ELECTRICITY AUTHORITY
TE MANA HIKO

2019 issues paper

Transmission pricing review

Consultation paper

Submissions close: **5pm 1 October 2019**

23 July 2019

Executive summary

A new approach to transmission pricing for the long-term benefit of consumers

The Electricity Authority (Authority) is proposing a new approach to transmission pricing. The Authority considers that changing the transmission pricing methodology (TPM) is necessary and becoming increasingly urgent.

The current TPM enables Transpower to recover its maximum allowable revenue, and signals to customers that their demand drives future investment in transmission capacity. In this way the transmission charges to some extent help to defer costly grid investments.

However, significant flaws in the TPM are leading to inefficient investment and consumption outcomes:

- The current charges spread the costs of regional grid investments across all New Zealand. This makes such investments look cheaper than they are at the local level, compared to local alternatives, while other regions pay for assets they do not benefit from.
- Interconnection charges are allocated based on consumption during just 100 regional peak trading periods in a year (the regional coincident peak demand or RCPD charge). This creates a very strong price signal to consumers, which:
    - inefficiently discourages electricity use at times consumers most value it, even when there are no grid congestion issues
    - encourages customers to unnecessarily invest in technologies such as batteries and distributed generation to avoid paying transmission charges, shifting charges to others without reducing Transpower's costs.
- South Island generators pay for all of the costs of the high voltage direct current (HVDC) line that transports electricity between the South and North Islands, though North Island generation does not face equivalent charges. This 'tax' on South Island generation encourages investment in otherwise more expensive North Island generation.[1]

These problems increase cost to consumers. They are likely to get worse as more grid investments are made to support growing regions and the transition to a low-emissions economy, and as distributed generation, such as solar panels, and batteries become more affordable.

If the RCPD is left unchanged, there is a very real risk of a substantial shifting of charges by households with the resources to take up these emerging technologies at scale. This accelerating shifting of charges will increasingly expose remaining households to RCPD price signals. That will increase their incentives to try to avoid these charges through inefficient investment. If we do not act now, consumers will get less benefit from the electricity system and pay more for it in the long-run.

The proposed TPM guidelines seek to address these problems. The Authority considers that a TPM consistent with the proposed TPM guidelines would unlock considerable long-term net benefits for consumers.

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[1] Some of these issues date to the late 1990s, when pricing was introduced that allocated costs of the HVDC in full to South Island generators and allocated interconnection charges on a measure of peak demand only.

Benefit-based transmission pricing

The Authority proposes a benefit-based approach to allocating transmission costs, where those who benefit from specific grid investments would pay for them. Key features of the proposal are:

- a benefit-based charge to recover costs of new grid investments and depreciated costs of seven major existing investments[2] based on their benefits to transmission customers
- a residual charge to recover any remaining transmission costs in a manner which does not distort incentives to invest or use the grid.

These new charges would replace the current RCPD and HVDC charges. They are purposely designed to be independent of grid use and so hard to avoid. This would mirror Transpower's own cost structures which are largely fixed and not dependent on grid use. The proposed charges would therefore minimise inefficient grid use and inefficient investments.

These new charges would send better signals to consumers about the economic cost of using the grid, without distorting grid use or investment in grid-connected generation and transmission alternatives. This approach is aligned with the new distribution pricing principles that the Authority released recently, which guide distributors in adopting cost-reflective network pricing.[3]

The guidelines in respect of the connection charge[4] are proposed to remain largely unchanged, while some minor modifications are being proposed to the current prudent discount policy.[5]

Wholesale market prices will work alongside the TPM to manage peaks

The Authority recognises that some form of peak pricing will continue to play a key role in the management of demand in the case of congestion, and to defer grid investment until the timing is right. The design of such a charge has been a topic of much consideration (see Appendix E).

The Authority considers that the well-established mechanisms adopted in 1996 by New Zealand to determine wholesale market prices at grid injection and exit points (nodal or locational marginal pricing) deliver the most responsive and efficient signal of transmission costs and congestion. As the International Energy Authority has stated:

> "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments".[6]

Nodal prices can do a better, more targeted job of providing a timely signal of the actual cost of using the grid (such as congestion) at specific locations than the blunt and typically excessive signal currently provided by the RCPD charge or an alternative long-run marginal cost (LRMC) charge.

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2 The HVDC, North Island Grid Upgrade, Upper North Island Dynamic Reactive Support, Wairakei Ring, Bunnythorpe-Haywards Reconducturing, Lower South Island Reliability, and Lower South Island Renewables.

3 The principles are published in our distribution pricing decision paper at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/

4 Recovers the costs of assets that connect transmission customers to the transmission grid.

5 A discount to avoid a customer disconnecting from the grid, which would raise costs to others.

6 International Energy Agency (2007). All academic references are cited in full in the Bibliography.

The Authority is of the view that the increasing uptake of emerging technologies by consumers, the introduction of real-time pricing, and the emergence of new business models will make nodal pricing an increasingly responsive and efficient tool to manage grid congestion.

This approach avoids the costs under the RCPD charge of discouraging consumers from making use of the grid where there is spare capacity available, as currently happens. It would only generate higher prices where grid congestion exists, until prices indicate that grid investment is efficient.

The Authority acknowledges there is some uncertainty regarding the immediate impact of removing the RCPD charge. For example, it is not known with certainty how distributors would adapt their demand response programs, such as ripple control of hot water tanks.

In response, the proposal also provides an option for Transpower to introduce a transitional peak charge, to operate alongside nodal prices, at specific points in the grid that would otherwise experience congestion. However, the Authority considers any need for a separate peak transmission charge will disappear over time, as new demand response arrangements emerge with the support of new technology and the introduction of real-time pricing.

A durable TPM – why some historic investments are proposed to be included

The Authority recognises its proposal to recover the depreciated costs of ‘historical investments’ – major investments in recent decades that are still being paid for – through the benefit-based charge has been contentious. This is not a retrospective charge, but the reallocation of the remaining depreciated costs to those who are benefitting from each grid investment.

The Authority’s key reason for applying benefit -based charges to some historical investments is to make a new TPM durable.[7] This is important if the efficiency benefits are to be achieved, and to stop ongoing uncertainty about the TPM. Uncertainty is not conducive to making long-term investment decisions.

Consumers need to be able to accept the pricing methodology and pricing outcomes. In the Authority’s view, pricing arrangements are more durable when you ‘pay for what you get’. The pricing arrangements for connection charges have not been contentious because they are based on that principle: customers pay for the connection assets that they use and do not pay for other customers’ connections.

The Authority considers that durability would be undermined if consumers in some regions would have to pay both for new investments made for their benefit and continue to pay for major investments they didn’t benefit from.[8]

For example, with a benefit-based charge Christchurch consumers could expect to pay most of the $283 million cost of the planned new switching station and new transmission line into Islington. If the seven major grid investments were to be grandparented, the same consumers would also continue to pay nine percent of the cost of investments that benefitted mainly North Island consumers, such as the $876 million North Island Grid Upgrade.

[7] More generally the Authority as a matter of principle does not ‘grandparent’ regulatory settings, as that would tend to provide preferential treatment to incumbents and can reward inefficient actions.

[8] To illustrate, 77% of the benefits that the seven major investments generate accrue to upper North Island customers, but those customers currently pay only 35% of their costs.

A more specific reason for including historic assets is HVDC-specific. The Authority considers there is no rationale for continuing to put what is essentially an extra tax on South Island generation. It inefficiently discourages investment in South Island generation, and is inconsistent with tackling the broader challenge of materially increasing New Zealand's renewable generation portfolio to support the transition to a low carbon economy.

Compromise on historic investments might seem expedient, but would undermine the durability of the TPM. The Authority is conscious of the example set by the review that produced the current TPM, which was implemented in 2008. That review produced a TPM which, in the Authority's view, has fundamental flaws – including that it failed to address the issue of historical investment costs – and as a result it did not prove to be durable. In fact, a new review of transmission pricing began almost immediately[9], leading to 10 years of uncertainty for the industry. Taking a lesson from that experience, we consider that it is important to address this issue head on with stakeholders.

In terms of quantifiable efficiency benefits, we have found little difference between including and excluding these historic investments from the benefit-based charge. The Authority has not been able to quantify the costs of a less durable proposal (that is, one that excludes the seven historic investments), and does not think that it can be done robustly, although the Authority considers these costs could be considerable.

The Authority also notes a number of contextual points, in that the Authority:

- has not always proposed to apply benefit-based charges to historical investments. Previous proposals for the TPM guidelines considered a range of approaches. Submissions, such as Professor Littlechild's 2016 report, gave reasons why including historical investments would promote efficiency.[10]
- sought advice on this issue from Professor Hogan, who is a well-known expert and had been involved with the New Zealand electricity market from prior to its establishment. He said that there was nothing that he was aware of that was inefficient or inappropriate in applying benefit-based charging to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered in our 2016 proposal and that are presented in this proposal.[11]
- considers its proposal is consistent with its approach to distribution pricing in this regard. The distribution pricing principles do not promote – and, to the Authority's knowledge, distributors are not contemplating – reform of their pricing structure that would apply only to future investment in the distribution network. Such a limited approach would not succeed in addressing the urgent problems that distributors are facing in terms of distributed energy options and other new technologies. Neither would a limited approach with grandparenting succeed in the transmission space.

9 The Authority's predecessor, the Electricity Commission initiated a further review of the TPM in April 2009. It established a Transmission Pricing Technical Group (TPTG) to provide advice and assistance on the TPM review. Around the same time, the New Zealand Electricity Industry Steering Group, which was established by the CEOs Forum, undertook a review of transmission pricing.

10 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016.

11 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

The proposal would be for the long-term benefit of consumers

The Authority considers that its proposed TPM guidelines would better promote its statutory objective in section 15 of the Electricity Industry Act (Act), in particular by promoting the efficient operation of the electricity industry for the long-term benefit of consumers.

This is supported by the cost-benefit analysis (CBA), which has quantified the proposal's net benefits to consumers. The quantified costs and benefits are set out in Table 5, Chapter 4.

Consumers would benefit, for example, if the proposal were to lower the cost of using electricity, or if they didn't have to take actions to avoid overly high peak charges – whether that be by turning off heating on cold winter nights or by investing in alternatives to grid supplied electricity, for example, installing solar panels and batteries. A CBA captures such net benefits in dollars.

A CBA is not a precise exercise, but it does give a sense of the order of magnitude of benefits and costs that are involved. While for ease of presentation and comparison the Authority presents a point estimate as its central scenario, this estimate should be viewed as a reasonable but not definitive point within a wider range of estimates.

The CBA describes qualitatively a number of important impacts that have not been able to be quantified. The lack of quantified dollar amounts does not make such impacts any less relevant. Specific examples of probably the most important unquantified impacts are:

- the benefits from removing the incentive for mass-market consumers to invest in technologies that help them avoid transmission charges
- the costs of a less durable proposal (that is, one that excludes the seven historic investments) which the Authority considers could be considerable.

In addition, a CBA is only a tool to support deliberation and decision-making, with the insights it provides to be considered along with a much broader range of factors.

The CBA shows that a TPM consistent with the proposed guidelines would likely deliver significant benefits to consumers between implementation and 2050. The key quantified results are, in approximate terms:

(a) a net benefit of $2.7 billion for our proposal over the status quo for the central scenario within a broader estimated range of $0.2 billion to $6.4 billion, where:

   (i) $2.36 billion would come from reducing electricity cost and increasing its use at peak times when consumers value it most highly. This is after netting out costs such as for implementation and grid investment brought forward

   (ii) $200 million would come from more efficient (that is, avoided) investment in technologies such as grid-scale batteries that would otherwise be used mainly to avoid transmission charges

   (iii) $145 million would come from more efficient investment in transmission and generation and consumer decisions about connection, electrification and location, as a result of allocating grid costs to those who benefit

(b) a net benefit of $858 million compared to the alternative option that we modelled, which replaces existing charges with a broad-based usage charge.

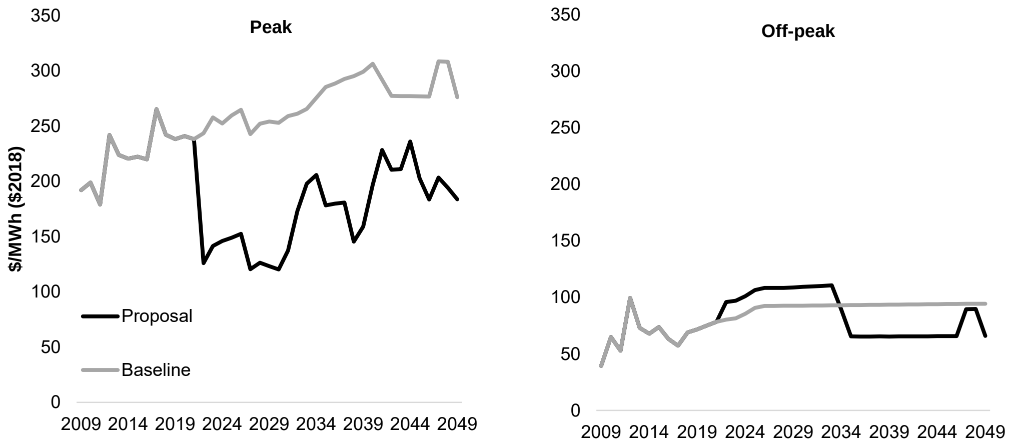
The range represents, at the low end of the spectrum, a scenario with the most cautious of assumptions and at the high end of the spectrum the most optimistic but still realistic of assumptions. Presenting a range is good practice. It gives readers a sense of the effect of uncertainties and unknowns to which professional judgement has had to be applied.

The main benefits to consumers come from improving transmission price signals, which will encourage more efficient grid use. These types of benefits had been assumed to be minor in previous modelling, but we consider that these consumer benefits are in fact significant.

This is because the current RCPD charge creates a very strong price signal that inefficiently discourages consumers to reduce electricity use at peak times, even though the grid has capacity for this demand, and encourages them to unnecessarily invest in technologies like solar panels and, in future, increasingly in batteries. The signals will get stronger as distribution pricing becomes more cost-reflective.

As shown in Figure 1, the proposal would cause a fall in peak prices by an annual average of 38% out to 2049, compared to the status quo, avoiding the RCPD cost-spiral. Off-peak prices would rise initially by an average 19%, compared to the status quo, but then fall roughly 40%. This is because of increased investment in generation to meet higher peak demand, and reduced use of network-scale batteries under the proposal, which reduces off-peak demand, compared to the status quo.

Figure 1: Effective electricity prices (wholesale prices plus interconnection charges)



The proposal provides protection against high price rises

The proposal would involve a rebalancing of transmission charges between customers.

Some consumers and businesses would pay lower charges initially, and some would pay higher charges than they would under the current TPM. This is the consequence of the proposed:

- allocation of depreciated cost of seven major (historical) grid investments based on benefit
- distribution of other costs across all load customers through a residual charge.

For those customers who would face higher transmission charges, increases are mostly modest. For example, in networks where charges rise, the increases would average $21 for the year on an average residential consumer bill.[12] Increases would be significantly higher for some major industrial customers that have responded to current incentives and made operational investments that mean they currently pay very low or no interconnection charges.

12 The average household bill is $2,100 per year; consumers can save an average $200 per year by switching retailer.

To reassure consumers that they will not experience an electricity bill shock, the proposal provides for a 3.5% cap on increases in the total electricity bill as a result of a new TPM consistent with the proposed guidelines. A cap, recommended by submissions to the 2016 issues paper, would give households and businesses certainty on the level of charges in advance and allow industrial customers time to adjust to the new charges.

The cap would mean that, in areas where transmission charges rise, average electricity bills would not need to rise by more than 3.5% as a result of the proposal. For directly-connected large industrials the cap would rise after five years by two percentage points per year.

The Authority's modelling indicates the price cap would support three distribution networks and, in particular, four directly-connected industrial consumers. This proposed support of $15.4 million in year one would be funded by all transmission customers in proportion to their total benefit-based and residual charges. Price cap support would fall to zero over time.

Some of the changes since the previous TPM proposals

The proposal set out in this 2019 issues paper builds on the Authority's past TPM proposals, but has also changed, having been informed by the submissions on the second issues paper and supplementary consultation paper. For example, this paper includes proposals to:

- allow Transpower greater discretion in designing the TPM to balance competing objectives such as precision vs robustness, simplicity, certainty and implementation costs
- raise the threshold for high-value investments from $5 million to $20 million as proposed for example by Transpower, PwC and Castalia, to reduce the administrative burden on Transpower and to align with the Commerce Commission's approach
- reduce the number of current assets that would be subject to the benefit-based charge to seven major investments, where the Authority has estimated clear benefits to consumers
- set the benefit-based charge for those seven investments according to an allocation determined by the Authority, in response to Transpower's view that this would reduce the administrative burden. The Authority considers this would enable earlier implementation, ensuring the gains associated with the new TPM are achieved earlier
- make the peak transmission charge a transitional and non-mandatory arrangement, and that its design is not restricted to a Long Run Marginal Cost form
- allow Transpower to use proxies for the net benefits of grid investment when determining benefit-based charges, to reduce administrative burden, as various submissions suggested that producing precise estimates would be too difficult.

Structure of the 2019 issues paper

Chapter 1 sets out the practical information that stakeholders need to know in order to make a submission

Chapter 2 outlines key elements of the current TPM and sets out why the Authority considers that improvement of the current TPM is necessary

Chapter 3 summarises the Authority's proposed new TPM guidelines and outlines what the Authority considers to be the main advantages of its proposal

Chapter 4 sets out the Authority's cost-benefit analysis of the proposal

Chapter 5 presents the impact that the Authority considers its proposal would have on transmission charges in 'year one'

Chapter 6 proposes a process for the development and approval of the TPM to apply once new guidelines have been published

Chapter 7 provides a history of the TPM review and notes the significant changes the Authority has made in this 2019 issues paper compared to the 2016 proposal.

Further information and technical detail about the Authority's proposal is contained in appendices.

Appendix A contains the current drafting of the Authority's proposed TPM guidelines

Appendix B sets out the policy intent behind the proposed guidelines. It also sets out a number of potential alternative options relating to the details of the proposed guidelines

Appendix C sets out why the Authority considers there to have been a 'material change in circumstances' (a threshold to be met before the Authority can review the TPM)

Appendix D elaborates on the decision-making and economic framework that underpins the Authority's review

Appendix E addresses more high level alternatives that the Authority considered when reviewing the TPM

Appendix F sets out potential Code amendments that the Authority considers would be necessary to accompany our proposal (if adopted)

Appendix G sets out the Authority's response to some criticisms it has received

Appendix H sets out methods used for determining the proposed charges and benefit-based allocation of the depreciated cost of seven major investments made prior to 2019.

Appendix I brings together the consultation questions raised through the paper**.**

We are also publishing a technical paper containing method notes and assumptions for the CBA.

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1 What you need to know to make a submission

Purpose of this document

1.1 Transpower delivers the infrastructure that transports electricity from where it is generated to local lines companies and large industrial users. The transmission pricing methodology (TPM) sets out how Transpower will recover its maximum allowable revenue from its transmission customers. This is expected to amount to an average of $853 million per year between 2020 and 2025, rising to more than $1 billion per year by 2030.[13]

1.2 The Electricity Authority (Authority) is reviewing the guidelines that Transpower must follow in developing the TPM. The Authority considers that improvements to the TPM are needed in order to accommodate a material change in circumstances and to better promote efficient use of, and investment in, transmission and other electricity assets, and the efficient operation of the electricity industry.

1.3 This 2019 issues paper sets out the Authority's proposal for revised TPM guidelines, and explains why the Authority considers that this proposal would deliver substantial long-term benefits to consumers, consistent with the statutory objective as set out in section 15 of the Electricity Industry Act 2010. This is a new proposal and differs in significant ways from the Authority's earlier proposals. However, it builds on previous work, including submissions received in respect of the Authority's previous consultations on this subject, which have been taken into account in preparing this 2019 issues paper.

1.4 While the proposal in this issues paper reflects the Authority's current thinking on the best approach to revise the TPM guidelines, it remains subject to the Authority's consideration of all submissions received in respect of this 2019 issues paper. The purpose of this issues paper is to invite submissions on this current proposal, so that we can ensure that the outcome of the Authority's review of the TPM best meets the statutory objective. Submitters are encouraged to focus their submissions on the specific matters raised by the consultation questions, but the Authority welcomes feedback on any aspect of this issues paper. This includes feedback on the potential for improvement to any of the reasoning, analysis and calculations.

1.5 Please do not feel that you need to limit your responses to the consultation questions or that you need to answer them all. Instead these questions can be treated as a guide and you may wish to answer any you consider are important. Your input will help us to test and enhance the Authority's proposal before the Authority makes a final decision on whether to publish new TPM guidelines.[14]

1.6 Following consultation, the Authority will review the submissions and, in light of those submissions, consider whether to finalise and publish the TPM guidelines (with any amendments) around April 2020. Transpower would then develop the TPM guidelines. Chapter 6 sets out the process from then on.

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13 Commerce Commission, *Transpower's individual price path from 2020 Draft decision and reasons paper*, May 2019. Available at https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020?target=documents&root=102833

14 Please note that if you wish the Authority to consider again an argument or some evidence that you have provided in a previous submission, you are welcome to cross refer to the specific place in your previous submission where the point is covered.

How to make a submission

1.7 The Authority's preference is to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Consultation Paper—Transmission pricing review' in the subject line.

1.8 If you cannot send your submission electronically, post one hard copy to either of the addresses below.

Postal address	Physical address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, Harbour Tower 2 Hunter Street Wellington

1.9 Please note the Authority wants to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider that part should not be published

(c) provide a version of your submission that can be published (if the Authority agrees not to publish your full submission).

1.10 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.11 However, please note that all submissions received, including any parts that are not published, can be requested under the Official Information Act 1982. This means the Authority would be required to release material that was not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12 Please deliver your submissions by **5pm** on **Tuesday 1 October 2019**.

1.13 This deadline allows 10 weeks for submissions, rather than the Authority's typical six-week consultation period. The Authority has communicated publicly in advance so that stakeholders have been expecting this issues paper.

1.14 The Authority will acknowledge receipt of all submissions electronically. Please contact submissions@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

Further information

1.15 The Authority will publish details of briefings to help stakeholders understand this proposal on the Authority's transmission pricing review webpage at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/.

1.16 You are encouraged to attend a briefing in the first instance. Please direct any specific questions or queries to: TPM@ea.govt.nz.

2 Current situation and problem

Background to the 2019 issues paper

2.1 The current TPM took effect on 1 April 2008 introducing, for example, the allocation of interconnection costs according to regional coincident peak demand (RCPD), although some relevant features were in place since the late 1990s. Other than some operational changes, such as a change to the number of offtake periods used in calculations, the TPM has largely remained unchanged since 2008. In fact, the TPM reflects a pricing methodology that has been in place since 1999.[15]

2.2 The Authority's predecessor, the Electricity Commission, first initiated a review of the TPM in 2009. This work was continued by the Authority.

2.3 In 2016 and 2017, the Authority consulted on a second issues paper and a supplementary consultation paper (jointly referred to as the 2016 proposal). The 2016 proposal set out a comprehensive proposal to change the TPM guidelines. The review process, including preparation of a new cost benefit analysis, was put on hold temporarily in June 2017 to allow time for the new Authority Board members to get up to speed with the project.

2.4 This 2019 issues paper is the Authority's new proposal to change the TPM guidelines. While the Authority's current proposal is similar to the 2016 proposal, it does contain significant changes and refinements based on consideration of previous submissions and following further analysis.

2.5 A summary of changes since 2016 is set out in chapter 7. That chapter also contains a more detailed history of the 10 year review of the TPM.

15 Electricity Commission, *Transmission Pricing Review: High-level options,* 2009. Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c6763

The current TPM

2.6 The current TPM has three main charges corresponding to the three types of grid assets as summarised in the table below.

Table 1: Transmission assets and charges

Asset	Description	Nature of the charge
HVDC	Interconnects transmission customers in the North Island with those in the South Island.	South Island generators pay their share of costs based on a measure of South Island Mean Injections (SIMI) averaged over a five year period.
Interconnection	Most of the network, by value and length, interconnecting transmission customers.	Distributors and direct consumers pay a share of costs based on their contribution to the 100 highest peaks in a region in the prior year.[16] This charge is referred to as the Regional Coincident Peak Demand (RCPD) or interconnection charge.
Connection	Connects parties to the grid. A connection asset serves one or a few parties.	Cost of assets paid by connecting parties.

2.7 The following high-level characteristics are relevant when transmission pricing is being discussed:

(a) Charges for **connection assets** are on a user-pays basis. Parties that demand these assets are identifiable. However, connection charges can be avoided by taking steps to reclassify the assets as interconnection assets. Another issue is how to ensure a first mover is not discouraged by the total cost of the connection, if others may share the connection assets in future.

(b) The **HVDC** link enables energy to flow between the South and North Islands and provides benefits to all of New Zealand via the ancillary services market. Energy often flows South to North, although in dry years the flow can be reversed. However, only South Island generators pay for the HVDC costs while North Island generators do not pay an equivalent charge. Another issue is that the HVDC rate does not reflect the incremental cost of using the HVDC link.

(c) **Interconnection assets** connect generators and consumers located across the whole country. Distance, geography, and differences in reliability standards or other features mean the cost to supply grid services will vary across the country. However, interconnection asset costs are currently charged on a “postage stamp” basis – the same rate per kW across the country – which does not reflect differences in the economic costs to supply the service or in benefits to transmission customers.

16 For example, the charges for the 1 April 2019–31 March 2020 pricing year use a capacity measurement period 1 September 2017–31 August 2018.

The TPM in a changing environment

2.8 Major changes in the environment and associated evidence of inefficient outcomes are necessitating changes in the TPM. These are set out below.

2.9 Some of these factors have been present since the review of the TPM started in 2009. Others are becoming more pressing over time. These changes make it increasingly important that transmission charges are efficient – that is, reflect economic costs and do not distort consumption and investment decisions – in order to ensure that consumers benefit in the long term.

2.10 Clause 12.86 of the Code enables the Authority to review an approved TPM if the Authority considers that there has been a "material change in circumstances". Appendix C sets out the Authority's assessment as to why it considers there has been a material change of circumstances, such that it can review the current TPM and prepare new guidelines. Some of the matters discussed below are relevant to that assessment and, where this is the case, we have explained that in appendix C.

Changes in climate change policy

2.11 The Government has announced ambitious targets to reduce New Zealand's emissions, including a proposed net zero carbon emissions target.[17] Responses to climate change are likely to transform how we use and supply electricity. This will have implications for the transmission grid. Consumers of all sizes from households and small businesses to industrial consumers are likely to face increasingly strong incentives to turn to low-emissions energy sources.

2.12 *Te Mauri Hiko – Energy Futures*[18] suggests that electrification of transport and industrial processes could double electricity demand by 2050, with peak demand increasing by two-thirds. This is just one scenario among many, and it is the case that consumption has been flat over the last decade, showing little sign of growth.[19,20] Regardless of what scenario will play out, it is anticipated that the future will bring plenty of new investment in renewable energy (solar, wind, and geothermal) from grid-connected and distributed generation, presenting a challenge for transmission.

2.13 Efficient prices, at all points in the electricity supply chain, will be very important to support the transition to a low-emissions economy at least cost. Efficient prices ensure that energy-related consumption and investment decisions are made because these are the most efficient option to meet household and business energy demands – not because they shift the cost of infrastructure to others, as the Authority considers happens to a material degree under the current TPM. This is one way by which efficient prices will help improve affordability of electricity for consumers in the long run.

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17 https://www.parliament.nz/en/pb/bills-and-laws/bills-proposed-laws/document/BILL_87861/climate-change-response-zero-carbon-amendment-bill

18 Transpower, *Te Mauri Hiko – Energy Futures. Transpower white paper*, 2018. Available at: https://www.transpower.co.nz/about-us/transmission-tomorrow/te-mauri-hiko-energy-futures

19 New Zealand Productivity Commission, *Low emissions economy – Final report,* 2018. Available from www.productivity.govt.nz/low-emissions

20 See MBIE Electricity Statistics, available at https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/

Rapidly-changing technology

2.14 There have been changes in technology, and it is anticipated that exponential changes in technologies will transform the way in which consumers and businesses engage with electricity markets. Small-scale distributed generators, batteries, electric vehicles and smart energy-management systems will offer new ways to produce, sell, buy, and use electricity. The resulting changes will be far-reaching. They could change the place and role of the transmission grid, as will likely happen for distribution networks.

2.15 Transmission prices need to send the right signals about the economic cost of the national grid, and the local distribution networks. An efficient price signal avoids inadvertently promoting or discouraging any particular technology, and instead promotes competition by providing electricity services on an even footing. That is, efficient network prices would level the playing field for new solutions, for the benefit of consumers.

