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Submissions
Electricity Authority
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By email: submissions@ea.govt.nz

Dear TPM team,

RE: Consultation Paper-Transmission pricing review

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]

Individual members have also made submissions which the IEGA support.

We acknowledge the work undertaken by the Authority since early 2018 to amend previous TPM proposals and finalise this paper. However, we remain highly concerned about the intended and unintended consequences of this proposal on distributed generation and the NZ electricity system in general.

Our submission is structured as follows:

1. an elaboration of our significant concerns about detailed aspects of the TPM proposal, namely the proposed change to Part 6 of the Code; removal of a permanent peak demand signal; use of Gross AMD as an allocator and the different treatment of grid connected and distributed generation
2. high level concerns that the TPM proposal is inconsistent with the government's key energy sector policies, the Authority's own cost reflective distribution pricing principles and good regulatory practice
3. our suggested revised TPM.

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

1. Concerns about the detail of the TPM proposal

The IEGA is significantly concerned about the:

a) proposed change to Part 6;
b) removal of a permanent peak price signal;
c) use of Gross AMD as an allocator of a significant portion of transmission costs ; and
d) different treatment of grid connected and distributed generation in the allocation of transmission costs.

a) the proposed change to Part 6

The IEGA submits that the wording in Part 6 must be future-proof to any definitions or words used in other relevant documentation. We are looking to ensure that any change in Part 6 does not interfere with, or trigger reopening, any existing contractual obligations and is fit-for-purpose for any future mechanism that could result in distributors incurring lower transmission charges due to distributed generation.

b) Removal of a permanent peak price signal

The IEGA submit eliminating the current peak demand charge overnight is a risky experiment which no-one can foresee the consequences of. Transpower publish the regional coincident peak volumes – 5,791MW in 2018/19[2]. This is the measure that has been used by Transpower and distribution companies to manage investment in capacity for decades.

The Authority has calculated the total maximum demand at a point in time on 298 nodes at 8,766 (average over 2014-2018). There is almost 3,000MW difference in these two numbers (+51% on RCPD volumes). While these measures may not be directly comparable, they may become more comparable if the coincidence of anytime maximum demand becomes more correlated over time or in regions.

It is hard to ignore Transpower's high level analysis[3] by its power systems planning and system operations staff of the potential implications of removing the RCPD peak price signal:

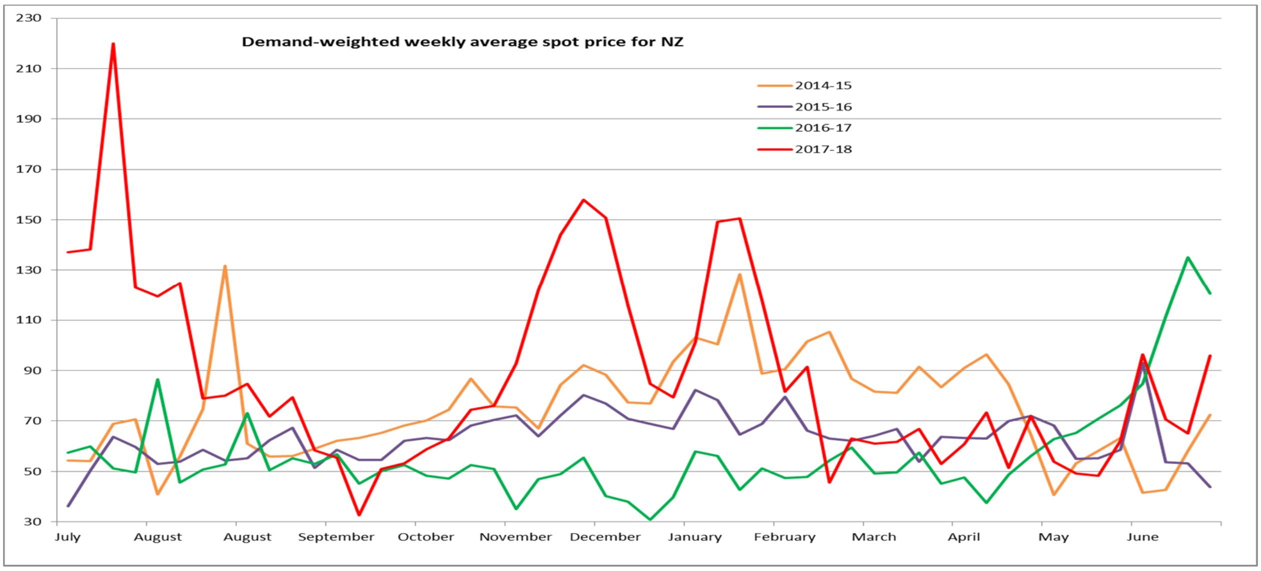
> *"20% 'gross demand' met by demand response and DG. Grid cannot meet gross demand in all areas. Extreme change in DR and DG behaviour will affect grid operations, create market constraints with increased opportunities for pivotal behaviour by generators. It may lead to load shedding."*

