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Submissions
Electricity Authority
P O Box 10041
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By email: Submissions@ea.govt.nz

Dear Electricity Authority Board members,

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

Kawatiri Energy owns and operates a 4.2MW hydro generating station at Lake Rochfort in the Buller region on the West Coast. This plant has storage and has been operating since 2013. Water comes into the storage lake from a number of tributaries along the Mt Rockfort range and the generation plant can operate at 100% capacity for 2.5 days from a position of full storage. The plant has a frequency governor and is able to support the entire Buller network outside of peak load periods as well as inject power into the transmission network.

Kawatiri's plant is significant in the Buller Electricity Limited (BEL) network. Distributed generation (DG) accounts for ~30% of maximum coincident MWs and GWh demand on that network[1].

Transpower[2] explicitly includes Kawatiri generation in its planning for operating and maintaining the grid to the required standards.

Kawatiri is a member of the Independent Electricity Generators Association Incorporated (IEGA) and support the IEGA's submission.

[1] Buller Electricity Limited 2018 Asset Management Plan. Maximum coincident demand on the network is 11MW made up of supply from DG of 3MW and supply from the grid at 8MW. For the year end 31 March 2019 BEL forecast DG to supply 16GWhs of total demand of 54GWhs.
[2] Page 284 Transpower New Zealand Limited Transmission Planning Report https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%20Final.pdf

KAWATIRI ENERGY

The Authority is not in a position to decide about DG eligible for ACOT in the Upper South Island

The Electricity Authority (Authority) is not in a position to decide about DG eligible for ACOT in the Upper South Island (USI) because Transpower did not meet its obligations under The Code in its report to the Authority.

The Authority described a test in the amended Code that Transpower was required to use to assess DG. This is, "*Transpower must … provide a report to the Authority that identifies which (if any) distributed generation located in the Upper South Island is required for Transpower to meet the grid reliability standards in the period ...*"

However, this is not the approach that Transpower took and is not the analysis that Electronet Mitton (Mitton) were asked to undertake. Mitton's analysis "*focuses on determining the Distributed Generation (DG) "required", to maintain N-1 security until 2025.*" "*… the analysis was completed by comparing the differences between:*

- *a "DG ON" scenario, with DG contributing to the network, according to their measured recent contribution, at times of network peak demand; and*
- *a "DG OFF" scenario, with all DG switched off."*

This n-1 analysis is not the same as analysing DG that is required to ensure the Grid Reliability Standards (GRS) detailed in the Code.

The Code states under clause 2 of schedule 12.2:

> "2 The grid reliability standards
>
> (1) The purpose of the grid reliability standards is to provide a basis for Transpower and other parties to appraise opportunities for transmission investments and transmission alternatives.
>
> (2) For the purpose of subclause (1), the grid satisfies the grid reliability standards if—
>
>> (a) the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented; and
>>
>> (b) with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following a single credible contingency event occurring on the core grid."

In the context of the ACOT assessment distributed generation is being assessed as a transmission alternative. As the transmission lines into Westport are non-core grid then sub-clause under 2(2)(b) – n-1 – does not apply and only clause 2(1)(a) – economic reliability – applies. However, even for core grid <u>both</u> n-1 and economic reliability must apply.

The Code defines economic reliability investments under sub-clause 3(2) of schedule 12.2:

> "(2) Economic reliability investments means investments in the grid and transmission alternatives that would satisfy the economic test for an investment proposal applied by the Commerce Commission under Part 4 of the Commerce Act 1986—

(a) assuming that the economic test was applied to both investments in the grid and transmission alternatives; and

(b) having regard to Parts 7 and 8 (including the policy statement)."

This definition again makes it clear that the test applies to transmission alternatives, such as distributed generation, and must pass an economic net benefit test as specified by the Commerce Act. The test must be applied for any potential change to the Grid Reliability Standards whether they result in an increase of service level or a decrease.

Transpower has clearly not met the requirement in the Code because its assessment was entirely based on n-1 criteria, even on non-core grid. There is good reason to believe this has led Transpower to come to the wrong conclusions about eligible distributed generation.

A relevant example of where the incorrect approach may have led to the wrong conclusions is the issue of voltage stability in the USI.

Voltage stability on the West Coast and Upper South Island has been an issue highlighted by Transpower in both its 2015 and 2017 Transmission Planning Reports[3] in its analysis of the West Coast grid. Both of the planning reports identify possible voltage instability on the West Coast 110kV and 66kV for certain bus faults, the outcome of which would be dependent on the contribution from local generation (among other factors).

The Mitton report identifies the potential for voltage collapse on the 66kV for a circuit failure if one of the DGs that has been deemed necessary to maintain n-1 reliability is not in service. Mitton raised concerns about voltage stability in its report but has not investigated it because it doesn't meet the brief provided by Transpower (necessary to meet n-1).

However, the test given to Transpower for the DG assessments (detailed in the Code) was to assess if the Grid Reliability Standards were met, i.e. economic reliability at all GXPs as a minimum.

Transpower's reasoning in the Transmission Planning Reports for not requiring a grid investment to fix the voltage problem is that the local customers have not asked for higher reliability. However, any reduction of active voltage sources and potential providers of dynamic reactive support in this region must increase the voltage stability problem. For example, the Kawatiri power station absorbed 2,000 AMPs when the 33kV line between Karamea and Ngakawau touched so that this voltage excursion was not seen at the transmission grid at Robertson Street GXP. Any reduction in DG contribution is a reduction in the service levels for the USI and must pass an Economic Investment Test to be applied as Grid Reliability Standards.

