**Power NI Energy Limited**
**Power Procurement Business (PPB)**

# I-SEM Detailed Design

# Capacity Requirement and De-Rating Factor Methodology

# Response by Power NI Energy (PPB)

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Power Procurement Business

## Introduction

PPB welcomes the opportunity to respond to the RAs consultation on the Capacity Remuneration Mechanism (CRM) detailed design consultation on the Capacity Requirement and De-Rating Factor Methodology.

## General Comments

The CRM is a critical element of the I-SEM that is essential to ensuring the long term stability and security of supply (SoS) in a small island market. Reliability Options (ROs) are relatively complex instruments that incorporate both a hedge against high spot market prices and scope to recover money that is missing more generally from the energy market. Their operation is further complicated in the context of a small system that is targeting high levels of intermittent generation.

To assist in the consideration of the proposed de-rating methodology for interconnectors, Viridian commissioned a note from NERA which provides their views on ESP's methodology paper. NERA's Memo is appended and we draw from it in this response.

We also note that there are a number of areas where thinking is stated to be still under development (e.g. in relation to the treatment of storage) or where the models used were "test models"[1]. The NERA Memo also highlights that in many areas there is insufficient information or explanation in the ESP paper to enable comment. Given these gaps, we would request that the SEMC consults further on these once the further thinking and analysis is complete and the models are fully commissioned.

### *Delivering Security of Supply for Customers*

The revisions proposed for the CRM are radical and unlike under the current capacity mechanism where excess capacity dampens the price received by all capacity, the proposed CRM will result in a significant quantity of capacity that will receive no capacity contract and hence will have a very strong signal to exit the market. The consequences of this are that there is a high probability that the capacity remaining in the market will match the calculated Capacity Requirement. Hence the Capacity Requirement that is used to set the level of contracts will set the actual security of supply provided to customers.

Assuming the Capacity Requirement is correctly determined (which we do not consider the current calculation does), this will represent a significant change

[1] TSOs' "Proposed Capacity Requirement and de-rating Methodology" paper – Section 9

for customers who will on average experience 8 hours of loss of supply per annum. Firstly, this creates a discrepancy for customers in NI where the standard for security of supply is higher. However, more critically, customers have benefitted from surplus generation for many years and no customer has been disconnected in Northern Ireland because of a generation capacity shortage in the last 40 years (and we expect this has also been the case in RoI).

We have previously argued, and provided evidence, that the actual SoS standard that is demanded has been much better than 8 hours (see PPB's response dated 22 June 2015 to the consultation on the Fixed Cost of a BNE Peaking Plant and the Capacity requirement for 2016 (SEM-15-032)) and hence providing capacity in line with an 8 hour standard will be a significant shock for customers when disconnection occurs and will be detrimental to ambitions to attract inward investment into Ireland.

Given the strong exit signals, the accurate calculation of the Capacity Requirement is critical. However as we identify below in response to the specific questions, the figure determined by the TSOs is extraordinarily low and we believe it is wholly inconsistent with the capacity requirement inherent from the "All-Island Generation Capacity Statement (2016-2025)", understating the requirement by over 1000MW before any consideration of an increase to cover the operational reserve requirement.

***Over-reliance on Interconnectors with no evidence to support such reliance***

The proposals bullishly credit interconnectors with significantly higher de-rating factors than GB credit them in their decisions. Such an approach is extremely surprising since the analysis relies on energy flows being delivered into Ireland when there is scarcity in Ireland. However the new wholesale market arrangements are not yet operational and even when they are, the most complete coupling will occur at a day-ahead stage when scarcity is unlikely to be an issue.

The potential for scarcity may be more visible Intraday but the intraday market coupling is limited to 2 auctions[2] that only cover the last 12 and last 6 hours of the day respectively and both have long lead times that again will most likely limit the capability to identify scarcity or to react to it.

