81a Hakiaha Street

PO Box 363

Taumarunui 3946

Phone: 027 4792 388

Email: cfincham@kce.co.nz

Electricity Authority
Level 7, AON Centre
1 Willis Street
Wellington 6011
New Zealand

19 October 2022

King Country Energy Submission on ACOT Code Change

King Country Energy (KCE) welcomes the opportunity to provide feedback to the Authority on their Avoided Cost of Transmission (ACOT) – proposed TPM related amendments consultation paper (**Consultation paper**).

The Authority intends to:

- Amend the pricing principles which require distributors to consider how distributed generation lowers their transmission costs when determining the DG's connection costs.
- Potentially introduce these changes without a transition.

KCE owns and operates 45.2 MW of distributed generation, 37.9MW of which is storable over the week. We have managed our plant to target Regional Coincident Peak Demand (RCPD) periods for many decades. This operation has helped to alleviate peak congestion providing a valuable service to New Zealand's transmission network.

We are concerned about the transition away from the RCPD charges. Previously these price signals have had an important impact on our operational decisions, facilitating the efficient operation of distributed generation at peaks.

New Zealand is expected to undertake transformational demand growth due to electrification. There is currently active interest in the reliability of New Zealands electricity network following the 9 August event and recent, ongoing publicity around a number of other potential supply issues. These reinforce the public interest in ensuring that sufficient capacity, from both distributed generation and load control is operating to reduce demand at a GXP at during peak demand periods.

It is simply not acceptable for the lights to go out. A transional arrangement away from the RCPD charge provides important insurance against this occuring during a period where the industry is grappling with an uncertain energy transition and seeking to undererstand the new energy ecosystem that is emerging, including as a result of changes to the TPM.

The current RCPD price signal has been neccesary to ensure that we operate our plant during peak periods and has influenced decisions beyond what nodal pricing incentivises. We have cancelled planned outages as a consequence of revised projections which suggested that an RCPD period was expected to occur within the timeframe of the outage.

KCE currently continues to operate our plant as if we were to continue to recieve RCPD charges. This choice is as a precaution in case the implementation of TPM were to be delayed or if a transitory arrangement were to be put in place. Once we receive certainty regarding the removal of these payments we will no longer make such adjustments to target peaks. The potential difference in nodal prices created will be too small to justify cancelling our arrangements for planned outages with contractors. Furthermore the time periods in which the nodal price signal might impact our behaviour such as scaracity events are unknowable far enough in advance for us to adjust our behaviour.

The risk of planned outages occuring during peak periods in the shoulder periods of the year is more likely for comparitively smaller generators such as KCE as we have to work around the availability of expect contractors. These contractors are often unavailable during the lower peak risk summer periods as they are undertaking maintanence work on the larger plant of our competitors.

These operational decisions demonstrate that the value of the RCPD signal has been critical in influencing behavior. The nodal price has too much uncertainty as to whether or not a transmission constraint or scarcity event will actually occur and consequently does not influence these types of decisions which must be made in advance.

Calderwood Advisory's case study (as attached as an appendix) found that KCE's Mangahao generation has been neccessary to ensure N-1 reliability at the MHO0331 grid connection point. This value has been historically recognized by ACOT payments and there is network support contracts in place. Until grid or local network support arrangements can be put in place there is a strong case for a transitory period for the removal of ACOT. Otherwise the Authority risks a network solution inefficiently being brought forward.

The answer to this requires an understanding of the true value of network alternatives. This issue is expected to be addressed by the current workstreams underway on flexibility markets both in New Zealand and abroad, but until these markets are appropriately understood and developed then we suggest that it is critical to have transitional arrangements in the interim.

Without such arrangements there is likely to be the loss of a low cost source of flexibility putting pressure on system delivery at the very time we are seeking to promote the industry to new players.

Any questions relating to this submission please contact me.

Kind Regards

Chris Fincham - General Manager

King Country Energy

Calderwood Advisory Limited

38 Seychelles Drive
Papamoa Beach 3118
PO Box 11425
Palm Beach 3151
peter@calderwood.co.nz
+64 21 953104

CASE STUDY – MANGAHAO GENERATION GRID SUPPORT

REPORT PREPARED FOR KING COUNTRY ENERGY

Version Final - 20 October 2022

1 Scope

King Country Energy **(KCE)** has engaged Calderwood Advisory to provide advice in relation to grid support provided by the Mangahao hydroelectric power scheme **(MHO HEPS)** owned KCE. Traditionally grid support has been compensated by way of avoided cost of transmission **(ACOT)** payments under the existing Transmission Pricing Methodology **(TPM)**.

This report describes the impacts of the removal of the RCPD signal and associated ACOT payments may have on the operation of MHO if the preferred solution proposed by the Electricity Authority **(the Authority)** is adopted.

2 Authority's preferred option

The Authority's preferred option is to cease all ACOT payments to eligible generators from 1 April 2023 when the new TPM comes into effect. In the absence of any other commercial arrangement with Transpower or Electra there is no incentive other than responding to spot prices for KCE to operate MHO to support N-1 security into Mangahao Substation **(MHO SS)**.