Kawatiri concludes that the Authority does not have the right information to be able to determine if Kawatiri is eligible to continue to receive ACOT. Transpower has failed to meet its Code requirements by applying an n-1 test when it should have applied an Economic Investment Test. It is likely that applying the correct test would lead to substantially different conclusions.

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[3] Transpower New Zealand Limited, 2017 Transmission Planning Report page 294 https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%20Final.pdf

Implications of Electricity Authority's boundary decisions

There are three decisions made by the Authority during implementation that mean that the Authority does not have the correct information in order to make a decision on whether Kawatiri should be ineligible to continue to receive ACOT.

a. Inconsistent application of assessment analysis - the bright line for DG investment does not apply to transmission investment

The Authority's Code change created a bright line and froze existing DG in stone on the date of the announcement of the Code change – 6 December 2016 without equivalent treatment of transmission investment or the transmission grid.

Mitton's analysis for the first transmission region – the Lower South Island – used the 2015 Transmission Planning Report. Subsequent analysis for the other regions has used the 2017 Transmission Planning Report (TPR) – updated for new assumptions about both demand and supply.

This approach has allowed Transpower to take into account changes in assumptions about regional demand as well as changes in assumptions about transmission investment projects. This has happened without detailed analysis of whether existing DG, or other transmission alternatives, would be a more efficient investment compared with traditional transmission infrastructure.

One side of the contract can make no changes (DG) while the other side can (transmission) – this is not consistent with natural justice.

b. Decision to implement the Code change in a particular order

The Upper South Island (USI) region is widely recognised as being a constrained part of the transmission grid. BEL coordinates its demand management with Westpower, Network Tasman, Nelson Electricity, Marlborough Lines, Orion, MainPower, EA Networks and Alpine Energy to manage the USI peak.[4]

The Authority recognised this when it chose to implement the revised Code in the USI last. The Authority described the reason for phasing implementation in the December 2016 decision paper[5]:

> 3.43 The phasing also recognises that:
>
> (a) distributed generation located in the UNI region are more likely to deliver avoided transmission benefits than those in the LSI or LNI (but less likely than the USI)
>
> (b) potential reliability risks in the UNI region are higher than in the LSI or LNI (but lower than in the USI).

If the Authority's decision had been to implement the Code change for the USI first, using the 2015 TPR, the outcome would have been substantially different.

[4] Buller Electricity Limited 2018 Asset Management Plan Page 130 https://www.bullerelectricity.co.nz/wp-content/uploads/BEL-AMP-2018.pdf

[5] https://www.ea.govt.nz/dmsdocument/21514-decision-paper-review-of-distributed-generation-pricing-principles Page 33

For example, the demand forecast differences between 2015 and 2017 are substantially different and are highly likely to affect conclusions. In the 2015 TPR demand was forecast to be 70MW in 2015 growing to 85MW over 15 years. Whereas the 2017 TPR forecasts demand of 49MW in 2017 growing to 68MW over 15 years. This is a difference of over 20MW or a 29% reduction in the peak demand forecast from 2015 to 2017.

Kawatiri submit this is not a robust, best practice outcome for a credible regulator.

c. Assessment period

The Authority determined that DG's contribution to grid reliability be assessed over only a short three year period, 1 April 2017 to 31 March 2020. Correctly, in our view, Transpower also analysed the contribution of DG out to 2021 and also in 2025 to provide more context for the analysis.

It is particularly concerning that Mitton has identified that DG connected to four more GXPs are necessary to meet n-1 reliability from winter 2021 based on regional grid analysis – this is only a year after the end of the period determined by the Authority for this analysis. In the context of transmission planning and asset life a year is drop in the ocean.

Mitton identified that a total of 85% of currently installed USI DG is required for Transpower to meet an n-1 standard in winter June 2021.

No information is provided about the sensitivity of the n-1 test to changes in demand assumptions. A small, even seasonal, change in, say irrigation, load could mean DG currently assessed as not being required to meet the n-1 test is required before 31 March 2020.

Kawatiri submit the Authority has insufficient information to be assured that the n-1 test won't be breached.

Counter-intuitive outcome

That Kawatiri is excluded from the list of DG eligible for ACOT is counter-intuitive because:

- the Authority determines the phasing of the USI assessment acknowledging that the USI is most likely to need ACOT and is the highest reliability risk,
- the phasing of the USI analysis leads to Transpower rebasing its assumptions from those used on earlier ACOT assessments,
- which leads to, in conjunction with applying the incorrect criteria (n-1 only), the conclusion that the riskiest transmission region most likely to require DG does not require much DG for grid reliability.

Recommendations

In order for the Authority to have the information they require under the Code to assess DG eligibility, Kawatiri recommends that:

- the Authority discard its draft list of USI distributed generation that qualifies for ACOT
- the Authority instructs Transpower to do the correct Economic Investment tests against the Grid Reliability Standards as it is required to under the Code

- the Authority instructs Transpower to use the same baseline, grid configuration and input assumptions as it used for the first ACOT assessment.

Kawatiri Energy would appreciate the opportunity to discuss this submission with the Authority's Board members.

Yours sincerely,

Duncan McKinlay

Director

Kawatiri Energy Limited