[2] There is a third auction but it is effectively another Day Ahead auction as it occurs at 15:30, not long after the results of the formal DAM are known and there is unlikely to be any different information on scarcity than was known at the time of the initial DAM

Scarcity is most likely to occur close to real-time and hence the most likely opportunity to respond will be through SO-SO trading. However there is no information or decisions on how such trades will be arranged, how they will be priced, and we are not aware of any agreement that will define the respective TSOs' obligations to offer term or to honour flows when they are managing scarcity events in their controllable area.

It is therefore imprudent and highly risky to assume that energy flows will conform to economic theory, and even more so when the different price caps indicate that there would a skew towards exports to GB during co-incident scarcity, which is likely given demand correlations.

Evidence following sustained operation of the new wholesale market arrangements may allow confidence to be developed based on actual experience but we consider it would be reckless to give the interconnectors the high de-rating factors proposed which impose a high reliance on flows from GB to minimise customer disconnections in Ireland and deliver security of supply to the required standard.

It is clear that GB has taken a much more conservative approach and that they are seeking evidential experience to support any relaxation. Given that EWIC and Moyle represent a much more significant share of demand in Ireland than they do in GB, there is a strong case to take an even more conservative approach than GB has taken, which can be reviewed over time with the benefit of experience and following the bedding in of the new market arrangements.

The NERA memo comments on many of these issues.

## Responses to the Specific Questions

### *Chapter 2. Capacity Requirement and De-Rating Factor Methodology*

### *Q1: The determination of the Capacity Requirement*

We believe the Capacity Requirement is understated and that there are a number of flaws in the methodology and analysis that serve to drive this result. We have previously highlighted our concerns with what we consider are significant flaws in the annual derivation of the Capacity Requirement in the SEM (as has the EAI) and unhelpfully the response has been an unwillingness to change, with the primary justification being that the methodology was consistent with the approach used in previous years.

However, as we have pointed out each year in our responses to the consultations, and to the mid-term review, errors exist such that the SEM Capacity Requirement is understated and the methodology must be corrected since reliance on consistent application of a flawed approach is not sustainable. Perpetuating these flaws has far more serious consequences to security of supply under I-SEM which is designed to allocate capacity contracts to meet the calculated Capacity Requirement and send a sharp exit signal to capacity that does not receive an RO. This is also compounded by the increased volume of intermittent renewable capacity that was not significant a decade ago.

The TSOs' paper tries to reconcile the capacity requirement back to the SEM requirement for 2017[3] but given the previously identified errors, the only relevant reconciliation is to ensure reconciliation with the GCS figures. A simple cross-comparison for the 2017/18 year shows that the Capacity Requirement of 7,312MW, that equates to 8,012MW of installed capacity is over 1,066MW less than the capacity requirement that can be back calculated based on the Surplus shown in the GCS relative to the capacity available in the year.

It is also important to note that the GCS does not seek to provide any uplift for the provision of reserve in addition to demand to provide cover for the largest infeed and hence its inclusion in the GCS calculation would increase the gap between the Capacity Requirement determined in the TSOs paper and an adjusted GCS requirement (to account for the largest infeed).

[3] Section 9.2 on page 35

A summary of this simple calculation is shown in the table below and the more detailed analysis showing the source of the data is shown in the Appendix.

| **Data from the 2016-2025 GCS (taking 25% of 2017 and 75% of 2018)** | |
|---|---|
| | **MW** |
| **Total Dispatchable Capacity (NI + RoI)** | 10,706 |
| **Capacity Credit of Wind/Solar** ***(using the 12.5% capacity de-rating factor)*** | 569 |
| **Total effective Capacity available** | **11,275** |
| **Surplus determined** ***(1,988 MW of perfect plant converted to installed capacity using the system weighted average de-rating factor of 90%)*** | **(2,209)** |
| **Capacity required to meet 8 Hours LOLE standard** | **9,066** |
| **Capacity requirement determined for I-SEM CRM** | **8,012** |

**Other detailed concerns with the methodology**

***Use of hourly data***

The de-rating analysis is completed using hourly data. Using hourly data will result in lower average demand than would be the case if the demand data was half hourly and as a result will tend to understate the LOLE.

