23 December 2021

Submissions
Electricity Authority
PO Box 10041
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By email: TPM@ea.govt.nz

Cross-submission on 2021 Proposed Transmission Pricing Methodology (TPM)

1. Contact Energy has been a long-standing supporter of the TPM process. We agree with the problems with the existing transmission pricing arrangements identified by the Electricity Authority and the broad principles set out by the Authority for the way forward (i.e. the removal of the HVDC and interconnection charges and their replacement with a benefit-based charge and a residual charge).

2. Our submissions to date have centred on important points of detail rather than the overall approach. Our submission on 2 December 2021 raised the broader concern at the complexity of the new regime and question marks over how electricity lines businesses pass through transmission costs to load customers. We noted the inability of stakeholders to model for themselves transmission charges prior to making an investment decision and how this uncertainty creates its own inefficiencies. We see this as a fatal flaw in the new regime.

3. On reviewing the 31 other submissions to the Authority's 8 October 2021 *Consultation Paper*, we have been struck by the level of concern expressed by the vast majority of those who submitted, including from lines companies, major industrials, and generators. These concerns range from the philosophical to the practical, with the level of complexity frequently cited as a cause for concern[1]. This does not bode well for the durability of the new pricing regime.

4. We do not think the Authority can dismiss these concerns as the self-interested positioning of those who stand to be financially worse off under the new regime. Rather, we think the Authority should accept the consensus view that, at a minimum, there is little faith that the new TPM will deliver the benefits the Authority claims. Put bluntly, we think the Authority needs to step back and reconsider its approach.

5. We submit that the identified shortcomings of the existing TPM can be largely addressed through targeted and incremental changes to the status quo. Such an approach would include:

[1] As examples, see submissions from Counties Energy, Mercury, NZ Steel, Nova, Orion, Refining NZ, Rio Tinto, Trustpower, and Unison.

- a **connection charge** that is broadly unchanged;

- a **benefit-based charge to cover new grid investments of >$20 million** but using a simplified and transparent calculation method such that any reasonably informed electricity stakeholder can model transmission charges for themselves;

- a **residual charge to be based on the existing RCPD interconnection charge** but with the number of peak trading periods used as the basis to calculate the charge increased from 100 to ~500[2] (to reduce the overly strong price signals created using the existing method);

- the **complete removal of Avoided Cost of Transmission payments** that incentivise embedded generation and effectively transfer transmission costs onto other users; and

- **extending the prudent discount policy** as outlined in the *Consultation Paper*.

6. We consider that the approach outlined above would be achievable, an improvement on the status quo, more broadly acceptable to most stakeholders, and ultimately more durable.

7. Two possible alternatives to the incremental improvement to the status quo approach outlined above are:

    (1) Addressing the legitimate points of concern of stakeholders through further consultation and directly in the Code. The multiple rounds of consultation to date have addressed many stakeholder concerns (e.g. the treatment of grid-connected batteries) but a wide range of outstanding points have been made in the cross submissions that warrant, in our view, further consideration. We cite as examples:

    i. Using a non-coincident AMDR for multiple GXPs existing at the same location that are never used simultaneously and that serve the same source of demand. At face value, this will overstate the actual AMD of that load customer. This point was raised by Buller Electricity (for GXPs ORO1101 and ORO1102), Network Waitaki (for GXPs WTK0111 and WTK0331), NZ Steel (at GXPs GLN0331 and GLN0332, although this example is slightly different to the other examples cited), and Oji Fibre (three GXPs with load shifting occurring across the GXPs depending on the configuration of the site and Transpower's needs).

    ii. Using a gross AMDR allocator for the residual charge for a load customer served by a cogeneration plant where, given the configuration of the load customer's factory and requirement for steam, the load customer can never draw its gross AMD from the grid (Nova, NZ Steel, Oji Fibre). At face value,

[2] Our initial modelling suggests an appropriate range of between 400 to 800. The number needs to be high enough to avoid shifting charges from one part of the year to another for the Lower South Island given its relatively flat seasonal shape but not so high that it effectively shifts costs from the Upper North Island and Lower North Island onto other parts of the country given the steeper shape of their load duration curves.

this appears to greatly overstate the value and services provided by the grid to these load customers.

iii. The constraints on Transpower's development of factuals and counterfactuals to establish the expected net private benefits of BBIs in some circumstances could constrain it to scenarios that are not credible, which would make the consequential allocations lacking in legitimacy (Unison).

iv. The timing of related reviews (e.g. ACOT and existing prudent discounts that need to be reapplied for in 2022) and the proposed implementation of the new TPM in April 2023 is exceedingly tight, creating significant uncertainty right up to the point when the new TPM is implemented (Horizon Networks, Southern Generation Ltd Partnership).

v. The timing, cost, and uncertainty around the prudent discount policy may in some instances result in stranded assets (see submissions from Northpower and Refining NZ on the incentives that Northpower has to disconnect at BRB GXP following the closure of the refinery and connect at MDN GXP even though this is likely an inefficient outcome because it results in decommissioning working assets and removes capacity at BRB that other parties may want to utilise in the future for new generation or load developments).

(2) Provide Transpower with significant discretion to respond to the individual circumstances of transmission customers on a case-by-case basis.

8. We consider both approaches to be unsatisfactory. The first approach may resolve the specific concerns of individual transmission customers but fails to address the overriding concern that nobody knows with any certainty what their transmission charges will be moving forward. This arises because no one other than Transpower can model the expected net private benefits of benefit-based investments. This undermines the whole premise of encouraging scrutiny of transmission investments and to our mind is a fatal flaw to the new regime.

9. The second approach suffers from the same shortcomings as the first approach, while adding a further layer of uncertainty. Transpower has consistently opposed the new TPM and we have little confidence that Transpower would make case specific decisions consistent with the Authority's overall policy intent. As an example, we cite Transpower's move to recover a large portion of their overhead costs through the benefit-based charge rather than the residual charge. Transpower argued that this approach was more consistent with the Authority's statutory objective compared to how the Authority had interpreted it through multiple consultation rounds and representations to Transpower. We consider this tantamount to operational entrepreneurship. It is simply not Transpower's place to reinterpret the Authority's statutory objective when the Authority has already made its position clear.

10. We acknowledge the significant amount of work undertaken by the Authority and Transpower to get to this point. However, time and effort invested to date are poor reasons to proceed if the result is a complex entanglement of arrangements that no one bar Transpower can interpret. We urge the Authority to step back, reconsider its proposals, and focus on incremental improvements that address the widely accepted problems with the current transmission pricing regime.

11. If you have any questions, please contact David.Buckrell@contactenergy.co.nz or myself.

Yours sincerely,

Chris Abbott
Chief Corporate Affairs Officer