The IEGA is sceptical about the Authority's reliance on the wholesale spot price to signal peak demand periods and to incentivise consumers to undertake demand response. Intra-day the spot price is higher in morning and evening periods. However, these higher priced periods do not appear to correlate with the incidence of Gross AMD. Analysing one year of the Authority's data[4] on Gross AMD

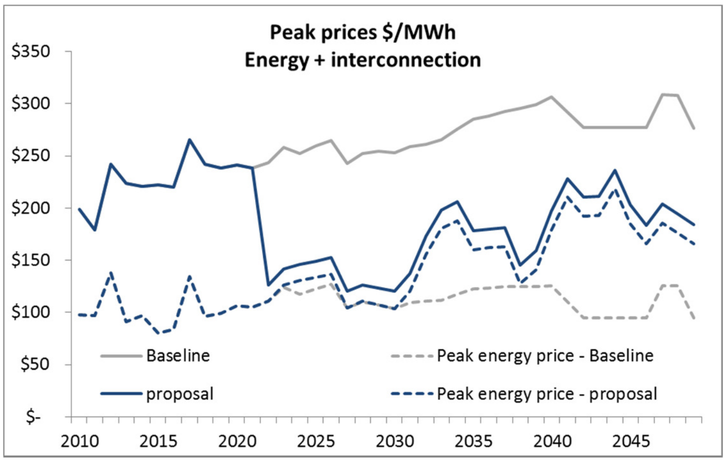
[2] Source: Transmission Pricing Data on this page https://www.transpower.co.nz/industry/revenue-and-pricing/pricing
[3] https://www.ea.govt.nz/dmsdocument/21135-transpower page 21
[4] Data for 2014 from Gross AMD Calculation spreadsheet

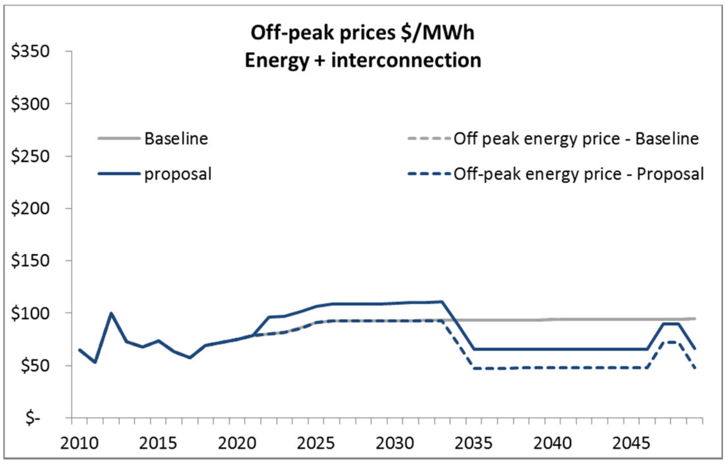
reveals the AMD trading periods are scattered pretty evenly throughout the day (with no trading period representing more than 7% of all Gross AMDs across 298 nodes).

Inter-day New Zealand's electricity spot price reflects fuel availability. The following graph shows the demand-weighted weekly average spot price for New Zealand for the financial years included in the Authority's TPM modelling 1 July 2014 to 30 June 2018.[5] For 2 of the 4 years in the Authority's sample, the spot price was as high in summer/autumn[6] as it was in June, July and August when demand is the highest.[7] In 2014, 63% of the highest measures of Gross AMD occurred in these three winter months.



