



TRANSPOWER

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01 October 2019

James Stevenson-Wallace
Chief Executive
Electricity Authority
PO Box 10041
Wellington 6413

By email: submissions@ea.govt.nz

Dear James

Submission: Transmission pricing review 2019 issues paper

Transpower appreciates the opportunity to submit on the Electricity Authority's (Authority's) transmission pricing review 2019 issues paper.

As the Authority will be aware, the transmission pricing methodology (TPM) debate is now well into its second decade. The Authority's own transmission pricing review began more than seven years ago. There is widespread agreement that a timely and workable solution to the TPM debate is needed to give all market participants certainty and confidence in the TPM framework. This is particularly the case for those parties poised to make investments that will help the country achieve its climate change ambitions through electrification and renewable generation.

We have valued the opportunity to hear from the Authority's team and other stakeholders at the workshops held during the consultation period. We support the Authority's decision to seek cross-submissions. The Authority has also indicated it may include a conference as part of the final stages of its review. We strongly support the addition of this step, particularly given it has been more than six years since the conference held in relation to the first issues paper.

Executive summary

We acknowledge that there are significant elements of the TPM that require review and we are supportive of the need for the Authority to move quickly on these. We note that the positions in the Authority's current proposal are consistent at a high level with the Authority's earlier transmission pricing review proposals. While our stance on these points is largely unchanged,¹ we consider that it is important to restate our view that the Authority's current TPM proposal runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers. Moreover, we are concerned that the proposal may not support New Zealand's transition to a low-emissions economy.

We are supportive of a measured approach to amending the TPM and Transpower is appreciative of the extensive work the Authority has conducted in identifying a number of significant issues that

¹ Our positions on the Authority's earlier transmission pricing review proposals are summarised in **Appendix 2**.

require review. In our view, extensive reform of the sort proposed by the Authority may not be the most effective or efficient manner to address TPM concerns. We consider that the concerns with the TPM may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology. This would have the benefit of bringing the reforms to the market more quickly with a substantially lower risk of unintended consequences. Our submission proffers some practical options for such reform.

In the event that the Authority's proposal was to be implemented, then we consider that there are some workability issues in the drafting of the proposed new TPM guidelines (**Guidelines**) that would benefit from further review.

Introduction

The Authority is proposing to introduce new Guidelines designed to deliver a paradigm shift in transmission pricing, based broadly on a concept of beneficiaries-pay through fixed charges. As noted above, where the positions in the Authority's current proposal are consistent with its earlier transmission pricing review proposals, our stance on these points is largely unchanged. However, as the issues around climate change have advanced at pace since the TPM process began, we have recharacterised and amplified our position on the criticality of acknowledging the importance of the government's climate change goals in setting the TPM for the future. We submit that our position on the TPM being responsive to climate change issues is consistent with and supportive of the Authority's statutory objective.

We are financially neutral to the pricing outcome of the TPM review, since our overall revenue requirement is determined by the Commerce Commission through a separate regulatory process. Accordingly, we consider that we are well placed to provide a balanced, impartial, and informed commentary on the Authority's proposal. This is reinforced by our position at the centre of TPM development, implementation and ongoing operation.

In our view it is important for the TPM and Guidelines to:

- support timely, efficient transmission investment via the Commerce Commission's processes;
- limit the risk of unintended consequences (including of inadvertently undermining New Zealand's efforts to respond to climate change);
- be workable, practicable and understandable to our customers and stakeholders; and
- limit the risk of legal challenges to transmission pricing decisions by being objective and fair.

When considered in context and against the counterfactual, it is not clear to us that the Authority's TPM proposal is consistent with these requirements. We elaborate on these points in the remainder of this submission.

We provide our views on how the problems with the current TPM identified by the Authority could be addressed more quickly through incremental reform of the current TPM and Guidelines. We also submit that changes to the Authority's proposal would improve its workability and address some of its potential, predictable, and unintended consequences.

Our submission comprises this letter and the following supporting information:

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|-------------|---|
| Appendix 1: | Options for incremental TPM reform |
| Appendix 2: | Transpower's positions on the Authority's transmission pricing review |
| Appendix 3: | Case Studies – application of benefit-based charging |
| Appendix 4: | Analysis of the proposed price cap |

- Attachment A: Axiom Economics - Economic review of transmission pricing review consultation paper
- Attachment B: Clause-by-clause commentary on proposed TPM Guidelines
- Attachment C: Answers to the Authority's questions in the 2019 Issues Paper.

Transmission pricing needs to support climate change response

The Authority states on its website that:

We consider [our] proposal would deliver significant benefits to consumers in the long-term, and support the transition to a low-emissions economy at the least cost to consumers.²

The Authority considers its cost-benefit analysis (CBA) supports a conclusion that its proposed approach to transmission pricing would promote the efficient operation of the electricity industry for the long-term benefit of consumers. To inform our submission on this premise we commissioned an expert review of the CBA from Axiom Economics (**Axiom**).³

Axiom concluded that the CBA cannot safely be taken at face value. Axiom considers that correcting two of the more serious errors in the Authority's CBA would turn the estimated net benefit into a substantial net cost. If the CBA was to be taken at face value, the modelling concludes that the proposal may not deliver a material net benefit for 12 years. However, the modelling also expects there to be a significant "political uncertainty event" within 11 years, which could take the form of another substantial change to the TPM.⁴ In other words, the Authority's CBA suggests the proposed TPM reform might deliver no net benefit for eleven years before it is itself supplanted by another reform.

We consider such a material change in approach to transmission pricing should be supported by a CBA that achieves a high level of acceptance from the experts who review it. We are therefore interested to hear the opinion of experts commissioned by other submitters, and from the Authority as to its confidence in how its proposal would benefit consumers over these timeframes. We repeat our recommendation that these views could be effectively and efficiently tested through an industry-wide conference.

There is a broad and growing consensus within New Zealand and throughout the world that urgent and substantial action is needed to combat climate change. To that end, in October 2018 we outlined our view to the Electricity Price Review panel (**EPR**),⁵ noting the government's priorities of a pathway to our climate change goals required also addressing energy affordability and hardship. We stated that the country's 2050 goals require significant change in the sector and the economy, and establishing and maintaining a public consensus is needed to ensure the energy sector is working for all New Zealanders. In the year that has elapsed since we raised these views to the EPR, the need for profound movement on climate change, and renewable energy as an enabler, has only become more urgent.

² <https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/>

³ Axiom Economics is an independent economic consulting firm that specialises in the provision of expert and strategic advice on competition, economic regulation, third party access, commercial disputes and policy issues. We commissioned Axiom Economics to review the 2019 issues paper and cost-benefit analysis. Axiom's report is in **Attachment A**.

⁴ The Authority's 'top-down' modelling of "uncertainty benefits" reveals that it expects there to be a significant "political uncertainty event" within 11 years. Refer to [CBA technical paper](#) page 90

⁵ Transpower [submission](#) to the Electricity Price Review's First Report, 23 October 2018

Our *Te Mauri Hiko – Energy Futures* work explained why decarbonisation depends on expanding our renewable electricity base and our ability to electrify new parts of the economy, such as transport and process heat.⁶ We have predicted that electricity demand in New Zealand will grow significantly from 2020 and may double by 2050, as consumers invest in electric vehicles and other emerging technologies. The effectiveness with which we manage this transition will play a decisive role in meeting New Zealand’s climate change objectives and commitments; the TPM has a significant role to play in the transition to a decarbonised economy.

The key *Te Mauri Hiko* messages and modelling have strong convergence with the Productivity Commission’s ‘*Low-emissions economy*’ report.⁷ More recently, the Interim Climate Change Committee’s ‘*Electricity inquiry - Final Report*’ reinforced the importance of electrification to New Zealand’s climate change response. It recommended taking action to reduce greenhouse gas emissions in the sector.⁸ The report contained the stark warning that “continued delay is not an option”. We concur with that assessment.

We are working to understand how we can ensure our business will keep pace with the new grid connections needed to enable electrification. These new connections could give rise to a need for new interconnections that relieve constraints and unlock grid capacity. Our project, “Enabling New Connections” is considering what Transpower and the industry needs to do to ensure timely, efficient grid investment can support New Zealand to meet our significant decarbonisation challenge. We must be confident we can provide clear and understandable pricing information to support those investment decisions.