***Spot peak demand is not used***

Similarly, we understand the peak demand figures (historic and forecast) are based on average demand over either an hour or half-hour (not clear from the GCS which is used). However, regardless of which applies, the actual spot instantaneous peak demand within that period will be higher than the average. When PPB was responsible for producing the GCS and overall generation security in N. Ireland, our records showed the spot peak could be nearly 2% higher than the demand averaged over the half-hour period. If the analysis does not reflect the need to meet these spot demand peaks, then the LOLE will be understated and as a result the Capacity Requirement will also be understated.

***Relevance of older Load Duration Profiles***

The analysis uses load duration curves from 2007 to 2014. However it is likely that the profiles for the earlier years will be less reflective of the current demand profiles. This is likely to be particularly the case for years prior to and during the early part of the economic downturn that occurred in 2008. Similarly other developments such as energy efficiency investments will have a more pronounced impact and again the earlier profiles are less reflective of current customer consumption patterns. Such factors could have a significant impact on the resulting LOLE estimates.

***Netting Off Non-Market Generation understates the Capacity Requirement***

Section 3.4 of the TSOs' consultation papers states the intention to net Non-market generation off demand. It is not fully clear how this is being done but either the full exclusion of the generation or a deduction scaled by a wind capacity credit factor will result in the true Capacity Requirement being understated. Either approach implies there is a quantity of "perfect capacity" but this capacity may not be available (as is often the case on very cold dats when peak demand occurs) and hence by excluding it from the probabilistic analysis of all generator availability, it will overstate the probability of capacity availability and hence understate the LOLE and the Capacity Requirement.

***Availability Data***

Section 4.3.3 of the TSOs' paper indicates that availability data from retiring units is still used in the averaging because exclusion would fail to account for unit performance changing with age. However, elsewhere[4] it is noted that availability of older less efficient capacity is unreliable because the capacity rarely runs and as a consequence its availability is unproven and questionable. These two positions conflict since the latter implies the availability of older units is actually overstated and hence is skewing the data by overstating availability.

***Availability Data for new units in a new category***

Section 4.4.2 of the TSOs' paper indicated that new capacity that does not conform to an existing category will be allocated values based on the system average. However since the system average is heavily weighted by existing proven conventional technology, applying the system average may greatly overstate the contribution of capacity from a new technology which would be

[4] Section 5.4 relating to availability statistics

compounded should that be committed under a long term RO. We agree that conservatism should be applied but we do not consider that using the system-wide average delivers such conservatism and could create significant risk for security of supply. As capacity falling within new categories is unlikely to be a frequent occurrence, it may be better to assess its capability and contribution on an individual basis, consulting on it when it arises.

***Averaged Availability Statistics for Technology Categories***

Section 5.4 of the TSOs' paper sets out the proposals for determining the average technology banded availability that is then used in the derivation of the de-rating factors. The paper states that using run-hours "*has the advantage of reducing the contribution of units that have rare but very long outages, limiting the impact these have on the category weighting*".

However, in a small system such long outages create the most risk to security of supply since during such outages there is a much greater risk of coincident outages that will result in scarcity events and therefore not reflecting the risk that such extended outages do occur will result in a conscious understating of the capacity requirement thereby creating risks to security of supply for customers.

We also note that the example set out in footnote 5 at the bottom of page 20 is nonsensical since how can a peaking unit that runs for 2 hours have zero availability in the second hour it runs? If it is unavailable it cannot run!

The second last paragraph on page 20 also incorrectly states that "*Wind generator output is correlated to weather conditions and hence to demand*". It is clear that demand in Ireland is inversely correlated to temperature and the highest demand tends to occur on the coldest days. However it is also the case that during spells of very low temperatures, wind speeds also tend to be very low and hence at the critical high demand points wind generation and demand are inversely correlated (while there is little correlation beyond this).