Further, the volatility implied by the Authority's forecast peak and off-peak prices will make it hard to 'bank' any new renewable generation projects. For example, the peak price increases from $104/MWh in 2030 to $188/MWh in 2034 (~20% per annum compound), declines to $128/MWh by 2038 and then increases to $210/MWh in 2041 (another ~20% per annum compound increase).[8]

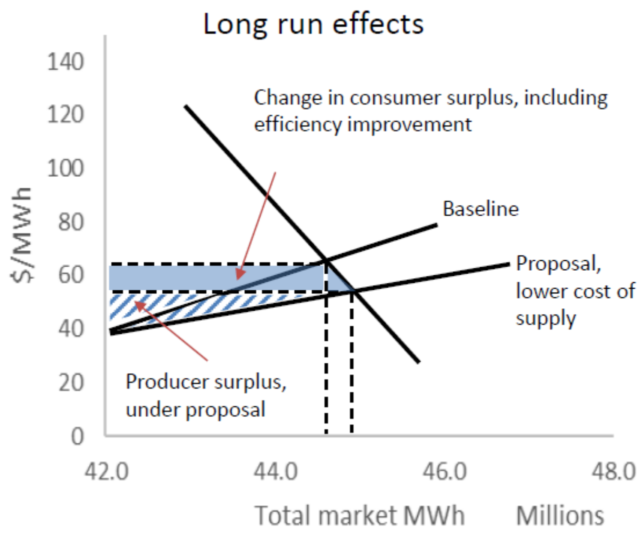




[5] Data from EMI website
[6] Graph from EMI website, NZ demand-weighted average weekly spot price for the four years 1 June 2014 – 31 July 2018
[7] Note the ICCC final report states that a more pronounced seasonal pattern is expected into South Island hydro lakes by 2050 – with summer inflows significantly reducing and winter inflows significantly increasing. https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf Section 3.6
[8] Information from question asked by Pioneer Energy during consultation period

There is also the issue of whether the Authority's modelled wholesale prices result in an adequate return on generation investment.

The long run effects chart show a price of ~$58/MWh from the proposal[9]. This compares with an average LRMC of ~$100/MWh from potential generation build before any CCGTs are the next lowest SRMC – taken from the Authority's possible_gen spreadsheet in the CBA files.[10]



In addition, we suggest the Authority's analysis does not adequately consider the system impact that any increase in peak demand has on the quantity of losses. We estimate that a change in consumption profile including more energy use at peak periods could increase losses by 10% per annum. This energy has to come from somewhere at a cost to the consumer.

c) Use of Gross AMD as an allocator of a significant portion of transmission costs

The Authority proposes to fix allocation of both the Residual and Benefit-based charges on historic measures of demand and net private benefits respectively.

The issues we have with these historic allocations is that:

- it locks in behaviour that the Authority is trying to discourage – namely people consuming less when they value electricity the most
- The Authority's consultation paper states "*A key assumption is that mass-market load will respond to both transmission and wholesale price signals over the period to 2049.*"[11] There is no point in responding to transmission price signals if transmission costs are allocated to network companies on the basis of historic Gross AMD
- it does not support cost reflective network management of peaks
- network companies are penalised for investment in distributed generation on their networks which can provide substantial benefits to them in the management of their network and to their local consumers (for example, distributed generation supplies ~50% of the load on the West Coast)
- under Gross AMD no alternatives can compete with transmission to deliver electricity to consumers – that is network companies are disinterested in distributed generation on their networks supplying their customers close to load
- stymies innovation as there is no financial benefit from investment that alters consumption patterns or the source of electricity

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[9] Source: page 14 Electricity Authority presentation for CBA technical workshop

[10] Source: possible_gen spreadsheet under CBA modelling on the EMI website

[11] Consultation paper paragraph 4.43 page 28 - 29

- it is potentially inflexible to moderate changes in consumption or generation patterns.

The IEGA recommends the use of average or median demand for allocating the balance of Transpower's revenue to load, including industrials. Network companies and industrials must be able to net off average or median output of distributed generation to work out the allocation. As New Zealand focuses on electrification of industrial processes and transport, average or median consumption will be more flexible or reflective of consumption over time.

This is more reflective of ongoing use of the grid (especially as the incidence of Gross AMD is highly dispersed intra-day) and allows some benefit from investment in commercial scale distributed generation and co-generation. The impact on industrials with distributed generation highlights our concern. The use of an arbitrary price cap only serves to mask the underlying material impacts on businesses facing cost uncertainties in the face of climate change policy.

In the context of Gross AMD, one of the key concerns outlined by the Authority in the TPM proposal is 'cost shifting'.

The impact of cost shifting from investment in commercial scale distributed generation was addressed by the Authority's December 2016 changes to Part 6. The distributed generation that continues to be eligible for avoided transmission charge payments has been assessed to be an integral part of the transmission grid as it is required for Transpower to meet its grid reliability standards. 80% of existing distributed generation, contributing 628MW to winter load, has been identified as being essential to grid reliability. If this distributed generation does not inject electricity into the local network it seems likely Transpower will consider grid security to be compromised. Further, 100% of existing distributed generation in the Upper North Island is required to meet Transpower's grid reliability standards – contributing 177MW to winter load. It is unknown how much transmission investment would be required to offset the loss of any distributed generation in that region. Further, there is the issue of the time and cost involved in planning, consenting and constructing transmission to replace this distributed generation to maintain grid reliability.

d) different treatment of grid connected and distributed generation in the allocation of transmission costs

The proposal to treat grid connected generation differently from network connected generation is grossly inequitable and economically inefficient.