Importantly, we do not consider the Authority’s transmission pricing proposal, in its current form, would assist in unlocking renewable energy resources.⁹ It appears, from our analysis relative to the current TPM, that it is more likely to have the contrary objective of putting the much-needed transition to a low-emissions future in question. Key aspects of the proposed methodology are, in our view, more likely to disincentivise electrification and deter or delay greenhouse gas emissions reductions across the economy. In this respect, the proposal may be inconsistent with New Zealand’s broader energy policy framework.

Our key points

- **The Authority’s proposal may not support New Zealand’s climate change response:** Our analysis indicates that the Authority’s proposal may consciously encourage additional consumption during peak periods. This is likely to put upward pressure on wholesale prices and cause more investment in gas-fired peaking generation, the transmission network and distribution networks. The net result would be higher electricity prices and elevated greenhouse gas emissions. This would exacerbate energy affordability problems and compromise the achievement of climate change objectives.¹⁰

⁶ Transpower [Te Mauri Hiko – Energy Futures](#), June 2018. See also our latest [quarterly update](#).

⁷ NZ Productivity Commission [Low Emissions Economy - Final report](#), August 2018. Te Mauri Hiko reported a doubling of electricity demand, the Productivity Commission more than 1.5 times.

⁸ Interim Climate Change Committee, [Electricity Inquiry – Final report](#), April 2019.

⁹ While any review of the TPM provides an opportunity to address the ‘first mover disadvantage’ under the connection charge, we consider the solutions could be accommodated with change under the policy framework of the current Guidelines (we need the opportunity to consult on and propose changes to the TPM itself).

¹⁰ The Authority has stated that addressing climate change is not part of its statutory objective. However, in our view, this is an unnecessarily narrow interpretation of the objective. We consider that the long-term effectiveness of the Guidelines and the TPM are a key component to achievement of the Government’s clearly signalled policy in this area and it is critical that the TPM and future-focussed policy are aligned.

- **The Authority’s proposal would put timely, efficient grid investment at risk:** The Authority concludes that introducing the proposed ‘benefits-based’ (BB) charge would have a significant and beneficial impact upon the Commerce Commission’s grid investment approval processes, resulting in more efficient expenditure. We find it difficult to agree with the Authority’s analysis and submit that it is, instead, more likely to create sources of dispute and may incentivise parties to withhold information rather than share it. Where disputes over price outcomes hinder timely, efficient investment in transmission and generation, higher electricity prices (a disbenefit to consumers) and elevated greenhouse gas emissions are likely consequences.
- **The Authority’s proposal would not ensure those who benefit pay for transmission investment in the longer term:** Customers’ BB charges would be based on the benefits that Transpower estimates they will receive over the life of an investment at the time that it is made (or at the commencement of the new TPM in the case of the historical investments). Actual benefits will diverge from estimated benefits over time – perhaps dramatically. Moreover, the initial allocations would also apply to any upgrades made many years later.¹¹ It is hard to see how such a regime could be durable – a problem the Authority itself acknowledged in its first issues paper.¹² To illustrate some of the challenges with the proposed BB charges we have provided in **Appendix 3** some simplified case studies of how the charge might apply to (hypothetical) grid investment.
- **A peak price signal is needed for an efficient TPM:** The Authority’s proposal appears to be unsympathetic towards retaining a peak pricing signal in the TPM. We submit that a peak price signal for transmission saves consumers money by deferring new transmission investment. Real-time nodal energy prices cannot do this job – as the Authority has acknowledged in the past.¹³ Opportunities to incentivise peak-demand management through the design of transmission charges should not be passed up in favour of more expensive alternatives, such as paying for demand response as a transmission alternative or through the wholesale energy market. We are firmly of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry’s climate change response.
- **Independent analysis suggests the Authority’s CBA may not support its proposal:** The Authority’s CBA suggests benefits more than 10 times the level previously forecast for (materially) the same proposal. We find this difficult to reconcile. Axiom has independently confirmed that our reservations have foundation. In Axiom’s assessment, the latest CBA suffers from methodological problems – many of them similar to those that resulted in the previous two CBAs being abandoned. In Axiom’s view, the CBA has limited probative value.
- **The Authority’s proposal has no international precedent:** The Authority’s proposal does not, in our analysis, accord with international precedent and appears to have been heavily influenced by the opinion of one international expert in electricity market design. By contrast, the contrary perspectives offered by several other equally well-qualified international experts preferring a more orthodox approach do not appear to have found favour in the Authority’s evaluation.

¹¹ The Authority has also stated that decommissioned plant should still attract transmission charges as if it still existed (see the [Authority’s answer](#) to Contact Energy Limited’s question about exit and entry of generation assets). This is a difficult position to understand or justify to our customers.

¹² Electricity Authority, [Transmission Pricing Methodology: issues and proposal, Consultation Paper](#), 10 October 2012, p.105.

¹³ See for example: Electricity Authority, [Transmission Pricing Review, TPM options, Working paper](#), 16 June 2015, p.53; and Electricity Authority, [Transmission Pricing Review, LPMC charges, Working paper](#), 29 July 2014, p.29-30.

- **Problems with the TPM could be addressed through incremental reform:** The Authority has identified some problems with the current TPM with which we agree.¹⁴ However, in our view, the problems could be dealt with more quickly, more effectively and more efficiently than extensive reforms, with less risk and at a lower cost by incrementally reforming the existing TPM and Guidelines. This approach would also carry a lower risk of unintended consequences and bring the reforms to the market in a more timely manner.
- **The Authority's proposed price cap would not prevent price shocks or smooth the transition:** We support the inclusion of transition provisions in the Guidelines. However, our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended. The cap would also have the unusual consequence of increasing the price rises that most load customers would otherwise face in its absence.¹⁵
- **The Authority's proposed TPM development process may not give us enough time to engage with our stakeholders:** In our view, allowing Transpower enough time to do a good job of developing any new TPM, including strong engagement with our stakeholders, would save time and work in the end. In our view 18 months to submit a new TPM is ambitious, any less introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. We would be more comfortable with 24 months.
- **Transpower needs certainty of cost-recovery ahead of time:** Finding an appropriate way for Transpower to recover its costs of TPM development, implementation and ongoing operation remains a pressing issue. Certainty ahead of time would allow us to better prepare to develop any new TPM within a reasonable timeline. We look forward to continuing to work with the Authority and Commerce Commission to resolve this matter.
- **There are workability issues in the proposed Guidelines:** The 2019 Issues Paper draft Guidelines are a significantly better and more workable than the 2016 version. Should the Authority proceed with its proposal there remain workability challenges. We provide our commentary on these in **Attachment B**. It would be prudent to undertake a 'technical drafting' consultation once the Authority has made any final decision to replace or amend the TPM Guidelines.

We expand on these key points below.

The Authority's proposal may not support New Zealand's climate change response

The Authority has stated that addressing climate change is not part of its statutory objective.¹⁶ We consider this is an unnecessarily narrow interpretation of Section 15 of the Electricity Industry Act 2010 and does not take into account the importance climate change and the reduction of greenhouse gas emissions have in assessing the long-term benefit of consumers. We think that it would be incongruous for the Authority to implement a methodology that would undermine New

¹⁴ The table in **Appendix 1** provides some examples of incremental reforms that could address some of the problems the Authority has identified with the current TPM.

¹⁵ Price caps normally work by delaying price reductions that customers would otherwise be facing in its absence. We provide some analysis of the price cap mechanism proposed by the Authority in **Appendix 4**.

¹⁶ Electricity Authority, [Interpretation of the Authority's statutory objective](#), February 2011, clause A.67(b). "efficient operation of the electricity industry is interpreted within the context of other Government legislation and regulation affecting the electricity industry, and in particular does not allow consideration of pan-industry externalities such as carbon emissions"

Zealand's broader energy policy objectives. In our view, the Authority's TPM proposal has a non-trivial risk of doing so, and may be detrimental to the long-term benefit of consumers by:

- the proposal consciously – and deliberately – encouraging additional consumption during peak periods, while removing the only explicit forward-looking price signal from the TPM; and
- putting upward pressure on wholesale prices and causing more investment in gas-fired peaking generation, the transmission network and distribution networks – since these are natural consequences of higher peak demand.