We also note the system wide average graphs for both Forced and Planned outages in Figures 6 and 7 are wrong and such simple errors raises concerns over the integrity of the wider analysis. Based on the individual categories, the Run Hours Weighted Mean Forced Outage rate should be 5.64% and not 5.3%. Similarly the Run Hours Weighted Mean Planned Outage days should be 20.18 days and not 26.5 days.

### *Tolerance Band for Capacity Adequacy*

The last paragraph of section 6.1 of the TSOs' paper states that "*If the LOLE is within a set tolerance of the adequacy standard then the portfolio is accepted as capacity adequate*". This implies that the analysis is not targeted at 8 hours LOLE but could have a higher LOLE and hence poorer security standard for customers.

The 8 hour standard has no tolerance band and hence it is unclear why one is introduced in this section and there is no quantification of the tolerance range that is used. As a consequence it is impossible to comment on the possible impact such an approach has on the analysis.

### *Netting off Wind based on the Wind Capacity Credit*

We have a concern, similar to that set out above for Out-of-Market Wind, that In-Market Wind is netted off the demand before the probabilistic assessment of LOLP is carried out. The effect of such an approach is to assume the Wind will always deliver to the level of that Capacity Credit whereas there will be occasions, such as during very cold days, when high pressure results in no wind. By deducting the wind credit off the demand, this scenario is not reflected in the probabilistic calculations of LOLP and LOLE thereby understating the capacity required to deliver security of supply to the 8 Hour standard.

We have highlighted this issue in our past responses to the SEM BNE and Capacity Requirement consultations but are not aware of any changes to the methodology employed.

### *Conclusion*

All of the above elements raise questions on the capacity requirement and de-rating methodology and, we believe, operate to cause the Capacity Requirement to be under-stated. This seems to be corroborated by the simple analysis to compare the TSOs' derived figure in their de-rating paper to the inherent figure for capacity needed to meet an 8 hour LOLE standard that is backcast from the data published in the GCS.

### *Q2: The treatment of Operational Reserves in the determination of the Capacity Requirement.*

We support the inclusion of reserve in addition to demand prior to running the probabilistic adequacy assessment. However the 444MW used in the TSOs' analysis does not represent the largest infeed in Ireland and 500MW should be used reflecting the maximum import that could be scheduled on EWIC which is the largest infeed.

The paper also references that the 444MW corresponds to the firm capacity of the largest single generator even though non-firm capacity is not restricted from participating in the CRM and could be operating at their maximum output level. Hence "firmness" should not be a factor although currently this is a largely academic point given EWIC has the highest capacity and its 500MW capacity is the relevant one for the purposes of identifying the largest infeed and the reserve cover required.

### *Q3: The technology groupings*

We recognise the possible value of multiple units dampening the effect of infrequent abnormal outages. However the result is an average that does not distinguish between those units that are better maintained and provides no real incentive to improve their availability performance.

The expectation was that Tolerance Bands would provide a mechanism to enable differentiation but the proposal to set the band to zero removes any such scope and therefore re-opens the question of the appropriate groupings. No analysis is provided to show the range of historic performances that exist within a technology band but we believe there is likely to be a broad range. In the absence of tolerance bands then an alternative would be to have low, medium and high performance sub-categories within each technology band.

### *Q4: Determination of the marginal De-Rating curves*

#### *(i) Selection of Portfolios for Different Demand Scenarios*

It is unclear how the selection of 5 random portfolios will affect the results. If the selection picks out only the smaller generating units then that would give a very different LOLE expectation than would be produced if all the larger units were in the portfolio. If there were a large number of random profiles then there would be less risk of any distortion but with only 5, there is a much greater risk of a skew.

Footnote 6 also notes that the interconnectors are also part of the selection of capacity units. This creates a risk of circularity and it would be useful to assess the impact of excluding I/Cs from the selection process.