2.16 When transmission price signals exceed the economic cost – as is often the case with the RCPD charge at peak times – it gives transmission customers strong, but potentially distorted, financial reasons to invest in distributed generation or batteries simply to avoid that charge (see the illustrative case study below). That is inefficient, and shifts costs to others without reducing the cost of transmission. The potential for a cost spiral will increasingly challenge the viability of transmission pricing, especially once these emerging technologies are taken up at scale by residential consumers.

Case study: inefficient investments to avoid transmission charges

A load customer buys a 10 MW diesel-fired generator in a location that has ample transmission capacity allowing energy into the region.

The generator targets 150 peak periods to reduce the load customer's RCPD charges. The transmission charge paid by the customer reduces by $1 million per year. But as the cost of the grid has not changed, other load customers must pay this $1 million instead.

The generator's operation incurs fuel costs of approximately $225,000 per year. This generation provides some energy benefit, but based on the spot price during times of operation this was around $75,000 per year. This means that ultimately there is a net economic cost of around $150,000 per year ($75,000 minus $225,000) from inefficiently burning diesel (not counting environmental costs due to carbon emissions).

A growing transmission grid

2.17 Transpower's regulatory asset base (RAB) has increased (following a period of limited investment in the 1990s) from $2 billion in 2005/06 to $4.7 billion in 2018/19.[21] Given the projected growth in transmission costs, if people are increasingly charged for services that primarily benefit others, as under the postage stamp approach, it will raise durability issues.

2.18 A high volume of investment is expected to be required in Transpower's fourth and fifth regulatory control periods, due to a large number of grid assets requiring replacement and reconductoring as they come to the end of their economic life. Transmission revenues have been signalled to rise by18% after 2025, to over $1b by 2029/30.[22]

21 Transpower, Commerce Act (Transpower Thresholds) Notice 2008 Compliance Statement Assessment Date: 30 June 2011, September 26, 2011, and Transpower, RCP3 Revenue Model, at www.transpower.co.nz

22 Commerce Commission, 2019, op.cit. Figure X1, p7.

2.19 Transmission prices that send poor signals about the grid's economic cost or value will amplify poor outcomes as the transmission grid grows. The current RCPD charge spreads the costs of investments across all customers regardless of where they live – a so-called postage stamp charge. As a result, the Authority considers that customers that will benefit from a grid investment have strong incentives to support it since they will be paying only a fraction of its cost. Incentives to oppose inefficient investments are weaker for customers in the rest of the country as the charges associated with that investment are thinly spread.

2.20 The fact that the interconnection charge is based on RCPD does help to defer grid investment by discouraging demand for grid-supplied electricity at peak times. But because the charge is not an economic signal, it unnecessarily discourages demand even when and where the grid has capacity, and may unduly defer investment that is valued by customers.

Durability issues

2.21 The postage stamp approach to charging means customers are paying for grid upgrades that benefit others. If they are charged for transmission services they do not receive, this may create tensions that can undermine the durability of the pricing methodology and result in a loss of confidence in the electricity sector as a whole.

2.22 For example, the $876 million North Island grid upgrade (NIGU), approved in 2007, was primarily to improve security of supply to Auckland. The Authority's recent analysis of the beneficiaries of this investment show the benefits are concentrated in the upper North Island. These benefits are primarily in the form of greater reliability of supply and lower energy prices for Auckland and Northland consumers, and access to the Auckland market for generators. However, two-thirds of the costs are paid by households and businesses across the rest of the country.

2.23 Future grid investments related to the Government's commitment to a transition to a low-emissions economy, and significant replacement and refurbishment costs being projected, will bring these issues into sharper focus. The uneven sharing of costs and benefits of the transmission grid, and the ability of customers to avoid their share of charges and shift costs to others, will raise questions about whether the pricing methodology is reasonable.

2.24 The Authority considers that the current TPM is not durable. There has been long-term and consistent pressure for the TPM to be reformed – it has been under almost constant scrutiny for the last decade at least. This situation creates significant costs in reviewing regulations and lobbying for and against change. The lack of durability also creates uncertainty, which is not conducive for making long-lived investment decisions.

2.25 The recent Electricity Price Review highlighted the consequences of such tensions. It focused on questions about the efficiency of the electricity sector, and affordability and fairness of electricity prices. While fairness is not part of the Authority's statutory objective, the Authority has the long-term interests of consumers at the centre of its decision-making. Perceptions of unfairness can detract from the durability, associated certainty and so the efficiency of the TPM. A pricing approach where people pay for what they get is likely to be more durable.

Problems with the current TPM

2.26 The transmission network is a central and crucial part of a large, complex system that provides households and businesses with safe and reliable access to electricity 24/7, year-in year-out. The current TPM plays its part in allocating the cost of providing, maintaining and developing the network, and in signalling the cost of its use to generators and consumers.

2.27 However, the Authority considers that the current TPM has a number of shortcomings, which may distort the relative costs of and decisions about:

(a) consuming grid-supplied electricity

(b) the merits of investing in distributed generation and batteries

(c) where to locate energy-intensive industry or generation.

2.28 Such distortions can cause inefficiencies in the operation of the electricity sector, which is not in the long-term interest of consumers. In addition, the Authority considers that the current TPM is not durable. This is because some customers benefit from the grid without paying their share of costs, while others pay more than their share. This lack of durability leads to further inefficiency, through uncertainty and added cost.

2.29 These problems will likely grow in size as more grid investments are made to support growing regions and the transition to a low-emissions economy, and as distributed renewable generation and batteries become more affordable. The latter will enable more customers to take actions which have the effect that they avoid paying their share (which may detract from the TPM's durability), even though overall transmission costs do not change. In reviewing the TPM, the Authority is therefore looking to address some of these issues.

The RCPD charge distorts the cost of using the grid

2.30 In 2019/20, the RCPD charge seeks to recover interconnection revenues of $652 million ($109 per kW) based on electricity consumption during the top 100 peak trading periods in a year.[23] This approach was adopted because peaks in electricity consumption drive the amount of transmission capacity needed, and thus provide a basis for allocating costs.

2.31 The RCPD charge is not linked to customer benefits in the same way that market prices are. For example, two thirds of the costs of an interconnection asset aimed at improving services for customers in the Upper North Island would be paid by other regions.

2.32 The Authority considers that the RCPD charge is a poor signal of economic costs. An efficient, cost-reflective charge would rise when the grid gets congested, and drop when there is spare capacity. The RCPD charge does the opposite: it generally increases after Transpower has invested in the grid to increase its capacity. The RCPD is not the only, or an efficient, approach to managing peak demand and efficiently deferring grid investment.

2.33 The RCPD signal is also very strong relative to the wholesale price of electricity. It can be up to $2,180/MWh depending on how many peak periods the customer is taking into account.

2.34 This may lead load customers to change their demand to avoid the charge, which may be inefficient. Customers might stop an industrial process, or switch off water tank heating on a

23 Transmission Pricing Data for 2019/20 Pricing year, available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Rates%20Table%20April%202019.pdf

cold winter night. Consumers may also make unnecessary investments to avoid the charges or the downsides of load control (such as installing bigger hot water cylinders or gas-heated hot water, or investing in wood-fired heaters or generators).

2.35 Such actions may not actually cut grid costs if there is spare capacity. They may just shift costs. Similar perverse incentives on grid users to shift costs onto others (and incur real expenses to do so) have also been recognised in Texas, a jurisdiction that has a charge very similar to the RCPD charge.[24]

2.36 The RCPD charge could interfere with the wholesale electricity market, by suppressing nodal prices.[25] Further, the Authority is aware of a number of cases where transmission customers withdrew reserve offers of interruptible load so they could avoid using electricity from the grid during a peak period. This behaviour increases the cost of reserves.

Case study: unpredictable outcomes

Electricity Ashburton's transmission charges rose $10 million from $6.5 million in 2018–19 to $16.7 million in 2019-20.[26] This was not because grid capacity or quality had increased or because grid use was up 2.5 times. It was because of a change in the timing of the top 100 half hour demand periods used to determine transmission charges for each transmission customer in the upper South Island region.

The consequence was that the network's delivery prices for irrigators and major users increased unexpectedly by almost 40% on the previous year, and 10% for general consumers. To reduce future bills, the distributor has asked irrigators to reduce their demand by 35%.[27] This could affect farm productivity and, if successful, it will just shift costs to another transmission customer as the cost of the grid has not changed. This volatility is highly problematic for the distributor and its customers.

The RCPD charge leads customers to invest to avoid transmission charges

2.37 Customers appear to be responding to the incentives produced by the current TPM, for example, by investing in distributed generation. However, this is likely to do little to reduce the cost of the grid. Instead, customers would be shifting transmission costs onto other customers, while also incurring the cost of developing, running and maintaining the distributed generation.

2.38 Investment in distributed generation can be an efficient way to meet energy needs and reduce future transmission costs if it addresses reliability or congestion problems. However, the current TPM encourages businesses to buy distributed generation and batteries for the purpose of operating these during peaks, to avoid transmission charges, without it necessarily reducing total transmission costs.

2.39 These problems will worsen as households become increasingly exposed to RCPD price signals (through cost-reflective distribution pricing) and emerging technologies become more affordable over time. Inefficient investment in residential-scale batteries and demand-management technologies could rapidly spiral out of control if a RCPD charge remained.

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24 See, for example, Hogan and Pope (2017), pp 76-78.

25 This effect has also been recognised in Texas (see Hogan and Pope, op cit. p76).

26 Electricity Ashburton Networks, Electricity Distribution Network Pricing Methodology 2019/20, 2019, page 5. Available at https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other-Disclosures/da43bd63ad/EA-Networks_Pricing-Methodology_2019_Final.pdf. Transpower disclosures show Electricity Ashburton Networks' charges had been $12m in 2017-18.

27 See https://www.eanetworks.co.nz/power/irrigation-demand-control/

2.40 This is not just a theoretical concern: residential consumers have shown they will respond rapidly to financial incentives. Australia, for example, saw huge household take-up of solar panels due to subsidies in place from 2008 to 2011 (including feed-in tariffs) and poorly structured network tariffs.[28] Even in Victoria (which experiences a low level of sunlight compared to Queensland, for example, and thus may be a more useful comparison for New Zealand), the penetration rate for residential rooftop solar is over 14%.[29]

2.41 The incentive has increased in recent years as the RCPD charge has risen, from around \$70/kWh a decade ago to \$109/kWh now, while the economics of distributed generation have improved.

2.42 The 2016 Code change narrowed the list of distributed generation eligible to qualify for ACOT payments under regulated terms. However, there is still an incentive for load customers to invest to avoid transmission charges. The rising availability, and falling cost, of distributed energy resources (DER) including batteries means the scope for such cost avoidance will grow.

2.43 The current TPM creates other cost avoidance incentives. For example, there are circumstances where new generation can choose to either connect to the grid or to a distribution network. If new generation connects to a distribution network, it may reduce that distributor's transmission charges (by reducing its peak demand). This creates an incentive to encourage the generator to connect to the distribution network even if that would result in higher overall costs for consumers, because these costs are shifted to other parties.

2.44 An example of embedding generation in response to transmission price signals is Meridian's White Hill wind farm in the South Island. Meridian has stated that "the size (MW) of that wind farm has been limited by the decision to embed it, ie, the design may not make the best use of the wind resource, but does optimise the economics of the site given the transmission cost signals in place".[30]

The RCPD distorts customers' location decisions

2.45 Transmission charges set under the current TPM can encourage consumers and businesses to spend money on investments that may not be needed, whose location may cause inefficiencies, or may cost more than alternative investments.

2.46 A business deciding where to locate has no incentive to consider the cost of any new investment in interconnection assets that's needed to support their business – whether this is load or generation.[31] This could lead to higher-than-necessary transmission charges for other customers.

28 Wood, T., Blowers, D., and Chisholm, C., (2015), p.12: "Households responded enthusiastically to the subsidies and took up solar PV at a rate much faster than state governments had anticipated and budgeted for."

29 Australian Energy Council, Solar Report, January 2019, p.8, Figure 5: Penetration rate of residential rooftop solar across financial years 2015 to 2018

30 Meridian's submission to the problem definition working paper: https://www.ea.govt.nz/dmsdocument/18673-meridian-energy. P6. According to Meridian's submission, the HVDC charge was a factor in the decision.

31 By contrast, customers do pay for their own connection assets, which gives them the correct incentives with respect to connection: to locate where connection is low cost.

Case study: Distorted decisions

A dairy plant owner seeking to electrify a plant could upgrade the capacity of its connection to the grid, which might require an interconnection upgrade, or do something that does not require the interconnection upgrade (eg, install renewable distributed generation).

Under the current TPM, the plant owner has an inefficient incentive to favour the upgrade of grid capacity, even if other electrification options are more cost effective. This is because the plant owner would only face a fraction of the full cost of any required interconnection upgrade, whereas the majority of the full costs of a grid upgrade would be paid for by other consumers.

The HVDC charge distorts the cost of South Island generation investments

2.47 Only South Island generators pay the HVDC charge ($145 million in 2019/20, but set to reduce to $99 million in future years). North Island generators do not face an equivalent charge. This distortion can result in investments in higher-cost generation in the North Island taking precedence over lower-cost South Island investments, increasing electricity prices for everyone.

2.48 The HVDC charge appears to be large enough to affect investment decisions, as it has added a 10% cost in terms of the wholesale price of electricity.[32] This acts as a disincentive to invest in South Island generation. This may in part explain why there has been little generation investment in the upper South Island in recent years, despite relatively high nodal prices, ample wind resource, and consented sites available.

2.49 This disincentive to invest in new South Island generation can also be seen in MBIE's modelling of future generation investment. For example, some North Island wind generation projects are higher up in the merit order of generation investments, over some South Island projects, because the latter carry the HVDC charge.[33]

The TPM provides poor incentives to scrutinise grid investment proposals

2.50 The current RCPD charge spreads the costs of investments across all customers regardless of where they live. Customers who would benefit from a proposal know the proposal is to a large extent subsidised by the rest of the country.

2.51 This creates strong incentives for customers to submit information in support of grid investments that they would benefit from, even if, from a national perspective, the benefits do not necessarily exceed the cost, or it would be better to delay the investment until a later point. The incentive is even stronger for generators as they do not face the RCPD charge. Incentives and practical opportunities to put the counterpoint would be weaker for customers in the rest of the country.[34]

2.52 The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. However, Transpower's capital planning and the Commission's testing of investment proposals reflect prevailing conditions

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32 Transpower's 2019/20 pricing sheet indicates injection of 17,000 GWh and a HVDC charge of $144.87m, meaning the HVDC charge would cost $8.52/MWh.

33 See MBIE modelling tools at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/interactive-electricity-generation-cost-model/.

34 Those customers do have some (but similarly weak) incentives to oppose investments that would be net beneficial to the country, in order to avoid costs to them.

and trends. The risk is that these trends reflect the skewed consumption and investment incentives that are described in this paper. The Commission's process would be enhanced if customers had incentives to reveal information that more accurately reflected a proposal's net benefits or considered the merits of alternatives. This would be the case, for example, if those supporting and providing information about particular grid investments knew they also had to pay for them.

Case study

There is currently some demand in Auckland to require the undergrounding of transmission lines.[35] Underground cables are generally 5 to 15 times more expensive to install and maintain than overhead lines[36], and this approach has currently been ruled out by Transpower.[37]

Local consumers and their representatives could petition for changes to local planning regulations to rule out overhead lines, knowing Auckland consumers will only pay the minor part of the cost of any undergrounding that occurs. Then this would limit the grid investment options that Transpower can propose and the Commerce Commission can test. Under the current TPM, the cost of undergrounding – or the increased cost of some less efficient grid investment option that occurs instead – would then be spread across New Zealand.

Other issues

2.53 This 2019 issues paper deals with a number of other potential problems with the current TPM, including problems related to the prudent discount policy, the recovery of the costs of reactive support assets, loss and constraint excess, avoided cost of transmission payments, and restrictions on amending the TPM. These are described in appendix B (where the proposal is explained in detail) and in appendix F (where potential amendments to the Code are discussed).

Q1. Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

35 For example, see https://www.stuff.co.nz/auckland/95370258/auckland-council-concerned-about-future-of-transmission-towers and https://www.stuff.co.nz/auckland/105565566/auckland-mayor-phil-goffs-top-finance-man-floats-targeted-rate-to-bury-power-lines

36 Transpower. *Undergrounding electricity lines*, p.2. Downloaded 19 May 2019 from https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Undergrounding%20electricity%20lines.pdf

37 Transpower. *Powering Auckland's Future*, at www.transpower.co.nz: "We are unable to fund undergrounding via our current regulatory framework and this is unlikely to change in the foreseeable future." See also Transpower submission to Petitions 2011/95 and 2011/96, 5 December 2014, page 7, para 26.

3 Overview of the proposal

3.1 The Authority is proposing new TPM guidelines that seek to address the core problems summarised in the previous section. The most important features of the Authority's proposal are summarised below. Appendix B has a detailed examination of the policy proposal.

3.2 At the heart of the proposal is a desire to ensure that transmission prices (together with wholesale electricity prices):

(a) signal the economic (incremental) costs of transmission services

(b) allocate the cost of transmission investments to customers that benefit from them

(c) recover costs in ways that do not distort consumption and investment decisions.

3.3 The proposal is to replace the RCPD and HVDC[38] charges in the current TPM with two new core charges:

(a) a benefit-based charge on generation and load customers that benefit from particular grid investments

(b) a residual charge to recover remaining costs from load customers in a non-distorting way.

3.4 Wholesale market prices, established at the different points where electricity exits the transmission network (so-called nodal prices), would take on the role of rationing demand for grid-supplied electricity at grid exit points when congestion arises, and delivering an efficient economic signal to inform future grid investment decisions.

3.5 The Authority considers that the proposed approach would mean that the wholesale market would signal transparently where grid congestion exists through higher nodal prices at congested nodes, and lower nodal prices elsewhere.

3.6 The Authority considers that the proposal would encourage more efficient grid use and investments in generation, transmission and other electricity assets, and a more durable TPM (which means reduced inefficiency and enduring efficiency benefits for consumers), by:

(a) rebalancing transmission charges, so those who benefit from the grid pay for it

(b) making best use of available capacity, and relying on market-based signals to constrain demand and inform grid investment decisions

(c) removing cost-avoidance and cost-shifting incentives

(d) avoiding distorting decisions about where to locate generation or industrial plant

(e) creating the right signals about the relative cost and value of local generation, local storage and local demand management services, to enable economic trade-offs.

3.7 This will promote the efficient operation of the electricity industry for the long-term benefit of consumers.

3.8 The following tables provide an overview of the proposal. The descriptions are not intended to be complete or exhaustive. For the complete proposal see the proposed TPM guidelines at appendix A and the detailed policy proposal at appendix B.

[38] The HVDC assets perform an interconnection function and this is how we treat them in the proposal.

Table 2: Outline of the Authority's TPM proposal

Main components	Key features of the proposal
Connection charge	Each transmission customer would pay a connection charge to recover the cost of assets that connect it to the interconnected grid.
Benefit-based charge	Transmission customers would pay a benefit-based charge to recover the costs of new investments in the interconnected grid. The charge would replace the RCPD and HVDC charges. The benefit-based charge would be allocated between load and generation customers in accordance with the benefits each customer is expected to receive from the investment. A standard method to allocate benefit-based charges would apply to "high value" investments valued at $20 million or more, aligned with the Commerce Commission grid investment test. The standard method would allocate charges based on each customer's expected positive net private benefit, or a proxy for these benefits. For "low value" investments worth less than $20 million at the time of commissioning, a simpler benefit-based method would apply for practical reasons. The allocation of benefit would generally be fixed, though there is a provision for these to be revised in certain circumstances. As well as applying to new investments, the benefit-based charge would also apply to seven recent major investments listed in clause 13(b) of the proposed guidelines. This is discussed in more detail later in this document.
Residual charge	Transpower's load customers (including generators to the extent that they are also load customers) would pay a residual charge – the mechanism that would enable Transpower to recover up to its forecast maximum allowable revenue in any year. The default allocation would be based on gross anytime maximum demand (gross AMD) averaged over at least two years ending prior to 1 July 2019. The intent is that this ensures the charge does not affect designated transmission customers' decision-making.
Prudent discount policy (PDP)	The proposal makes some modifications to the current PDP so that: (a) prudent discounts would be available for the remaining life of the relevant asset (b) prudent discounts would be available to a load customer if it is privately beneficial but inefficient and not for the long-term benefit of consumers to build and operate alternative energy sources to disconnect their demand from the grid.

3.9 The proposed guidelines also include a requirement for a transitional price cap to reassure households and businesses that they would not experience high price rises as a result of the proposal, to provide certainty on the level of charges in advance, and to allow businesses time to adjust to the new charges.

3.10 The proposed guidelines include seven additional components. Transpower must include these in the TPM if its analysis shows that it would better meet the Authority's statutory objective to include them. Implementation of these additional components (except for the transitional peak charge) must be deferred where necessary to expedite the implementation of the benefit-based charge for high-value investments.

Table 3: Outline of the additional components

Additional components	
Staged commissioning	Would allow Transpower to propose a method to adjust the time profile of charges over the life of an investment that is initially a connection investment and later becomes an interconnection investment, to reflect the relative benefits that it provides during these two stages of its life.
Charges for assets principally providing connection services	Would allow Transpower to propose a method to ensure that interconnection assets that principally provide connection services are charged for as if they were connection assets, even if they do not meet the technical definition of a connection asset.
Charges for connection assets	Would allow Transpower to amend the method for determining the annual amount to be recovered in connection charges (for each new connection asset) so that it aligns with the method for applying the benefit-based charge.
Transitional peak charge	Would allow Transpower to propose a transitional peak charge to influence demand for use of the grid where that would better meet the Authority's statutory objective.
Benefit-based charge for additional pre-2019 investments	Would allow Transpower to propose a method for extending the definition of benefit-based charge investment to pre-2019 investments in the interconnected grid other than the ones listed in the guidelines.
Charging for opex	Would allow Transpower to propose a method to allocate operating and maintenance costs to the transmission customers paying charges in relation to assets or investments subject to the connection and benefit-based charges, without using a proxy or generalised rule for allocation.
Kvar charge	Would allow Transpower to propose a kvar charge to recover the cost of static reactive investments from parties whose actions exacerbate the need for such investments.

3.11 This issues paper also discusses prospective changes to the Code relating to matters relevant to the TPM guidelines proposal but not covered by the guidelines. The Authority is considering whether to propose these amendments in the near future. However, the Authority is not at this stage proposing that the Code be amended. These potential Code changes are discussed in detail in appendix F.

3.12 These potential Code changes would:

(a) set out a calculation method for loss and constraint excess (LCE) payments that ensures that LCE attributable to specific assets is allocated to transmission customers that pay charges in relation to those assets in proportion to each customer's charges;

(b) amend the rules in Part 6 of the Code on avoided cost of transmission (ACOT) payments to ensure that payments are made where the operation of distributed generation would reduce grid costs; and

(c) allow the Authority to review the TPM after it has been approved if the Authority considers that the TPM, or some part of it, has become unworkable in its implementation or been implemented in a manner inconsistent with the Authority's policy objective as contained in the guidelines.

3.13 The proposed TPM guidelines would change the basis for ACOT payments. Currently ACOT payments are made to eligible distributed generators when they reduce distributors' RCPD charges due to the operation of distributed generation. However, if the Authority's TPM proposal comes into effect, distributors will no longer pay RCPD charges. Instead, they will pay other charges, including:

(a) charges with a largely fixed allocation such as the benefit-based charge, residual charge and connection charge

(b) variable charges such as the transitional peak charge and the kvar charge, if these are included in the TPM.

3.14 If those variable charges are included in the TPM, it may be efficient for distributed generation to receive ACOT payments if distributed generation were to reduce distributors' transitional peak and kvar charges. However, there would be no other basis for ACOT payments, as distributed generation is not intended to affect the benefit-based or residual charges. Instead investment in distributed generation would be in response to wholesale market prices. This is discussed in detail in appendix F.

Main advantages of the proposal

3.15 The Authority considers that the proposed revision to the current TPM guidelines would better promote the Authority's statutory objective. In particular, the Authority considers that the proposal would promote efficient investment in and efficient operation of the electricity industry. The main ways in which the proposal would promote efficiency (including by promoting a more durable TPM) are set out below.

Customers that benefit from an investment would be charged for it

3.16 Under this proposal, the costs of new investments (and certain existing investments) in the interconnected grid would be recovered from load and generation customers that benefit from each investment. Those who didn't benefit from an investment wouldn't pay for it (unlike now).

3.17 As a consequence, the Authority considers that this largely fixed charge would:

(a) Reduce the distorting cost of the HVDC assets on generation investments – South Island generators would pay a benefit-based proportion of the costs of the HVDC link, not all of the costs, just as North Island generators and consumers would also pay a benefit-based share.

(b) Remove the incentive to take actions to avoid paying for the cost of the grid, and so eliminate the costs incurred in taking such actions.

(c) Encourage investment in local generation and batteries because of the real benefits they can provide – not solely to shift costs to others

(d) Bring implications for grid-related costs into proper consideration when businesses make location and other investment decisions.

(e) Encourage customers to participate in the scrutiny of investment proposals and reveal their best information about benefits and costs of those proposals.

Recovery of revenues would not distort grid use or investment decisions

3.18 The residual charge would recover transmission costs that are not recovered through other charges. These costs include overheads and the costs of those historical investments that are not covered by the benefit-based charge.

3.19 The residual charge would be spread widely amongst load customers (distributors and grid-connected industrials). The charge would be allocated based on the amount of electricity customers used in the past. It would be a generally fixed charge, which means customers would not be able to influence how much they have to pay by when they use the grid.

3.20 As a consequence, the Authority considers that this fixed residual charge would:

(a) collect the required revenue with minimum impact on customers' grid use and investment decisions; and

(b) make it difficult for customers to avoid paying their share and shift it to others.

Better targeted price signals of grid congestion

3.21 Under the Authority's proposal, grid congestion would be signalled and regulated through nodal electricity prices determined in the wholesale market. Nodal prices provide a timely and efficient signal of the actual cost of grid congestion at specific locations. This avoids discouraging consumers from making use of the grid even during peak periods (the times when consumers place the highest value on using electricity) particularly where there is spare capacity available.

3.22 This can be contrasted with the RCPD charge, which is very high during the peak periods when it applies, regardless of whether or not the grid is congested, and is the same rate regardless of location.

3.23 The proposal allows for a transitional peak charge to be included in the TPM if Transpower considers that it would better meet the Authority's statutory objective (e.g. if it is needed to control peak demand). This would address any uncertainty around the effect of removing the current RCPD charge (whether or to what extent distributors might change their ripple control practices, what might happen to demand, and when other arrangements might be in place if retailers, demand aggregators, or others see value in load control).

3.24 This transitional peak charge would be targeted at the parts of the grid that are congested. It would be phased out within five years (with the possibility of an extension). The Authority intends the charge to be phased out as eventually it wouldn't be needed. This is because the Authority expects consumers to become more responsive to nodal prices, for two main reasons:

(a) the increasing adoption of technology and business models allowing the control of electricity demand in real time; and

(b) incentives arising from the Authority's real-time pricing project (which will stimulate efficient demand response through scarcity pricing).

The proposed pricing methodology would be more durable

3.25 Apart from the incentive advantages, the Authority regards the benefit-based charge as more likely to be perceived as fair and reasonable than the current approach to spreading the costs of investments across the country.

3.26 Over the long-term, pricing arrangements where you 'pay for what you get' would not be contentious (much like the current arrangements for connection charges). As a result, the proposal would lead to more durable transmission pricing arrangements than the existing TPM. A durable TPM is important if the efficiency benefits are to be achieved, and to stop ongoing uncertainty about the TPM. Uncertainty raises the costs of investments.

3.27 The Authority's proposal to allocate the depreciated costs of seven major existing investments through the benefit-based charge would also make a new TPM more durable compared to the case where the benefit-based charge was only applied to future investments. The Authority considers the latter would not be enduring, because if the benefit-based charge was only applied to new investments, then consumers in some regions could end up paying both for new investments and for investments that they didn't benefit from.

Case study: The trouble with a 'future investments only' benefit-based charge

If the benefit-based charge was only applied to future investments, Christchurch consumers could expect to pay most of the $283 million cost of the new switching station and new transmission line into Islington that Transpower is planning to build.[39] The same consumers would also continue to pay 9 percent of the costs of recent major grid investments that benefit mainly North Island consumers (such as the $876 million North Island Grid Upgrade).[40]

A cap on initial price changes to protect the interests of consumers

3.28 The proposed TPM would involve a rebalancing of charges. This would deliver long-term benefits for consumers overall.

