1 Do respondents agree with the minded to decision to set tolerance bands to zero?

No. EI believes that non-zero tolerance bands are required for DSUs – see response to 2.2.1 D.

3.2.2 Alternative views on tolerance bands

EI believe that a tolerance band of at least ±10% should be applied to DSUs. This is based on the significant discrepancy of nearly 20% between forced outage rates for EI's DSU and the indicated values for the DSU-AGU group – see response to 2.2.1 D. While there appears to be a fairly close correspondence between the resultant de-rating factors and '100% minus the forced outage rate', a tolerance band greater than ±10% would allow scope for something other than a one-to-one relationship in the model.