Chapter 4 of the consultation paper refers to a 'phase out' option where the ACOT payments are ramped down over two years to allow alternative commercial arrangements for grid support to be developed. The remainder of this report demonstrates the critical support that MHO HEPS gives to the grid and the increasing reliance on generation at local peak demand periods to support security.

3 Regulatory Framework

Transpower is jointly regulated by the Commerce Commission and the Authority.

Part 12 of the Electricity Industry Participation Code 2010 **(the Code)** requires the EA to set grid reliability standards **(GRS)**. The present GRS defines the 110 kV lines connecting to MHO SS as non-core grid. As such it is not required to meet N-1 security under the GRS.

4 Reliance on MHO HEPS

Transpower's latest Transmission Planning Report[1] highlights the need for generation support from MHO HEPS to support N-1 security for load at MHO SS both for transformer capacity and voltage. (See Box 1)

11.5.5 Mangahao supply capacity

Issue

The Mangahao load is supplied by:

- two 110 kV circuits from Bunnythorpe, each rated at 48/59 MVA (summer/winter)
- two 110/33 kV transformers providing:
  - total nominal installed capacity of 60 MVA
  - n-1 capacity of 37/39 MVA (summer/winter).

An outage of one 110 kV circuit will also remove the associated 110/33 kV transformer from service.

Peak load at Mangahao already exceeds the n-1 capacity of the supply transformers (see Figure 11-7). The forecast conservatively assumes the Mangahao power station, connected to the 33 kV bus, is not generating. When Mangahao is not generating, low 33 kV voltage following an outage of either a circuit or supply transformer will limit supply capacity before the capacity of the circuits or transformers. This low voltage is due to the lack of on-load tap changers on the 110/33 kV transformers.

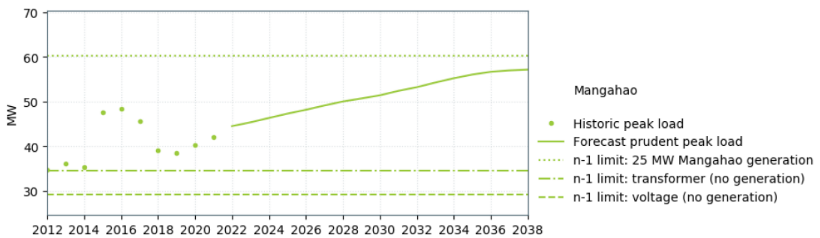
Box 1 - Mangahao Capacity Issue

[1] https://www.transpower.co.nz/sites/default/files/publications/resources/2022%20Transmission%20Planning%20Report.pdf

Given that the assets that are constrained are connection assets resolution of the problem is jointly owned by Transpower and the local connected customer, Electra.

The chart in Box 2 shows that even now transmission capacity is reliant on MHO HEPS generation.

Figure 11-7: Mangahao supply capacity



Note: Any difference in the supply capacity on the graph (in MW) and the asset rating (in MVA) is due to load power factor and impedance.

Box 2 – Mangahao Supply Capacity

Figure 1 attempts to explain the contribution that MHO HEPS gives to support security at MHO SS. This chart is similar to the one in Transpower's TPR but adds some extra information.

Based on the chart in Box 2, I have estimated the gross MHO SS demand levels that trigger a breach of N-1 security at 0 MW and 25 MW MHO HEPS generation as 35 MW and 60 MW respectively. I have also estimated the level at which N-1 is breached for voltage with no MHO HEPS generation at 29 MW.

As well as single highest peak each year between 2012 and 2021 I have also plotted with a blue dot each half hour trading period that exceeded N-1 security with no MHO generation. This indicates the essential backup that MHO HEPS provides. Also on the chart is a line with a count of the number of occurrences in each year. For 2022 up to 30 September 2022 this was 1967. That means that in 2022 to date there were 1967 trading periods where some MHO HEPS generation was required to maintain N-1 security.