The net result is likely to be higher overall electricity prices and elevated greenhouse gas emissions – a double-blow for the New Zealand economy. Specifically, the proposal would exacerbate the well-documented energy affordability problems that are afflicting too many consumers and compromise the achievement of broader climate change objectives.

This potential impact of the Authority's proposal on New Zealand's greenhouse gas emissions should be discussed among stakeholders and other policy makers. Many parties are working hard to achieve a low-emissions economy. In our view, it is imperative that these effects are considered properly before any TPM-related policy changes are made.

The Authority's proposal would put timely, efficient grid investment at risk

We are unable to agree with the Authority that introducing BB charges would have a significant and beneficial impact upon the Commerce Commission's grid investment approval processes, resulting in more efficient expenditure. It is, instead, more likely to result in the proceedings getting bogged down in private interests and disputes at the expense of security, reliability and wider economic and social wellbeing considerations (including responding to climate change). We note Axiom's view that:

if the proposal has any effect on the grid investment approval process, it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information.

Consequently, we do not find support for the large benefit (\$77m) the CBA attributes to the Authority's proposal encouraging greater scrutiny of grid investments. For the reasons set out above (and in more detail in Axiom's report), there is no reason to think there would be any such benefits in principle. Moreover, as Axiom explains, the specific methodology the Authority has used to derive the benefit estimate would appear to be flawed.

The Authority's proposal would not ensure those who benefit pay for transmission investment in the longer term

If the Authority's proposal was implemented, Transpower would be required to allocate BB charges to customers based on our estimates of the benefits they will receive over the life of an investment at the time that it is made.¹⁷ Our customers' collective utilisation of the grid is constantly changing, and over time that change can be fundamental to what benefits (or disbenefits) are realised by individual customers. Inevitably, any forecast of benefits that will arise over several decades will be wrong. In our considered view, the probability of the benefits estimates proving to be right, or materially right, over the 30 to 50 year life of an interconnected grid investment is low.

For example, it is relatively easy to deduce that upper North Island consumers would be 'immediate' beneficiaries from our proposed Waikato and Upper North Island Voltage Management project. However, once we start to get more granular and look further into the future, things get more complex. For instance, it is very challenging to forecast how the relative benefits of the investment

¹⁷ Or at the commencement of the new TPM in the case of the historical investments.

would accrue between consumers in Top Energy's network relative to consumers in Vector's network, say, ten or twenty years from now.

This is not a reason to never change the TPM. Rather, it is a reason to ensure the TPM can adapt in response to change. BB charges can be designed to adapt. For example, adopting a method consistent with that applied in the United States (US) would go some way to achieving this. There, charges are fixed ahead of time to large beneficiary zones and then on-charged to individual parties (in the US context these are generally transmission owners) who themselves on-charge using traditional tariff structures, including peak charges.¹⁸ A similar approach in New Zealand would, in our view, significantly improve the chances of a successful move to BB charging.

To illustrate some of the problems and challenges with the Authority's proposed BB charges, we have included in **Appendix 3** some case studies for how the charge might apply to an upgrade of our transmission line between Wairakei and Hawke's Bay (hypothetically).

In our view, the alternative approach reflecting US precedent we have recommended above is likely to prove more workable and reasonably durable. In contrast, a highly granular approach that sought to lock-in charges and seldom – if ever – revisit them would have very little chance of being sustainable in the long-term. The Authority conceded as much in its first issues paper.¹⁹

A peak price signal is needed for an efficient TPM

We agree with the Authority there might be benefits to be obtained from reforming the current (RCPD) peak pricing signal in some way, (such as 'weakening' the strength of the signal and/or making it more targeted). However, our analysis strongly reinforces our belief that the long-term risks associated with removing entirely all peak price signalling from the TPM far outweigh any potential near-term benefits. We believe that dynamic efficiency benefits from peak-pricing outweigh any allocative efficiency benefits from their removal. Put another way, the potential long-term economic costs from having a peak signal that is 'too weak' outweigh the near-term costs associated with a signal that is 'too strong'.²⁰

We also do not accept the Authority's claim that nodal prices alone can result in efficient short-term grid usage decisions *and* the right long-term investment outcomes, thereby obviating the need for a peak price signal in the TPM. This contention is not only at odds with widely accepted economic theory (as Axiom details in its report), it is also inconsistent with what the Authority has said in the past (when it supported unambiguously the economically orthodox position)²¹ and what it continues to say in the context of distribution pricing (where it is encouraging peak pricing).²²

Even if there are some parts of the grid with excess capacity at present, it does not follow that all peak pricing signals should be removed permanently. We would be open to modifying the existing signal. But removing it in all locations would, in time, spur peak demand growth and bring forward

¹⁸ [Joint report](#): Electricity Authority, Commerce Commission and Transpower, Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment, 20 June 2018 – page iii.

¹⁹ Electricity Authority, [Transmission Pricing Methodology: issues and proposal, Consultation Paper](#), 10 October 2012, p.105.

²⁰ [The role of peak pricing for transmission](#) (Transpower, November 2018).

²¹ See for example: Electricity Authority, [Transmission Pricing Review, TPM options, Working paper](#), 16 June 2015, p.53; and Electricity Authority, [Transmission Pricing Review, LRMC charges, Working paper](#), 29 July 2014, p.29-30.

²² See for example: Electricity Authority, [More efficient distribution network pricing – principles and practice Decision paper](#), 4 June 2019, p.iii.

generation, distribution and transmission investment costs. Without a peak signal, we would not be able to efficiently defer those costs, or the increased greenhouse gas emissions that they would bring. We therefore remain of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry's climate change response.

Independent analysis suggests the Authority's CBA may not support its proposal

Axiom's view is that the CBA is compromised, including for the following reasons:

- Neither the grid use model (which generates 96% of the estimated net benefits) nor the top-down modelling reflect the Authority's proposal.
- The net benefit estimate mistakenly includes \$2.3b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry. The analysis also ignores a \$1.9b cost of additional investment that is estimated to be needed to produce the modelled benefits. Addressing these errors alone reduces the Authority's net benefit estimate to *negative* \$1.5b.
- The modelling rests on assumptions that do not reflect the ways in which the electricity market works, or market participants act.
- Aspects of the modelling hinge crucially on assumptions and inputs that are arbitrary or lack objective foundation.

Axiom concludes that the CBA has no probative value and lends no support to the Authority's proposal.

Problems with the TPM could be addressed through incremental reform

The table in **Appendix 1** provides some examples of incremental reform options that could address the problems the Authority has identified with the current TPM.

In our view, this type of reform has significant advantages over the "root and branch" type reform of the Authority's proposal. It is faster and less expensive to implement, bringing the reforms to the market more quickly, and there is a lower risk of unintended consequences.

The Authority has previously noted (most recently in response to the EPR's hedge market reform proposals) that major regulatory changes carry a risk of unintended consequences and should be approached cautiously. For example, in the context of the Authority's proposal, there is a risk that the BB charge could inefficiently distort the wholesale electricity market and generation investment decisions. One concern we have is that the BB charge would send a signal to delay potential new generation until spot prices are not only high enough to cover the cost of the generation but also the new, and potentially uncertain, transmission charges. This would create windfalls (higher price benefits) for generators operating in areas that are subject to lower BB charges.

The Authority's proposed price cap would not prevent price shock or smooth the transition

The proposed price cap is not effective because it does not apply to all transmission charges. This means the price cap would not prevent price shocks. We provide, for clarity, some analysis of the proposed price cap mechanism in **Appendix 4**.

The Authority predicts that some of our distributor customers would face transmission charges increases of 100% or more and predicts large percentage increases for most of our direct-connect industrial customers.²³

²³ Electricity Authority TPM review 2019 Issues Paper Table 12.

The Commerce Commission tends to cap regulated price increases at between 5% and 10% to fulfil its statutory obligation to minimise undue financial hardship for suppliers and price shocks for consumers. Most of our customers who are predicted to face increases in their transmission charges would incur increases far in excess of 10%.

The choice to base the price cap on a percentage (3.5% initially) of the total consumer bill would not have the effect of capping increases in consumers' bills at that percentage, not only because the price cap does not apply to all transmission charges but also because the TPM does not control how distributors pass transmission costs onto their customers. The total consumer bill approach also introduces complexity and estimation error into the calculation.