3.29 Under the proposal some groups of consumers would face higher charges, as charges for other consumers reduce. This would be a rebalancing of transmission charges, not an increase in the total amount that Transpower is allowed to recover. It would re-allocate more of the regulated amount to those who benefit from specific grid investments.

3.30 The Authority recognises that households and businesses will be concerned about how these changes might impact on their own bill. Therefore, the proposal includes a price cap, recommended by submissions to the 2016 issues paper, to give households and businesses certainty on the level of charges in advance and allow industrial customers time to adjust to the new charges. The cap would limit any initial price rises due to the

39 The planned Upper South Island voltage stability project involves a switching station at Rangitata and a new line to Islington. It is expected to be delivered over 2022 – 2035 at a cost of $283m. Transpower, *Securing our Energy Future 2020 – 2025, Regulatory Control Period 3 Proposal*, November 2018, p.40, Table 10.

40 Assuming the existing allocation of costs was to continue, Orion would be expected to pay around $7m each year towards the costs of just three of the big North Island investments (the North Island Grid Upgrade, UNI reactive support and the Wairakei Ring).

introduction of the benefit-based charge and residual charge, to 3.5% of a transmission customer's electricity bill (excluding inflation and demand growth).

Q2. What are your overall views on the Authority's proposal for changes to the TPM guidelines?

4 Cost-benefit analysis

4.1 A cost-benefit analysis (CBA) seeks to quantify the proposal's net benefits to consumers.

4.2 A CBA is not a precise exercise, but it does give a sense of the order of magnitude of benefits or costs that are involved. While for ease of presentation and comparison an estimate is presented, this should be viewed as being a point within a wider range of estimates. The quantified aspects of the CBA do not pick up a number of important impacts that we have not been able to quantify. But that does not make them any less relevant. These unquantified effects are described qualitatively to be considered with the numbers.

4.3 Further, the CBA is a tool that supports analysis and decision-making. The CBA has provided important insights via the general magnitude of the potential impacts (rather than the exact dollar values estimated) and their sensitivity to assumptions. However, the CBA is only one of the range of factors that the Authority has considered in developing its proposal .

4.4 Table 4 summarises the quantified costs and benefits of the proposal and an alternative option that replaces the regional coincident peak demand (RCPD) charge with a broad-based usage charge (but no benefit-based charge).[41]

[41] This could occur if Transpower decided to undertake an operational review of the TPM to remove the RCPD charge. It could also occur through the Authority's review of the guidelines (for example, if we made the guidelines more restrictive in a way that required Transpower to reform the current RCPD charge). This alternative option is also considered in appendix E.

Table 4 Summary of quantified costs and benefits ($ million)

Quantified benefits	Proposal	Alternative
More efficient grid use	$2,579 ($81 - $5,678)	$1,775 ($4 - $4,197)
More efficient investment in batteries	$202 ($137 - $786)	$222 ($137 - $786)
More efficient investment in generation and large load	$43 ($9 - $112)	--
More efficient grid investment – scrutiny of investment proposals	$77 ($29 - $125)	--
Increased certainty for investors	$26 ($10 - $48)	--
Total quantified benefits	**$2,926 ($266 - $6,749)**	**$1,997 ($141 - $4,983)**
Quantified costs	Proposal	Alternative
TPM development / approval	$8 ($4 - $12)	$6 ($3 - $8)
TPM implementation costs	$9 ($4 - $13)	$4 ($2 - $5)
TPM operational costs	$9 ($5 - $14)	$0.3 ($0.2 - $0.5)
Grid investment brought forward	$188 ($51 - $324)	$135 ($6 - $264)
Load not locating in regions with recent grid investment	$1 ($0 - $2)	--
Efficiency costs of price cap	$1	--
Total quantified costs	$215 ($65 - $366)	$144 ($11 - $278)
Results		
Net (benefits less costs)	**$2,711 ($201 - $6,383)**	**$1,853 ($130 - $4,705)**

4.5 Each of the benefit and cost categories set out in the above table is discussed in the sections that follow.[42]

4.6 In summary, the estimated quantified net benefit of the proposal is $2.7 billion, within a range of between $0.2 billion and 6.4 billion, compared with the status quo. This is the net present value of estimated cost and benefits that are modelled to occur over the 2022–2049 period as a result of the proposal.

4.7 The modelling is sensitive to assumptions. In accordance with good practice, Table 4 also presents the ranges for each line item. The range represents, at the low end of the spectrum, a scenario with the most cautious of assumptions and at the high end of the spectrum the most optimistic but still realistic of assumptions. These are discussed in more detail in this chapter, and in the accompanying technical report. Sensitivities are also discussed from paragraph 4.181.

4.8 These net benefits are far greater than those identified in the CBA of the 2016 TPM proposal. A key reason for this difference is that the 2016 CBA did not investigate consumer benefits arising from more efficient grid use. This was because they were considered to be minor. Instead, it focussed on the benefits from more efficient investment.

42 The price cap is categorised as a cost in the table because we have only quantified the efficiency costs (which are smaller than the total amount transferred) of this element of the proposal. The price cap also has benefits (which in the Authority's view are likely to outweigh its costs), however, we have not quantified these benefits.

4.9 Consumer benefits from more efficient grid use are an important focus for analysis in 2019. This is because the growth in transmission alternatives, and because the Authority expects consumers in the mass-market to become increasingly exposed to cost-reflective distribution pricing and real-time wholesale prices over time.

Options: proposal and alternative proposal

4.10 The CBA is an assessment of the main (what would be mandatory) components of the proposed guidelines.

4.11 The benefits and costs of the seven additional components of the proposed TPM guidelines have not been assessed, because these are optional components only. Transpower will propose one or more of them for inclusion in the TPM only if, in Transpower's reasonable opinion, including the relevant component would better meet the Authority's statutory objective than not including it.

4.12 In undertaking this CBA, the Authority has had to make assumptions on what would unfold under the current TPM, and how this may be different under the proposal. A summary of assumptions is contained in the accompanying technical paper on CBA assumptions and methodology, published with this 2019 issues paper.

4.13 The Authority also has had to make assumptions about what a TPM designed in accordance with the proposed guidelines might look like. For example, we have assumed that the vSPD model is used to estimate benefits of transmission investments $20 million and over (for future as well as historical investments) and that the residual charge is allocated based on shares of historical AMD. These assumptions are not intended to constrain Transpower (or the Authority) in its future task of designing (or reviewing) a TPM; they are made simply to make the CBA modelling workable.

Baseline: status quo

4.14 The options under consideration are assessed against a baseline of the current TPM, as issued under the current guidelines, and the current Code (together the current TPM arrangements).

4.15 The baseline is defined by considering how the relevant variables would be expected to evolve over time in the absence of the proposal. So we have allowed for expected growth (if no action was taken) in demand, investment, costs and so forth.

Categories of costs and benefits quantified

4.16 The following table summarises the categories of impacts the Authority has quantified in the CBA.

Table 5 Categories of quantified benefits and costs

Benefit categories	Description
More efficient grid use	Increased efficient use of electricity at times when use is most highly valued by consumers.
More efficient investment in DER	Reductions in inefficient investment in DER (grid-scale batteries) for the main purpose of avoiding transmission charges.

Benefit categories	Description
More efficient investment by generators and large consumers	More efficient investment by generators and large consumers (as they will take account of the costs of all required grid upgrades when making location decisions).
More efficient grid investment – scrutiny of investment proposals	More efficient grid investment (due to greater scrutiny, and less lobbying for inefficient investments).
Increased certainty for investors	Increased certainty reduces the required return on investment.
Cost categories	**Description**
TPM development and approval costs	Costs such as policy analysis, modelling and legal fees.
TPM implementation costs	Costs of computer hardware and software, development and testing and user training.
TPM operational costs	Costs of data gathering and management, invoicing and customer liaison.
Grid investment brought forward	Cost of transmission investment occuring earlier to cater for increases in peak demand.
Load not locating in regions with recent grid investment	Distortion from large energy-intensive consumers avoiding investing in a region that has a benefit-based charge.
Price cap	Suppressed demand from customers with uncapped charges.

4.17 This excludes a number of impacts that we have not been able to quantify, for example, due to lack of relevant data, but which are just as relevant for consideration. These impacts are described qualitatively.

4.18 This is a bespoke analysis, as the proposal is specific to New Zealand's electricity sector context, which has to be reflected in the methodology. Although the CBA follows a conventional approach, we have not identified a standard or agreed methodology for conducting CBA on proposals for reform of transmission pricing arrangements.[43]

Assessment methodology: grid use model

4.19 The remainder of this chapter describes the key features of the assessment methodologies used for the different benefit and cost categories and the results of those analyses. We provide detailed analysis of the key results in Table 4 .

4.20 We first explain how we modelled the benefits from more efficient grid use and more efficient investment in DER (particularly grid-scale batteries).

4.21 We then summarise the approach to, and the results of, quantifying benefits related to more efficient investment in generation and load, and in grid investment.

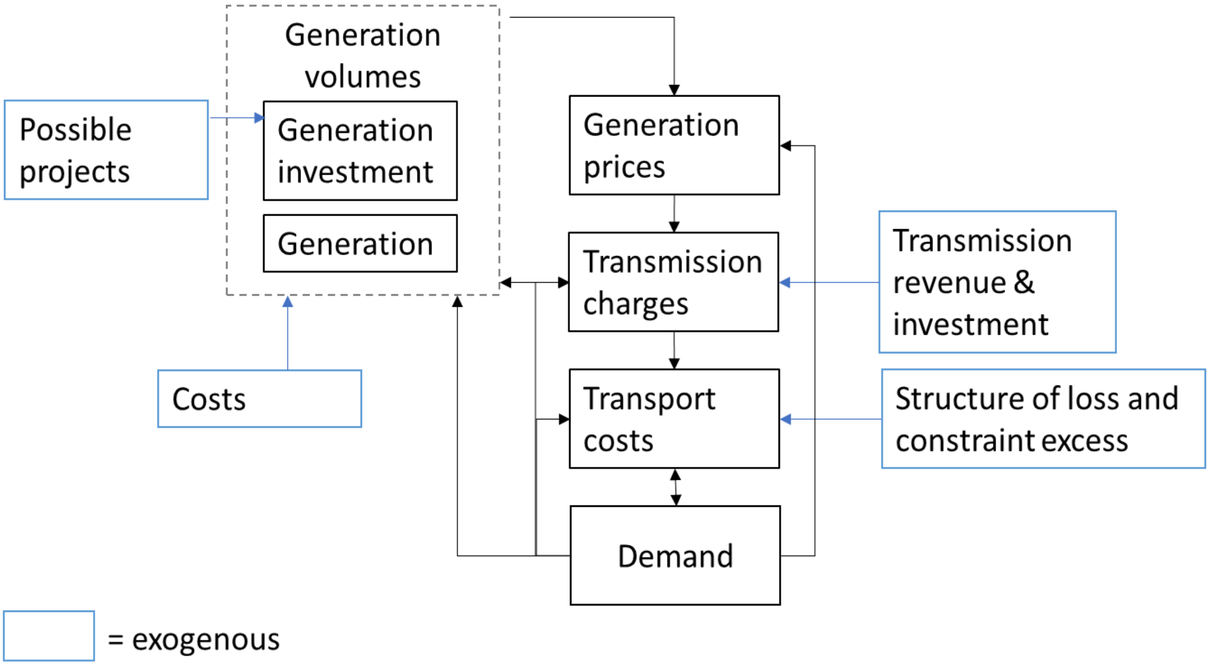
43 In an attempt to identify a standard method we surveyed reviews of transmission pricing methodologies in Australia, the UK, the USA and Canada that occurred within the past (approximately) 10 years.

4.22 A subsequent section in this chapter discusses the approach to, and results of, estimating each of the costs of the proposal.

Modelling benefits from more efficient grid use

4.23 The modelling is structured as a number of interdependent components that consider the effects of transmission charges on costs, prices, consumer demand, and generation investment. The structure of the grid use model is set out at a high level in the following diagram.

Figure 2: High level structure of grid use model



4.24 The modelling process takes input data on volumes and prices (of generation and demand) for a given year, and then calculates a new set of prices and demands for the subsequent year. The model allows for an interaction between demand, wholesale prices, and generation investments, though energy prices can also be held at historical averages.

4.25 Demand and costs are projected for the baseline and the proposal for the period 2018 to 2049,[44] and results compared to calculate cost differences and consumer welfare changes.

4.26 The central scenario for this model is based on an updated version of the 'Mixed renewables' scenario in MBIE's 2016 Electricity Demand and Generation Scenarios (EDGS). We updated this scenario to reflect actual and forecast changes in the electricity industry and the New Zealand economy since the EDGS were finalised.

4.27 The central scenario assumes that all potential major capital expenditure in Transpower's investment proposal for Regulatory Control Period 3 (RCP3) takes place, including the potential major capital expenditure for RCP4 and RCP5, as indicated in that proposal.

4.28 The model uses a representation of the transmission grid consisting of 14 separate geographical areas (backbone nodes). Figure 3 below shows the location of these backbone nodes and illustrative transmission line connections between them.

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44 While the full modelling period runs from 2018 to 2049, we model the proposal as coming into effect in 2022. So the changes expected to result from the proposal are modelled over the 2022 – 2049 period.

Figure 3: Simplified 14 backbone node grid

Benefits: assessment methodology and results

Benefits from more efficient grid use

4.29 The Authority's proposal is expected to lead to more efficient grid use. The RCPD charge sends a very strong price signal that often does not reflect the economic cost of using the grid. Removal of the RCPD would mean a significantly lower effective price for consumption during times of peak demand, when consumers value electricity most highly. This price effect would be expected to increase consumption at times of peak demand.

4.30 The charges that would replace the RCPD charge under the proposal would raise effective prices at all times, but with minimal distortion of grid use. The net effect would likely be that consumers derive greater value from their use of electricity (as they face reduced costs associated with their demand at times when electricity is particularly valuable).

4.31 To quantify this effect, we modelled the expected change in peak prices over the modelling period, effects on demand, and the value of the change in consumption. We also modelled the expected change in prices, demand and the value of consumption during shoulder and off-peak periods.

4.32 We took into account some expected indirect effects of the proposal. For example, if additional peak demand under the proposal would lead to changes in generation investment, that could also affect wholesale electricity prices, which could in turn affect consumption of electricity.[45]

4.33 The discussion in the remainder of this section covers, in turn, the following aspects of the modelling of more efficient grid use:

(a) modelling the proposed changes to transmission charges

(b) changes in prices arising from the proposal

(c) changes in demand

(d) consumer welfare changes

(e) effects on investment in grid-connected generation and energy costs.

Modelling the proposed changes to transmission charges

4.34 The key elements of the proposal that affect efficiency from grid use are as follows:

(a) removal of the RCPD charge and the HVDC charge

(b) introduction of a residual charge and a benefit-based charge.

4.35 In this section we describe how these changes are modelled.

Modelling the removal of the RCPD charge and HVDC charge

4.36 The most important aspect of the proposal from the perspective of the efficiency of grid use is the removal of the RCPD charge. This charge would also be removed under the alternative to the proposal. The RCPD charge sends a very strong price signal at times of peak demand, and suppresses demand during those periods. In order to model this effect, we need to specify the types of consumer affected by the RCPD charge and the time periods in which its effects are felt.

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45 The modelling of generation investment assumes investors will install new generation plant in a given region after short-run wholesale prices in that region exceed long-run marginal cost in any year.

4.37 The model distinguishes demand by time of use and energy source as follows:

(a) grid offtake during demand peaks (the top 1600 trading periods)

(b) demand served by distributed generation during demand peaks

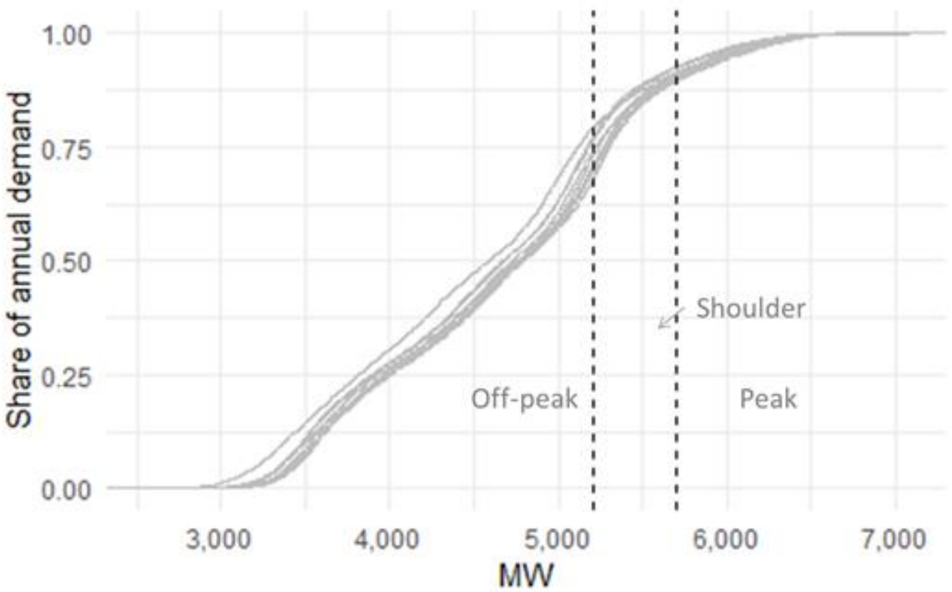
(c) demand met by grid offtake and distributed generation during shoulder periods (the next highest 3,075 trading periods)

(d) demand met by grid offtake and distributed generation during off-peak periods (the lowest 12,845 trading periods).

4.38 The RCPD charge is charged only during the top 100 periods in each of the four transmission pricing regions. But its effects are felt over a larger number of periods. This is because the top 100 periods are identified ex post, so in order to be sure of avoiding the top 100 periods, load customers need to reduce their consumption over a larger number of periods. The choice of 1600 periods for the peak is based on a cluster analysis of trading periods, by transmission pricing region.

4.39 The cluster analysis identified six clusters of demand. As the cluster of chief interest is peak demand – given its impacts on system capacity and costs – the first two clusters have been separated (denoted the peak and shoulder) and the subsequent clusters have been combined into a single off-peak period. Figure 4 below sets out annual national load curves with the derived boundaries between times of use (peak, shoulder and off-peak) based on averages between 2008 and 2017.

Figure 4: Cluster analysis: peak, shoulder and off-peak periods



4.40 The model of electricity demand distinguishes between two types of consumer: distribution-network-connected and transmission-network-connected. We do not distinguish between consumers connected to distribution networks. Rather, we model all load connected to a distribution network as a single entity. This is an important simplifying assumption. It means the model does not consider the degree to which distribution prices reflect transmission prices, or the extent to which distribution price signals are passed through into retail prices.

4.41 Other simplifying assumptions are that:

(a) load customers are assumed to face energy prices that cover wholesale electricity prices (including nodal price differences) and transmission charges[46]

(b) transmission charges are modelled as if they were charged as a fixed cost spread across a consumer's usage (measured in $ / MWh) by time of use. Under the status quo, the interconnection charge is a per MWh charge during peak periods while under the proposal energy prices would be much lower during peak periods, and somewhat higher in shoulder and off-peak periods (as transmission costs are also assumed to be recovered during the latter periods, not just at peak).

4.42 The Authority understands that the RCPD charge is not paid directly by mass-market consumers.[47] Similarly, mass market consumers pay retail prices that typically (with some exceptions) do not involve direct exposure to wholesale electricity prices or transmission prices.

4.43 Nevertheless, a key assumption of the grid use modelling is that mass-market load will respond to both transmission and wholesale price signals over the period to 2049.

4.44 The Authority's view is that this is a reasonable assumption. There are a number of reasons for this view, including:

(a) distributors are expected to pass on RCPD price signals to their customers through their allocation of cost between customer categories and through increasingly cost-reflective distribution pricing[48]

(b) retailers operate in a workably competitive market and will face competitive pressure to respond to distribution price signals (including RCPD price signals) and wholesale price signals. This could occur:

(i) by retailers passing on these price signals to their customers through their retail pricing structures—either unchanged (as Flick Energy does with both wholesale energy prices and distribution prices), or in a reasonably cost-reflective manner (eg, controlled/uncontrolled rates)

(ii) by retailers managing both consumers' and their own exposure to wholesale price risk and, increasingly, distribution price risk (and so effectively responding to these price signals on behalf of consumers)

(c) emerging business models such as aggregators will increasingly manage consumers' exposure to wholesale price risk and distribution price risk (and so will effectively respond to these price signals on behalf of consumers)

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46 By "transmission charges", we refer to RCPD charges, benefit-based charges and residual charges.

47 Distributors face RCPD charges but do not pay for wholesale electricity. Retailers face wholesale electricity prices and distributors' prices, but do not pay RCPD charges directly.

48 The majority of ICPs are already subject to cost-reflective allocation methodologies at the macro level. This is because customer categories that attract high costs due to the RCPD charge (such as residential consumers, who disproportionately consume electricity during peak periods) are charged higher rates. This means that, even if distributors continued to allocate costs in the way they currently do, residential consumers will see lower rates as a result of the proposal and will consume more at peak times. This will occur even for residential consumers who pay flat rates for energy use (that is, without taking into account time-of-use pricing and controlled load). Distribution pricing is expected to become more cost-reflective over time as distributors move to more cost-reflective pricing (such as time-of-use tariffs). It follows that under the status quo, RCPD price signals would increasingly be passed through into distribution prices.

(d) emerging technology (such as more sophisticated load control and battery technology) will increasingly facilitate real-time demand response, which will enhance both the ability of consumers to respond to more cost-reflective retail pricing and the ability of retailers and aggregators to manage consumers' exposure to wholesale price risk and distribution price risk

(e) market design evolution (eg, the introduction of real-time pricing) will also increasingly facilitate real-time demand response and thereby enhance the ability of retailers and aggregators to manage consumers' exposure to wholesale price risk

(f) the CBA measures the effects 'at the margin'[49], based on empirical estimates of demand response to prices. In effect, the modelled effects reflect the fact that not all consumers are directly exposed to transmission price and wholesale price signals: it is enough that some of them are (either directly or indirectly).[50]

4.45 The level of demand response could be expected to increase further with increasing adoption of the business models and technologies noted above.

4.46 We also model the removal of the HVDC charge under the proposal. The HVDC charge is modelled as continuing to be in place under the alternative to the proposal.

Modelling the introduction of a benefit-based charge and a residual charge

4.47 We model the benefit-based charge under the proposal (but not under the alternative to the proposal) by allocating revenue according to:

(a) estimated shares of benefits from the historical investments in schedule 1 to the proposed guidelines (based on the allocation set out in schedule 1)

(b) shares of benefits from forecast expenditure on new transmission investments (which is discussed further below).

4.48 In modelling the allocation of forecast expenditure on new transmission investments under the benefit-based charge, the modelling includes all potential major capital expenditure in Transpower's RCP3 proposal, including potential major capital expenditure in RCP4 and RCP5 (to June 2035). This includes these investments:

(a) Waikato and upper North Island voltage management

(b) South Island reliability — HVDC two replacement cables and one new cable

(c) Upper South Island voltage stability — switching station at Rangitata

(d) Upper South Island voltage stability — new line Islington

(e) South Island reliability — lower South Island (Clutha – Upper Waitaki).

4.49 Under the proposal, the cost of each of these major transmission investments would be allocated in proportion to the benefits it is expected to have for each transmission customer. In modelling the distribution of these benefits for CBA purposes, the objective was to reach a conservative allocation that would not cause the benefits of the proposal to be overestimated (recognising that the task of modelling benefits more precisely is outside the scope of the CBA).

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49 The effects measured in the CBA's central scenario involve changes of around 1% of electricity expenditure. This could be thought of as, for example, 10% of consumers increasing their expenditure at peak by 10%. The model does not involve 100% of consumers raising their expenditure.

50 We take a different approach when we consider an alternative approach to measuring consumer welfare (the compensating variation approach), discussed below.

4.50 It is assumed that the benefits of these and all other grid investments and associated operating costs would be allocated as follows:

(a) 50% of the value of the investments would be allocated based on the shares of the loss and constraint excess (LCE) estimated to accrue to each of the 14 areas in the model (reflecting that some of the main benefits of grid investments are the reduction of losses and mitigation of constraints)

(b) 50% of the value of the investments allocated based on shares of maximum demand and injection, to reflect relative benefits from reliability,[51] with generators' share set at 1% to reflect a lower value of reliability to them (assumed $200/MWh) compared to consumers (assumed $20,000 per MWh[52]) (a sensitivity has been conducted where generators' share of benefits is fixed at 37.6%).

4.51 These allocations are simplifications, made in order to keep the CBA modelling manageable. That is, we are not suggesting that the costs of major transmission investments would actually be allocated in this way if the Authority's proposal is adopted. The Authority considers that adopting this simplifying assumption is reasonable for CBA purposes.[53]

4.52 The Authority considers this allocation method to be conservative. If an alternative allocation method was used, so the costs of investments were borne by beneficiaries located in a single benefiting region, the benefits of the proposal would likely be higher. This view is based on a modelled scenario in which we assumed the costs of the WUNI voltage stability project would be imposed only on consumers supplied by the Huntly, Otahuhu and Marsden backbone nodes. This would be a reasonable assumption, given that the purpose of the project is to resolve voltage stability issues in Waikato and the upper North Island. In this scenario, the proposal would deliver $52 million in additional consumer welfare benefits compared with the current TPM arrangements. This would be additional to the main allocative efficiency results.

4.53 The estimated net benefits of the proposal, in terms of consumer welfare, are larger once major transmission capital expenditure has been taken into account. This reflects allocative efficiency gains that scale with the amount of revenue at stake. We also take into account the flow-on effects of changes in investment in grid-connected generation and energy costs that result from changes in demand due to these major transmission investments.

4.54 The residual charge is modelled by allocating the funds recovered through the residual charge based on the average AMD over the five years prior to the introduction of the proposed changes to transmission prices.[54]

Changes in prices arising from the proposal

4.55 By removing the RCPD charge, the proposal would cause a large reduction in the price attached to consuming electricity during peak periods, which would benefit consumers.[55]

51 As we don't know the proportions of future investments that will be made for reasons of reliability versus reasons of reduction of losses and mitigation of constraints, we have assumed 50% each.

52 This assumption reflects the value for expected unserved energy set out in the Code: Schedule 12.2, clause 4.

53 It should not be assumed that Transpower will make a similar assumption for the purposes of determining benefit-based charges. We expect that Transpower will use more exacting methods to estimate the benefits of high-value post-2019 investments.

54 The use of the average of the AMD across the past five years is to simplify the modelling. The proposed guidelines also require that Transpower apply a ten-year lag, or use an alternative method of allocating the residual charge which would better meet the Authority's statutory objective.

4.56 In practice, the reduction in that price depends on the number of trading periods in which demand can respond. For example, if demand responded during the 100 trading periods used to calculate the RCPD charge, the estimated strength of a $109/kW charge is $2,180/MWh. If demand responded during 1600 periods: the estimated strength of the signal is $136/MWh. Regardless, these are significant price signals compared to the wholesale electricity price.

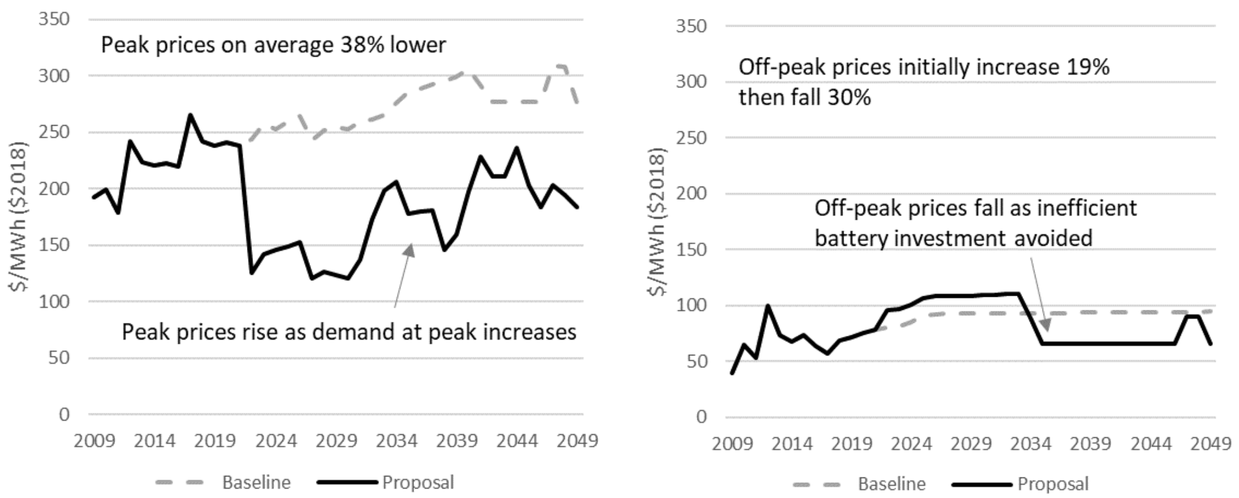
4.57 If the RCPD charge were removed (and replaced with the proposed charges), demand would initially experience a 48% drop in peak period prices. Model results indicate that the peak period price would on average be 38% lower over the modelling period under the proposal compared to the status quo.