***(ii) Marginal De-rating Process***

The process set out in Section 6.2 describes how a notional unit is added to a capacity adequate portfolio and then demand is increased iteratively until the LOLE is again 8 hours (no tolerance noted here). However unlike all previous methods, where the demand curve is scaled up on a pro-rata basis, the demand increments in this analysis are done by adding the fixed increment in all hours. Such an approach of adding a fixed increment across the demand curve rather than scaling up the curve by a fixed percentage will tend to give less credit to the generator increment and as a result will drive lower de-rating factors.

There is no justification for adopting a different approach here than is used to scale up the base demand curves to reflect the forecast peak demand in any given year.

We note the methods employed for autoproducers and storage units. For autoproducers, it is noted that the de-rating factor would apply to its maximum export capacity and not its installed capacity. This seems to imply that the host site demand is excluded from the analysis but if the autoproducer unit is unavailable then we presume that demand will be met from the Grid. If the host demand is not included then the demands that may need to be met is under-stated which will result in the Capacity Requirement being under-stated. For storage units, we note that further work is being conducted in parallel with the consultation on the approach to adopt for storage. We presume the results of this development will then be consulted upon to enable wider industry comment?

***Q5: The determination of the Effective Interconnector Capacity***

Our first major concern with the Interconnector De-Rating methodology is that it makes a number of simplifying assumptions, assertions and estimations, the consequences of which are unknown.

Our second major concern is that the Effective Interconnector Capacity (EIC) and the subsequent De-Rated Capacity factors are much higher than GB has adopted for Interconnectors (in particular for EWIC and Moyle) in their assessment. Placing heavy reliance on energy flows being delivered during scarcity events represents a high risk strategy and this should be a major concern for the I-SEM given the facts that there will remain many uncertainties until such time as there is evidential experience that can better inform the considerations. Such uncertainties include:

(i) there is no experience of market coupling to rely upon;

(ii) the IDM provides limited opportunity for cross-border trading until XBID is operational and the interim arrangements propose only 2 true Intra-Day coupled auctions[5] which have relatively long lead times and only facilitate trading for the last 12 and last 6 hours of the trading day;

(iii) in other markets IDM trading is usually thin which may have implications for I-SEM, particularly given the IDM and BM are open contemporaneously;

(iv) there is no clarity as to how TSO-TSO balancing trades will be conducted or how they will be priced and this could result in limited coupling in the realtime balancing timeframe;

(v) the dynamic of higher price caps in GB than in I-SEM should result in flows to GB at times of co-incident scarcity; and

(vi) there is uncertainty as to whether TSOs will actually disconnect local customers to maintain exports.

All of these risks and uncertainties should point to placing a conservative reliance on Interconnectors until there is proven experience of energy flows during scarcity events when the markets are fully coupled. The regret cost of over-reliance is significantly greater than from taking a prudent approach since the consequence is likely to result in the closure of capacity in I-SEM which is not an outcome that can be easily reversed.

It is also noteworthy that GB has adopted a conservative policy, starting off at a low level of reliance that can then be increased as experience is gained. There are compelling reasons why I-SEM should take a more conservative approach that GB since 950MW of Interconnector capacity represents nearly 15% of I-SEM peak demand whereas the Irish Interconnectors only account for c1.8% of the GB peak demand. Hence the regret cost to GB is much less material yet they still adopt a conservative approach.

[5] There is a third auction but it is effectively another Day Ahead auction as it occurs at 15:30, not long after the results of the formal DAM are known and there is unlikely to be any different information on scarcity than was known at the time of the initial DAM

Other factors that should also be taken into account when assessing the de-rating factors for the interconnectors include:

(i) GB is known to be facing scarcity over the next number of years with early closure of coal plants, nuclear closure and delays in their replacement, etc. This is supported by the recent evidence showing a change to the direction of interconnector flows;

(ii) The analysis excludes prolonged outages on Moyle from the Forced and Planned Outage rates. This is different to the methodology adopted for generators in the I-SEM and there is no basis for such exclusion. The recent forced outage on EWIC (that is likely to extend to 6 months duration) provides further evidence that such outages must be included in the analysis.