Another choice, to use transmission charges for the 19/20 pricing year as the comparator for the price cap regardless of when any new TPM takes effect in prices, means the year-to-year price impact on our customers would be different to the indicative effect modelled by the Authority.²⁴

We submit that a better approach would be to apply the cap to all transmission charges and base the cap on a percentage of final year of transmission charges under the current TPM. Alternatively, the new transmission charges could be phased in in combination with the existing ones, similar to the transition from HAMI to SIMI for the current HVDC charge.

Process concerns – Timeframe and cost-recovery

Should the Authority proceed with its proposed new approach to transmission pricing, proper engagement with our stakeholders during TPM development would be critical to producing the most durable TPM possible within the constraints of the Guidelines. Constructive and highly engaged stakeholder participation would be key to achieving a successful development and implementation of any new TPM.

In our view 18 months to submit a new TPM consistent with the Authority's 2019 proposal, would be an ambitious and very challenging timeframe. Any less time introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. For reasons we have stated previously, we would be more comfortable with 24 months.

There remains uncertainty about how we would recover our costs of TPM development, implementation and ongoing operation, should the Authority decide to issue new Guidelines. Certainty about this early in the process would support our ability to develop the new TPM in a suitable timeframe.

Comments on draft Guidelines

We have challenged ourselves to consider afresh how we could make the Authority's proposal work. A significant focus of our review of the Authority's proposal has been on the draft Guidelines and what changes to these would be needed if the Authority were to adopt its current proposal. We have identified a number of drafting and workability issues in the draft Guidelines that need to be resolved. These are highlighted in our clause-by-clause comments on the Guidelines in **Attachment B**. We would welcome the opportunity to work through these issues with the Authority and other stakeholders. Some of the issues remain from previous drafts of the Guidelines.

²⁴ The Authority's modelling assumes the new TPM to take effect in prices from April 2021, which would require a new TPM to be approved in time for Transpower's 2020 pricing round, commencing July 2020. Chapter 6 of the Authority's 2019 Issues Papers contemplates a new TPM taking effect from April 2024. We consider this outcome is more plausible.

In our view it would be prudent for the Authority to undertake a technical drafting consultation once it has made final decisions on whether to replace or amend the Guidelines.

Transpower New Zealand

Transpower is committed to playing its part to address climate change and help New Zealand transition to a low emissions economy. We are part of the Climate Leaders Coalition in New Zealand – standing publicly with many other businesses to declare and report on our mission to reduce emissions in New Zealand. We are actively seeking to reduce our own greenhouse gas emissions across all areas of our own inventory of emissions, and we are working hard to ensure we enable the transition to a low-emissions electricity future.

We consider that timely, efficient transmission investment will be vital to support New Zealand's commitment to the international community through the Paris Agreement. In our view, the Authority's proposal is at risk of exacerbating the well-documented energy affordability problems that are afflicting too many consumers and compromise the achievement of New Zealand's climate change objectives and commitments.

The problems the Authority has identified with the current TPM can, in our submission, be dealt with more quickly, more efficiently, and more cost-effectively through incremental reform of the existing TPM and Guidelines. This approach would also carry a lower risk of unintended consequences. We would welcome the opportunity to consider these options in conversation with the Authority, our customers and other stakeholders.

Yours sincerely

A handwritten signature in black ink, appearing to read 'Alison Andrew', written in a cursive style.

Alison Andrew
Chief Executive

Appendix 1: Options for incremental TPM reform

The table below lists some high-level examples of incremental reform options that are available to address the problems the Authority has identified with the current TPM.²⁵

Problem	Incremental reform solutions include:
Interconnection charge	
The interconnection charge method spreads the costs of regional transmission investment too widely, across all New Zealand	<ul style="list-style-type: none"> • Tilted postage stamp • Regional postage stamp (using location as a proxy for benefit) • Regional postage stamp with net importing regions (and/or generators) picking up a proportion of the cost of net exporting regions
The current RCPD method sends a peak price signal that is too avoidable, shifting costs onto other parties	<ul style="list-style-type: none"> • Mean offtake as an allocator (in whole or part) • Two-part tariffs (fixed/volume/mean + peak usage)
The current RCPD method peak price signal is too high, promoting inefficient investment to avoid it	<ul style="list-style-type: none"> • Two-part tariffs (fixed/volume/mean + peak usage), perhaps with ability to dial-up the peak usage part as constraints are foreseen in short-to-medium term grid planning) • N (number of peaks) > 100
RCPD method can result in unpredictable year-to-year price volatility	<ul style="list-style-type: none"> • Multi-year averaging for capacity measurement
HVDC charge	
South Island generators pay for the inter-island HVDC link but North Island generators do not face an equivalent charge	<ul style="list-style-type: none"> • Bi-directional HVDC charge on generation in the sending island, calculated half-hourly
Generators in the upper South Island pay for the inter-island HVDC link despite that region being a net import region	<ul style="list-style-type: none"> • Exemption for upper South Island generators, or more general recognition of intra-South Island zonal import/export characteristics
HVDC charges on injection into the grid by South Island generators incentivise embedding of large-scale generation	<ul style="list-style-type: none"> • Generation plant with a capacity above a threshold is deemed grid connected

²⁵ We canvassed many of these options in our Invitation to Comment on a [possible 'Operational Review 2'](#) of the current TPM, June 2017. The feedback from stakeholders was positive.

Transmission charges on generation	
Generators should contribute to the costs of transmission to the extent their location contributes to transmission investment needs	<ul style="list-style-type: none"> • Bi-directional HVDC charge on generation in the sending island, calculated half-hourly • Generators pay part of the interconnection charge • Use bilateral investment contracts to partially or fully fund transmission investment to release generation capacity

In our view, the problems relating to undergrounding costs and stakeholder engagement in investment decisions are adequately addressed through our regulation by the Commerce Commission under Part 4 of the Commerce Act.

We understand the Authority's concern that Transpower may, in future, be pressured by local communities or required by council policies to underground our assets in a way that pushes the associated (significantly higher) costs onto consumers in other communities. We agree this risk needs to be managed, but consider managing it through the TPM introduces significant implementation issues. In our view, management of this risk is more appropriately within the jurisdiction of the Commerce Commission where it is already well managed via its decisions on our individual price-quality path and our capex investment proposals. We believe these mechanisms are better able to respond over time to new and emerging trends, including societal expectations and technology changes, than the TPM. A possible solution may be for local communities to bear the incremental costs of any locally-required undergrounding directly through bilateral investment contract cost recovery outside our regulated asset base.

Appendix 2: Transpower's positions on the Authority's transmission pricing review

The Authority's transmission pricing review began in February 2011, with consultation amending the regulatory framework for the Transmission Pricing Methodology - specifically, to remove the pricing principles and the application and interpretation provisions from the Electricity Industry Participation Code.

To date Transpower has contributed 16 submissions and 2 cross-submissions, including this October 2019 submission. From the beginning our key messages have been strongly consistent.

Our submissions listed below, are all publicly available. The balance of the Appendix provides a snap shot of some key messages in the form of quotes from these submissions. The summary highlights that the views and positions we have expressed since of the Authority's transmission pricing review remain relevant to consideration of the 2019 Issues Paper.