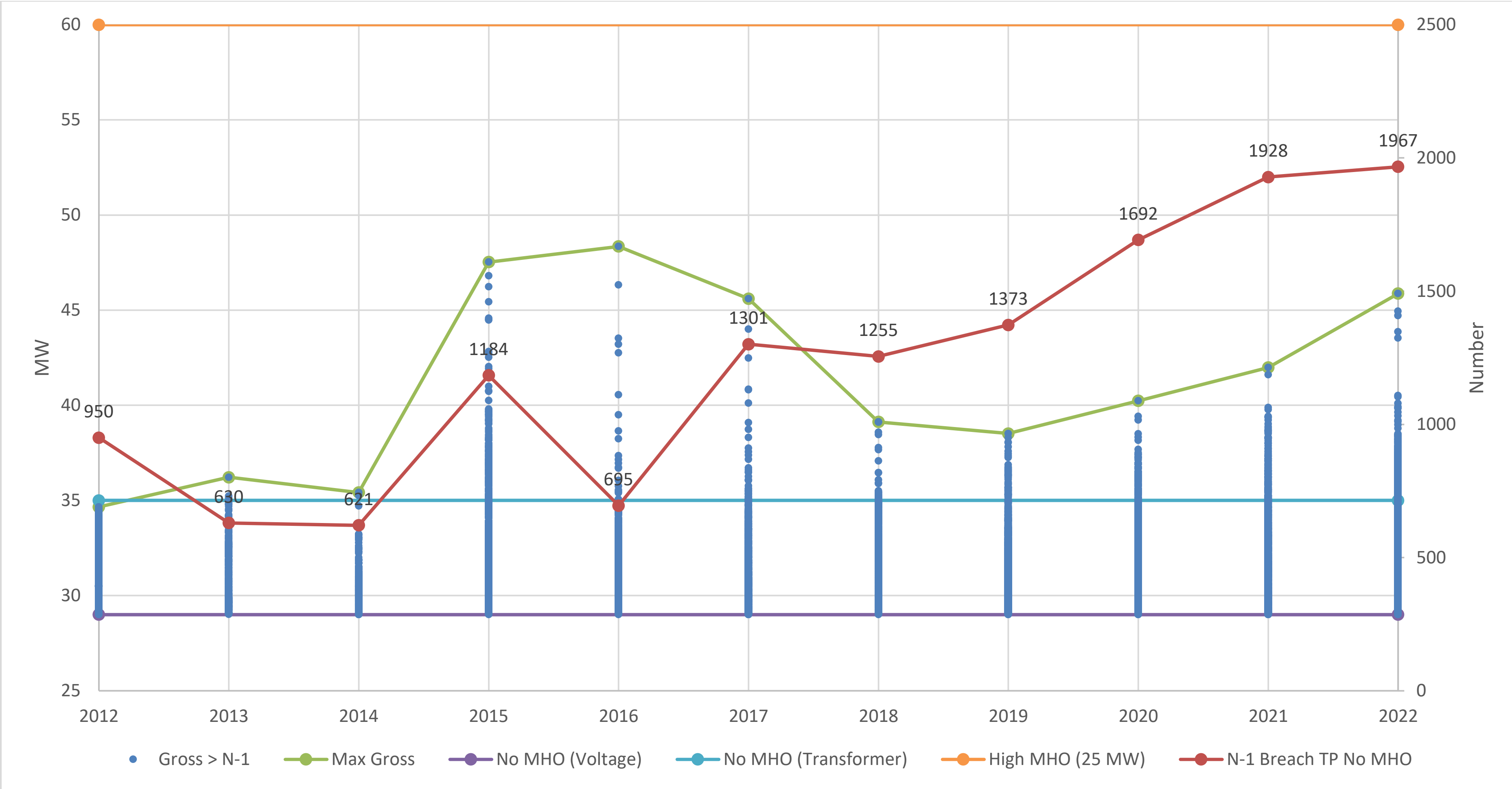


Figure 1 - MHO N-1 Support

5 The problem going forward

The question is how Transpower and Electra ensure that MHO HEPS is generating when the supply into MHO SS is not meeting N-1 security.

Up until now MHO HEPS has been compensated for supporting security at MHO SS via ACOT payments. If these are not available from 1 April 2023, or from some later date then, in the absence of a grid support contract with Transpower or Electra, there is no incentive for MHO HEPS to operate at peak periods, other than to maximise spot revenue. Given that MHO HEPS offers its generation at $0/MWh for volumes provided for grid support via ACOT there will be minimal constraint payments when it is needed to relieve a constraint. Altering offer strategies may breach the trading conduct provisions under the code.

Box 3 is an extract from a Transpower document describing the design features of grid support contracts.[2] . An arrangement with KCE would not be considered as a Major Capex Proposal or included in Transpower's opex proposal.

4.2 Including GSC costs in Transpower's regulated revenue

Transpower as a commercial company will not offer GSCs unless it can recover the costs, which requires that they are included in its regulated revenue. There are two approval avenues from the Commerce Commission:

- Include GSCs in a Major Capex Proposal[11,12]
- Include GSCs as part of Transpower's opex proposal at the start of the regulatory period (five year).

For an MCP, the CapexIM defines non-transmission solution as costs incurred by Transpower in relation to one or more of the following things:

- Electricity generation
- Energy efficiency
- Demand-side management
- Local network augmentation
- Improvement to the systems and processes of the System Operator
- The provision of ancillary services[13]

Transpower recovers its regulated revenue from designated transmission customers in accordance with the transmission pricing methodology (TPM)[14].

Box 3 - Grid Support Contracts

Thus, there does not seem to be a way for KCE to be compensated for providing support services from MHO HEPS other than a payment from Electra to support security for their customers. This suggests there is a strong case for a transitionary period while alternative grid or local network support arrangements can be put in place.

Guidance from the Authority on how it expects grid support arrangements to be remunerated would be welcome.

[2] https://www.transpower.co.nz/sites/default/files/plain-page/attachments/design-features-for-grid-support-contracts_0.pdf