For the Benefit-based charge, the Authority proposes transmission cost allocation to grid connected connection is reduced by netting off their load at the generator against generation volumes at the GIP.

However, in the reverse, network companies' and industrials' load volumes are not net of any generation volumes on their network.

Put another way, the Residual charge is allocated to load customers. Allocation of the Residual to grid connected generators is based on any load at their GIPs – and not generation volumes. In contrast, distributors' are charged on load including that often supplied by distributed generation.

It is also difficult to understand why the allocator for the Benefit-based charge is a net basis and for the Residual is gross basis. How does one customer benefit from transmission differently (for two different charges) when they are consuming only one service (transmission)?

Under the TPM proposal, distributors pay 86% of the Residual charge. Distributors could decide that their allocation of the total transmission charge has increased because of the distributed generation attached to their network. The IEGA urgently seeks clarity from the Authority that the increase (relative to the status quo) in transmission charges associated with using a gross AMD calculation, which does not recognise any value from distributed generation, is intended to be passed on by distribution companies to their load on the network and not to the distributed generation connected to the network.

If distributors pass on Residual charges to distributed generation on the basis of their generation (and not load) this will be a significant financial impost which grid connected generation do not face.

2. High level concerns about the TPM proposal

At a high level the IEGA consider the TPM proposal is inconsistent with the:

- government's key energy sector policies;
- Authority's own cost reflective approach for distribution pricing; and
- good regulatory practice.

These inconsistencies are discussed below.

Inconsistent with the Government's key energy sector policies

The government's key energy sector policies are transitioning NZ to a low emissions economy and the target of 100% renewable electricity by 2035.[12] Examples of the inconsistency between the TPM proposal and government's key energy sector policies are:

- While the Minister of Energy and Resources is seeking advice on barriers and opportunities for local generation from EECA, the Authority is eliminating any motivation to invest in local generation via the proposed allocation of transmission charges. The independent Interim Climate Change Committee (ICCC) recommended to government that "*Barriers to distributed and off-grid renewable generation are identified and addressed and ways to ensure communities can participate are considered*."[13]

- The government has accepted the recommendations[14] of the ICCC. One recommendation was that regulators take into account emissions reduction objectives in any rule or policy changes:

[12] Noting the Minister of Energy & Resources has said the government will be pragmatic about achieving the last few percentage points

[13] https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf Recommendation 6 c. page 105

[14] https://www.beehive.govt.nz/release/nz-embracing-renewable-electricity-future

> *"The Committee recommends that regulators be required to take emissions reductions objectives into account, as well as facilitating and enabling new generation and both market and distribution innovation."*[15]

Further, the ICCC states *"The actions we recommend are the first steps in a long journey – a journey that will stretch over decades. Continued delay is not an option."*[16]
The proposed TPM is a fundamental, once-in-a-lifetime change to the allocation of transmission costs. The IEGA submits the Authority must be required to take into account emission reduction objectives in developing its proposal.

- Modelling of generation investment for the TPM CBA is based on the 2016 EDGS and has no regard to the generation build modelling undertaken by the ICCC as requested by the Minister. The ICCC conclude that solar and batteries have an important role to play. "*The modelling shows that, under a business as usual future, New Zealand is likely to reach an average of 93% renewable electricity by 2035. More wind, solar and geothermal will be built, and more batteries will be deployed*."[17]
  The ICCC modelling includes both demand response and batteries to keep non-supply to very low levels. The ICCC modelling for the recommended accelerated electrification scenario (with a modelled wholesale price of $85/MWh) has 500MW of batteries deployed by 2035 while the Authority's CBA includes benefits from deferring any battery deployment until ~2041.
  The IEGA submit the TPM CBA must be re-run with the generation build profile identified by the ICCC to achieve the government's renewable target in order to ensure the TPM proposal is consistent with the government's renewables target.

- The TPM proposal is designed to increase (or not disincentivise) demand during peak periods. The most efficient and quickest way to manage increases in peak demand in the short terms is to construct thermal peaking plant close to load. It is proven consenting of these plant takes less time that renewable generation plant and thermal peaking plant is economic with the likely higher peak spot prices. This outcome is completely inconsistent with the government's climate change objectives and international commitments. It is also inconsistent with the government's 100% renewables target.