4.58 A significant part of this difference is caused by an upward spiral in the RCPD rate under the status quo, driven by load customers investing in DER (in particular, network-scale batteries) in order to avoid paying the RCPD charge. Customers' ability to avoid the RCPD charge in this way is expected to increase over time with the reducing cost of DER (such as batteries). An important source of consumer benefits of the proposal comes from avoiding the economic costs of this spiral.

4.59 Off-peak prices would rise initially by an average 19%, compared to the status quo, but then fall roughly 40% (due to greater generation capacity and reducing use of grid-scale batteries under the proposal). These price differences are illustrated in the following figure.

Figure 5 Effective price– wholesale electricity prices + transmission charges

Transmission charges refers to RCPD, benefit-based and residual charges.



4.60 These are forecasts and as such, a degree of caution is appropriate. Future prices may be influenced by a range of events, a number of which will be unanticipated. For example, forecasts of wholesale prices are quite sensitive to assumptions about generation investment behaviour (which in turn is influenced by a range of factors).

4.61 In addition, it is possible that the price effect includes some wealth transfers from generators to consumers. That is, if wholesale prices reduce under the proposal, it could be argued that consumers gain at the cost of generators. The Authority does not take wealth transfers into account in making decisions.

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55 The price of consuming electricity means the total of wholesale energy prices and transmission prices.

4.62 However, the Authority does not consider the energy price effect to be predominantly a wealth transfer. Generators would not lose out to consumers, because, in the model, the falling prices are a result of generators expanding efficiently in response to increased demand and prices that justify the expansion. The expansion benefits both generators and consumers.

4.63 Even so, it is possible there are some wealth transfers among the efficiency effects, but these are difficult to disentangle. For this reason, in presenting the net benefits, the Authority has moderated the impact of expected price changes. This was done by calculating net benefits to consumers based only on changes in volumes, transport costs and transmission prices both with energy price effects, and with energy prices held constant, and taking a simple average of the two results.

4.64 Changes in prices are modelled for all 14 geographical areas. The effects of the proposal on prices differ between regions. These distributional effects under the central scenario (the simple average of grid use efficiencies without and with energy price effects) are illustrated in Table 6.

4.65 Consumers in almost all regions would be better off as a result of the proposal. There are a small number of exceptions. These generally reflect the role of distributed generation in avoiding transmission charges under the status quo, which would not be possible under the proposal.

Table 6 Distribution of consumers' benefits

Net present valued benefits as a percentage of wholesale market costs in the baseline

Backbone node	Large industrial	Non-residential	Residential	Total
Marsden	--	-3.1%	1.3%	-1.3%
Otahuhu	0.0%	0.5%	6.1%	2.6%
Huntly	2.8%	2.2%	6.9%	3.9%
Tarukenga	5.2%	4.3%	9.4%	6.2%
Whakamaru	--	-17.1%	-17.9%	-17.4%
Stratford	-0.4%	3.4%	8.4%	5.2%
Redclyffe	2.7%	5.3%	11.0%	6.3%
Bunnythorpe	2.7%	1.9%	6.5%	3.6%
Haywards	--	3.1%	8.8%	5.5%
Kikiwa	--	2.8%	7.9%	4.9%
Islington	7.5%	5.1%	10.3%	7.2%
Benmore	--	6.5%	11.7%	8.5%
Roxburgh	--	3.3%	8.7%	5.5%
Tiwai	5.0%	5.0%	9.9%	5.3%
Total	3.8%	2.4%	7.6%	4.4%

4.66 The result for the central North Island, represented by the Whakamaru backbone node, reflects that the grid use efficiency benefits will not be sufficient to offset the increase in 'fixed-like' transmission charges as a result of the proposal. The Lines Company (TLC), Eastland Network, Waipa Networks and Unison connect to this node – Unison being the main one. As set out in Chapter 5, transmission charges for TLC would indicatively rise from $3.3 million to $5 million per year. . To put this into context, that chapter also illustrates that, in practice, the impact on total electricity bills even in the short run is not sufficiently large for the proposed price cap to make an impact.

Changes in demand

4.67 We model consumers switching their electricity use between different time periods (such as peak and off-peak) as prices change. With the removal of the RCPD charge, consumers are expected to use more energy at peak times (1.2% more on average). We also model consumers switching between grid-supplied electricity and electricity supplied by distributed generation. The effects differ between regions, again due to differences in the benefit-based charge and also due to the different amounts of distributed generation available in each region.

4.68 Table 7 sets out modelled changes in aggregate national demand at peak, off-peak and shoulder periods.[56]

Table 7 Changes in demand by time of use

Demand response scenario, average MW 2022-2049

	Peak MW	Distributed generation peak MW	Shoulder MW	Off-peak MW
Proposal	6,405	485	6,082	4,667
Status quo	6,330	515	6,110	4,674
Change	75	-30	-28	-6
% change	1.2%	-5.8%	-0.5%	-0.1%

4.69 We have empirically estimated consumers' responsiveness to prices of electricity. These price elasticities of demand describe how changes to prices of electricity at different times of use cause changes in the allocation of demand across different times and between peak grid demand and peak demand for distributed generation.

4.70 This empirical analysis shows that consumers' responses to price changes vary between transmission-connected demand and distribution-connected demand. For example the price elasticity of:

(a) distribution-connected demand at peak times (after allowing for changes in total electricity expenditure) is estimated at -0.054. This demand also includes automated demand response (such as distributors' ripple control) that, empirically, operates to reduce demand when demand or prices are high and may translate into observed sensitivity to price changes

(b) demand by transmission-connected consumers at peak times (after allowing for changes in total electricity expenditure) is estimated at -0.003.

4.71 These elasticities are estimated using annual data and represent expected annual changes in demand given an annual average price change.

56 The results reported in this table and in this paragraph are drawn from a scenario that focuses on removal of the RCPD charge, and excludes other effects such as distributed generation and grid investment effects.

4.72 In general, distribution-connected demand is more price-sensitive during peak demand periods than transmission-connected demand. This reflects a common finding, from empirical estimates of demand response, that business demand is less price-sensitive than residential demand.[57]

4.73 Due to the very substantial fall in peak prices (including transmission charges) it causes, the proposal is estimated to result in a significant increase in peak demand, in the order of 1.2% (75MW nationally) on average over the modelling period. By contrast, demand during shoulder and off-peak periods is expected to fall (on average by 0.5% and 0.1% respectively). These changes have implications for consumer welfare, which is considered in the next section. They may also be expected to have flow-on effects on wholesale energy prices and investment in generation and transmission. These effects are considered below.

Consumer welfare changes

4.74 Removing the RCPD charge on peak demand would benefit consumers by reducing their cost of using electricity at times that it is particularly valuable to them.

4.75 This value is well illustrated by the fact that around 30% of wholesale market expenditure occurs in the top 1600 trading periods, which account for only for 9% of all trading periods in a year. Those are the times that, for example, consumers want to use electric heating (on a cold winter night) or cook dinner when they get home from work.

4.76 At the same time, the cost to consumers would effectively rise at off-peak and shoulder periods (if we assume for modelling purposes that the proposed 'fixed-like' transmission charges would be recovered across all trading periods). See Figure 6.

4.77 A key question for this cost benefit analysis is how to value the relative change in costs – in terms of consumer welfare and hence allocative efficiency. We have considered this question using two mainstream methods, providing a cross-check on the benefits.

Consumer surplus

4.78 The Authority's main approach is to calculate a conventional consumer surplus measure. Consumer surplus is an economic measurement of consumer benefits. It exists when the actual price of a service is less than a consumer is willing to pay. Consumer surplus increases when the price of a service to the consumer falls, and consumer surplus reduces when the price to the consumer rises.

4.79 How this would apply in terms of changes to transmission pricing is illustrated in the diagrams below.

57 For example, Frontier Economics, Peak-use charging; A review of price elasticity of demand, October 2018 https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf See p.23 of the Frontier report.

4.80 Figure 6 shows demand for electricity during peak periods and also during off-peak periods.[58] It shows:

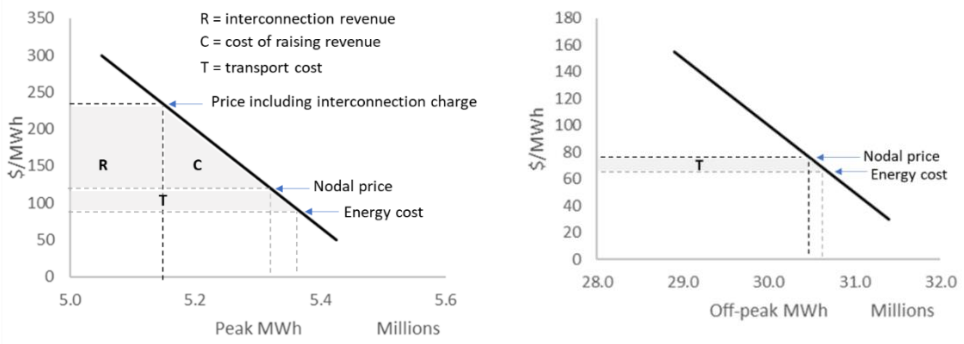
(a) the transport cost (T), ie, the difference between the energy prices paid by consumers at the GXP and those received by generators, for both peak and off-peak periods

(b) interconnection revenue (R), that is, RCPD charges paid by consumers at peak

(c) the efficiency cost (C), or "deadweight loss" of raising this interconnection revenue: this is the (very substantial) loss of allocative efficiency caused by the RCPD charge distorting consumers' decisions around grid use and investment (peak periods only).

4.81 Consumer surplus is the area under the demand schedule (the dark diagonals) and above the price including interconnection charge (peak) or the nodal price (off-peak).

Figure 6 Efficiency cost of RCPD charge under the status quo

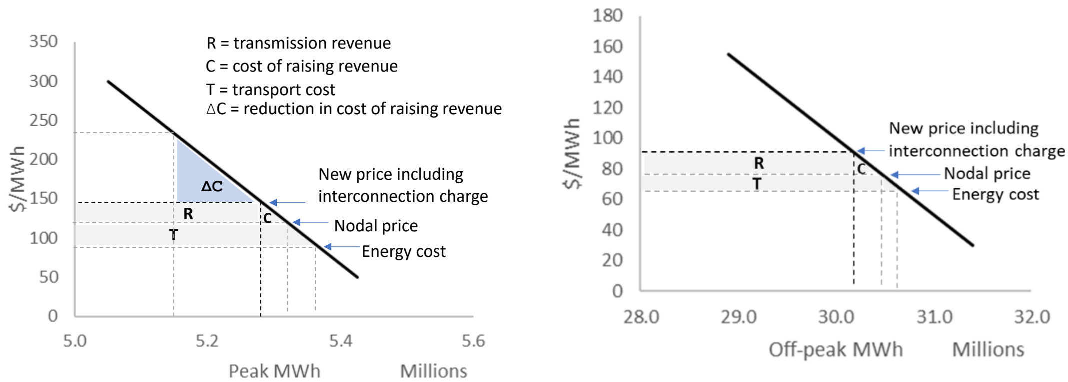


4.82 Figure 7 shows the changes that occur under the proposal. It shows:

(a) transmission revenue (R) would be recovered during both peak and off-peak; the two Rs in this figure add up to the R in Figure 6.

(b) a small efficiency cost (c) of raising revenue applies during peak and off-peak.

Figure 7 Increased allocative efficiency due to removal of RCPD charge



4.83 The net efficiency gain is the (large) reduction in the efficiency cost of raising revenue at peak (ΔC) less the smaller cost of raising revenue off-peak (c).

58 For simplicity, shoulder periods are not shown. We have also omitted the supply curve as these are only illustrative charts illustrating demand effects. More generally in the modelling, no explicit assumptions have been made about the shape of the supply curve. Supply is modelled using annual averages and the shape of the supply curve during a particular time of use will reflect the capacity of generation assumed to be available and the short run marginal costs of that generation.

4.84 Using a consumer surplus measure, the central estimate of the allocative efficiency gains associated with changes in grid use (before adjusting for other benefits and costs) are:

(a) $2.6 billion from the proposal (in a range of $81 million - $5.7 billion)

(b) $1.8 billion from the alternative to the proposal (in a range of $4 million - $4.2 billion).

4.85 Given the very substantial reduction in peak prices over the period to 2049 discussed above, it is not surprising that the allocative efficiency gains from the proposal are so substantial. As noted above, an important source of consumer benefits from the proposal stems from escaping an upward spiral in the RCPD rate under the status quo, driven by load customers investing in DER.

Compensating variation

4.86 As an alternative approach to test these numbers, we also estimated the consumer benefits using a compensating variation measure. This approach estimates how much money is needed to compensate consumers so they are no worse off after a price increase (or how much money consumers would need to give up to be no better off after a price reduction).

4.87 A reduction in the price of a good or service means consumers can buy more (their purchasing power increases), which makes them better off. This methodology is more sophisticated than the consumer surplus measure. That is because it considers the impact of a price change in terms of consumers' total expenditure patterns (that is, on electricity and other goods and services), and by recognising that people change their expenditure patterns (e.g. substitute away from a good) as prices change. [59]

4.88 Under certain conditions the consumer surplus and compensating variation measures of consumer benefit are equivalent, but in practice the size of benefit indicated by compensating variation will exceed the consumer surplus measure. Compensating variation is however a better measure when price changes are large, such as under the proposal.

4.89 One of the reasons is that, unlike consumer surplus, it captures the non-linear nature of demand. Generally speaking, the benefit a consumer gets from buying more of something gets smaller as they consume more of it. This non-linearity can give rise to big effects when prices fall.

4.90 Consumer surplus is better known because it has been around longer and relies on less information and calculation to estimate (a starting price and quantity, a price change, and a measure of consumer response, or price-elasticity).

4.91 With all this in mind, the Authority presents the consumer surplus measure as its main estimate of grid use benefits that would arise from the proposal; but it is informative to understand the compensating variation measure as part of establishing bounds around the estimates.

4.92 In order to be conservative, we have discounted some of the welfare effects obtained using the compensating variation measure for mass market consumers in the early years of the proposal (by around 80% initially). This is on the basis that consumers are not exposed directly to transmission price signals, which may mute the initial impact of removing the RCPD charge. This discount reduces over time to reflect expected changes in the adoption

59 Deaton A and Muellbauer J, (1980). A summary of its history and subsequent applications is available at https://www.nobelprize.org/uploads/2018/06/advanced-economicsciences2015.pdf

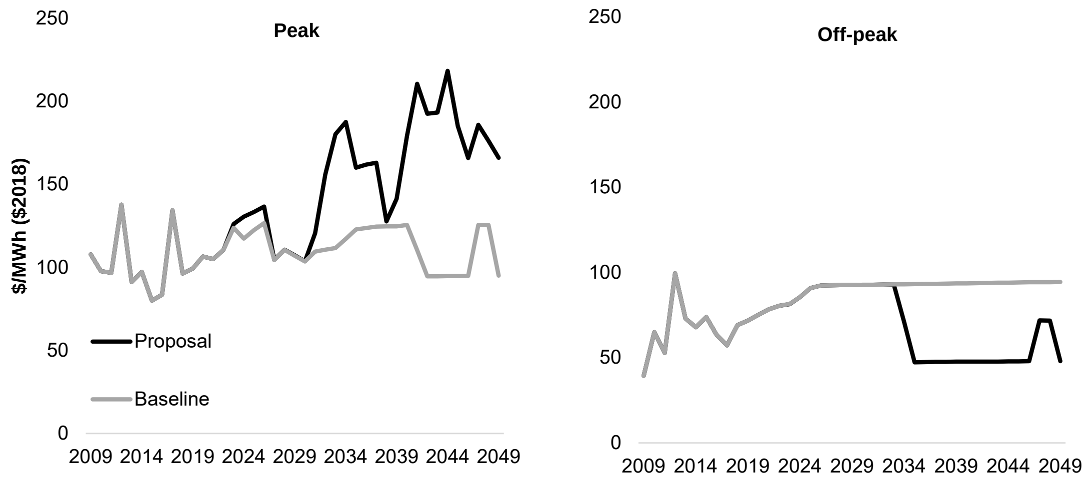
of technology and new business models, which we expect will result in more consumers being exposed to transmission price signals.[60]

4.93 The assumptions behind the use of the non-linear expenditure function do not necessarily apply to industrial users of electricity. Opportunities to substitute to other forms of energy are less viable for very large industrial users of electricity (such as steel, and pulp and paper) where electricity use is a core part of production. So, in combination with applying the compensating variation measure for mass market consumers, we have assessed impacts on transmission-connected demand according to the linear consumer surplus calculation. This combined assessment has been used to inform the high end of the range of efficiency benefits ($5.68 billion for the proposal and $4.20 billion for the alternative).

Effects on investment in grid-connected generation and energy costs

4.94 Under the proposal, we expect that increased peak demand (caused by the removal of the RCPD charge) would lead to an increase in peak wholesale energy prices and greater expenditure on electricity (from grid-connected generation).[61] This increase would not be much compared to the removal of the RCPD charge. At the same time it would stimulate investment in generation capacity and so lead to lower energy prices, as Figure 8 shows (this is particularly visible in the case of off-peak prices).

Figure 8 Wholesale energy prices (ex interconnection cost) under the proposal



4.95 One of the effects of more expenditure on electricity from grid-connected generation is to bring forward investment in grid-connected generation.[62] This is because the expected return on an investment in this type of generation would be higher. So, a potential grid generation investment could become economic at an earlier date if the proposal goes ahead than if it does not.

4.96 Additional investment in generation has both costs and benefits. The costs consist of the additional capital and operating expenditure for the additional generation plant. The benefits

60 It is not necessary to apply this discount under the consumer surplus approach. This is because under the consumer surplus approach, the modelled efficiencies are marginal effects, derived from the actions of the marginal consumer. So it does not matter that not all consumers are exposed to transmission price signals: it is enough that some of them are (either directly or indirectly). By contrast, under the compensating variation approach the efficiency effects come from expenditure by all consumers.

61 The increase in peak wholesale energy prices is expected to be substantially outweighed by the removal of the RCPD charge, so the overall effect is still a significant reduction in the cost of consuming electricity at peak.

62 The proposal has a different effect on investment in distributed generation, which is discussed below.

relate to the resulting reduction in wholesale electricity prices due to the increase in the supply of electricity into the wholesale market. That is, while the proposal is, in the shorter term, likely to cause an increase in energy costs, these are offset to some extent by increased generation investment.

4.97 The modelling indicates that energy prices would be around 1% lower, on average (undiscounted) over the modelling period due to generation investment under the proposal, relative to the current TPM arrangements. This is due to a decline in shoulder and off-peak prices outweighing an increase in peak wholesale energy prices (which are estimated to rise above what they would be under the current TPM arrangements for most years between 2022 and 2049).[63]

4.98 This net reduction in energy prices benefits consumers by enabling them to use this saving to buy more electricity or other goods or services that benefit them. The potential benefits are very large (in the order of $4 billion over the modelling period).

4.99 However, the Authority considers it should place less reliance on the potential benefits from this generation investment and energy price effect, compared to the allocative efficiency effects that would come about directly from the proposed change in transmission prices. This is for two main reasons:

- the estimates are sensitive to assumptions about generation investment behaviour. Consumer surplus estimates including energy price effects range from -$330 million to $10.8 billion, depending on the assumptions about generation investment and the tightness of the generation market
- the estimates may contain a mix of 'pure' allocative efficiency effects and some wealth transfers from generators to consumers that may be difficult to disentangle, as discussed earlier.

4.100 For these reasons, the Authority's main estimate takes a simple average of a consumer surplus estimate that holds energy prices constant, and one that includes the energy price effects. Model averaging is a common adjustment when there is uncertainty about the best approach. The Authority considers this to be an appropriate adjustment in this case too.

Benefits from avoiding inefficient investment in DER

4.101 The Authority considers the proposal would significantly improve the efficiency of future investment in DER (particularly batteries, but potentially also including distributed generation and/or load control technology). Generally, investment in DER is for useful and efficient purposes such as providing ancillary services. Such investment would continue under the proposal.

4.102 However, as explained above, the highly concentrated peak transmission charges could be expected to cause inefficient investment in DER that would be made mainly to avoid the peak transmission charges. The investment is inefficient if this doesn't change transmission costs to be recovered. (That is, if customers invest in batteries that are cheaper than peak electricity prices including peak transmission charges, but which are more expensive than peak electricity prices excluding uneconomically high transmission charges.)

4.103 The extent of any such inefficiency depends critically on the relative cost of new technologies. The Authority's assessment suggests that, over the next 20 years, the cost of new technologies is likely to cause a large amount of inefficient investment in DER (such as

63 Noting we are talking about wholesale energy prices only – ie, the RCPD charge is not included.

batteries) that deliver access to electricity at a cost higher than peak electricity prices (excluding inefficient transmission charges).

4.104 This assessment is based on gains from investing in network scale batteries to arbitrage peak electricity prices inclusive of transmission charges. Storage technologies are the most relevant technologies for this assessment as other technologies are either already economic, under limited circumstances (such as distributed wind generation), or do not affect peak charges unless storage costs are considered (such as solar generation).

4.105 This assessment is conservative in that it does not take into account investments by mass-market consumers (including inefficient investments in hot water cylinders or gas-heated hot water, wood-fired heaters, generators or small-scale batteries). In the absence of the proposal such investments would likely become more common as the mass market becomes increasingly exposed to cost-reflective pricing over time. In aggregate these sorts of investments can be very substantial.

4.106 The proposal is estimated to deliver a benefit of $202 million (within a range of $137 million-786 million). This benefits stems from avoiding investment in DER (particularly network-scale batteries) that would otherwise be inefficiently brought forward under the current TPM arrangements. The alternative to the proposal is estimated to deliver a similar benefit ($222 million) within e same range as for the proposal.

Benefits: more efficient generation investment – HVDC charge

4.107 The HVDC charge faced by generators in the South Island reduces returns on investment in South Island generation, even where projects exist that are otherwise relatively low cost.

4.108 The Authority expects that the proposal would bring efficiency benefits through the removal of the HVDC charge. These benefits are included as part of the estimated benefit of more efficient grid use discussed above.

4.109 These benefits are not reported as a separate figure as it is difficult, if not impossible, to completely disentangle the effects of the distortion from the HVDC charge on generation investment. This is because the current TPM reduces peak demand growth, which reduces the frequency with which new investment is profitable, regardless of transmission prices faced by investors in generation. Further, if lower-cost generation is inhibited by transmission costs and is replaced by more expensive generation elsewhere in the country then this will flow through into higher energy prices, further retarding demand growth and further reducing opportunities to invest.

More efficient investment in generation and large load

4.110 One of the other main expected benefits of the Authority's proposal is more efficient investment by both generation and large loads. Under the current TPM, these parties do not face the full costs of any required upgrades to the interconnected grid when making location decisions. As their marginal private costs are lower than marginal social costs, the decisions of these parties may not lead to results that are efficient for society as a whole.

4.111 By contrast, a TPM issued under the proposed guidelines would provide generation and large loads with the incentive to take account of the costs of any such required upgrades. This is because they would face the full costs of any required upgrades to the interconnected grid, through paying the benefit-based charge. Over time, the Authority expects this to result in lower total costs of grid investment.

4.112 In considering this potential benefit, we also consider a potential distortion to investment decisions that could be created by the proposal, if large energy-intensive consumers avoid investing or locating in a region that already has a benefit-based charge. We take account of this potential distortion in quantifying the benefit of more efficient investment by generation and load, and report it separately below under costs.

4.113 We took a top-down approach to assessing these categories of benefits, as explained below. We have undertaken a Monte Carlo analysis to test the sensitivity of the results to different assumptions.[64] The Authority's estimate for this category of net benefits is $42 million – the mean of the Monte Carlo distribution of results. The assessment indicated substantial upside potential. In the following subsections we discuss the two constituent parts of this estimate: first, more efficient investment and consumption by load; and second, more efficient investment by generation.

Grid efficiency due to more efficient investment & consumption decisions: load

4.114 More efficient investment and consumption decisions by consumers are expected to result in the efficient deferral of grid investment. We quantified this effect based on:

(a) the estimated extent to which cost-reflective and benefit-based transmission prices reduce demand growth in areas that are likely to require transmission investment

(b) an assumption about the extent to which transmission investment follows demand growth (as opposed to enabling generation growth)

(c) assumptions on the expected incremental costs of grid investment

(d) assumptions on the expected timing of grid investment.

4.115 With respect to (a), we estimated the percentage reduction in demand that is expected to occur with benefit-based charges using a long-run price elasticity of demand of -0.74 (which is an empirical estimate, and is consistent with assumptions used in the model of grid use efficiencies). This elasticity represents the long-run percentage change in electricity demand for a one-off change in aggregate (annual weighted average) electricity prices. This elasticity is estimated using the aggregate price elasticity of mass market demand. It reflects consumers' investment decisions as well as short-run consumption decisions.

4.116 We also relied on assumptions about the scope and incidence of benefit-based charges over the period up to 2049. The effect of the benefit-based charge on demand is evaluated at its maximum value in terms of deferral, occurring immediately before the transmission investment occurs, when expected benefit-based charges are largest.

4.117 With respect to (b), we assumed that 80% of transmission investment is undertaken for reasons of demand growth (as opposed to enabling generation growth). This is based on analysis of recent historical grid investment and of Transpower's RCP2 and RCP3 proposals.

4.118 With respect to (c), we assumed that long-run (efficient) transmission investment is a constant function of growth in peak demand. So the current value of total transmission costs reflects the change in aggregate peak demand and the long-run incremental costs of transmission investment. This view of transmission costs is consistent with efficient, cost minimising, transmission investment decisions assuming constant productivity.

4.119 With respect to (d), we considered forecast trend growth in peak demand, and also forecast transmission enhancement and development expenditure. The latter depends on the current status of transmission capacity: it is expected to be lower when grid capacity is less

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64 Monte Carlo techniques rely on repeated random sampling from probability distributions over parameters to model the likelihood of various outcomes. They are used to understand the impact of uncertainty in a model.

constrained and higher when capacity is more constrained. Based on this consideration we were able to model the timing of efficient grid investment deferral, which is an important consideration for welfare consequences (in present value terms).

4.120 The central estimate for the value of more efficient investment and consumption decisions by consumers is $31 million.

Grid efficiency due to more efficient investment decisions: generation

4.121 More efficient *generation* investment decisions due to generation customers paying the benefit-based charge are also expected to result in the efficient deferral of grid investment. To be clear, this effect is not quantified in the grid use model and is different from the effects discussed above.[65] The net benefit resulting from this analysis is additional to those discussed earlier in this chapter.

4.122 To quantify this effect, we used a similar approach to that used to model benefits from more efficient investment by load, with some adjustments to account for the fact that the analysis considers the effects of generation injection rather than demand.

4.123 We identified areas where increases in generation are likely to create a need for investment in transmission capacity to enable injection and export of energy. We estimated the extent to which cost-reflective and benefit-based transmission prices reduce the requirement for such additional transmission capacity (using the grid use model). This allowed us to estimate the value of this efficiently deferred investment (using the assumptions on the expected incremental costs and timing of grid investment discussed above).

4.124 The central estimate for the value of more efficient investment decisions by generation is $11 million.

4.125 The Authority's approach is conservative because of its focus on efficiency benefits relating to inter-regional transmission. There may also be benefits relating to intra-regional transmission. The latter category of benefits is not captured in this modelling.

More efficient grid investment due to scrutiny of proposed investment

4.126 One of the main expected benefits of the proposal is more efficient grid investment due to the enhanced incentives on beneficiaries of transmission investments that pay benefit-based transmission charges to:

(a) more closely scrutinise proposed transmission investments

(b) provide information that enables lower cost transmission investments or transmission investment alternatives

(c) not propose or support inefficient transmission investments.

4.127 The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. Those processes would be enhanced under the proposal as customers would have incentives to reveal information that more accurately reflected a proposal's net benefits or considered the merits of alternatives.