The risk of over-reliance on interconnectors can be simply illustrated by contrasting the peak demand with the determined de-rated Capacity Requirement and considering the consequences of imports not occurring at times of scarcity on a peak demand day when there is zero wind.

| **Illustration of the impact on capacity margin if imports do not occur during scarcity events where there is zero wind** | |
|---|---|
| **2017/18** | **MW** |
| **De-Rated Capacity Requirement determined for I-SEM CRM** ***(from Table 5 in section 9.2 of the TSOs' paper)*** | 7,312 |
| **Capacity Credit of Wind/Solar** ***(using the 12.5% de-rating factor shown in Table 4 in section 9.1 of the TSOs' paper)*** | (569) |
| **Capacity Credit of I/Cs** ***(using de-rating factors shown in Table 4 in section 9.1 of the TSOs' paper)*** | (824) |
| **De-Rated Capacity available to meet demand** | **5,919** |
| **Nominal Capacity available to meet demand** ***(using an average de-rating factor of 10% to convert to installed capacity)*** | **6,577** |
| **Median Market Demand + reserve** | **7,090** |
| **Capacity Shortfall** | **(513)** |

This shows that on the peak day with no wind and no interconnector flows and even with all other capacity fully available, there would be a capacity shortage of over 500MW. This shortage would be further exacerbated if exports were actually scheduled (e.g. because GB prices were higher than the I-SEM price cap) or there were outages on other conventional capacity.

The analysis shown in our response to Question 1 above highlights that the Capacity Requirement is understated relative to the figure derived from the GCS and if the Capacity Requirement were increased to align with that higher figure then the above c500MW deficit would be a surplus that could cope with the outage of one large conventional unit but not two and nor would it protect should the interconnectors export when there is scarcity. This further supports our view that a more prudent de-rating factor should be adopted which could be incrementally increased over time as evidence of the operation of the interconnectors during scarcity events is witnessed.

A further cost of conferring a high de-rated capacity to interconnectors relates to the decision that Interconnectors are only liable to make difference payments under the RO when they are physically unavailable. Hence when market prices would otherwise trigger RO payments for other RO holders, no payments would be made by the Interconnector capacity on such occasions and also regardless of which direction energy is flowing on them. This creates a significant “hole in the hedge” for suppliers. Based on the TSOs’ calculated Capacity Requirement of 7,312MW, the proposed de-rated Interconnector capacity of 824MW represents 11.3% of the ROs and hence creates a hole covering 11.3% of Customer Demand. This has significant implications for customers and, potentially, Supplier cashflows as they are exposed to funding any shortfall where any such “hole in the hedge” arises.

The NERA Memo also highlights a number of flaws in the proposed methodology which supports our considerations set out above.

***Q6: The use of the TSO De-Rating Model in conjunction with the RA determined values of Effective Interconnector Capacity and the outage rates for the Interconnector Technology Class to determine the marginal de-rating factors to be applied to the interconnectors.***

As outlined in response to Question 5, the mechanistic approach of applying the TSOs methodology, used to assess the marginal value of conventional capacity, is not an appropriate approach when considering interconnectors. As we have highlighted above and as also discussed in the NERA Memo, the drivers of availability and the potential for energy delivery in times of scarcity are very different for interconnectors and have very different consequences for consumers. As already noted, the exposure to the interconnector owner is very different to that of a conventional generating unit since Interconnectors only pay out when they are physically unavailable but have no obligation to deliver energy to meet customer demand.

Similarly, the price caps are higher in GB than in I-SEM and this could influence flows into GB notwithstanding there is scarcity in I-SEM. Further there may be other factors in GB such as locational or transmission network constraints, or National Grid’s policy in relation to balancing / rescue flows when the GB system is tight, which mean they may not agree to SO-SO trades that are assumed to be available under the ESP methodology.

The consequence is that we do not believe the proposed approach takes adequate account of the risks of reliance on support of energy flows across Interconnectors during scarcity events which results in the proposed de-rating factors for Interconnectors being too high.

