INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

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

Dear TPM team,

RE: Consultation Paper-Transmission pricing review Cross submission

The Independent Electricity Generators Association Incorporated (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) 2019 transmission pricing methodology proposals. We commend the Authority for including the opportunity for cross-submissions. [1]

This submission addresses three topics raised in submissions:

1. The need for a permanent peak demand price signal
2. The quality of the cost benefit analysis and treatment of wealth transfers
3. The use of gross AMD as an allocator of a significant portion of transmission costs.

The detail in submissions indicates to the IEGA that the Authority has a substantial amount of work to undertake before finalising any change to the transmission pricing Guidelines.

The IEGA suggests the Authority hold a workshop to discuss any changes being considered to provide stakeholders with transparency about the direction of travel and so that feedback can be provided in a timely manner.

Overall, we support Transpower's submission and their proposed approach to transition changes in the transmission pricing methodology as well as retaining a peak demand price signal.

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[1] The Committee has signed off this submission on behalf of members.

1. The need for a permanent peak demand price signal

As you are aware, numerous submitters support retaining a peak-usage signal – we agree with this view. Submitters suggest reform of the current RCPD charges to make them more cost-reflective and better targeted. Other submitters, like the IEGA, are also skeptical about the Authority's hypothesis that efficient behaviour and investment decision-making will arise from nodal prices alone. [2]

In previous TPM submissions the IEGA provided analysis by EnergyLink of the impact on wholesale spot prices if the Upper South Island's current ~100MW load control did not exist. This study proved that wholesale spot prices can be highly volatile to small changes in load. An 110MWh increase in demand resulted in a 3.4% increase in the wholesale price while in a different trading period a 300MWh increase in demand resulted in an 87% increase in the wholesale price. The risk of this price volatility will result in an increase in consumer prices.

We also agree that some form of peak charge would make transmission pricing potentially more aligned with distribution pricing - a number of submitters believe the current TPM proposal is not aligned with the Authority's desired direction for distribution pricing.[3]

2. The quality of the cost benefit analysis and treatment of wealth transfers

There has been significant feedback[4] on the CBA and the treatment of wealth transfers. We submit the Authority should provide stakeholders with the opportunity to understand in an interactive forum the difference between the Authority's methodology and the feedback provided.

The IEGA did not have the resources to critique the CBA but we note the key issues highlighted in submissions about the CBA include:

- the failure of the model to recognise market behaviour leading Genesis to question the results
- the modelling ignores the cost of increasing network investment when peak demand increases
- the treatment of wealth transfers, for example:

  ENA noted that the 2016 TPM proposals did not include the market derived dynamic efficiency improvements to consumers and questions why the Authority has changed its approach to include "*a direct transfer of existing wealth from generators to consumers for electricity that would have been consumed anyway*".

  Vocus suggest it would be "*beneficial for the Authority to be transparent about the efficiency and price impacts (wealth transfers) of the Authority's proposals*. *This would be consistent not only with Commerce Commission precedent, and also the approach the Authority adopted in relation to its review of distributed generation pricing principles (see table below)*"

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[2] Submitters on these topics include: Buller, Contact Energy, Counties Power, The Distribution Group, EA Networks, Electra, ENA, Electricity Trusts of NZ, EPOC, Entrust, Electric Kiwi, Flick Electric, Golden Bay Cement, Powerco, Pan Pac, Solar City, Trustpower, Unison and Centralines, Vector, Waitaki Power Trust, Wellington Electricity

[3] Submitters on these topics include: Flick Electric, Vocus, Wellington Electricity, WEL Networks

[4] Submitters on this topic include: Genesis Energy, Counties Power, Electra, EMA Northern, Entrust, Federated Farmers (Northland and Auckland), Horizon Networks, Northpower, Norske Skog Tasman Ltd, Oji Fibre Solutions, Top Energy, Transpower, Trustpower, Vector, Vocus

Table 1: Expected economic benefits and gross benefits resulting from the proposal, relative to the current DGPPs

	Expected economic benefits, in $million present value terms	Gross benefit to consumers, in $million present value terms
Current TPM	2.0 – 21.7	232 – 325
Current TPM for two years from April 2017, then area-of-benefit-based TPM	0.5 – 4.2	46 – 64 plus effect after 2019 (not quantified)

Axiom Economics report for Transpower notes "*the net benefit estimate mistakenly includes $2.6b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry*".

- the failure to include the $1.9b additional investment that is estimated to be needed to produce the assumed benefits in the CBA
- the fact the modelling concludes that the proposal may not deliver a material net benefit for 12 years.

Overall Axiom describe the quantitative CBA as "irredeemably flawed" concluding that if errors were addressed the net **cost** from the proposal is $1.5b – ie the proposal has no probative value.

Trustpower highlight the risks from the proposed one-off move to a very different allocation of transmission costs and conclude:

> *The largest benefits are the most analytically contentious, most speculative, and furthest out into the future whilst the costs and disruptions come almost immediately. These benefits arise from a flawed comparison between two extreme scenarios. A much smaller change in the RCPD charge structure would realise the bulk of benefits estimated, thus avoiding uncertain risks associated with pivoting from one extreme to another. In any event one should not place reliance on benefits arising from comparisons of extreme scenarios, as the natural purpose of such comparisons is to make headline points, not nuanced recommendations.*

3. The use of gross AMD as an allocator of a significant portion of transmission costs

The IEGA provided a number of reasons why we consider gross AMD is the wrong allocator for a significant portion of transmission costs via the residual charge. Fonterra submit gross AMD will overstate the residual. Powerco submitted for the use of historical AMD that nets off all forms of generation and demand-side response ie assess peak demand consistently which is consistent with Transpower's assumptions about peak demand in its grid investment tests.

Relatedly, the Electricity Trusts of NZ (ETNZ) highlighted that ACOT is the only significant arrangement that helps address the Commerce Act's s54Q requirement:

> **54Q Energy efficiency**
>
> The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services.

ETNZ submit that "*if the value of ACOT payments for distributed generation is reduced or the allocation changes under the proposed TPM then the incentive it provides distributors to invest in local generation [or contract with third party owners of distributed generation] which reduced line losses will be reduced or changed accordingly*". The IEGA supports the ETNZ submission there should be further consultation about ACOT "*to consider how ACOT might be enhanced to support the objectives of s54Q"*.

The IEGA agree it is appropriate for the TPM Guidelines to require Transpower to determine the best allocator for any residual charge.

4. Suggested revised TPM

Reading submissions has confirmed our view that the IEGA does not support the Authority's TPM proposal as it creates significant uncertainty at a time when certainty is required. Overall, we consider the TPM proposal to be an economic experiment with a high probability of having serious unintended consequences.

Our view is consistent with a number of submitters who suggested less radical changes can be made to the TPM that will achieve the Authority's statutory objective and motivation for changing the TPM with less risk.

We repeat our suggested revised TPM as there are a number of variants of this approach amongst submissions:

- amend the current measure of regional coincident peak demand to reduce the strength of the peak time price signal;
- introduce a permanent peak price signal that is more flexible – could be location specific with a variable price as constraints become more prevalent;
- reallocate the historic and future HVDC costs to the wider group of parties that benefit from this asset; and
- if there is a need for a new charge that recovers the balance of Transpower's allowable revenue that is based on the average or median demand so that network companies and industrials have some benefit from local generation.

In addition, we support other submitters calling for any change to the TPM to be implemented in an incremental manner so that the intended and unintended consequences can be assessed and the approach tweaked to ensure reliable electricity supply and strong competition in electricity generation and retailing.

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

Yours sincerely

Warren McNabb
Chair