4.128 While noting that the support that may be drawn from comparisons with other jurisdictions is limited, we note that in other contexts the increased participation of consumers in

65 That said, the analysis in this section does draw on information produced by the grid use model, as discussed below.

regulatory decision-making processes has been found to lead to various improvements, including:

(a) lower transactions costs and faster speeds of regulatory decision making (Chakravorty, 2015)

(b) lower prices through lower regulated returns (Fremeth et al, 2014)

(c) lower costs of accessing information and lower costs to consumers associated with regulatory decisions (Fremeth and Holburn, 2012).

4.129 The Authority considers that the proposal would increase the incentives of interested parties to contribute to the decision-making process around transmission investments (while confining these incentives to parties with an interest in the economic efficiency of investments).

4.130 To quantify this effect, we assume that these incentives lead to a productivity gain in the long-run costs of transmission investment. We have assumed different rates of reduction in costs for different categories of investment, including:

(a) enhancement and development (E&D) capex

(b) replacement and refurbishment (R&R) capex

(c) major capex projects and listed projects.[66]

4.131 We assume a 4% reduction in costs for proposed E&D base capex investments that the Commerce Commission does *not* review when approving Transpower's proposal for a given regulatory control period (investments added by Transpower *after* the Commerce Commission approves Transpower's expenditure proposal for the regulatory control period).[67] We note this number is similar to the 4.4% reduction in capex achieved through the Commerce Commission's scrutiny of the proposed E&D base capex projects in Transpower's submission on the Commerce Commission's draft RCP2 determination. This is indicative of the approximate magnitude of efficiency gains that may be expected via scrutiny, and so provides comfort that the assumption is reasonable.

4.132 We assume a 2% reduction in costs for proposed E&D base capex investments that *are* reviewed by the Commerce Commission when approving Transpower's proposal for a given regulatory control period. The Authority considers it is reasonable to expect a positive efficiency gain (albeit smaller that achieved with respect to the above category) due to greater stakeholder engagement. This could occur in part through beneficiaries testing the reasonableness of project cost drivers. We see this with connection assets.

4.133 For R&R capex investments that we consider more susceptible to efficiency gains, we similarly assume a 2% reduction in costs. R&R capex investments that we consider more susceptible to efficiency gains include, for example, interconnection transformer capacity, AC substation busbar refurbishments and security upgrades and transmission conductor

66 'Listed projects' are projects with a capital cost of $20 million or more, and which come under Transpower's R&R capex. In contrast, 'major capex' projects have a capital cost of $20 million or more, but come under Transpower's E&D capex.

67 During a regulatory control period, Transpower can add/remove transmission investments to/from the list of investments seen by the Commerce Commission when approving Transpower's base capex allowance for the regulatory control period. Additionally, the investments seen by the Commerce Commission when approving Transpower's base capex allowance would be expected to almost always change in some way by the time the project starts, due to Transpower's standard project design and planning processes.

capacity into a region. We estimate approximately 15% of R&R capex outside the listed projects category falls into this category.[68]

4.134 For base R&R capex investments that we consider less susceptible to efficiency gains, we assume only a 1% reduction in costs. R&R capex investments that we consider less susceptible to efficiency gains include, for example, tower painting, tower foundation refurbishments and improving the seismic performance of HVDC buildings.

4.135 We also note that a portion of base R&R capex is recovered via connection charges. Beneficiaries of this base R&R capex are already strongly incentivised to promote efficiency gains so it would not be appropriate to assume further efficiency gains for this portion.

4.136 The central estimate for the combined value of more efficient grid investment due to scrutiny of investment in all the categories of base capex above is $31 million.

4.137 For major capex and listed projects, we assume a 4% reduction in costs. Under the proposed TPM guidelines, such projects can have a significant impact on an individual customer's transmission charges if that customer is deemed to benefit from the project. As the impact on charges will be much greater under the proposal than under the current regime, we consider it reasonable to expect that beneficiaries of a proposed major capex investment would engage more with Transpower and with the Commerce Commission over the proposed investment's costs and benefits. The Authority considers it reasonable to expect that additional engagement by customers would deliver a similar investment efficiency gain to that achieved by the regulator. This would primarily be through informed discussion and analysis of the proposal's expected costs and benefits.

4.138 The central estimate for the value of more efficient grid investment due to scrutiny of major capex and listed projects is $46 million.

4.139 The central estimate for the value of more efficient grid investment due to scrutiny and related effects of the benefit-based charge is $77 million across the modelling period. This estimate does not include the additional benefits that may result if some major inefficient investments that would have been made under the current TPM would be less likely to occur under a TPM aligned with the proposed TPM guidelines. An example of this category of benefits (related to undergrounding) is discussed below.

Case study: undergrounding

4.140 There has in recent years been advocacy promoting undergrounding of transmission lines around Auckland. Currently, undergrounding projects may not pass the Commerce Commission's Investment Test (as an above-ground project would likely be a lower-cost alternative).[69] However, if the planning requirements changed such that undergrounding was effectively mandated in certain areas, this would mean that the preferred option selected would be either an undergrounded project or a less efficient option (such as a longer overhead route that avoids the area where overhead lines aren't allowed). Under the existing TPM, such an inefficient investment would impose a substantially higher transmission cost on all load customers outside Auckland.

4.141 The Authority's proposal would have the effect of allocating the cost to the Auckland region, which means that Auckland consumers would ultimately bear the costs as well as enjoying the advantages of undergrounding. Under a benefit-based TPM, local bodies with

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68 This estimate is based on analysis of Transpower's RCP3 proposal.

69 The Investment Test is set out in Schedule D Division 1 of the Commerce Commission's Capital Expenditure Input Methodology (Capex IM) for Transpower.

responsibility for planning regulations would need to weigh up the perceived advantages against the expected costs of undergrounding. As a result they would be less incentivised to mandate undergrounding of transmission lines (compared to the status quo, under which the local region does not bear the full cost). It follows that – while undergrounding may still proceed in some cases – overall, *inefficient* undergrounding investment would be much less likely to proceed.

4.142 If it was assumed that undergrounding was between 0% and 50% less likely to proceed under a benefit-based TPM (with a central estimate of 25%) the resulting estimate for the value of this benefit would be around $200 million in avoided costs of investment.[70] Further, in addition to the benefit from avoided investment costs there would also be substantial benefits from avoided consumer welfare costs. This is because under the Authority's proposal, consumers outside Auckland avoid a significant increase in transmission charges. However, in order to be conservative, these potential benefits have not been included in the central estimate for the net benefits of the proposal.

Benefit of a more durable TPM: increased certainty for investors

4.143 The proposal is expected to increase policy certainty for investors, and thereby reduce the cost of investing (that is, reduce the return needed to trigger an investment) in generation, load, and transmission. This is based on evidence that uncertainty increases the value of delaying an investment (so-called real options) and increases the level of private benefits required to trigger an investment.

4.144 For example, research from the United States quantifies, empirically, links between policy uncertainty, reversals and reduced investment.

(a) Fabrizio (2013) found that in the United States policies aimed at increasing investment in renewable electricity generation (Renewable Portfolio Standards) had no effect in states that had reversed earlier measures to restructure the electricity industry. States with more stable policy environments experienced an increase in investment in renewable electricity generation.

(b) Ford (2018) found that a reversal of regulatory settings in the telecommunications industry in the United States in the 2010s – raising the prospect of increased regulatory controls – caused a 20% decline in investment in internet services.

(c) Gulen and Ion (2016) used an index of policy uncertainty throughout the economy to estimate effects of uncertainty on economy-wide investment and found that "a doubling in the level of policy uncertainty is associated with an average decrease in quarterly investment rates of approximately 8.7% relative to the average investment rate in the sample" (p.525). They also found that the dampening effect of uncertainty on investment is highest in industries where investments are typically irreversible.

4.145 These findings are supported locally by researchers at the Reserve Bank of New Zealand who found a negative relationship between uncertainty and macroeconomic measures of economic activity including investment.[71]

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70 This estimate is for the scenario where an undergrounded option was selected. However, as noted above, another possibility is that the preferred option selected is a less efficient above-ground option. We have not estimated the costs associated with a less efficient above-ground option.

71 https://www.rbnz.govt.nz/-/media/ReserveBank/Files/Publications/Analytical%20notes/2018/an2018-01.pdf?revision=7377a00f-a898-43d4-b1b2-5dbff8005bdb

4.146 The Authority's analysis requires specifying the impact (size of shock) of the proposed TPM on uncertainty and specifying the marginal effects of uncertainty on investment costs. The Authority's preliminary estimate of the size of the benefit from increased certainty is $26 million (in net present value terms).

Expanded prudent discount policy

4.147 We have estimated the incremental benefits of the proposed extension to the prudent discount policy (PDP) separately for the two key elements of the extension:

(a) to extend access to a prudent discount to consumers that would disconnect from the grid in favour of alternative supply

(b) to allow for a prudent discount to be agreed for the life of a transmission asset to which the prudent discount applies (instead of the current maximum of 15 years).

4.148 In both cases the magnitude of the benefits of the change depends on the size of the load that might disconnect. That is because, the larger the load disconnecting, the greater the reallocation of transmission charges and the greater the allocative efficiency loss to consumers. So we measure the estimated cost in $/MW of load.

4.149 The proposed extension of access to a prudent discount is expected to result in allocative efficiency benefits to consumers by allowing for the costs of transmission investments to be spread as broadly as possible over the beneficiaries of transmission assets. The cost to consumers from a transmission customer disconnecting from the grid is estimated (using the grid use model described above[72]) by assessing the welfare consequences of consumers facing an increase in charges to recover the revenue no longer paid by the disconnecting customer. The estimated cost is a maximum of $137,000 per MW of load disconnected (2018 dollars). The proposed extension of access would increase the likelihood that consumers could avoid this cost, via a prudent discount.

4.150 We note that this assessment is conservative. This is because we have not assessed the costs of inefficient investment in the infrastructure required for the load party to disconnect. These costs would also be avoided by the extension to the PDP.

4.151 The extension of the prudent discount policy to allow for agreements for the life of a transmission asset would improve the efficiency of prudent discounts by ensuring that they can be set at levels that are no larger than necessary to prevent inefficient disconnection. The value of this improvement is assessed to be $85,000 (present value) per MW of demand to which a prudent discount applies (after discounting for probability of occurrence). We assessed the benefits to consumers based on assumptions about the likely duration of the alternative supply arrangement that a customer is entering into (assumed to be 30 years) and the levels of discount required to induce the customer to enter such an agreement.

4.152 The incremental costs of the expanded PDP have been taken into account in assessing the development, implementation and operation costs of the proposal.[73]

4.153 In the Authority's view the incremental benefits of the changes to the PDP set out above can be expected to exceed the incremental costs of development, implementation and operation that are attributable to the changes to the PDP. We have not estimated the expected number of MW of demand that are expected to be the subject of prudent discount

[72] See *the* discussion under the heading *Modelling the proposed changes to transmission charges*.

[73] See the discussion under the heading *Costs of development, implementation and operation: TPM guidelines*.

agreements under the Authority's proposal. However, in the Authority's view at least one prudent discount agreement is likely to occur due to the extended PDP over the CBA's assessment period. This view is based on the existence of two prudent discount agreements and one notional embedding agreement currently. Even one agreement is estimated to deliver benefits that exceed the costs of revising the PDP (which are discussed below under the heading [Costs of development, implementation and operation: TPM guidelines]).

Costs: assessment methodology and results

4.154 In this section the methodology and results for each of the costs of the proposal are discussed in turn.

Costs of transmission investments brought forward

4.155 Lower charges for peak demand, under the proposal and the alternative proposal, would likely cause increases in peak demand compared to the baseline. This could bring forward transmission investment. While this would be an increase in cost, it would be one that resulted in net benefits for consumers overall; the price signal from the RCPD charge is too strong and inefficiently discourages demand at peak.

4.156 The approach to estimating the cost of bringing forward transmission investments starts with the assumption that current forecast transmission revenue per forecast peak MW represents an optimal ratio. As peak demand increases, additional grid investment is assumed to be needed to maintain this ratio.

4.157 This approach provides an initial cost range of $67 million - $421 million over the period to 2049. This requires an adjustment because:

(a) the numerator (transmission revenue) includes costs that we consider not driven by changes in peak demand (such as unallocated overheads and R&R expenditure).

(b) the denominator (MW of peak demand) is on the low side because it has been determined using a scenario in which inefficient investment in network-scale batteries results in less transmission investment than is expected to occur under the central scenario for the proposal.

4.158 We have adjusted transmission revenue by excluding unallocated overheads – on the basis that these are not driven by changes in peak demand.

4.159 No adjustment has been made to MW of peak demand. Hence, the resulting range of $51 million - $324 million could be considered conservative (that is, potentially overstated). For our central estimate of grid costs brought forward under the proposal, we have adopted the mid-point of this range ($188 million).

4.160 The CBA does not include any costs for distribution network investment brought forward. This is because the focus of the CBA is transmission, not distribution. Accordingly, we have not evaluated either the incremental costs or the incremental benefits associated with the distribution network.

4.161 On the benefit side, we have valued consumption at the price paid at the grid exit point (GXP), rather than the price paid at the customer's point of connection on a local network. This approach excludes the additional consumption benefits relating to the value that consumers place on the distribution network. The Authority is aware that most distribution networks around New Zealand have spare capacity. It follows that incremental distribution costs of the proposal are likely to be low, and in the Authority's view, are likely to be exceeded by the incremental benefits associated with the distribution network.

4.162 The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.

Costs of load not locating in regions with recent investment in capacity

4.163 As noted above, we also considered a potential distortion to investment decisions that could be created by the proposal, if large energy-intensive consumers avoid investing or locating in a region that already has a benefit-based charge and instead gravitate to areas without a benefit-based charge (or with lower benefit-based charges). This effect could include either a large consumer moving its demand, or a large consumer increasing its demand in one region while a large consumer in another region delays increasing its demand.

4.164 Displacement of demand investment would be inefficient if the decision to invest in load in a location with lower benefit-based charges brings forward transmission investment in that location at a speed and scale that exceeds any incremental effects on the need for new transmission investment in the area with higher current benefit-based charges.

4.165 To quantify this effect, we modelled costs from displaced demand investment using a similar approach to that used to model more efficient investment by load. However, we made two key adjustments to the approach to reflect the following considerations.

4.166 First, electricity prices are only one part of a large consumer's decision to choose a location for new investment. Other factors include local amenities, local prices for, and availability of, inputs including land, raw materials, and human capital, local demand, and transport costs. So to be conservative we discounted the amount of the forestalled demand that is displaced to another region due to a benefit-based charge by 50%. The amount of demand displaced to another region is likely to be less than 50%, because these other factors are likely to be more important influences on location decisions than electricity prices. The lower the percentage of demand displaced due to the benefit-based charge, the lower the costs associated with the proposal.

4.167 Second, we took into account the likelihood that demand will gravitate to areas that are least constrained (in terms of grid capacity) as energy prices will be lowest in these locations. We have assumed that demand-driven grid investment in this other region would not be needed for at least 10 years, as displaced demand would not locate in a region where transmission investment was likely to occur in the short to medium term.

4.168 The central estimate for the cost of distortion to investment by consumers is $1 million.

Costs of generation not locating in regions with recent investment in capacity

4.169 The proposal includes a distortion, in so far as the benefit-based charge applies to generation and would disincentivise investment in generation in areas that have benefitted from transmission investment. This cost is estimated as part of estimating the benefit of more efficient grid use discussed above. The benefit of more efficient grid use that is estimated in the CBA is calculated net of the cost of this distortion to location of generation.

Costs of development, implementation and operation: TPM guidelines

4.170 We estimate the costs of development, implementation and operation for the proposal would have a net cost of approximately $26 million (2018 dollars). Applying a +/- 50%

sensitivity to this estimate gives a range of net costs associated with the proposal of \$13 – \$39 million. Further details are set out in Table 8

Table 8 Estimated costs of TPM development, implementation and operation

	Examples	Estimated net cost (mid-point)
TPM development and approval	Policy analysis Modelling Legal fees	$7.83 million[74]
TPM implementation	Computer hardware and software Development and testing User training	$8.61 million[75]
TPM ongoing administration/operation	Data gathering and management Invoicing Customer liaison	$9.26 million[76]

Cost due to a lack of durability

4.171 We also estimated the costs and benefits of a 'future-only' version of the proposal that would apply the benefit-based charge to future grid investment and recover the costs of past investment via the residual charge.

4.172 We estimate that this would result in net benefits of $2.73 billion ($18 million or 0.7% more than the proposal). This difference is not significant in the context of the scale of the benefits estimated, and the estimates' range under different assumptions. Nor does this estimate take into account the costs of a less durable proposal, which have not been quantified.

4.173 The Authority is reporting this result here because the decision on whether or not to apply the benefit-based charge to historical investments is one of the key decisions the Authority needs to make following this consultation.

4.174 A future-only application of the proposal would be significantly less durable than the main proposal (which applies to seven historical investments as well as to future investments). This is because it would require some customers to continue paying for existing assets (many of which are relatively recent) from which they do not benefit, while also paying the full cost of future investments from which they do benefit. This could be perceived as unreasonable and so undermine the regime's durability.

4.175 Arguably, this means that implementing a future-only version of the proposal would put at risk many of the efficiency benefits that the proposal might otherwise be expected to bring. A less durable proposal would mean that the TPM guidelines would be more likely to be overturned and replaced by a different regime (such as a return to the existing TPM).

74 Comprising $4.08 million of Transpower costs, $0.75 million of Authority costs, $1.5 million of stakeholder costs, and $1.5 million of legal costs across the Authority, Transpower and various stakeholders.

75 Comprising $6.44 million of Transpower costs, $0.67 million of stakeholder costs and $1.5 million of legal costs across the Authority, Transpower and various stakeholders.

76 Comprising $8.885 million of Transpower costs and $0.370 million of stakeholder costs.

4.176 This would suggest that the estimated benefits of the future-only version of the proposal need to be discounted to represent the likelihood that it fails to produce an enduring transmission pricing regime. The magnitude of these costs resulting from a lack of durability would necessarily be a matter of judgement. In principle, these expected costs could be quantified and taken into account, but at this stage we have not done so and are not aware of how this could be done in a robust fashion.

4.177 Nevertheless, the Authority's current view is that recovering the costs of seven major historical investments via the benefit-based charge would better promote the efficiency of a TPM based on the proposed guidelines. This view is based on the qualitative analysis set out in appendix B.[77] In the Authority's view, the lack of durability of a future-only version of the proposal means that it would result in fewer net efficiency benefits compared to the main proposal. That is, the Authority considers that in efficiency terms the qualitative factors it has outlined in this paper outweigh the difference in quantified benefits between the proposal and the future-only version of the proposal. We consider this would be the case even if the difference in quantified benefits was in the order of several hundred million dollars.

Price cap

4.178 The interim cap on transmission charges has a modest negative effect on the allocative efficiency of the TPM proposal. The price cap makes the proposal's estimated improvement in consumer welfare decline by $1 million in present value terms. This is an effect on allocative efficiency related to the fact that for most consumers (those whose charges are not limited by the cap) the price cap causes transmission charges to be higher than they otherwise would be. It is estimated using the grid use model described above.[78]

4.179 It is assumed that funding of the price cap has no effect on the efficiency of investment in generation. This is a reasonable assumption given that the increase in transmission charges paid by generation customers caused by part-funding the price cap is small.

4.180 In the Authority's view the price cap would have net benefits for consumers, despite the fact that we have quantified a net cost in allocative efficiency. The cap is a transitional measure that protects consumers from a price shock, provides certainty on the level of charges in advance and allows businesses time to adjust to the new charges. One important expected benefit of the cap is that, in protecting consumers, it would make the proposal more acceptable, which would facilitate implementation of the proposal in order for the modelled efficiency gains to be realised. In the Authority's view this benefit alone is likely to exceed the allocative efficiency costs of the price cap that are noted here.

Sensitivities

4.181 We have undertaken sensitivity analysis on a number of key input assumptions that have the potential to affect the results of the modelling.

4.182 The sensitivity analysis undertaken for benefits relating to grid use and battery investment is summarised in Figure 9, which shows the range of variation in the net long-term benefits to consumers based on changes in each variable of interest. The central estimate in the central scenario is net benefits of $2.7 billion.

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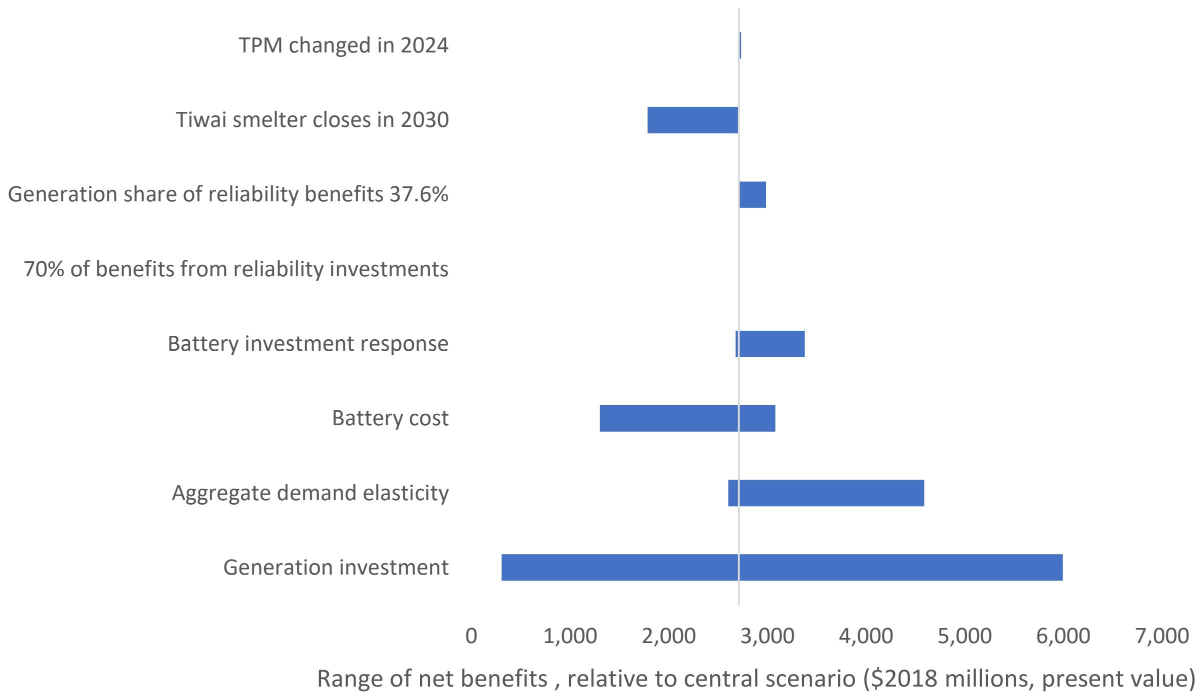
77 See discussion in appendix B. Other potential benefits from applying the benefit-based charge to historical investments include the provision of information about the value of future investments, and the discouragement of rent-seeking behaviour in the future (as it would signal to the market that the Authority is not willing to grandparent historical inefficient regulations). These effects have not been quantified.

78 The grid use model is described under the heading Modelling the proposed changes to transmission charges.

Figure 9 Sensitivity of net efficiency results for grid use and battery investment



4.183 As illustrated in the chart, results for grid use and battery investment are sensitive to assumptions about battery costs, aggregate demand elasticity and generation investment. Results are not sensitive to assumptions about the date the possible new TPM is introduced, the proportion of the benefit-based charge that is allocated to generation or the split between reliability investment and constraint-relieving investment.

Date assumed for introduction of new TPM

4.184 The Authority's CBA is calculated based on the assumption that a new TPM is implemented in 2022. This assumption has been used as a placeholder, given that the Authority has not yet formed a firm view on the likely date that any new TPM would be introduced.

4.185 This assumption may not be correct, but as Figure 9 illustrates, it has little effect because the majority of the benefits and costs of the proposal occur in later years.

Tiwai point shut-down

4.186 CBA results are sensitive to assumptions about the continued operation of the aluminium smelter at Tiwai point.

4.187 We considered a scenario in which the smelter closes in 2030 (under both the status quo and the proposal). This would reduce the net benefits of the proposal for two reasons. First, it would significantly increase charges for remaining industrial load at the Tiwai backbone node (though the guidelines do provide a mechanism for adjusting the charges in specific circumstances). Second, the large reduction in demand would mean that generation investment that occurs late in 2033 in the central scenario, reducing prices during periods of peak energy demand, would not occur.

4.188 However, the central assumption is that the smelter continues to operate throughout the modelling period. The Authority considers that this is reasonable as it avoids speculating on closure dates and it does not *increase* the benefits associated with the proposal. We did not incorporate any other assumptions in relation to this point because a single estimate of the direction of effect provides assurance that the assumption of the smelter continuing to operate does not unduly bias the CBA.

Benefit-based charge allocation

4.189 A key assumption is the proportion of revenue recovered through the benefit-based charge that is allocated to generation customers (as opposed to load customers). This is related to the proportion of investment cost recovered through the benefit-based charge that is assumed to be incurred for reasons of improving reliability (as opposed to reasons of relieving constraints).

4.190 CBA results are not very sensitive to this assumption.

4.191 As nobody knows the proportions of future investments in the period to 2049 that will be made for reasons of reliability versus reasons of reduction of losses and mitigation of constraints, we assumed:

(a) 50% of the value of the investments is allocated based on the shares of the loss and constraint excess (LCE) estimated to accrue to each of the 14 areas in the model

(b) 50% of the value of the investments is allocated based on shares of maximum demand and injection, to reflect relative benefits from reliability, with generators' share set at 1% to reflect a lower value of reliability to them (assumed \$200/MWh) compared to consumers (assumed \$20,000 per MWh[79]).

4.192 The second of these has the effect that load customers receive a substantially higher share of benefit-based charges over the CBA modelling period than generators.

4.193 A scenario was considered in which benefit based-charges from reliability-related investments are allocated 37.6% to generation and 62.4% to load. This would mean the CBA's benefits would rise to near \$3 billion.

4.194 We also considered a scenario in which 70% of revenue recovered through benefit-based charges is for reliability-related investments. This would have no discernible impact.

Drivers of investment in batteries

4.195 A key assumption is the degree of sensitivity of investment in network-scale batteries to changes in their cost. That is, when the cost of batteries falls and becomes a profitable investment choice, how rapidly investors will respond by investing in batteries. In practice, if batteries are 10% cheaper than paying for electricity at peak, it is unlikely to be possible for all transmission customers to replace their peak demand with battery-stored energy. This assumption limits the magnitude of investment response.

4.196 CBA results are sensitive to this because small changes in this assumption can have a large effect on the speed of penetration of battery investment and cause higher costs under the baseline that are avoided under the proposal.

4.197 The central assumption is that if batteries are 10% cheaper than peak grid demand then transmission customers will invest in a 5% increase in local distributed energy resources (0.5). This seems reasonable because it prevents the model from assuming large amounts of investment, which is likely to be implausible due to physical limits affecting the availability of batteries and the speed at which they can be installed.

79 This assumption reflects the value for expected unserved energy set out in the Code: Schedule 12.2, clause 4.

4.198 A range of sensitivities was considered: at the top end of the range, assuming a value of 2 – that if batteries are 10% cheaper investors would increase their local capacity of distributed energy resources by 20% – would mean the CBA's benefits would rise to $3.4 billion.

4.199 At the bottom end of the range, assuming a value of 0.25 would mean the CBA's benefits would fall to just below $2.7 billion.

The declining cost of batteries

4.200 Another key assumption is the rate of decline in the capital cost of network-scale batteries.

4.201 CBA results are sensitive to this because changes in this assumption can have large effects on the speed of penetration of battery investment and cause higher costs under the baseline that are avoided under the proposal.

4.202 The central assumption is that costs decline by 7% per annum. This seems reasonable because Bloomberg New Energy Outlook 2018 projects battery costs to decline by 66% over 13 years (an average annual decline of approximately 8% per year).

4.203 A range of sensitivities was considered: at the top end of the range for benefits, assuming an 8% rate of decline would mean the CBA's benefits would rise to $3 billion.

4.204 At the bottom end of the range, assuming a 4% rate of decline would mean the CBA's benefits would fall to $1.3 billion.

Price elasticities of demand

4.205 Consumer welfare changes are affected by how much people pay in transmission charges and other electricity supply costs, as well as consumers' price elasticities of demand for electricity. In relation to price elasticities, other things being equal:

(a) a consumer with a high price elasticity of demand for electricity will face a higher welfare loss from an increase in the cost of electricity than will a consumer with a lower elasticity of demand

(b) for any reallocation of transmission charges, if electricity prices increase for consumers with lower price elasticities of demand for electricity and decrease for consumers with higher price elasticities of demand for electricity, the reallocation of transmission charges will result in a net consumer welfare gain.