February 2011	Code amendment proposal: Regulatory framework for Transmission Pricing Methodology (TPM)	submission
February 2012	Decision-making and economic framework for transmission pricing methodology review	submission
March 2013	Transmission Pricing Methodology: Issues and proposal	submission cross-submission
October 2013	TPM working paper – Transmission Pricing Methodology CBA	submission attachment: CEG report
November 2013	TPM working paper – Sunk Costs	submission attachment: CEG report
January 2014	TPM working paper – ACOT payments for distributed generation	submission
March 2014	TPM working paper: Use of LCE to offset transmission charges	submission
March 2014	TPM working paper: Beneficiaries-pay	submission attachment: CEG report
June 2014	TPM working paper: Connection charges	submission
September 2014	TPM working paper: LRMC charges	submission
October 2014	TPM working paper: Problem definition relating to interconnection and HVDC assets	submission
August 2015	TPM Options paper	submission appendix: CEG report appendix: Scientia report
July 2016	TPM: Second issues paper	submission appendix: guidelines mark-up appendix: Axiom report appendix PWC report appendix: Scientia AOB report appendix: Scientia gross demand report

February 2017	TPM: Second issues paper supplementary consultation	submission appendix: guidelines mark-up appendix: Axiom report appendix: ENA distribution pricing consultation submission
March 2017	TPM supplementary consultation: asset valuation	cross-submission
April 2017	TPM: Oakley Greenwood CBA	submission
October 2019	TPM 2019 Issues paper	Submission available here from 2 October 2019

Overall views on the proposal for radical change: "Having participated fully in this process to date and from a largely 'value neutral' perspective we have been unable to convince ourselves of the case for radical change. On the contrary, as the process progresses, it has become increasingly apparent that current TPM operates well and that a stable, simple and durable TPM is highly valued. We remain extremely concerned about the risk of unintended consequences or 'collateral damage' from radical reform." (October 2013)

Questions about EA work prioritisation: "a major structural change to the TPM would consume considerable scarce resources within the EA and across the industry at a time when the EA has far more urgent priorities that have the potential to provide greater long-term benefit to consumers." (February 2012)

"Transmission pricing is challenging and has a history of causing dispute. As a sector, we have allowed this challenge to divert resources and attention away from issues that have greater potential to improve outcomes for consumers." (March 2013)

Transpower is engaging constructively to try and help make the Authority proposals work: "Notwithstanding, our focus remains on helping the Authority reach a satisfactory conclusion to its review of the TPM Guidelines; this is reflected in the content of this submission. Similarly, if the Authority decides to issue new Guidelines, then we will do our best to develop those into a robust, workable and durable TPM." (February 2017)

We are open to changing the TPM: "To be clear, we are not averse to change where it makes sense, and consider that the investigation process has advanced understanding of some specific problems, e.g. ... the strength of the UNI RCPD price signal, where there is clearly room for improvement (and potentially elsewhere). However, we simply do not think large-scale change makes sense and, rather than pursue radical departure from current arrangements, the investigation should focus on understanding and remedying the specific problems that have been identified." (October 2013)

"In practice there is no perfect TPM: we agree problems exist with the TPM and that these should be assessed (and addressed, as appropriate, where there are clearly superior alternatives to the current settings). We also agree there is no perfect TPM and consider that perfect should not become the enemy of good." (October 2014)

"Our preferred outcome for this review is a decision that yields a workable TPM. This means that it finds general acceptance among the main stakeholder groups and encourages our customers to sensibly manage their loads (to help us defer investment) and to sensibly

engage in the grid investment process. Ideally this will not be excessively complex or costly to implement and operate.” (October 2015)

“We agree there is scope to improve the current transmission pricing methodology (TPM) including to improve cost-reflectivity and the targeting of price signals and that this is likely to require some changes to the Guidelines.” (July 2016)

An incremental approach should be taken: “It is clear from many submitters that the status quo for interconnection charging (aside from perhaps the HVDC charge) is preferred over the proposed use of the SPD method. Any further consultation should be on options to refine the existing arrangements, rather than on revisions to the original proposal.” (28 March 2013)

“In our view, the problems with the status quo, if any, are minor and point to less radical and much simpler approach to transmission pricing than the Authority is proposing. In our view that approach should recognise the stability and efficiency benefits of the current TPM and focus on incremental improvements.” (November 2014)

“We note that the current pricing arrangement of a regionally differentiated postage stamp interconnection charge and geographically-targeted HVDC charge already provides a relatively simple LRMC-like charge. As a less radical option, these charges could be modified over time to adjust price signals.” (September 2014)

Connection charging framework is sound: “The majority of submissions from our connection customers agreed there is no material problem with the connection charging framework, and connection charging was not a focus for most submitters with no strong endorsement for change.” (28 March 2013)

“The existing connection charge framework is fit for purpose and compatible with the investment and incentive regulation under Part 4 of the Commerce Act.” (June 2014)

Interconnection charges may send too strong pricing signals: “With respect to the interconnection charge the Authority has not adequately defined the problem it sees with the current TPM. Apart from the ‘signal strength’ issues that, if established as material problems, are readily addressable the problem definition to date has essentially been a statement of faith and belief: that its preferred solution could be ‘more’ efficient than the status quo. This simply does not constitute a robust problem definition.” (October 2013)

“... RCPD can over-signal the benefit of load-shedding ...” (October 2014)

Qualified support for charging beneficiaries: “We support in principle the intent of improving investment efficiency by identifying and charging beneficiaries. However, the proposal raises concerns due both to its complexity, and the high risk of unintended consequences.” (March 2013)

“... our broad support for beneficiaries-pay reflects that there are a number of options which would satisfy beneficiaries-pay, including the status quo; connection assets are charged to the sole beneficiaries (on a causer pays basis), South Island generators are major beneficiaries of the HVDC but, like the Authority’s GIT based charge options, not the sole beneficiaries, and smearing interconnection costs across load on a postage stamp basis reflects the large fixed and common costs of the transmission grid, and should result in a situation where no consumer group or region pays more for interconnection than their private benefit.” (March 2014)

Difficulty in identifying beneficiaries: “the charges will not accurately reflect the benefits of transmission investments (either in terms of approximating private benefits for individual parties, or providing a clear indication of overall benefits of investments).” (March 2013)

Removal of peak-usage charges would be undesirable: “Removal of a peak price signal could trigger an ‘over-correction’ where demand spikes lead to significant transmission investment being brought forward.” (July 2016)

“A peak price signal is essential for an efficient TPM. We disagree with the Authority’s reasoning and position on a peak Long Run Marginal Cost (LRMC) charge. The Authority’s current path risks grid over-build and security problems which could swamp any benefits from TPM change.” (February 2017)

Authority proposals could result in wholesale market distortions: “the charges may alter generator behaviours in ways that reduce the efficiency of the wholesale market. The economic costs of this may significantly outweigh any potential benefits.” (March 2013)

“[Benefit-based] charges would not provide the intended locational signal to generators and could result in inefficient investment decisions, as well as adversely impacting operation of the wholesale energy market.” (July 2016)

Proposals will undermine efficient investment: “The [Authority’s] concern is that grid investment processes lack adequate stakeholder engagement and that there is a systematic risk of the Commerce Commission approving inefficient grid investments. We do not believe that evidence supports these concerns, or that the proposed pricing changes would improve investment efficiency. To the contrary, there is a risk that the proposal will motivate obstructive or vexatious engagement to the detriment of investment efficiency.” (March 2013)

Proposals will increase disputes: “using a complex modelling approach to setting transmission pricing will only increase disputes.” (March 2013)

Investor certainty undermined by current review: “ongoing reviews of the TPM reduce investor certainty, which is especially relevant to the timely commitment of new investment in generation.” (February 2012)

“Investors would prefer a robust, enduring approach to transmission pricing that promotes a more certain commercial environment. Approaches which provide less certainty add to commercial risk, which increases some costs (e.g. borrowing costs), discourages some investment and reduces the values of some businesses.” (February 2012)

“The length of the review is creating considerable uncertainty. While the Authority should not rush the remainder of the process, particularly if substantive changes to the TPM are further considered, there are a number of lessons that can be taken from the review that would help ensure it is robustly completed in a timely manner.” (October 2014)

Need for transitional arrangements: “Large step changes to transmission prices can produce unintended consequences. The assessment of any amendments to the TPM that would result in large changes to individual customers’ charges must account for the need for such amendments to be introduced by way of transitional arrangements.” (February 2012)

Appendix 3: Case Studies - application of benefit-based charging

We have considered application of a simplified benefit-based charging regime in practice by considering a hypothetical need to upgrade the line between Wairakei and Hawke's Bay. We have undertaken this Case Study exercise as part of our efforts to explore ways in which the Authority's proposed benefit-based charge method (BBCM) could be made to work in a pragmatic, practicable and legally robust/certain manner.

The Wairakei-Hawke's Bay line case studies were chosen on the basis that they are relatively simple. To simplify further we have used approximate demands and costs, and have excluded consideration of the existing and any future transmission connection to the south. The case studies then don't need to consider the complexities of 'loop flow' and meshed characteristics of the wider interconnected grid which, combined with the large number of parties using the grid, may impact on the complexity and practicability of applying a BBCM. To simplify further we have considered only beneficiaries who are known load and generation transmission customers. This avoids practicability issues where the beneficiaries are unknown or the benefits are not attributable to existing individual transmission customers.