- The government is focused on electrification of industrial process heat activities. This can be achieved by expanding existing or building new distributed generation or co-generation but this investment is discouraged / disadvantaged by this TPM proposal.

- The government states NZ requires "*a forward thinking sector, geared towards seeking out and applying new technologies*". It also states "*We need to ensure our regulatory settings incentivise innovation and uptake of new technologies for the benefit of consumers*". [18]

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[15] https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf Recommendation 6a. page 105
[16] https://www.iccc.mfe.govt.nz/assets/PDF_Library/5fc8649516/FINAL-ICCC-Summary-report-for-electricity.pdf page 1
[17] https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf page 6
[18] https://www.mbie.govt.nz/dmsdocument/5960-transitioning-to-more-affordable-and-renewable-energy-the-energy-markets-work-programme-proactiverelease-pdf Paragraph 23c) page 6

What will incentivise development and investment in innovation if the allocation of transmission costs is fixed ultimately to an historic consumption profile under both the Residual and Benefit-based charge (respectively average Gross AMD for four years in the past and a static allocation of the Benefits-based charge once benefits have been determined before the transmission investment is constructed).

- EECA has identified significant energy efficiency opportunities costed at less than the next generation investment.[19] The CBA on this energy efficiency investment is over $2 billion. However, the proposed allocation of transmission costs does not consider or encourage energy efficiency.

Inconsistent with the Authority's own cost reflective approach for distribution pricing

A key thesis by the Authority is that consumers should not be discouraged from consuming electricity at peak times when they value the use of electricity the most – in peak use periods. This thesis drives the reason for removing the current interconnection charge based on regional coincident peak demand. Further the Authority's modelling does not consider the degree to which distribution prices reflect transmission prices.[20]

However, in the "It's time to reform distribution pricing" publication the Authority notes current standard distribution prices do not signal when the network is congested nor when there is plenty of capacity. The Authority notes distribution network costs are driven by periods of peak demand and that more efficient pricing models have a fixed and variable (marginal cost) charge that align prices with the cost drivers.

As a result distributors are transforming their tariffs to be cost reflective and time-of-use tariffs (based on a $/kWh rate varied by pre-defined time blocks) is described by the Authority to "provide a crude but actionable signal" consistent with allocative efficiency.[21]

The IEGA suggests that the principles that apply to distribution pricing should also apply to transmission pricing and that one of the key objectives of transmission pricing should be to signal to consumers that their demand drives future investment in transmission capacity to help defer grid investment. This deferral can be by changing consumption behaviour or by being less reliant on the transmission grid (and using local generation). Neither of these actions have any value nor impact in the TPM proposals.

Inconsistent with good regulatory practice

The IEGA agrees with the degree of discretion in the draft Guidelines for Transpower's development of the actual methodology.

However, the process outlined in section 6 of the consultation paper is, in our view, inconsistent with good regulatory practice. The IEGA submit that Transpower must be allowed sufficient time for

[19] https://www.eeca.govt.nz/news-and-events/media-releases/energy-efficiency-key-action-to-meet-renewable-energy-goals/
[20] Consultation paper paragraph 4.40 page 27.
[21] https://www.ea.govt.nz/dmsdocument/25528-distribution-pricing-practice-note-august-2019 page 13-14

thorough analysis and formal consultation while developing the methodology based on the Authority's Guidelines.

This goes to the durability of the allocation of transmission costs. If Transpower completes thorough consultation and engagement with industry stakeholders while considering options and finalising a methodology it puts to the Authority in the final step, when the Authority consults on Transpower's proposal the proposal should be well anticipated and transparent.

3. Suggested revised TPM

The IEGA acknowledges that the current RCPD signal is too strong (reflecting recent transmission investment and the limited number of trading periods used to measure peak demand). We also agree that the HVDC provides benefits to other parties as well as South Island generators.

However, the IEGA does not support the Authority's TPM proposal as it creates significant uncertainty at a time when certainty is required.

In our view the components of the current TPM can be adjusted to achieve the Authority's statutory objective and motivation for changing the TPM:

- 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, the IEGA submit that any change to the TPM must 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. Our view is consistent with that of the Electricity Price Review Panel in its Options Paper[22] when it appeared to endorse Transpower's submission that "*any change [to the TPM] was simple to understand and implement, and was incremental* …".

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

Yours sincerely

Warren McNabb
Chair

[22] https://www.mbie.govt.nz/assets/42ac93a510/electricity-price-review-options-paper.pdf page 23