4.206 The central assumption is that the demand elasticity for distribution-connected consumers is -0.11 and for transmission-connected consumers is -0.02. These elasticities reflect the responsiveness of annual demand to a change in aggregate (annual weighted average) electricity prices.

4.207 A range of sensitivities was considered with respect to this factor. At one end of the range we tested the effect of assuming greater demand responsiveness. This meant the CBA's benefits would rise to $4.6 billion based on the following assumed elasticities:

(a) transmission-connected consumers (-0.11)

(b) distribution-connected consumers (-0.2).

4.208 We also tested the effect of assuming lower demand responsiveness for distribution-connected consumers (-0.09), which meant the CBA's benefits would fall to $2.6 billion.

4.209 The Authority considers that the central assumption is reasonable. It is an estimate based on recent historical data from the wholesale market. The Authority's current view is that this assumption is likely to be conservative, given that load is expected to become more price-responsive in the future than it has been in the past. This is because:

(a) currently emerging and prospective load control technologies are increasingly able to facilitate real-time responses to system congestion

(b) the real-time pricing (RTP) project will introduce nodal-level scarcity pricing and thereby potentially stimulate a significant expansion in real-time demand response.

Generation investment

4.210 There are two key assumptions relating to generation investment. The first is about the amount of generation capacity that is not offered at its short-run marginal operating cost, due to factors such as transient market power and generators' assessment of the value of stored water in the hydro-lakes. This assumption is relevant to the tightness of supply conditions in the wholesale electricity market.

4.211 CBA results are sensitive to this factor because it affects the level of wholesale electricity prices. Modelled results for the timing of commissioning of new generation are highly sensitive to this assumption (and to the assumption on new generation investment discussed below). This means that the level of wealth transfers (for example, from generators to consumers) caused by modelled future wholesale price changes is also highly sensitive to these assumptions.

4.212 The central assumption is that market supply conditions are consistent with those observed in the 12 months to the end of August 2018. This is the assumption in the central scenario.

4.213 The second key assumption in this area is the assumed maximum number of generation investments that could take place in any one year. Investors are assumed to be aware of other potential generation investments, and to actively avoid making an investment at the same time as other investments, because of the impact of investments on future wholesale prices.

4.214 CBA results are sensitive to this factor because if high wholesale electricity prices cause large scale generation investment (multiple projects), there will be a prolonged reduction in prices following the increase in supply.

4.215 The central assumption is that, at most, two generation investments could take place in a year. This seems reasonable because we observe that only occasionally does more than one generation investment take place within a year, if wholesale prices are high enough. This is sufficiently uncommon that it is implausible to assume more than two in a year.

4.216 A range of sensitivities was considered. At the top end, CBA benefits rise to $6 billion based on assuming:

(a) very slack initial supply conditions (that is, plenty of generation capacity available relative to load)

(b) a maximum of five generation investments per year.

4.217 At the bottom end, CBA benefits fall to $0.3 billion based on assuming:

(a) extremely tight initial supply conditions

(b) a maximum of one generation investment per year.

4.218 Modelled future wholesale price changes show a particular sensitivity to assumptions around generation investment, as discussed earlier.

Sensitivity to combination of variables

4.219 With unfavourable assumptions across a range of variables, a plausible lower-bound estimate for benefits is around $201million, and a plausible upper bound for benefits is $6.4 billion.

Q3. Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?

Summary

4.220 The Authority's assessment is that the proposal would deliver substantial benefits for New Zealand's economy and that the central estimate of $2.7 billion reported in this chapter, within the range of $0.2 billion and $6.4 billion, is a realistic estimate of net benefits. This figure excludes some benefits that – if they were able to be quantified – would increase the value of the estimate. The exclusions include:

(a) unquantified avoided inefficient investment in emerging technology by mass-market consumers

(b) avoided costs of undergrounding.

4.221 The Authority considers that the main costs of the proposal have been taken into account.

4.222 As noted above, we have not quantified one of the main costs of a variant of the proposal – applying the benefit-based charge to future investments only. This main cost is the lack of durability of such a proposal, which would mean unrealised efficiency gains. As noted above, the Authority considers these costs to be very substantial.

Consideration of the Authority's statutory objective

4.223 The Authority's statutory objective in section 15 of the Electricity Industry Act is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers". In the context of transmission pricing, the Authority has interpreted this statutory objective[80] to mean that the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers.[81]

4.224 The Authority's proposal is primarily targeted at the efficiency limb of the statutory objective. This is because the proposal promotes efficient investment in and operation of the electricity industry. There is a trade-off between a high level of granularity in providing benefit-based charges and the costs of developing and administering the methodology. There is also a trade-off between dynamic efficiency, which the Authority considers supports benefit-based charges, and operational efficiency where charges need to avoid distorting operational decisions. The Authority considers that the proposal promotes efficient investment and operation while seeking to minimise inefficient avoidance through the inclusion of ex-ante charges that are aligned to benefits and a historical-AMD-based residual charge, both of which promote efficient operation.

4.225 Based on the CBA analysis presented in this chapter, we have estimated the gross efficiency benefits of the proposal at $2.9 billion, and costs of $215 million . On this basis the Authority concludes that the proposal has net positive effects in terms of the efficiency

80 Interpretation of the Authority's statutory objective, 14 February 2011, available at https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011

81 For further discussion of this point, see Appendix D.

limb of the statutory objective, estimated at $2.7 billion, within a range of $0.2 billion and $6.4 billion. . Further, the net benefits of the proposal are greater than the net benefits of the alternative to the proposal, at $1.85 billion, within a range of $0.1 billion and $4.7 billion.

4.226 More generally, the Authority considers the proposal also promotes the reliability and competition limbs of the Authority's objective (in ways that link to efficiency):

(a) it promotes reliability principally because it charges the beneficiaries of reliability investments, thus promoting efficient levels of reliability, as parties will only seek a level of reliability they are willing to pay for

(b) it promotes competition because benefit-based charges promote efficient choices between transmission and transmission alternatives such as gas transmission, demand response and distributed generation.

4.227 The Authority has not identified any significant problems with its proposal in relation to reliability and competition.

4.228 On this basis the Authority considers that the proposal promotes the statutory objective.

Q4. Do you have any comments on the matters covered in chapter 4?

5 Impact on transmission charges

Changes in customer charges as a result of the proposal

5.1 The proposal would deliver significant benefits to consumers compared to the current TPM.

5.2 This chapter presents estimates of the initial impact of rebalancing the charges between transmission customers as a result of the proposal. The changes do not mean an increase in the total amount that Transpower would be charging customers. However, in the event that new transmission pricing is introduced, some customers will be charged more, and some less, than they would under the current TPM. This is the consequence of:

- allocating the depreciated cost of seven major grid investments to those who benefit
- distributing other costs across all load customers through the residual charge.

5.3 In most areas where charges would increase initially, the impact in the first year on the average residential electricity bill is expected to be low – estimated at an average of $21 per year. To reassure households and businesses they would not face large cost increases, the proposal includes a cap on the amount that a transmission customer's price can rise.

5.4 This initial rebalancing of transmission charges is part of a proposal that delivers long-term benefit for consumers as estimated by the CBA. That shows a clear net benefit to consumers, and in addition indicates that, after allowing for electricity price reductions that are modelled to occur in future, consumers in almost all regions would be significantly better off compared to continuation of the current TPM.

Assumptions

5.5 The modelling and assumptions are explained in detail in appendix H.

5.6 The estimated charges assume that the proposal would be implemented in 2022 (ie, pricing year 2021/22)[82], and that in 2022 Transpower's maximum allowable revenue (MAR) would be $848 million[83]. Of this, a net $679 million (i.e. net of estimated loss and constraint excess revenue) would be reallocated through the proposed benefit-based and residual charges, based on the status quo where:

- $99 million would be recovered through the HVDC charge
- $580 million would be recovered through to the interconnection (RCPD) charge.

5.7 Other transmission charges, in particular connection charges, are not expected to change much as a result of the proposal, [84] and are thus not discussed any further.

5.8 The estimates for benefit-based charges rely on the expected revenues related to each of the seven major investments in 2022, provided on a best endeavours basis by Transpower.

5.9 The analysis also assumes that no new Transpower investments would be made by 2022; however, this could occur, in which case it would be reflected in the benefit-based charge.

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82 As set out in chapter 6, implementation could be later. However, estimates for 2022 provide a reasonable guide to the initial impact of our proposal on charges. Later implementation would reduce the benefit-based charge from existing investments.

83 Commerce Commission, Transpower's individual price-quality path from 1 April 2020, Draft decisions and reasons paper, 29 May 2019, Table X1. The Commerce Commission's final decision on Transpower's regulated revenue for regulatory control period 3, from 2020-21 to 2024-25, is expected in November 2019.

84 The Authority's proposal is that, apart from the matters covered in the Additional Components, the current guidelines for charging for connection assets would be largely retained.

The impact of change is smaller than in 2016

5.10 The year-one change in transmission customers' charges due to the proposal compared to charges expected in 2022 under the current TPM is expected to be much less than was proposed in 2016 (the second issues paper). For example, Vector's charges in 2016 were modelled to rise by $59 million, whereas on current estimates Vector's charges would rise by $7 million due to the proposal. By contrast, Meridian's charges were modelled to fall by $57 million, but under the current proposal they are estimated to fall by around $29 million.

5.11 The impact of the rebalancing of charges is now smaller than estimated in 2016 because:

(a) Transpower's expected MAR for 2022 has dropped due to a significant drop in the weighted average cost of capital (WACC), which reflects the fall in long-term interest rates since its WACC was previously set in 2014

(b) fewer pre-2019 investments are proposed to be subject to the benefit-based charge

(c) the seven major investments that would be included have depreciated since 2016, and a lower share of charges would be allocated through the benefit-based charge (27% instead of 36% in 2016)

(d) instead of only the (relatively wet) 2014 year, the modelling uses electricity data for July 2014 to June 2018, which is more representative of hydrology patterns over the last 10 years and thus better reflects the distribution of benefits from the HVDC

(e) a number of technical modelling assumptions are different to 2016 in significant ways. For example, in estimating long-term benefits from each of the seven major investments, we have assumed an impact on wholesale electricity prices in the absence of such investment that we consider is more realistic than the (higher) price assumption used for short run scenarios. This tends to dampen the benefits of the seven investments. The reasons and impacts are explained in Appendix H.

Impact by customer group

5.12 Table 9 summarises a breakdown of the two charges by customer group under a TPM that is consistent with the proposed guidelines, and before applying a price cap. It illustrates the initial impact on charges as a result of the proposal. Over time, amounts would change as assets depreciate and new investments are made and assigned via benefit-based chares.

Table 9: Estimated charges in 2022 by customer group, before price cap[85]

Customer group[86]	Benefit-based $m	Residual $m	Proposal Total $m	Status Quo $m	Difference $m
North Island generation	15.8	5.0	20.8	7.4	+13.4
South Island generation	57.2	3.4	60.6	90.6	-30.0
Upper North Island distributors	57.0	139.3	196.3	190.4	+5.9
Lower North Island distributors	21.8	154.5	176.4	187.4	-11.0
South Island distributors	18.7	132.2	150.9	138.6	+12.3
Major industrials	14.7	59.4	74.1	64.7	+9.4

85 All transmission charges set out in this chapter are indicative estimates only.

86 The South Island (grid-connected) generation group is defined here as covering Contact Energy and Meridian. Upper North Island distributors comprise Northpower, Top Energy, Vector, and Counties Power. The Lower North Island distributors group cover the other distribution networks in the North Island,

5.13 Table 10 and Figure 10 show the charges by customer group after applying the price cap (the price cap is discussed in more detail below and in appendix B).

Table 10: Estimated (capped) transmission charges in 2022 by customer group

Rounding means rows and columns may not add exactly

Customer group	Status Quo $m	Proposal Total $m	Cap fund /(support)	Capped Proposal Total $m	Total Change
North Island generation	7.4	20.8	0.5	21.3	13.9
South Island generation	90.6	60.6	1.5	62.0	-28.6
Upper North Island distributors	190.4	196.3	4.7	201.1	10.6
Lower North Island distributors	187.4	176.4	4.0	180.4	-6.9
South Island distributors	138.6	150.9	3.0	153.9	15.4
Major industrials	64.7	74.1	(13.8)	60.3	-4.4
Total	**679.1**	**679.1**	**0**	**679.1**	**0**

5.14 Key drivers of proposed changes to capped charges compared to the current TPM are:

(a) Benefit-based charges:

(i) Charges for upper North Island distributors rise to reflect their benefit from the seven major grid investments, whereas under the current TPM load customers are charged on their offtake during peak times regardless of location.

(ii) South Island generators would no longer pay 100% of the HVDC charge, but a reduced share that reflects their share of benefits from the HVDC.

(b) Residual charges are proposed to be based on a gross measure of demand, whereas the current interconnection charge is based on a measure net of local generation. Networks with substantial distributed generation – and load customers that have shifted their use away from the top 100 peak periods – would see charges rise.

Figure 10: Estimated (capped) charges in 2022 by customer group ($m)

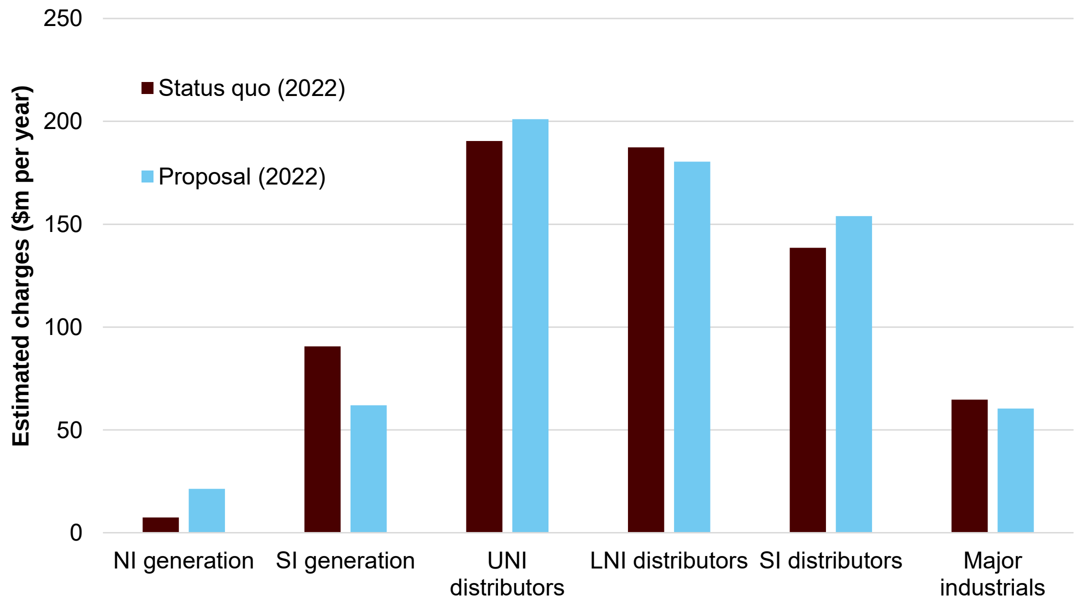


Table 11: summary analysis of changes in capped charges by customer group

Customer group	Explanation
North Island generation	The share of transmission charges **rises** from around 1% to 3%. Charges increase 188% due to benefit-based charges in line with North Island generators' share of benefits from grid investment. Currently North Island generation pays no interconnection charge (except as consumers).
South Island generation	The share of transmission charges **falls** 32% from around 13% to 9%. These generators would no longer pay 100% of the HVDC charges. These costs would be shared with: North Island industrials and distributors, who benefit from access to South Island generation; and with South Island distributors and the smelter, who benefit from access to North Island generation during dry periods. South Island generators' benefit-based charge would include a share for North Island transmission assets. For example, the North Island Grid Upgrade improves South Island generators' access to North Island consumers.
Upper North Island distributors	The share of transmission charges **rises** 5.6% from around 28% to 30%. The increase in transmission charges in 2022 reflects the benefits to this region from a significant share of the seven major investments. Their share of residual charges reflects their relatively moderate peak demand historically compared to the Lower North Island.
Lower North Island distributors	The share of transmission charges **falls** 3.7% from around 28% to 27%. In part this is because this group of distributors attracts just 12% of charges related to the seven major investments. However, this group does attract a relatively high share of residual charges, reflecting the highest measured share of electricity consumption compared to other regions. Also, this demand measure is gross of local generation, whereas currently peak demand is a net measure.
South Island distributors	The share of transmission charges **rises** 11% from around 20% to 23%. South Island distributors' transmission charges would rise 11.1% compared to under the current TPM. This is mainly because in general they are peakier users than other groups, and because of the proposed gross measure of demand to calculate the residual charge (which affects networks such as Buller, Westpower, and Tasman and Otago).
Major industrials	The share of transmission charges **falls** 6.7% from around 10% to 9%. Charges reduce by $11 million for the Tiwai smelter, but this is offset by a $6.9 million increase in transmission charges mainly for North Island based firms such as NZ Steel, Norske Skog and Pan Pacific. (See Table 12) Charges for industrials excluding the smelter would rise by $21.8 million, but for the cap, which has been proposed to protect against price shock and inefficient exit by firms. The significant support provided by the price cap for this group of consumers reflects they have been effective at responding to current incentives to avoid the RCPD charge. The cap is proposed to progressively lift for this group of customers.

Impact by transmission customer

5.15 Table 12 and Figure 11 below show the estimated charges for each transmission customer in 2022 under the current TPM and under a TPM consistent with the proposed guidelines, including the price cap.[87]

Table 12: Breakdown of estimated 2022 charges for each customer

Customer	Status quo $m	Benefit-based $m	Residual $m	Proposal pre cap $m	Pay to / (receive from) cap $m	Proposal post cap $m	Change in charges $m
Distributors							
Alpine Energy	11.3	1.4	8.9	10.3	0.2	10.5	-0.8
Aurora Energy	18.8	2.3	19.6	21.9	0.5	22.5	3.6
Buller Electricity	0.6	0.1	1.3	1.4	(0.3)	1.1	0.6
Centralines	1.9	0.3	1.1	1.4	0.0	1.4	-0.4
Counties Power	10.4	3.0	7.2	10.2	0.2	10.4	0.1
Eastland Network	4.9	0.4	4.2	4.6	0.1	4.7	-0.2
Electra	5.6	1.1	6.3	7.4	0.2	7.6	2.0
Electricity Ashburton	12.9	0.9	10.3	11.2	0.3	11.5	-1.5
Electricity Invercargill	8.1	0.9	5.7	6.6	0.2	6.8	-1.3
Electricity Southland[88]	0.5	0.0	0.3	0.3	0.0	0.3	-0.2
Horizon Energy	2.7	0.4	5.3	5.7	(0.1)	5.7	2.9
MainPower	9.5	1.4	8.8	10.2	0.2	10.4	1.0
Marlborough Lines	5.9	0.8	4.1	4.9	0.1	5.0	-0.9
Nelson Electricity	0.7	0.1	0.8	0.9	0.0	0.9	0.2
Network Tasman	7.7	1.2	8.7	9.9	0.2	10.1	2.4
Network Waitaki	3.0	0.6	3.9	4.5	0.1	4.6	1.6
Northpower	14.2	5.4	10.6	16.1	0.4	16.5	2.2
Orion	46.9	7.4	45.8	53.3	1.3	54.5	7.7
OtagoNet JV	4.0	0.7	4.2	4.8	0.1	5.0	0.9
Powerco	74.0	8.4	58.9	67.3	1.6	68.9	-5.1
Scanpower	1.2	0.2	0.9	1.0	0.0	1.1	-0.2
The Lines Company	3.3	0.5	4.3	4.9	0.1	5.0	1.7
The Power Company	7.0	0.8	6.5	7.2	0.2	7.4	0.4
Top Energy	3.8	1.0	3.9	4.9	0.1	5.0	1.2
Unison Networks	23.1	1.6	20.4	22.0	0.5	22.5	-0.6
Vector	162.0	47.6	117.5	165.2	4.0	169.1	7.1
Waipa Networks	6.0	0.9	4.2	5.1	0.1	5.3	-0.8
WEL Networks	17.9	2.2	16.5	18.7	0.4	19.2	1.3
Wellington Electricity	46.7	5.8	32.4	38.2	0.9	39.1	-7.6
Westpower	1.7	0.2	3.4	3.5	(0.2)	3.4	1.7

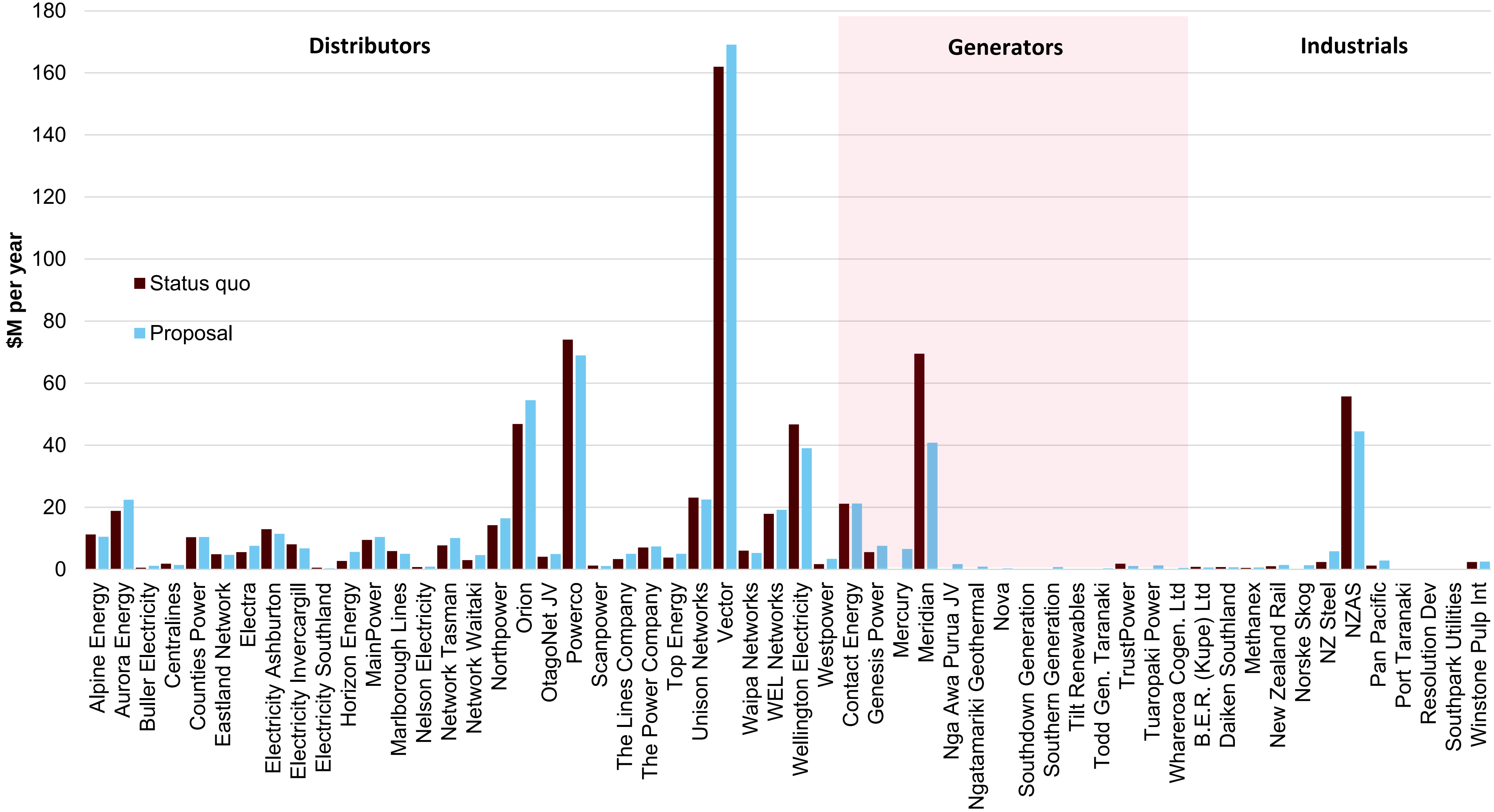
[87] The guidelines set out a principle that in allocating the residual charge, Transpower should adjust the allocation where a customer has experienced a substantial change to demand due to factors over which they have no control (such as an industrial consumer connected to a distribution network shutting down). We have not made any such adjustments in calculating the indicative charges set out in this chapter. However, we would expect any appropriate adjustments to be made before Transpower sets charges under any new TPM.

[88] Electricity Southland is an electricity network asset company that was formed in March 1995 by Electricity Invercargill Ltd and The Power Company Ltd. It owns the Lakeland electricity network at Frankton in the Queenstown Lakes area (and an embedded network in Wanaka).

Customer	Status quo $m	Benefit-based $m	Residual $m	Proposal pre cap $m	Pay to / (receive from) cap $m	Proposal post cap $m	Change in charges $m
Generators							
Contact Energy	21.1	19.0	1.7	20.7	0.5	21.2	0.1
Genesis Power	5.6	6.4	1.0	7.4	0.2	7.6	2.0
Mercury	0.0	5.0	1.4	6.4	0.2	6.6	6.6
Meridian	69.5	38.2	1.7	39.9	1.0	40.8	-28.7
Nga Awa Purua JV	0.0	1.4	0.3	1.7	0.04	1.7	1.7
Ngatamariki Geothermal	0.0	0.8	0.1	0.9	0.02	0.9	0.9
Nova	0.0	0.1	0.2	0.3	0.01	0.3	0.3
Southdown Generation	0.0	0.0	0.1	0.1	0.00	0.1	0.1
Southern Generation	0.0	0.1	0.6	0.8	0.02	0.8	0.8
Tilt Renewables	0.0	0.1	0.1	0.2	0.00	0.2	0.2
Todd Gen. Taranaki	0.0	0.3	0.0	0.3	0.01	0.3	0.3
TrustPower	1.8	0.9	0.1	1.0	0.03	1.1	-0.8
Tuaropaki Power	0.0	0.5	0.7	1.3	0.03	1.3	1.3
Whareroa Cogen. Ltd	0.0	0.04	0.4	0.5	0.01	0.5	0.5

Customer	Status quo $m	Benefit-based $m	Residual $m	Proposal pre cap $m	Pay to / (receive from) cap $m	Proposal post cap $m	Change in charges $m
Industrial customers							
B.E.R. (Kupe) Ltd	0.8	0.1	0.5	0.6	0.0	0.6	-0.2
Daiken Southland	0.7	0.2	0.5	0.7	0.0	0.7	0.0
Methanex	0.5	0.1	0.5	0.6	0.0	0.6	0.1
New Zealand Rail	1.0	0.2	2.4	2.7	(1.2)	1.4	0.4
Norske Skog	0.0	0.3	6.4	6.8	(5.4)	1.4	1.3
NZ Steel	2.4	2.3	9.6	11.9	(6.1)	5.8	3.5
NZAS	55.7	10.5	32.9	43.4	1.0	44.4	-11.3
Pan Pacific	1.2	0.6	4.4	5.0	(2.2)	2.9	1.7
Port Taranaki	0.011	0.002	0.014	0.016	0.000	0.016	0.005
Resolution Dev	0.004	0.002	0.016	0.018	(0.012)	0.006	0.002
Southpark Utilities	0.006	0.000	0.009	0.009	0.000	0.010	0.003
Winstone Pulp Int	2.3	0.4	2.1	2.4	0.1	2.5	0.1

Figure 11: Estimated (capped) transmission charges in 2022 for each customer ($m)



Breakdown by charges

Benefit-based charge allocation in 2022

5.16 The benefit-based charge would initially cover the depreciated value of the seven recent major investments listed in schedule 1 of the proposed guidelines. In 2022 the total amount charged for these investments is estimated to be $185.2 million.

5.17 Over time, the amount allocated via the benefit-based charge to each transmission customer would change as the recent major investments depreciate further. Also as new transmission investments are made and assets are replaced or refurbished, the costs of that new expenditure would also be allocated via the benefit-based charge.

5.18 Figure 12 illustrates the estimated distribution of benefits for the seven major investments, which are reflected in the proposed allocations in schedule 1 of the draft guidelines. The larger the dot, the larger the share. Red circles signify the customer is (predominantly) a generator and blue circles (predominately) load.[89]

5.19 For example, as shown in the map, it is estimated that central North Island generators and upper North Island distributors and direct connected customers are the major beneficiaries from the Wairakei Ring. These parties would pay the majority share of the (now depreciated) costs through the benefit-based charge.