We have tested application of a BBCM to achieve full consistency with clause 24 of the 2019 Issues paper draft TPM Guidelines. Specifically, we have ensured consistency with "the treatment of the relevant electricity market benefit or cost elements under the test used by the Commerce Commission in its approval of the post-2019 benefit-based investment". We have done this by considering benefits exclusively from the Part 4 market benefit test.

We are mindful that it would be undesirable to have to separate benefit tests (investment test under Part 4 Commerce Act, and BBCM test under the TPM), which provide potentially different and inconsistent information about proposed investments.

The application uses market benefit as a proxy for private benefit which may be reasonable if the two are considered to be sufficiently or strongly correlated (consistent with clause 22(b) in the draft Guidelines). Clause 22(b) requires that the "proxies ... result in an allocation of the benefit-based charge to each designated transmission customer who receives a major positive net private benefit from the benefit-based investment that broadly approximates the allocation that Transpower considers would have resulted had expected net private benefits been used to calculate the allocation". The extent to which our Case Study application meets this requirement is open to interpretation, and we detail some of the (known) reasons why there may be departures or differences.

We would welcome views from the Authority and other stakeholders about whether the approach we have taken for the Case Studies is considered to be a reasonable and workable approach that is consistent with the proposed TPM Guidelines and policy intent.

Case Study A: Load grows and triggers need for more transfer capacity into Hawke's Bay

Under Case Study A we have tested the scenario where load grows and triggers the need for more transfer capacity into Hawke's Bay.

The benefits we have identified are from reduced cost to meet load and resilience. We have assessed that Wairakei generators would receive 15% of benefits (using increased income as

a proxy for benefit, and based on assumption the market is perfectly competitive and offers/prices are set at SRMC), and Hawke's Bay load receives 83% of the benefits (assessed as the reduced cost to meet load, using the cost of a diesel generator as the counter-factual).

The assumptions we have used for Investment Test purposes may impact the determination of benefits. For example, the results could be quite different if the perfect competition assumption²⁶ was loosened or if the counterfactual assumed new permanent generation plant in the Hawke's Bay region (see the Case Studies below) rather than diesel generation. These assumptions could overstate consumer private benefits and understate generator private benefits. Likewise, we have used revenue as a proxy for producer surplus. This could overstate producer surplus if price matched cost (which would be the case in a perfectly competitive market) and the new generator earned normal profits only. As a corollary to this, if the perfect competition assumption is loosened then the benefit generators get from the expanded line may include an element of economic rent and, therefore, higher producer surplus and benefit. What the overall impact of the use of proxies is on the BBCM allocations may be ambiguous.

The increase in load would increase the benefits of the existing line. We have not modelled this. Consideration would need to be given to whether the proposed TPM Guidelines re-opener triggers had been met, if the existing line was treated as a benefit-based Investment (as per the Additional Component provisions). We note that the benefits from the existing line won't necessarily be the same as the 85:15 benefit split for the upgrade.

If benefit-based charges were applied to the existing line and upgrade it might make sense to undertake a single benefit-based assessment for the existing line and upgrade. This also gives rise to the question whether, if the existing line is not a BB investment, whether the upgrade or new investment should trigger the existing investment becoming a BB investment. Consideration would need to be given to the complexities of applying the BBCM to existing, historic investments, and the implications that it could divorce the BBCM from the Part 4 Investment Test.

Case Study B: 150 MW new generation is built in southern Hawke's Bay

Under Case Study B we have assumed 150MW of new generation is built in Hawke's Bay, with two sub-scenarios: under B1 the cost of new generation in Hawke's Bay is 7c/kWh (cheaper than from Wairakei) and under B2 the cost of new generation is 10c/kWh (more expensive than from Wairakei).

Under scenario B1 the new generation is cheaper than existing Wairakei generation and is dispatched. Under scenario B2 it is more expensive but cheaper than the cost of unserved energy so is used to make up any deficit in supply from Wairakei/line constraints. Under both scenarios no transmission investment is economic so there is no need to undertake a benefit-based allocation assessment.

It should be noted the B1 assumption that the cost of new generation in Hawke's Bay is cheaper than Wairakei means the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line may reduce, and may be lower than under the B2 scenario. The perfect competition assumption means that the Investment Test approach assumes

²⁶ The private benefits for generators would be greater in an oligopolistic market than a perfectly competitive market.

consumers will receive the full benefit of the lower SRMC. We have not modelled this, but consideration would need to be given to whether the proposed TPM Guideline re-opener triggers had been met if the existing line was a benefit-based investment.

Case Study C: 600 MW new generation is built in Hawke's Bay. To fully dispatch, need to expand Wairakei-Hawke's Bay

Under case study C there is 600MW of new generation built in Hawke's Bay. In order to be fully dispatched the Wairakei-Hawke's Bay line needs to be expanded. The new generation is assumed to be cheaper than Wairakei generation (as per scenario B1). The assumption that the new Hawke's Bay generation is cheaper than Wairakei means it is assumed that it would be fully dispatched if there are no line constraints.

The major beneficiaries are determined to be the Hawke's Bay generator with 71% of the benefit (increased dispatchable generation) and Wairakei load with 27% (reduced cost to meet load as the Hawke's Bay generation cost is 7c/kWh compared to Wairakei generation which costs 8c/kWh). Hawke's Bay load is a minor beneficiary with 2%.

The benefit to Wairakei load reflects that the Investment Test assumes perfect competition to the lower SRMC Hawke's Bay generation is assumed to benefit consumers. The outcome may be different (smaller benefit to Wairakei load, higher benefit to Hawke's Bay generation) if the perfect competition assumption was loosened. The modelling would need to include judgements about offer prices (and the extent they deviate from SRMC) and which generation sets the spot market clearing price.

Under a simple method the entire cost could be allocated exclusively to the Hawke's Bay generator and Wairakei load. Hawke's Bay load only get minor benefit from improved resilience (2% of the benefit). If a private benefit assessment was made it may be determined that Hawke's Bay load receives negative benefit as, in the absence of the line upgrade, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

The new generation investment in the Hawke's Bay would reduce the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line, particularly if the line becomes constrained (east to west). We have not modelled this, but consideration would need to be given to whether the proposed TPM Guidelines re-opener triggers had been met, if the existing line was a benefit-based investment. The 98:02 allocation would be unlikely to be suitable for application to the existing line as it had a different purpose and benefit (transporting electricity from Wairakei to Hawke's Bay) which would force departure from the BBCM and the Investment Test.

Case Study D: 600 MW new generation is built in southern Hawke's Bay. 300 MW new generation initially then second 300 MW generator built

Under Case Study D 300MW of new generation is built in southern Hawke's Bay (Generator 1). As with the Case Study B scenarios no new transmission is economic for the new generation. Under Case Study D a second 300MW generation plant is built (Generator 2) and to fully dispatch both the Wairakei-Hawke's Bay line needs to be expanded. The principle difference between Case Studies C and D is that there are two different new generators in Hawke's Bay in D. If a private benefit assessment was made it may be

determined that Hawke's Bay load receives negative benefit as, in the absence of the line, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

We make an important distinction between what caused the need for the new transmission line and who benefits from it. Generator 1 does not have any 'capacity rights' to the existing line. The change in market conditions, with development of a second generation plant in Hawke's Bay means both Generator 1 and Generator 2 would get the same (equal) benefit from the increase in line capacity i.e. both need the new line to be fully dispatched. Looked at another way, the new line would equally not be needed if Generator 2 entered the market and Generator 1 exited (plausible if Generator 2 is lower cost than Generator 1 and Generator 1 has high variable costs relative to sunk and fixed costs).

Generator 1 receives 35% of the benefit, Generator 2 receives just over 35% of the benefit, Wairakei load receives 27% of the benefit (reduced energy cost) and Hawke's Bay load receives 2% (reduced energy cost and resilience). If a private benefit assessment was made it may be determined that Hawke's Bay load receives negative benefit as, in the absence of the line, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

The new generation investment in the Hawke's Bay would reduce the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line, particularly if the line becomes constrained (east to west). We have not measured, but consideration would need to be given to whether the proposed TPM Guideline re-opener triggers had been met, if the line was a benefit-based investment.

