Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2010_25 & RC_2010_37
Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO) and Methodology 2 (Griffin Energy)

Submitted by

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Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

Infigen does not support this proposed rule change in its current form.

Given the IMO position in its draft report, it is clear that the proposed methodology based on the Sapere report will be generally accepted by the IMO. The process has been extremely flawed, and it is a stretch to call the introduction of a new methodology after the first submission period a "modification". Even with an extended second submission period and presentation, this is a poor precedent to set for future Rule Changes. Despite this, Infigen can support the methodology with several important modifications. The key elements in the implementation of the framework that Infigen does not support are:

a. the selection of the peak periods using the LSG method, and

b. the method of determining the adjustment for variability (in particular the use of the U factor),

It should also be noted that Infigen does not agree with the use of 12 peak intervals each year, and believes a more statistically robust approach would be to use all afternoon intervals in the hot season, however we can accept the use of 12 peak demand intervals over 5 years (selected without using LSG). This is also more aligned with international practice.

The reasons that these elements are not supported are detailed below.

Selection of Peak Periods Using LSG

The LSG concept is flawed, and cannot be supported by Infigen for the following reasons:

1. LSG introduces additional and unavoidable volatility of outcomes when new entrant data is introduced. LSG intervals for previous years (still used in calculations) will change with new entrant data, increasing uncertainty of revenues. This will make it almost impossible to rely on capacity credit revenue in financing new plant.

2. LSG manifestly discriminates against Intermittent Generation by discounting intervals where their generation is greater. For any two high load intervals with equal load, the interval where intermittent generation is least will be selected, thereby discounting its contribution. The argument that the system is at a higher risk during a higher LSG interval is spurious. Other generators are only judged on their performance during the identified high risk times, so the same should hold true for intermittent generators.

3. The IMO Draft Rule Change Report states "there is a strong rationale for using LSG …as LSG is highest in Trading Intervals when additional capacity has the highest value to the market." This is an additional criterion that would apply only to Intermittent Generators – the selection of the highest load trading intervals should already achieve this end. The highest marginal value of capacity credits is not used for other types of generation.

4. The LSG methodology also makes each independent intermittent generator dependant on the others for its contribution to the capacity market. This is not the case with other forms of Capacity Classes (Scheduled Generation, DSM).

5. Contrary to assertions in the Rule Change proposals and the Sapere report, LSG has not "gained acceptance'. It was not an agreed outcome of the REGWG. It also has no precedent in international markets.

6. Determination of LSG intervals introduces complexity and administrative cost into the process that is unnecessary, and does not provide any tangible benefit in return.

7. No Market Participant (or potential participant) can independently calculate their Capacity Credit revenue without requesting the LSG intervals from the IMO. Even when intervals are provided, they are likely to change with new entrants, and therefore require assumptions to be made about which new generation will enter the market at which time, and what that effect may be. ***This is already a problem as existing facilities have not been able to model the impact of Collgar wind farm on their capacity credits using the proposed methodology.***

8. ***Infigen Suggested Amendment.*** It is suggested that the proposed methodology replace LSG as the determinant of the 12 Trading Intervals used in each of the five years, and replace it with maximum demand.

Adjustment For Variability

The Milligan NREL report[1] referenced in the Sapere report distinguishes two broad categories of methodologies used in the US to determine capacity credits for wind generators, namely Effective Load Carrying Capacity (ELCC) and time based (Peak Period). ELCC is a complicated process that is used to determine risk in the network as a whole and uses sophisticated time weighted databases and Monte Carlo simulations. For this reason, time based Peak Period approximation methods are used in the majority of jurisdictions. The common themes in all of these methods are:

a. selection of intervals by using all identified peak time intervals in the high risk season,
b. use of a several year rolling average, and
c. no application of a correction factor.

The Sapere method is an attempt to produce a hybrid between ELCC and Peak period methodologies. The use of the Z method is only identified in one jurisdiction that uses ELCC. This method does not reflect the methodologies used in the WEM to identify high risk periods.

The two reasons put forward in the Sapere report to adjust the average facility output during peaks are:

1. To adjust for known variability in facility output.
2. To adjust for unknown performance during peak times.

The second reason is cited as dominant, however the method to account for this, namely the U factor, is a redundant element. When a 1 in 10 year POE event occurs, this will be reflected in the calculations without the need for the U Factor. The rolling five-year assessment means that a 1 in 10 year POE event will be reflected going forward for at least the next five years. This rolling average was selected in part because of the amount of data currently available. Moving forward, it is perhaps the case that this average should be extended on a year-by-year basis to finally reach and sit at a rolling 10-year average that is consistent with risk analysis of the system as a whole. New entrants without sufficient data could be allocated the fleet average capacity factor for the years they have no data.

Wind in WA is well correlated to system peak. Research by MMA used in the REGWG shows that the average annual capacity factor for WA wind farms has a very strong correlation to the performance of these wind farms during summer peak intervals.

Infigen Suggested Amendments

1. The U Factor should be removed from adjustment formula
2. The methodology should transition to a rolling 10-year average.

[1] Milligan, Porter, 2008, Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation, Conference Paper NREL/CP-500-43433 June 2008

Rule Change Should be Part of An Overall Review of System Risk and the Capacity Credit Mechanism

The latest IMO SOO shows that the highest risk times over the last few years have not all been high temperature events, but rather the Varanus Island explosion, and for the last year, the tropical cyclone interrupting supply during the hot season. There have been no calls to adjust the capacity values for gas generators due to heightened supply risks that have far more dire consequences for the system than wind intermittency.

It is also the case that at times when scheduled maintenance is taking place, there is also elevated risk to the system.

The current methodologies provide zero value to capacity contributions beyond a single 1 in 10 year event, however this has clearly been shown to be only one element of system risk, and not the major one in the last several years.

The overall capacity credit methodology should reflect time weightings over the course of the year to capacity values, and this should be reflected in the methodologies for determining the capacity values for intermittent generators.

Conclusion

Infigen will support the proposed methodology with the following changes:

1. Remove the LSG concept and select intervals based on peak demand.
2. Remove the U Factor from the adjustment formula.
3. Transition to a rolling 10-year average from 5 years as data becomes available.