5.20 As another example, the map illustrates that Vector, Northpower and Top Energy are estimated to be the major beneficiaries of the North Island Grid Upgrade project in terms of access to lower electricity prices and improved reliability. The Authority's modelling values the benefits of this investment at around $137 million per annum. This project had an approved cost of around $876 million, and Transpower currently estimates it would charge approximately $60.5 million for it in 2022. Under the proposal, these three networks would share over 50% of that charge. However, generators in both the North and South Island also benefit from this asset by being able to access the upper North Island markets, which would be reflected in benefit based charges.

5.21 Conversely, some other distributors benefit relatively little from most of the seven major investments. Figure 12 and Table 12 show that Electricity Ashburton, Buller Electricity, Network Tasman, Nelson Electricity, Alpine Energy, and Eastland Networks fall in this category. Accordingly, they would have a relatively low benefit-based charge in 2022. This could change over time if Transpower were to invest in assets that would benefit those customers.

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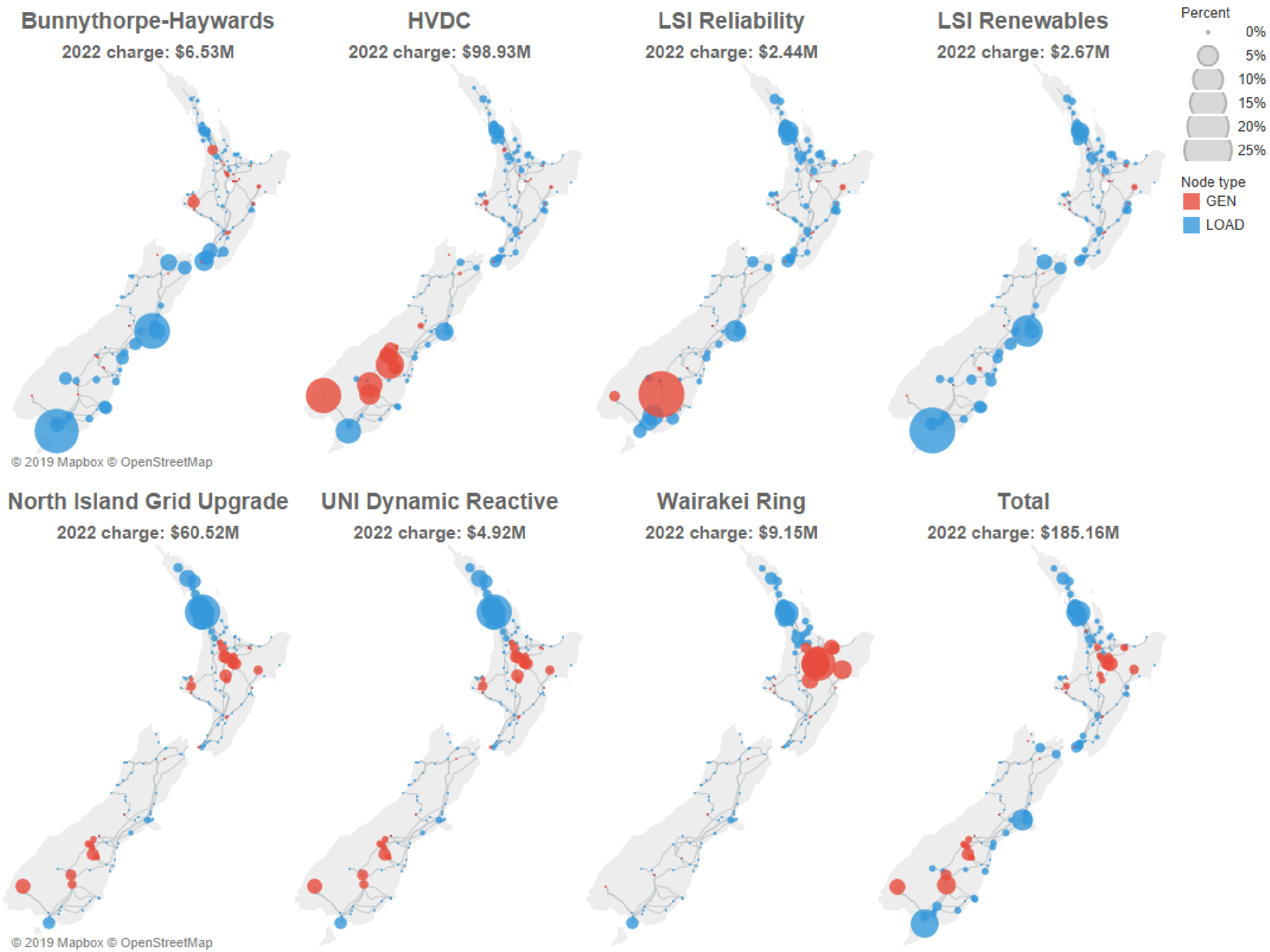
89 Nodes at which load customers offer interruptible load are classified as generation, and are coloured red.

Figure 12 Proposed TPM guidelines schedule 1 allocation of benefit for seven recent major investments

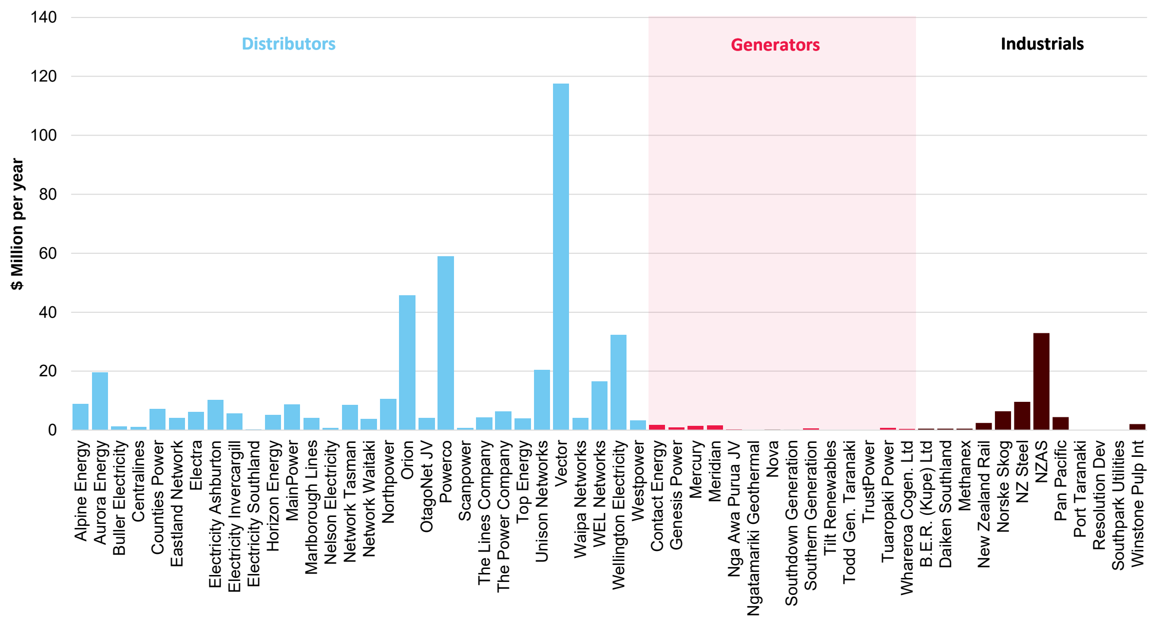


Residual charge allocation in 2022

5.22 Figure 4 illustrates the estimated allocation of the residual charge, which is proposed to be allocated using a measure of historical AMD.

5.23 Differences in the allocation of the residual charge between customers are generally less pronounced when the charge is expressed in terms of $/MWh. One explanation for the differences is the extent to which the customers have a high load factor (as NZAS does) or whether the load factor is low and 'peaky' (as New Zealand Rail's is).

Figure 13: Residual charge for each of Transpower's customers ($m for 2022)



Effect of the transitional price cap in 2022

5.24 As Figure 11 above showed, the rebalancing of charges under the proposal would mean that some customers would pay more and others less than they would under the status quo.

5.25 Changes in charges are estimated to generally be modest (with exceptions – see Table 12). To reassure household and businesses that they will not experience electricity bill shocks, the proposal provides for a 3.5% cap on increases in total electricity bills as a result of a new TPM consistent with the proposed guidelines.

5.26 A cap, recommended by submissions to the 2016 issues paper, would give households and businesses certainty on the level of charges in advance and allow industrial customers time to adjust to the new charges.[90]

5.27 The cost of this cap is $15.4 million, in the context of total charges of $679 million. It would be spread among other distributors, generators and direct-connect customers, with the share determined on the basis of their total charges.

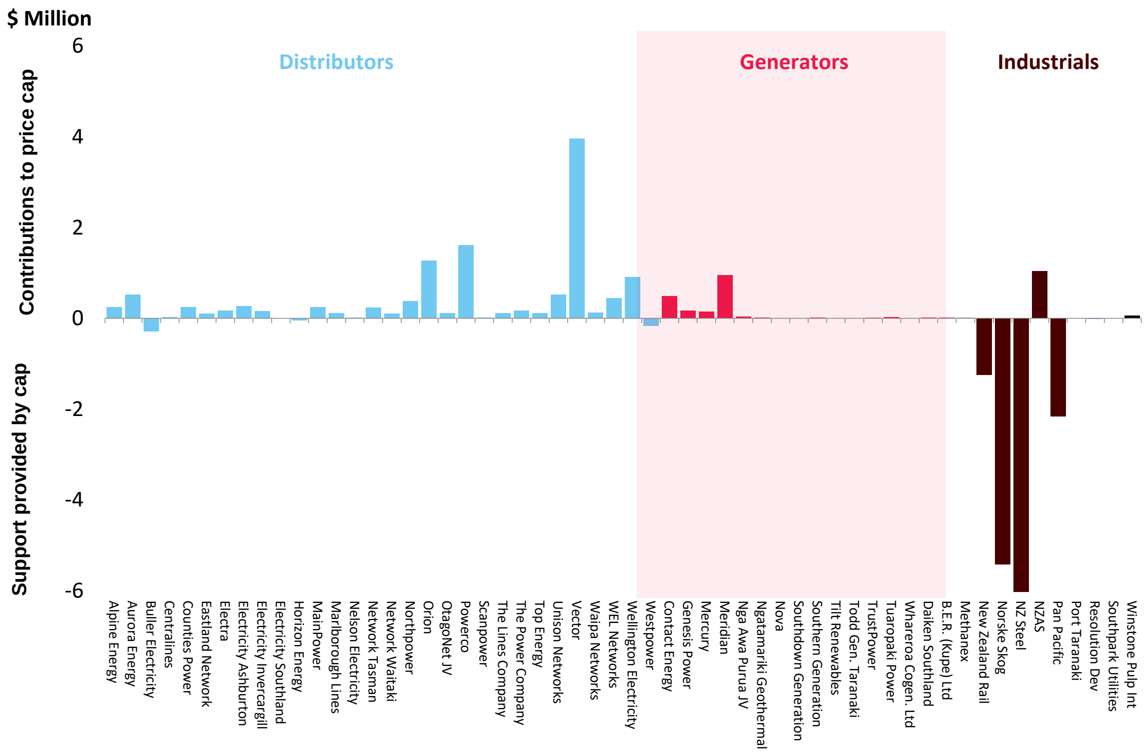
90 See the draft guidelines for how it is proposed this would be calculated. The cap would be 3.5% of the total electricity bill of consumers within each distributor's network, or of an estimate of the electricity bill of directly-connected industrial customers. The cap would start lifting for the latter group after five years.

5.28 Based on current estimates of proposed charges, this price cap would protect just three distributors (Buller, Horizon, and Westpower). This reflects the modest impact of the proposal.

5.29 However, a number of the direct-connect industrial customers would receive significant support from such a cap. That reflects these customers currently pay little, if anything, in terms of transmission charges, as they have responded to current incentives. The cap is proposed to progressively lift after five years for this group of customers so that they would pay full charges in future.

5.30 The indicative impact of applying the cap in the first year is shown in Figure 14, and detailed in Table 12 above. Where customers fund the cap, their contribution would be 2.4% of their total (pre-cap) charges. Appendix B presents more detail and specific consultation questions on the need for and features of the price cap.

Figure 14: Indicative contributions to, or support from, the cap in 2022

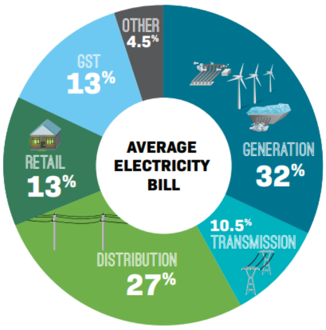


Impact on residential electricity consumers

5.31 Residential consumers do not pay transmission charges directly. They pay for the cost of transmission (and other services) as part of the total bill they pay to their electricity retailer. In 2016, 10.5% of the average residential electricity bill (averaged nationally) went towards the cost of transmission.

5.32 Figure 15 below shows the make-up of an average consumer's electricity bill, and how transmission charges are incorporated into that bill.

Figure 15: Transmission charges as part of the average residential electricity bill

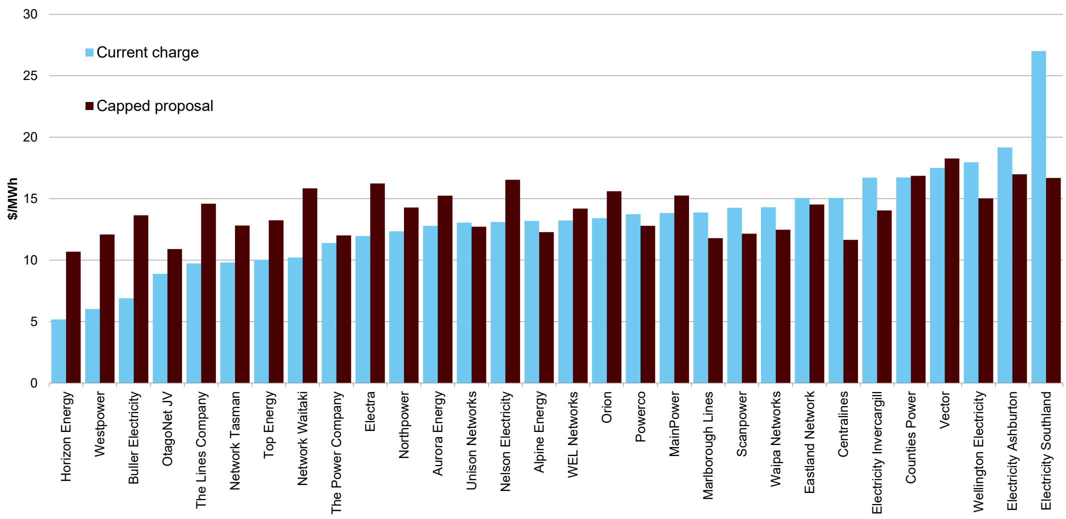


5.33 Figure 16 shows an estimate of the transmission portion of an average household bill for each network in $/MWh in 2022 under the current TPM and proposal (capped).

5.34 A range of factors may explain the differences, but one of the factors relates to the amount of local generation in an area. For example, Horizon Energy's charges are very low under the status quo as local generation helps to reduce its RCPD charges.

5.35 Electricity Southland's current interconnection charge is comparatively very high, and this should be taken into account in the results that follow. That charge, taken from 2019/20 disclosed charges data, was calculated following a year where Electricity Southland (whose gross load has doubled over four years) experienced its highest us over four years. The capped (mainly residual) charge is calculated based on a four year average of use.

Figure 16: Average transmission costs in $/MWh estimated for residential consumers in 2022, status quo and proposal (capped)[91]



91 The charges do not include a distributor's connection charges or charges from customer investment contracts (which sit outside the TPM) if they have any.

Initial impact of the proposal on residential consumer electricity bills

5.36 For the purpose of assessing the impact on residential consumers' electricity bills, it is assumed that distributors pass transmission charges on in full to consumers within their network in proportion to their energy use. (The focus on households in this section does not disregard that businesses connected to networks, would experience similar changes.)

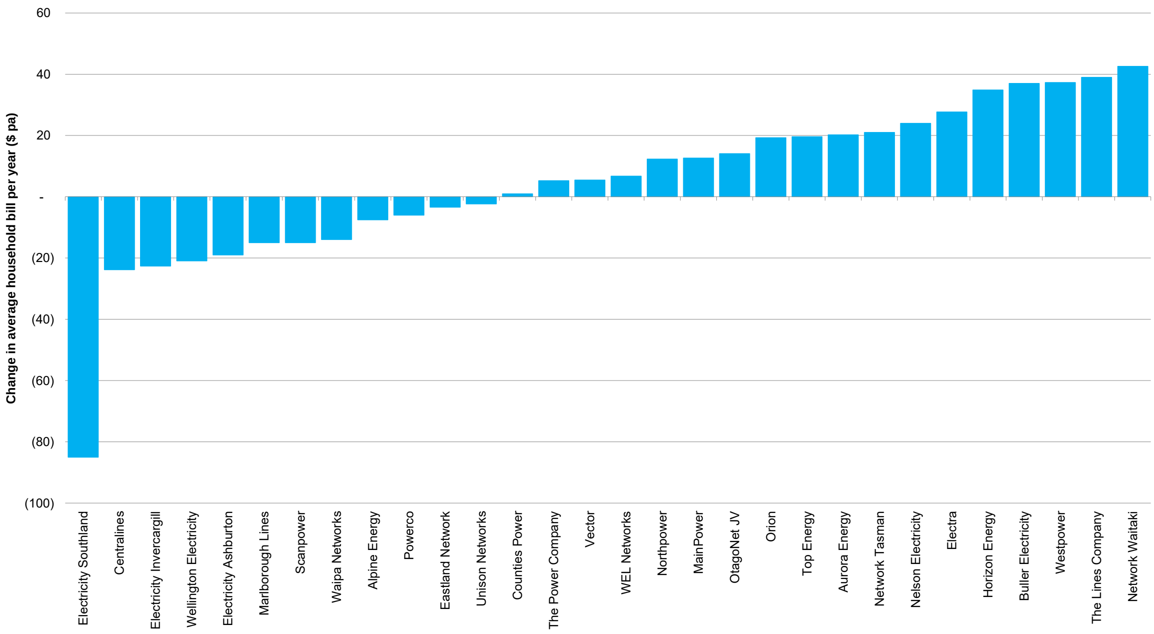
5.37 Figure 17 shows the estimate of the change in the average residential electricity bill following the rebalancing of charges expected to result from the proposal.

5.38 In the networks for which charges rise, the average increase in residential consumers' electricity bills is estimated to be $21 in 2022 year. Network Waitaki consumers would experience the largest average increase of $43 over 2022. Consumers in 12 networks would experience savings averaging $20 a year (or $14 ignoring the Electricity Southland result).[92]

5.39 These would be the initial impacts on transmission charges. This data does not take into account the long-term effects of the proposal which are expected to significantly benefit almost all consumers across New Zealand.

5.40 To put these initial price effects into perspective, on average, many residential consumers can immediately save more than $200 per year by switching from their current electricity retailer to the cheapest retailer on their network.[93]

Figure 17: Change in the transmission cost part of the average residential electricity bill estimated by distributor in 2022



92 Averages discussed in this paragraph are simple, unweighted averages.

93 Electricity Authority, Electricity Market Information, Residential savings, available at: www.emi.ea.govt.nz/r/xaspb

Effect of the proposal on ACOT payments

5.41 The Avoided Cost of Transmission (ACOT) payments are made by distributors to owners of distributed generation embedded within their networks. They are intended for situations where such generation would avoid or delay grid investments.

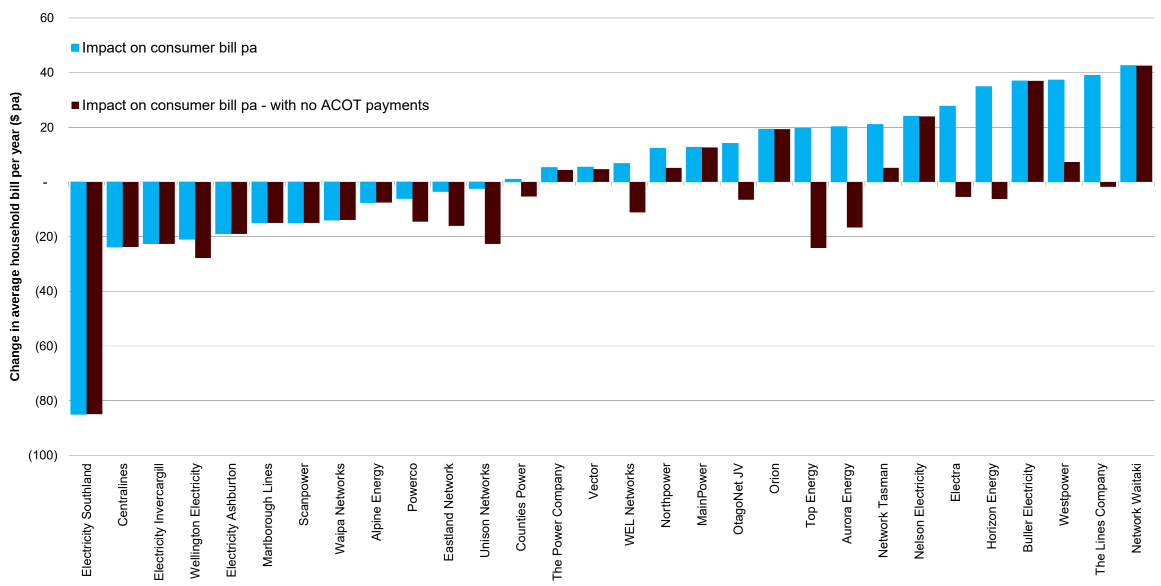
5.42 Under the current TPM, distributors pay the distributed generation where it produces power at peak times, because it lowers distributors' offtake from the grid at peak times and therefore reduces its share of the RCPD charge. Approximately $40 million in ACOT payments are made per year.[94]

5.43 The Authority's proposal would remove the RCPD charge and replace it with charges that could not be avoided. As such no ACOT payments would be made under the core charges in our proposal.[95]

5.44 We estimate that, if distributors ceased making payments for avoided transmission costs to distributed generation, savings to consumers in some parts of the country could be significant. For example, we estimate that consumers served by Aurora Energy, Counties Electra Energy, Horizon Energy, OtagoNet, The Lines Company, Top Energy and WEL Networks could pay lower distribution charges under our proposal (compared to the status quo) if the ACOT payment were no longer paid to distributed generation in those regions.

5.45 However, these effects represent an upper limit. If the additional components of a transitional peak charge or kvar charge were included in the TPM, there may be some cause for ACOT payments (in the locations to which these charges were applied), if it avoided or deferred grid investments. If so, the savings for consumers would be smaller but they would be receiving a 'service' from the distributed generation in exchange for the ACOT payment. If the transitional peak or kvar charges were found to be needed then this payment would be efficient.

Figure 18 Estimated impact of proposal on bills, with and without ACOT



94 Sourced from Distributors' Information Disclosures to the Commerce Commission.

95 This is discussed further in appendix F.

6 Proposed process for the development of the TPM

6.1 In this chapter the Authority proposes a process for the development and approval of the TPM to apply once new guidelines have been published.[96] We also set out an indicative timeline for the entire process from publication of the guidelines to the operation of a new TPM.

6.2 The Authority seeks comment from stakeholders on the proposed process and timeframes for the development and approval of the TPM.

Steps towards having a new TPM in operation

6.3 Once the Authority's consultation process in respect of this 2019 issues paper is complete and all submissions have been reviewed and considered, the Authority will seek to amend (as necessary), finalise and then take a decision on whether to *publish the new guidelines*. The remainder of this chapter considers the process from the point that new guidelines are published. The indicative timeline presented here assumes the guidelines are published in April 2020.

6.4 The steps to put a new TPM into operation after the Authority publishes new guidelines and the process for the development of the TPM are as follows:

(a) The Authority issues a request for Transpower to submit a *proposed TPM.*

(b) Transpower **develops** the *proposed TPM*, and **submits** the *proposed TPM* to the Authority.

(c) The Authority **considers** the proposed TPM, and either **refers it back** to Transpower for amendment and resubmission or **approves** it as a *proposed TPM* for consultation. The Authority may amend the proposed TPM itself if it is not satisfied with Transpower's amendments.

(d) The Authority publishes and **consults** on the *proposed TPM*, before deciding whether to incorporate it into the Code (which may entail some amendments as a result of the Authority's consideration of submissions on the *proposed TPM*).

(e) After an Authority decision to incorporate a new TPM into the Code, Transpower alters its processes and systems to **implement** the new TPM.

(f) The system **goes into operation** in the next pricing year after systems are ready.

Transpower to develop a TPM

6.5 Under clause 12.89(1) of the Code, Transpower must develop its proposed TPM to be consistent with:

(a) any determination made under Part 4 of the Commerce Act 1986

(b) the Authority's statutory objective[97]

(c) the published guidelines.

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96 Clause 12.81 of the Code requires the Authority to prepare an issues paper on the **process** for development and approval of the TPM as well as the **guidelines** to be followed by Transpower. Both must be developed in accordance with the Authority's statutory objective.

97 Section 15 of the Act: The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The process to develop a proposed TPM

6.6 The Authority would expect Transpower's development of the proposed TPM to include the following steps:

(a) identify options for a method for setting each required new charge

(b) assess which of the additional components better meet the Authority's statutory objective and should therefore be included in the proposed TPM

(c) identify options for a method for any additional components that will be included

(d) select and develop preferred option for each charge proposed to be introduced

(e) calculate indicative prices to show the impact of the proposed TPM on transmission customers

(f) show how the proposed TPM meets the requirements in clause 12.89(1)

(g) confirm the proposed TPM is workable, scope the level of implementation complexity, ongoing operational costs, timeline for the implementation phase.

Time period for development of the TPM

6.7 The time period in the Code for Transpower to produce a proposed TPM is 90 days, or such other time as the Authority allows. The Authority anticipates that Transpower would require significantly longer than 90 days to complete the above process.

6.8 In its submission in respect of the Authority's second issues paper,[98] Transpower sketched out the process it intended to follow to develop a proposed TPM for the Authority to consider, and then to implement the TPM (that is, to change its pricing and invoicing system) once the Authority had adopted a new TPM. Transpower further developed this in its February 2017 submission.[99]

6.9 While there are some differences between the 2016 proposal and this proposal, Transpower has confirmed it considers the implementation tasks broadly similar.[100] Based on this information Figure 19 shows an indicative timeframe.

Figure 19: Indicative timeline to operation of a new TPM

98 PWC, TPM change impact assessment: Responding to the Electricity Authority's consultation papers – A report for Transpower, July 2016.

99 Transpower's submission, TPM second issues paper, supplementary consultation, February 2017. Section 5, pp 27-34,

100 In March 2019, after having reviewed an initial working draft of the guidelines (but not the finalised proposal or process in this chapter), Transpower's chief executive confirmed that the timeline for a new TPM to take effect, and the one-off and ongoing costs are likely to remain comparable to both its February 2017 submission and, for implementation costs, to the high-complexity scenario in PWC's July 2016 report. She advised that any timeframe and cost gains from the Authority's preparation of the allocations for historic investments (in Schedule 1 of the guidelines) would be incremental.

6.10 New charges based on data from 2022/23 could apply from 1 April 2024, assuming the development of the proposed TPM is 18 months, and implementation takes 13 months (or 1 April 2025 if the implementation stage extended beyond 31 July 2023).

6.11 As indicated in Figure 19 above, Transpower has proposed that 18 months be allowed to produce a proposed TPM. The Authority is open to considering 18 months; however there may be opportunities to shorten this timeframe. The Authority is interested in hearing stakeholder views, including Transpower's, on how this might occur.

6.12 The Authority's currently preferred option is that the process should require Transpower to submit its draft TPM to the Authority by a set date, which would be somewhere between 12 and 18 months after the date the guidelines are published.

Q5. How long should Transpower have to complete its development of the TPM and why?

Checkpoints

6.13 The Authority would expect to engage with Transpower and work together formally and informally throughout the TPM development process.

6.14 In addition, the Authority proposes to set checkpoints during the period Transpower develops its TPM proposal, where Transpower would present the Authority with its emerging TPM designs for the Authority to consider. This is to ensure Transpower's proposal is well-aligned with the guidelines, so that when Transpower submits its proposed TPM, it is more likely to elicit the Authority's approval. If, in the Authority's view, the TPM proposal is not developing in a manner consistent with the guidelines and other requirements of clause 12.89(1), the Authority will ask Transpower to amend its developing TPM to be consistent with Authority comments.