Note that if the assumptions are changed such that Generator 1 is higher cost (variable cost) than Generator 2 then Generator 1 would receive a greater share of the benefits of the new line, because more of Generator 2's electricity would be dispatched under a constrained line scenario. Likewise, on a private benefit assessment, Generator 2 would receive a larger producer surplus than Generator 1 even if they generated the same amount of electricity. This highlights that BBCM allocations would be very dependent on the assumptions Transpower makes about the individual costs (including SRMC) of each generator's plant.

Appendix 4: Analysis of the Authority's proposed price cap

The TPM review process to date has shown the potential for very large transfers, some of which have the potential to affect the viability of enterprise or the economic wellbeing of residential consumers. We consider there to be a need to include or retain transition provisions in the TPM Guidelines. We are open to the inclusion of a price cap. However, we have a number of practical and substantive concerns with the design of the price cap and its expression in the draft Guidelines. These are largely the same as the concerns we expressed in response to the Supplementary Consultation (February 2017).

The specification of any price cap/transition mechanism should recognise the optimal design, including length of transition etc, can depend on the scale of the price shocks/changes. This would depend on a number of factors including when the new TPM is introduced, finalisation of Schedule 1, decisions on what the methodology is for setting Residual Charges and other factors that wouldn't be known until after the Authority has made final decisions on whether to change or replace the TPM Guidelines.

An effective price cap would also smooth the transition from current to new prices over a period of time i.e. delay when customers incur the full price increase/receive the full price decrease.

The Electricity Authority's 'price cap' would allow major price shocks for many consumers

We are concerned about the size of the price shocks that would result from the Electricity Authority's proposals. The Commerce Commission has capped network price increases at 9% (applicable to Aurora Energy for the 2025-25 DPP reset) under Part 4 of the Commerce Act in order to avoid price shocks for consumers. The Authority's proposed price cap would result in a number of undesirable outcomes:

- The price cap would result in many transmission customer's prices going up initially by more than they would absent the price cap (including 15 of the electricity distributors).
- The price cap would exacerbate price shocks for transmission customers that would incur higher transmission charges e.g. Westpower would face an initial price increase of 110% under the cap rather than 101% without the cap, Network Waitaki would face an increase of 55% rather than 51%, The Lines Company 50% rather than 46%, and Top Energy 32% rather than 29%.²⁷
- The price cap would result in some transmission customers (Counties Power and Contact Energy) whose prices would otherwise go down initially facing a price increase.
- The price cap would result in the customers that would get the biggest benefits (price reductions) from the new TPM getting proportionately more benefit straightaway than customers that would get smaller benefits e.g. Meridian would receive an

²⁷ Note that for modelling convenience, the Authority has adopted 2022 for the assumed implementation date for the new TPM. The assumed implementation date may impact on some of the assumed results e.g. if the implementation date is after 2022 then electricity retail prices may be higher than the Authority has assumed, meaning that transmission charges would not be able to increase as much before the cap takes effect.

(uncapped) 42.62% reduction in transmission charges and receives 96.77% of this in year one, NZAS would receive a 22.11% reduction uncapped and receives 91.55% in year one, and Unison Networks would receive a 4.80% reduction and would receive 52.42% of the benefit in year one.

- The price cap would result in some situations where customer A is facing a higher initial price increase than customer B yet customer B would face a higher price increase without the cap or after the price cap has been unwound e.g. NZ Rail and Buller Electricity face similar price shocks without the cap, of 157% and 149% respectively, but the price cap lowers the initial impact for NZ Rail by 120% and for Buller by only 51%.
- The price cap would result in situations where customer A and customer B would face the same increase without the price cap but a different initial increase under the cap e.g., absent the price cap, Buller Electricity would face a transmission price shock of 149% and Westpower would face a price shock of 110%. The price cap provides Buller with substantially bigger initial protection, reducing the price shock by 51% compared to less than 10% for Westpower. The impact is to flip the increases with Buller initially facing a lower initial increase of 98%, compared to Westpower with an initial increase of 101%, despite the fact that Buller's prices would ultimately go up by more than Westpower.

Level of price shocks under the Authority's proposed price cap

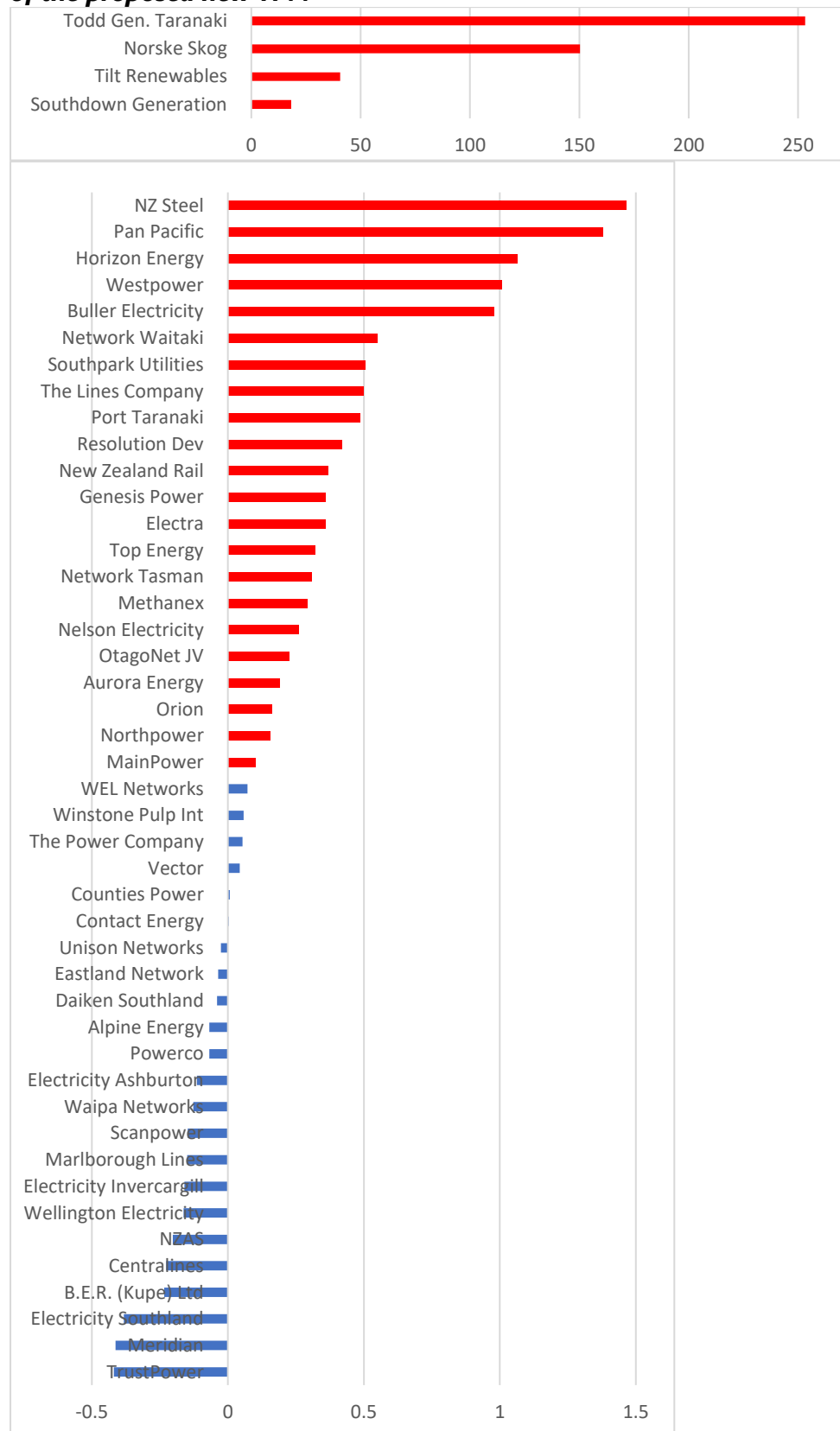
According to the Authority's calculations²⁸, half of all EDBs would be subject to price shocks ranging up to 98% increase in transmission charges for Buller in the first year of the new TPM, 101% increase for Westpower and 107% for Horizon.

The Authority's changes in transmission charges could undermine the Commerce Commission's attempt to avoid price shocks. For example, the effective impact of the change in transmission charges for Aurora would push its price increases up from the Commerce Commission's cap of 9% to the equivalent of a 15% increase.

