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INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

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Submissions
Electricity Authority
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By email: jo.mackay@ea.govt.nz

Dear Electricity Authority Board Members,

RE: Consultation Paper – List of distributed generation eligible to receive ACOT, Upper South Island

The IEGA recently became aware of further highly relevant information for your analysis of distributed generation that should be eligible for ACOT. This is contained in Transpower New Zealand's report to the Authority on "The role of peak pricing for transmission" – available on Transpower's web site[1].

This report analyses the impact of removing the price incentive to control load – that is, removing the RCPD price from the transmission pricing methodology.

This analysis is insightful about the potential impact of changing ACOT arrangements. The RCPD price incentivised distributed generation to maximise generation during regional peaks in order to receive ACOT payments. The incentives on distributed generation change with the removal of eligibility to ACOT.

A reduction in load control, ie increase in demand at peak, is exactly the same as a reduction in output from distributed generation at peak, ie, an increase in demand for electricity delivered by the transmission grid at peak.

Transpower has analysed the impact of a reduction in load control on:

- the need date for transmission investment of in two switching stations in the USI region bringing the need date for a $44.2m investment forward by 2-4 years – Attachment C Case Study 1; and

[1] See https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission

- wholesale electricity prices, confirming that load control in response to the TPM peak price signal has a positive system impacts (ie, lower wholesale prices) – Attachment D.

The following reviews the results of Case Study 1. Upper South Island voltage stability to examine the impact of a reduction in distributed generation output.

Case Study 1. Upper South Island voltage stability

The case study investigates how each transmission investment's need date might be impacted by removal of the existing price incentive (RCPD price) on EDBs to use load control to limit their offtake from the grid during regional coincident peaks. The study concludes that:

> When the EDB winter load in the USI is scaled up by 3%, the need date of the new switching stations is advanced by approximately 2 years from summer 2027 to winter 2025. When the EDB winter load in the area is scaled by 7%, the need date of the new switching stations is advanced by approximately 4 years from summer 2027 to winter 2023. The indicative cost of such a project is around $44.2 million.[24]

As discussed above, the RCPD price incentivised distributed generation to maximise generation during regional peaks in order to receive ACOT payments. The incentives on distributed generation change with the removal of eligibility to ACOT.

If the draft list of eligible DG is confirmed, there is 49.6MW of existing DG that has been contributing to the winter regional peak which is no longer incentivised to maximise generation during that period (ie the DG that has been identified as not being eligible to receive ACOT). This is the same as an increase in peak demand of 49.6MW and is 1.5x the increase in USI peak demand when Transpower used a scaling factor of 3%.

If it is assumed that a reduction in distributed generation of 49.6MW has the same impact on the need date for two new switching stations (estimated to cost $44.2 million), a reduction of this magnitude brings forward the need date by 3 years:

Transpower's analysis:	**Scale by 3%**	**Scale by 7%**
2018 Peak Demand Forecast (TPR-2017)	1,111.0	1,111.0
Scaled	1,144.3	1,188.8
Increase in peak load	33	78
Brings forward need date (years)	2	4
Estimating the impact of reduced distributed generation output:		
DG that no longer generates during peak demand	49.6	49.6
DG relative to increase in peak load	1.5	0.6
Brings forward need date (years)	3.0	2.6

The need date is bought forward by 3 years as soon as this DG is no longer eligible for ACOT (from 1 October 2019).

However, once / if the transmission pricing methodology is changed to remove the RCPD peak demand signal these impacts are cumulative.

The need date for the two new switching stations moves from summer 2027 to winter 2022 (3% scaling and 49.6MW less DG output) or summer 2020/2021 (7% scaling).

With 3% scaling the need date is almost within the timeframe used for the analysis of eligibility for ACOT; with 7% scaling it is clearly within the timeframe.

Conclusion

It is not clear if the same assumptions and modelling was undertaken in the two different studies – distributed generation contribution to n-1 reliability and the impact of load control on transmission need date.

The analysis of whether USI distributed generation contributes to n-1 reliability and is therefore eligible for ACOT assumed one new switching station at St Andrews:

- An additional load has been included at Studholme to represent a possible new substation, St Andrews, which has been included to assess issues at a regional and grid backbone level.

The Mitton ElectroNet report also states:

> If the existing Timaru – Studholme line is assumed as remaining unchanged following the additional load at St Andrews being added, voltage collapse occurs for numerous outages in 2021 and beyond. While it is unrealistic to use this for drawing conclusions, voltage stability is an existing issue in the area and is more likely to occur following the additional load being added. Albury DG will continue to assist with alleviating voltage issues in the area, although the extent of this cannot be accurately determined until more details of future upgrades are known.

However, the latest information demonstrates that the timing of the transmission investment needed to manage voltage stability in the Upper South Island is very sensitive to changes in peak demand which can arise due to reduced load control or reduced distributed generation output.

The analysis for ACOT eligibility was over 15 years. Within this timeframe it seems very likely the transmission pricing methodology will change. It seems unrealistic to ignore the impact of a change in peak pricing on load control in the analysis of whether distributed generation is needed to meet n-1 reliability in the Upper South Island.

Further, Transpower states its estimates of load control volumes are conservative. The IEGA provided a report from EnergyLink[2] with its submission on USI eligible DG which included data about USI load control managed by Orion. On 8 September 2015 91MW was controlled during the day and 114MW during the night. Further, Appendix D1 of Transpower's report shows the maximum load control reported by EDBs in 2016 was 210MW in 2016.

[2] See https://www.ea.govt.nz/dmsdocument/24277-iega-appendix-1

Recommendation

IEGA submits that before the list of eligible USI DG is finalised the Electricity Authority must take into account the combined impact on transmission investment of an increase in peak demand due to reduced load control and reduced output from distributed generation.

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb
Chair