## *Chapter 3. <u>Tolerance Bands</u>*

***Q1: Do respondents agree with the minded decision to set tolerance bands to zero?***

We do not agree with the proposal to set the tolerance band to zero. The SEMC decision was to provide for tolerance bands but setting the band to zero effectively overturns that decision.

As we have already discussed in our response to Chapter 2, Question 3, tolerance bands would allow some differentiation for units, that are confident their performance will exceed their “band average”, to contract for a higher capacity and for units with concerns over their availability (e.g. because it is approaching the end of its life) and who are not confident of achieving the “band average” technology class performance to take a more conservative approach.

As we also noted, having no tolerance band removes the incentive to improve performance which is inefficient and will impose unnecessary costs on consumers.

# Appendix :

## Reverse Engineering the Capacity required to meet demand to the Generation Security Standard (using data from 2016-2025 GAR)

| | From GCS | | Derived | *Note : 2017/18 is derived from taking 25% of 2017 and 75% of 2018 figures* |
|---|---|---|---|---|
| **All- Island Assessment** | **2017** | **2018** | **2017/18** | |
| | **MW** | **MW** | **MW** | ***Notes*** |
| Transmission Peak (MW) | 6,769 | 6,818 | 6,806 | *(from table A-1)* |
| TER Peak (MW) | 6,888 | 6,938 | 6,926 | *(from table A-1)* |
| | | | | |
| Total Conventional capacity in RoI | 7,704 | 7,706 | 7,706 | *(from table A-4 - includes EWIC)* |
| Total Conventional capacity in NI | 2,668 | 2,668 | 2,668 | *(from table A-5 - includes Moyle I/C)* |
| Total Dispatchable Renewables in RoI | 257 | 282 | 276 | *(from table A-9, excluding wind and solar)* |
| Total Dispatchable Renewables in NI | 53 | 58 | 57 | *(from table A-6, excluding wind and solar)* |
| | | | | |
| **Total Dispatchable Capacity in Ireland** | **10,682** | **10,714** | **10,706** | |
| | | | | |
| Wind/Solar in RoI | 3,040 | 3,355 | 3,276 | *(from table A-9)* |
| Wind/Solar in NI | 1,153 | 1,317 | 1,276 | *(from table A-6)* |
| **Total Non-Dispatchable Capacity in Ireland** | **4,193** | **4,672** | **4,552** | |
| | | | | |
| **Wind/Solar Credit** | **524** | **584** | **569** | *(based on proposed de-rating factor of 12.5%)* |
| | | | | |
| **Total Capacity available** | **11,206** | **11,298** | **11,275** | |
| | | | | |
| Surplus Capacity determined (De-Rated) | - 2,071 | - 1,960 | - 1,988 | *(as per Table A-17 – perfect plant )* |
| Surplus Capacity determined (Nominal) | - 2,301 | - 2,178 | - 2,209 | *(90% average De-Rating factor assumed to convert to installed capacity values)* |
| | | | | |
| **Inherent Capacity needed to meet GSS** | **8,905** | **9,120** | **9,066** | *(deducting the surplus capacity from the total capacity to leave the capacity needed to meet the Generation Security Standard)* |
| | | | | |
| Plant Margin vs Transmission Peak | **31.6%** | **33.8%** | **33.2%** | |
| Plant Margin vs TER Peak | **29.3%** | **31.5%** | **30.9%** | |

## Proposed Annual Requirement for 2017/18 (as per TSO paper dated 22 August 2016)

| | MW | |
|---|---|---|
| Capacity Requirement (De-Rated) | 7,312 | *(from Table 5 of the TSOs paper - page 35)* |
| Capacity Requirement (Installed) | 8,012 | *(from paragraph immediately below Table 5 of the TSOs paper - page 35)* |
| | | |
| **Difference to Capacity Inherent in GCS** | **- 1,054** | |
| | | |
| Plant Margin vs Transmission Peak | **18.4%** | |
| Plant Margin vs TER Peak | **16.3%** | |