The impact is even more significant for most major users, other than NZAS. The initial increase for Pan Pacific, NZ Steel, Southdown, Tilt, Norske Skog and Todd range 138% to 25,231%.

²⁸ Electricity Authority TPM review 2019 Issues Paper Table 12.

Figure 1: Electricity Authority's estimate of transmission price changes in the first year of the proposed new TPM^{29 30}



²⁹ Based on data from the Authority's 2019 Proposals Impact Modelling spreadsheet.

³⁰ Calculations are based on introduction of new TPM for 2022.

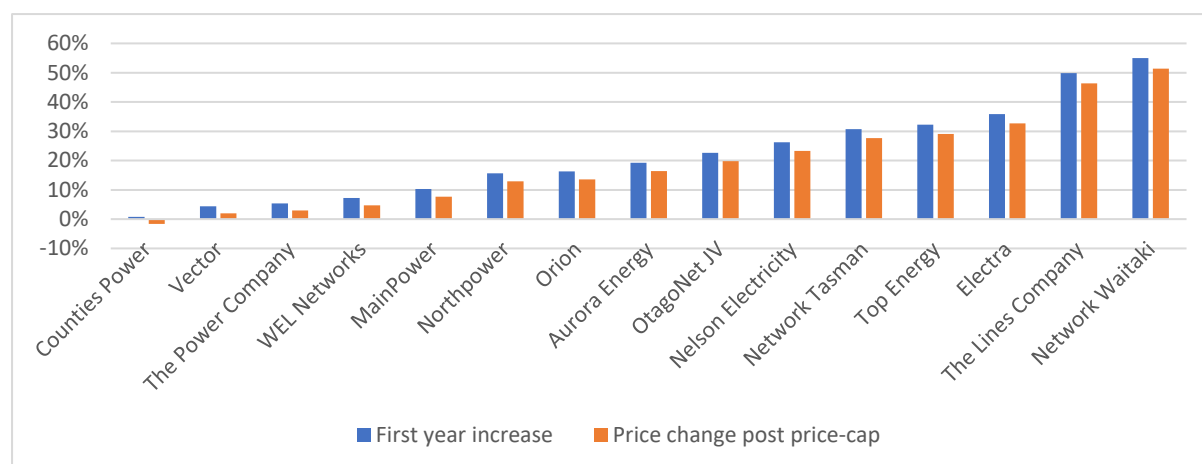
The Authority's proposed 'price cap' would result in unintended consequences

A price cap or transition would normally simply slow the rate of price increase (or decrease) to avoid price shocks. The Authority's proposal does not do this.

For the majority (15) of EDBs the price cap results in the initial price increase being higher than they would face without the cap, with transmission prices then reducing in subsequent years. In the case of Counties Power (and Contact Energy) the Authority's proposals are supposed to result in a reduction in transmission costs, but they initially instead would go up.

For the majority of these EDBs the impact of the price cap is actually to exacerbate the level of the price shock e.g. The Lines Company transmission prices would go up by 50% in the first year, instead of 46% without the price cap. Network Waitaki similarly would face an initial increase of 55% instead of 51%.

Figure 2: Initial transmission price increases for electricity distributors under the proposed price cap³¹



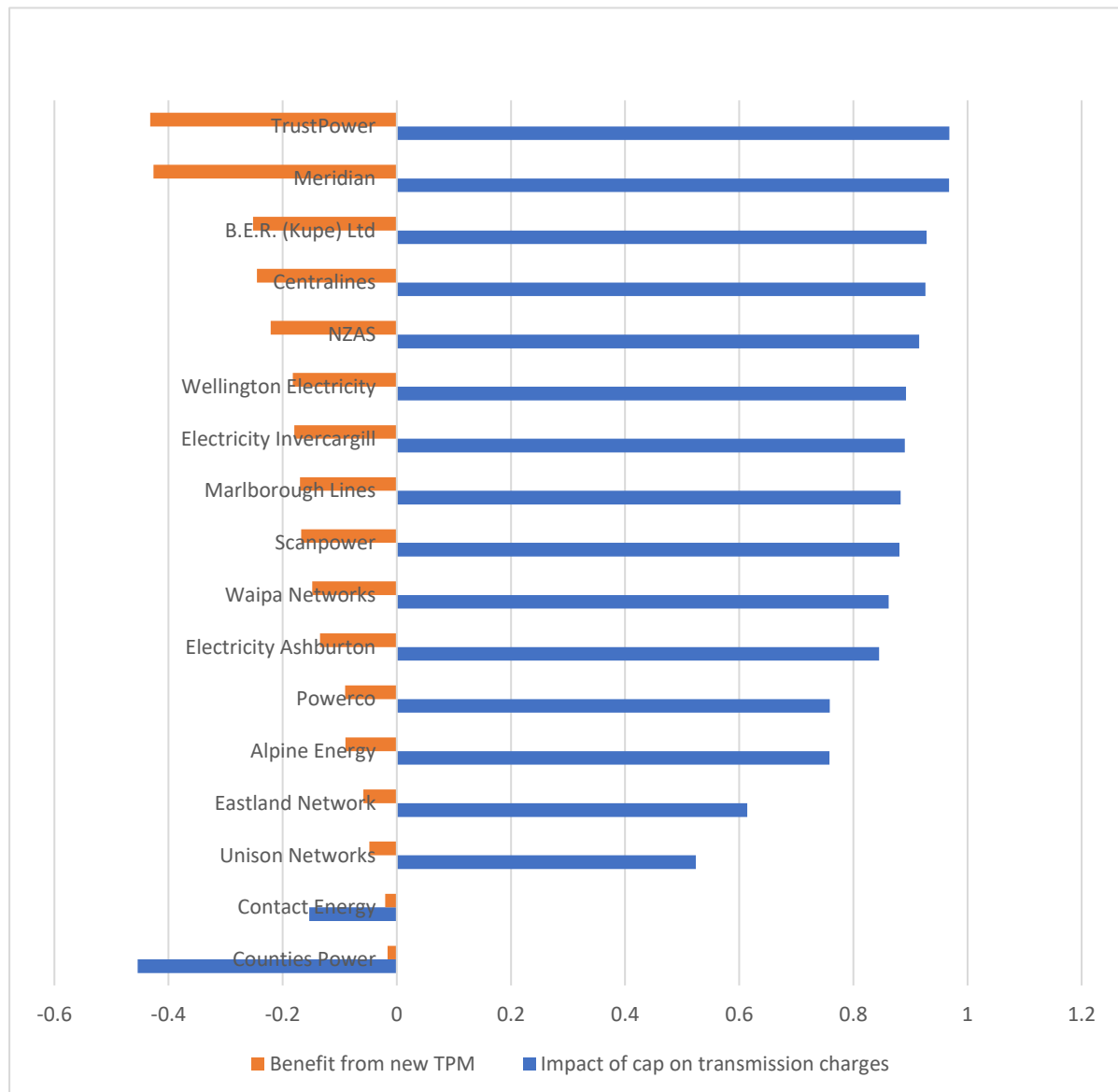
The transmission customers that would receive price reductions get all but 1.36-2.35% of the price reduction straightaway, without any real transition. For example, Meridian gets a 41.25% reduction straightaway, and initially misses out on 1.38% of the reduction they would ultimately receive. In contrast, Contact who would ultimately receive a reduction of 2.04% faces an initial price increase of 0.31%. The rapid phase in for transmission customers that are getting price reductions is funded by increasing the charges of the majority of transmission customers facing increases by increasing their charges by more than would occur absent the price cap.

The cap also results in the customers that would receive the largest benefits from the TPM having their price reductions least effected by the price cap e.g. Meridian would receive a (uncapped) 42.62% reduction in transmission charges and receives 96.77% of this in year one, NZAS would receive a 22.11% reduction and receives 91.55% in year one, Electricity Ashburton would receive a 13.43% reduction and would receive 84.54% in year one, Unison Networks would receive a 4.80% reduction and would receive 52.42% of the benefit in year

³¹ Based on data from the Authority's 2019 Proposals Impact Modelling spreadsheet.

one, Contact would receive a 2.04% reduction and their price actually goes up initially by 15.34%.

Figure 3: Direct correlation between size of price reductions and how much of the reduction customers receive straightaway under the price cap³²



³² Based on data from the Authority's 2019 Proposals Impact Modelling spreadsheet.