6.15 The Authority therefore proposes the following checkpoints:[101]

(a) by a set date after the guidelines are published (for example, two, three or six months after, depending on the period allowed for developing the proposed TPM), Transpower must provide the Authority with a written summary describing its proposed TPM, including setting out key design choices on allocation methods for the benefit-based charge and peak charge, and:

(i) six weeks later, the Authority would provide feedback on Transpower's summary and advise whether it will seek any revisions

(ii) if necessary, five weeks later, Transpower would provide a revised summary, incorporating the Authority's comments

(iii) five weeks later, the Authority would provide further feedback and advise whether it will seek any further revisions or any further steps.

(b) by a set date after the guidelines are published (such as nine, 10, 11 or 12 months after), Transpower must provide the Authority with a preliminary draft of the proposed TPM, including a detailed outline of its approach with respect to the allocation of the benefit-based charge and peak charge, and:

[101] The checkpoints may need to be amended to reflect the decision on the timeframe for the development of the TPM.

(i) six weeks later, the Authority would provide feedback on Transpower's preliminary draft and advise whether it will seek any revisions

(ii) if necessary, five weeks later, Transpower would provide a revised draft, incorporating the Authority's comments

(iii) five weeks later, the Authority would provide further feedback and advise whether it will seek any further revisions or any further steps.

6.16 The proposed checkpoints are intended to fit in with stakeholder engagement as discussed below and have minimal or no impact on the overall time required to develop the TPM.

Q6. What checkpoints (if any) should the Authority set in the TPM development process?

Stakeholder engagement

6.17 The Authority envisages that Transpower would also engage with industry stakeholders at various points in the development of its proposed TPM.

6.18 The Authority seeks stakeholder views on the proposed process for development of the TPM, including specifically what kind of formal or semi-formal involvement stakeholders should have in the process to develop a new TPM, and reasons for that.

6.19 The Authority's current preferred option is that, in developing its TPM, Transpower would engage with stakeholders at least twice via less formal engagement methods, for example via workshops, forums or similar. However, alternative options might include running one more formal process or having ongoing, but potentially less formal, engagement with the sector. The Authority considers that multiple full consultation rounds, as has been previously suggested by Transpower, would be unnecessary given that the Authority would have just consulted extensively on the proposed guidelines and would consult again on the proposed TPM.

6.20 The Authority considers that its preferred approach is consistent with Transpower's February 2017 submission that it expects its engagement with stakeholders within the period allowed to develop a proposed TPM "to utilise a variety of consultation techniques with the objective of gaining as much benefit for as little impost on stakeholders as possible".[102]

6.21 The Authority expects Transpower to run a transparent process[103], balancing an appropriate level of engagement with timely completion. As part of the checkpoints noted above, the Authority would expect Transpower also to report to the Authority on its engagement with stakeholders.

Q7. How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

102 Transpower's submission to the second issues paper, supplementary consultation February 2017, section 5.3.2.

103 Submitters including Business NZ, Canterbury Employers' Chamber of Commerce, and Business Central requested the process for developing the TPM be transparent.

Authority to consult on and approve the proposed TPM

6.22 As the TPM is a schedule to Part 12 of the Code, the adoption of a new TPM would be a change to the Code. Clauses 12.90 to 12.94 of the Code set out the process the Authority must follow to approve a proposed TPM for consultation (or request or make changes to it), consult on it, and incorporate it into the Code.

6.23 Once the Authority has received Transpower's proposed TPM, it may approve the proposed TPM under clause 12.91 of the Code. In particular, the Authority will need to be satisfied that Transpower's proposed TPM is consistent with any determination under Part 4 of the Commerce Act 1986, the Authority's statutory objective, and the guidelines. If the Authority is not satisfied, it may request that Transpower make changes to the proposed TPM and if those changes remain unsatisfactory, amend the proposed TPM itself.

6.24 Once the Authority has approved the proposed TPM for consultation, it must then publish and consult on the proposed TPM under clause 12.92. The Authority's consultation paper must address the requirements of section 39 of the Act, including that it must contain a regulatory statement which includes:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

6.25 Clause 12.92(2) requires at least 15 business days for the Authority's consultation on the proposed TPM. The Authority expects that it would provide at least the six weeks normally offered for Code amendments, as envisaged in the Authority's Consultation Charter. At this stage, the Authority does not consider that this consultation period needs to be longer than this, as Transpower will already have engaged with stakeholders during development work on the proposed TPM.

6.26 Clause 12.93 requires the Authority to complete consideration of all submissions within 40 business days of the submission expiry date (unless it allows itself a longer period) and to consider whether to include the proposed TPM within the Code. The Authority will assess and communicate the time it requires based on the volume and nature of submissions received. It will then determine what, if any, amendments to the proposed TPM are required, before determining whether or not to incorporate the TPM into the Code.

6.27 An indicative timeline for this phase is 1 November 2021 to 30 July 2022 (8 months).

6.28 The Authority would consult with the Commerce Commission about any decision to incorporate a new TPM into the Code under section 54V of the Commerce Act 1986, and would request that the Commission reconsider Transpower's individual price path to take account of Transpower's additional expenditure required to implement and administer the new TPM.[104]

[104] See also Commerce Commission, Transpower Individual Price-Quality Path from 1 April 2020. Draft decisions and reasons paper, 29 May 2019, p17, para X40. Available at www.comcom.govt.nz

Transpower to implement a new TPM

6.29 In its February 2017 submission Transpower provided a preliminary estimate of the time it would require to change its systems to accommodate a new TPM. The estimate was based on a semi-generic IT project of moderate complexity.[105] The time period mentioned was up to 28 months but this estimate lined up with the start of the next pricing year, so could be shorter.

6.30 At the time of the 2016 proposal consultation the starting point for system implementation for Transpower was Transpower's existing system including a central platform developed in 2001. Transpower is replacing this platform in the 2019/20 financial year *before* the TPM is implemented. The Authority expects it would be easier for Transpower to implement TPM changes on a new platform.

6.31 Under the proposed guidelines,[106] the TPM must provide for Transpower to prioritise and stage its system changes if this can speed up the implementation of high-value post-2019 benefit-based investments and pre-2019 benefit-based investments to which Schedule 1 applies. Transpower may phase in a benefit-based charge for lower-value investments and defer implementation of additional components (other than a transitional peak charge, if one is applied) if useful.

6.32 Transpower has advised that any new allocation method must be implemented in tools and processes by 31 July at the absolute latest in the year before the new TPM takes effect. The process to determine annual prices starts in July when critical input data, including Transpower's financial results and the grid configuration at the end of its financial year (30 June), becomes available. This is so Transpower can confirm to its customers certified prices complying with both the TPM and Part 4 regulation by 30 November of that year. These prices can then take effect from April in the following year.

Q8. In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

105 PwC in preparing costs for Transpower noted Transpower's "simplified staged approach" that Transpower presented in its submission to the second issues paper would be a medium-complexity IT project. The proposed guidelines similarly allow for a simplified approach to be taken to allocating benefit for smaller investments, so we think assuming the implementation time for a medium-complexity project is appropriate.

106 This comment refers to the Implementation section, paragraphs 27 to 29, of the proposed guidelines in Appendix A of this issues paper.

7 Background

7.1 This appendix provides a history of the last 10 years of TPM review[107] and notes the significant changes the Authority has made in this 2019 issues paper compared to the Authority's 2016 proposal.

A history of the transmission pricing review

7.2 In broad terms a transmission pricing framework including an HVDC charge paid by South Island generators and an interconnection charge paid by load customers based on peak demand has existed in essentially the same form since 1999.

7.3 That pricing framework was established in circumstances that are very different to today. For example, the benefits of the HVDC link are now broader compared to 1999. This is due to changes including the commissioning of Pole 3 and the decommissioning of Pole 1 and the establishment of a national reserves market and frequency keeping arrangements. The HVDC link now more often flows southwards and provides more widely spread benefits such as through its role in the provision of ancillary services.

7.4 The current TPM took effect on 1 April 2008. The Authority's predecessor, the Electricity Commission, initiated a review of the TPM in April 2009. It established a Transmission Pricing Technical Group (TPTG) to provide advice and assistance on the TPM review. Around the same time, the New Zealand Electricity Industry Steering Group, which was established by the CEOs Forum, undertook a review of transmission pricing, and submitted a report to the Electricity Commission in December 2009.

7.5 The Electricity Commission began the TPM review for the following reasons:

(a) it had approved Transpower making transmission investments in excess of $2.6 billion

(b) it recognised a potential for power flows across the grid to change as a result of investment in transmission and generation, and changes in the location of demand

(c) there was an increasing emphasis on security of electricity supply

(d) several parties requested that the Electricity Commission review aspects of the TPM.

7.6 The Electricity Commission completed two rounds of consultation, one in 2009 and one in 2010, on options for the design of the TPM.

7.7 The Authority replaced the Electricity Commission on 1 November 2010 and continued the TPM review. The Authority took into consideration the earlier work and advice from the CEOs Forum that the TPM review should be the Authority's top priority project.

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107 Readers can find all papers released by the Authority and submissions to Authority consultations under this review on the Authority's Transmission Pricing Review webpage. They are presented in reverse chronological order at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

7.8 From 2011 to 2017 the Authority:

(a) established the Transmission Pricing Advisory Group (TPAG). The TPAG comprised an independent Chair and consumer and participant representatives. It was tasked with advising the Authority on the TPM. The TPAG provided the Authority with analysis and findings on options for the TPM in August 2011, but was unable to provide unanimous recommendations on the most significant aspects of the TPM

(b) consulted in early 2012 on a decision-making and economic framework for the TPM review and published the decision-making and economic framework in May 2012

(c) consulted on the paper 'Transmission Pricing Methodology: issues and proposal', to obtain feedback on a package of charging approaches (the October 2012 issues paper). The consultation included a TPM conference on 29–31 May 2013, which was attended by all Board members

(d) consulted on a series of working papers to develop and further consider the following key aspects of a revised TPM proposal:

(i) CBA approach (3 September 2013)

(ii) sunk costs: the extent to which transmission costs are actually 'sunk', and the implications for transmission pricing (8 October 2013)

(iii) avoided cost of transmission (ACOT) payments for distributed generation (19 November 2013)

(iv) use of loss and constraint excess (LCE) to offset transmission charges (21 January 2014)

(v) beneficiaries pay options (21 January 2014)

(vi) connection charges and efficiency (13 May 2014)

(vii) long-run marginal cost (LRMC) charges (29 July 2014)

(viii) problem definition relating to interconnection and HVDC assets (16 September 2014)

(ix) TPM options to address the problems identified (16 June 2015)

(e) consulted on a second issues paper (from 17 May 2016) and as part of that process:

(i) consulted on a supplementary paper to the second issues paper (13 December 2016), which proposed refinements in response to consideration of submissions

(ii) invited cross-submissions on the valuation method used for the area-of-benefit charge (10 March 2017)

(iii) released revisions to the CBA (23 March 2017)

(iv) advised that the Authority would produce a new CBA (26 April 2017).

7.9 The second issues paper set out a comprehensive proposal to change the TPM guidelines. The key aspects of the proposal were to replace the interconnection charge and HVDC charge with an 'area-of-benefit' charge and a 'residual' charge. The Authority received 508 submissions.[108]

7.10 In late 2016 the Authority released a supplementary consultation paper setting out refinements to the proposal in the Authority's second issues paper, based on feedback received. The refinements were to increase the durability of the proposal, have more certain impacts on consumers, and give Transpower more flexibility to implement the proposal. The Authority received 219 submissions.[109]

7.11 The proposal was put on hold in May 2017 to allow new Authority Board members to come up to speed with the process. In mid-2018 the Authority announced the next steps would be to generate a fresh proposal and CBA, the result of which is this 2019 issues paper. The Authority announced that, in outline, the Authority's proposal would be similar to the 2016 proposal, with refinements based on consideration of submissions and on further analysis.

7.12 The Authority acknowledges the considerable time and effort parties have invested in making submissions to the second issues paper and supplementary paper consultations in 2016 and 2017. While a detailed response to all points raised in the consultations relating to the 2016 proposal has not been provided, this 2019 issues paper has developed out of the Authority's consideration of the many points raised by submitters. Where elements of the proposal reflect or respond to specific points raised in submissions, we have attempted to acknowledge this in this 2019 issues paper, particularly in appendix B where the policy intent of the guidelines is presented and explained in detail. As the 2019 issues paper also differs in significant ways from the 2016 proposal, some previous points raised in submissions may no longer be relevant, for example those relating to the previous CBA.

Significant changes since the 2016 proposal

7.13 In 2016,the Authority set out its then proposed changes to the TPM guidelines in the following consultation documents:

(a) Transmission Pricing Methodology: Issues and proposal: Second issues paper 17 May 2016 and

(b) Transmission Pricing Methodology: Second issues paper Supplementary consultation 13 December 2016.

7.14 In this paper the complete proposal set out in these two papers is referred to as 'the 2016 TPM proposal' or '2016 proposal'.

7.15 The following table sets out the main changes in this proposal compared to the 2016 proposal. The table does not include all the changes that have been made. In addition to the ones set out here, we have made changes to clarify numerous provisions in the guidelines and to better align definitions with the Act, the Capex IM and the Code.

7.16 The references are to the relevant clauses in the guidelines (appendix A). These matters are discussed in more detail in appendix B.

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108 See: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

109 See: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c16277.

Guidelines clause	Change
	Include an initial section in the guidelines that sets out the Authority's policy objectives for the guidelines.
1	In designing the TPM, Transpower must, as far as is practicable, balance precision against robustness, simplicity, certainty and implementation costs.
2	Transpower's TPM can differ in its details from the guidelines if that would better meet the Authority's statutory objective.
4	Require Transpower to report to the Authority where it has made assumptions or altered the detail of the guidelines
5	Remove consultation requirement for low-value investments.
6	Transpower must inform customers how its transmission charges have been calculated, including the extent to which the residual charge comprises investments that have been subject to reassignment and unallocated opex.
9 & 12	Change name of area-of-benefit charge to benefit-based charge.
10 & 11	Guidelines for connection charges largely retain the current guidelines.
13	Only seven recent major investments are now covered by the benefit-based charge.
15	Transpower may propose in the TPM an alternative method for the valuation and recovery profile for post-2019 investments under the benefit-based charge if that would better meet the Authority's statutory objective.
16	Cost recovery profile and asset valuation for pre-2019 investments covered by the benefit-based charge is consistent with Commerce Commission's approach.
18	The 'damage to an investment' provision was included in the second issues paper (as 'force majeure') but omitted from the proposal in the supplementary consultation paper. Now reinstated (in simple form).
21	Transpower required to use the Authority's benefit-based allocation of costs for seven pre-2019 investments (guidelines: schedule 1).
22	Transpower can allocate benefit-based charges on the basis of proxies for benefit under the standard method. Fallback methods (for use if estimating benefits impractical) now open to Transpower to specify.
23	For investments valued at under $20 million (rather than $5 million as previously), the benefit-based charge can be allocated using a simple method (which is simpler than previously provided for).
24 & 66	Definition of benefits for the benefit-based charge now consistent with Commerce Commission's approach (Investment Test).
26	The 'material change in circumstances' provision has been renamed to 'substantial and sustained change in grid use', and more specific criteria must be satisfied. The TPM must include a proposed method for revising investment allocation after a substantial & sustained change in grid use (and a method for determining whether such a change has occurred).

Guidelines clause	Change
29	Transpower must defer applying the benefit-based charge to low-value investments if that is necessary to expedite its application to high-value investments.
33 – 38	Change title from optimisation to reassignment. The proposal now states that Transpower must carry out reassignment where specified criteria are met and must remove reassignment if those criteria are no longer met. It specifies what happens to charges when reassignment occurs.
39	Overheads and unallocated operating expenses to be recovered through the residual charge.
40	Residual allocator could be based on data collected over at least two years ending prior to 1 July 2019.
41	The guidelines set out a principle that the residual charge allocation should be adjusted for a substantial change to demand due to factors over which the customer had no control.
42	A section has been included relating to adjustment of charges. Less prescriptive provisions for new entrants and customers changing their point of connection. Also provides now for partial sale of a business.
43 – 45	The provision relating to the potential need for scaling back of charges has been expanded.
50	The data and the formula that Transpower is to apply in calculating the price cap are specified.
51	The price cap is funded by a surcharge on the total of the benefit-based charge for pre-2019 investments and the residual charge (rather than the residual charge alone).
55	Staged commissioning additional component no longer clarifies the position on charging assets as connection assets.
56	Provides that assets that in substance provide connection services do not have their charges changed even if they change from formally being connection assets.
58 – 61	The additional component ‘LRMC charge’ has been replaced with a ‘transitional peak charge’ that phases out over a 5-year period (which may be extended).
62 – 63	TPM required to include a proposed method for allocating the benefit-based charge for pre-2019 investments brought in via Additional Component E. Charges for such investments to be capped at the estimated net present value of net private benefit.
66 (&24)	Definition of net private benefit: defined to be consistent with ‘electricity market benefit or cost elements’; now optional for Transpower to include other (non-electricity market) benefits and costs.
66	Cut-off date between new and existing investments is now the date of publication of the 2019 Issues Paper. Definition of post-2019 and pre-2019 investment clarifies that where pre-2019 investments have not been fully commissioned, the benefit-based charge initially applies only to the extent they have been commissioned.

Glossary of abbreviations and terms

ACOT	Avoided cost of transmission
Act	Electricity Industry Act 2010
AHC	Average Historic Cost
AMD	Anytime maximum demand
Authority	Electricity Authority
Capex IM	Capital expenditure input methodology
CBA	Cost-benefit analysis
CIC	Customer investment contract
Code	Electricity Industry Participation Code 2010
DER	Distributed energy resources
DGPP	Distributed generation pricing principles
DHC	Depreciated Historical Cost
DME framework	TPM decision-making and economic framework
EDB	Electricity distribution business or businesses
ENA	Electricity Networks Association
FTR	Financial transmission rights
GWh	Gigawatt hour
HVDC	High voltage direct current
ICP	Installation control point
IM	Input methodology
IPP	Individual price path
kWh	Kilowatt hour
Kvar	Kilovolt ampere reactive
LCE	Loss and constraint excess
LMP	Locational marginal price or pricing
LNI	Lower North Island
LRMC	Long-run marginal cost
LSI	Lower South Island
MAR	Maximum allowable revenue
MW	Megawatt
MWh	Megawatt hour

NAaN	North Auckland and Northland grid upgrade project
NIGU	North Island Grid Upgrade Project
NZAS	New Zealand Aluminium Smelters
PDP	Prudent discount policy
RAB	Regulatory asset base
RCP	Regulatory control period
RCPD	Regional coincident peak demand
RTP	Real time prices or pricing
SIMI	South Island mean injections
SPD	Scheduling, pricing and dispatch model
SRMC	Short-run marginal cost
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited
UNI	Upper North Island
USI	Upper South Island
VoLL	Value of lost load
VPO	Virtual price offer
vSPD	Vectorised Scheduling, pricing and dispatch model

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Appendix A Proposed TPM guidelines

Policy objectives

The Electricity Authority (the **Authority**) has reviewed the guidelines which Transpower is required by the Electricity Industry Participation Code 2010 (the **Code**) to follow in developing a proposed transmission pricing methodology (**proposed TPM**) (the **Guidelines**).

Having undertaken this review, the Authority considers that, in order to allow Transpower to recover up to its forecast maximum allowable revenue in any year and to better meet the Authority's statutory objective, the proposed TPM should contain the following components:

(a) a connection charge;

(b) a benefit-based charge;

(c) a residual charge;

(d) a prudent discount policy;

(e) a cap on transmission charges; and

(f) seven additional components which are to be implemented if they better achieve the Authority's objective.

Connection charge

The purpose of the connection charge is to charge each designated transmission customer to recover the cost of the assets that connect it to the interconnected grid.

Benefit-based charge

The purpose of the benefit-based charge is to recover the costs of new and certain existing investments in the interconnected grid (including investments in transmission alternatives). The charge is to be allocated between designated transmission customers in accordance with the estimated positive net private benefits that each transmission customer is expected to receive from the investment (or a proxy for these benefits). The positive net private benefit of the transmission customer includes the positive net private benefit of any parties that are connected to the interconnected grid through the transmission customer.

Residual charge

The purpose of the residual charge is to provide a mechanism to ensure that Transpower is able to recover up to its forecast maximum allowable revenue in any year in a way which does not affect designated transmission customers' decision-making.

Prudent discount policy

The purpose of the prudent discount policy is to allow Transpower to discount the transmission charges of a designated transmission customer who otherwise would find it viable to inefficiently bypass the grid (including inefficiently disconnecting from the grid in favour of alternative supply).

Cap on transmission charges

The purpose of the cap on certain transmission charges is to minimise price shock by limiting the total increase in transmission charges relating to the existing interconnected grid that each load customer faces relative to the charges that the customer actually pays for the existing interconnected grid in the 2019/20 pricing year. The cap applies only as long as it is effective in limiting a designated transmission customer's transmission charges subject to the price cap as set out in clause 49.

Additional components

Transpower would include each additional component in the TPM if doing so would better achieve the Authority's statutory objective.

(a) Staged commissioning. The purpose of this component is to allow Transpower to adjust how it recovers the cost of an investment that is commissioned in stages, so the charges better reflect the positive net private benefits it provides.

(b) Assets that in substance provide connection services. The purpose of this component is to ensure that if a connection asset that continues in substance to provide principally connection services is reclassified as an investment in the interconnected grid, it is still charged for as a connection asset.

(c) Charges for connection assets. The purpose of this component is to allocate connection charges in substantially the same way as benefit-based charges.

(d) Transitional peak charge. The purpose of this component is to efficiently influence grid use at peak times for a limited transitional period, if nodal prices are not adequate to meet this objective.

(e) Extension of benefit based charge. The purpose of this component is to allow Transpower to extend the benefit based charge to further pre-2019 investments.

(f) Opex. The purpose of this component is to attribute opex to the investment or asset that it is spent on without recourse to proxies.

(g) kvar charge. The purpose of this component is to allow Transpower to impose a charge on reactive power.

General matters

1. In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable:

   (a) set charges in a way that reflects:

   (b) the cost of providing designated transmission customers with:

      A. new investment in the grid;

      B. access to the parts of the grid relevant to them; and

      C. use of the grid to transport energy;

      (ii) the **positive net private benefits** those designated transmission customers derive from those things;

   (c) balance the economic benefits and costs of precision of the **TPM** with the economic benefits and costs of practical considerations including:

      (i) robustness;

      (ii) simplicity;

      (iii) certainty, including through limiting the need for Transpower to exercise a discretion; and

(iv) costs associated with developing, administering and complying with the **TPM**;

(d) avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;

(e) avoid creating incentives for distributed generators to seek avoided cost of transmission payments, except to the extent that the payments reflect a saving in the costs of transmission (not just a saving in **transmission charges** to the relevant distributor);

(f) avoid discriminating between designated transmission customers, except to the extent necessary to achieve the Authority's statutory objective; and

(g) allow Transpower to recover its **forecast MAR**, should it wish to do so.

2. Transpower may propose a **TPM** which differs in its details from the particular requirements in the **Guidelines**, if it considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the **Guidelines** in their entirety.

3. All subsequent provisions in these **Guidelines** are to be interpreted and applied subject to clauses 1 and 2 above.

4. In developing the **TPM**, Transpower must prepare an outline of Transpower's reasons for proposing the particular methods it has included in the **TPM**, to be provided to the Authority along with the **TPM**. This outline must include details of:

(a) where, under clause 2, Transpower proposes a **TPM** which differs in its details from the particular requirements of the Guidelines, how the **TPM** differs from the **Guidelines** and Transpower's reasons for proposing a **TPM** which differs from the **Guidelines**, including why it considers that its proposed **TPM** better meets the Authority's statutory objective; and

(b) where Transpower has made an assumption in developing the **TPM**, the assumption made and Transpower's reasons for making that assumption.

5. The **TPM** must include requirements for Transpower to consult on:

(a) the proposed **benefit-based charge** and its allocation between designated transmission customers for each proposed **high-value benefit-based investment**;

(b) the proposed allocation of the **residual charge**;

(c) important parameters used to calculate those charges and allocations;

(d) any proposed material changes to those charges or allocations (in which case consultation must extend to whether such changes are warranted by a change in circumstances); and

(e) any assumptions made in calculating those charges, allocations or material changes to those charges or allocations,

with parties who have a material financial interest in the charges. Where Transpower can demonstrate that such parties have already been consulted on the above (whether by Transpower or any other party), it need not repeat that consultation for the purposes of this clause.

6. The **TPM** must include a requirement for Transpower to provide each designated transmission customer with information regarding how its **transmission charges** have been calculated, including the basis on which its **benefit-based charge** and **residual charge** have been set. The basis on which the **residual charge** has been set includes the extent to which the **residual charge** comprises unallocated **opex** and the extent to which it comprises costs which have been reallocated to the **residual charge** as a result of **benefit-based investments** having been subject to **reassignment**. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to verify the accuracy of Transpower's calculations of its **transmission charges**.

7. The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, or incentives on, a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, or incentives on any parties directly or indirectly electrically connected to that designated transmission customer.

8. The **TPM** must provide for the treatment of a transmission alternative to be consistent with the treatment the investment which the transmission alternative seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, for the cost of transmission alternatives to be allocated to the designated transmission customers that benefit from them in proportion to the relative level of benefit that each customer receives.

Main components

9. The **TPM** must include:

   1. a charge for **connection assets**;
   2. a **benefit-based charge**;
   3. a **residual charge**;
   4. a prudent discount policy; and
   5. a cap on specified **transmission charges**.

   The total recovered by Transpower under these components may not exceed Transpower's **forecast MAR**.

Main component 1: connection charge

10. The **TPM** must provide for the costs of **connection assets** to be recovered from those connected to them.

11. The **TPM** must include a definition of deep connection, which must be applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent reasonably practicable.

Main component 2: benefit-based charge

Benefit-based charge must apply to benefit-based investments

12. The **TPM** must include a **benefit-based charge** for each **benefit-based investment**.

13. A **benefit-based investment** means:

    (a) any **post-2019** investments in the **interconnected grid**, including any transmission alternatives;

    (b) the following **pre-2019** investments in the **interconnected grid:**

        (i) the Bunnythorpe-Haywards Reconductoring Project

        (ii) investments in and associated with the HVDC link

        (iii) the Lower South Island Renewables Project;

        (iv) the Lower South Island Reliability Project;

        (v) the North Island Grid Upgrade (NIGU) Project;

        (vi) the Upper North Island Dynamic Reactive Support Project; and

        (vii) the Wairakei Ring Project;

    (c) **upgrading expenditure** as provided for in clauses 30 to 32 below; and

    (d) **pre-2019** investments in the **interconnected grid** identified by means of a method established under clauses 62 and 63 below**.**

Benefit-based charges must recover the covered cost of benefit-based investments

14. The **benefit-based charge** for a **benefit-based investment** must recover, over the **benefit-based investment's remaining life**, the present value of the **covered cost** of that **benefit-based investment**, which comprises:

    (a) the capital cost of the **benefit-based investment**, based on:

        (i) for **post-2019 benefit-based investments**, the **value of commissioned assets** forming part of that **benefit-based investment**;

        (ii) for **pre-2019 benefit-based investments**, the depreciated value of the assets comprising the **benefit-based investment** as recorded in the **regulatory asset base** at the date the **benefit-based charge** is first applied to the **benefit-based investment**;

    (b) a return on capital for the **benefit-based investment**, based on its capital cost as allowed for under paragraph (a) and **WACC**;

    (c) an amount of forecast **opex** reasonably attributable to the benefit-based investment based on an allocation of the **opex** allowance for the **pricing year** as set by the Commerce Commission in the **IPP**; and

    (d) any other costs attributable to that **benefit-based investment**.

Recovery of the covered cost of a benefit-based investment over time

15. The **TPM** must provide for the **annual benefit-based charges** for each **post-2019 benefit-based investment** to be calculated:

    (a) using the following method:

        (i) the expected **benefit-based charge** for the **benefit-based investment** is divided into equal annual amounts over the **benefit-based investment's remaining life**; and
        (ii) the annual amounts determined under subclause (a)(i) are adjusted for inflation over the **benefit-based investment's remaining life** using an index determined by Transpower; or

    (b) according to an alternative method, where that alternative method:

        (i) would better meet the Authority's statutory objective than the method described in paragraph (a); and

        (ii) would still recover the **covered cost** of that **benefit-based investment**.

16. The **TPM** must provide that Transpower's recovery of the capital components for each **pre-2019 benefit-based investment** for a **pricing year** under the **TPM** must be the same as the forecast depreciation and forecast capital charge in that **pricing year** for the assets of that **benefit-based investment** under the **IPP**.

17. The **TPM** must allow Transpower to adjust future **annual benefit-based charges** for a **benefit-based investment** if, in Transpower's reasonable assessment, there has been, or will be, a material change to any of the expected future:

    (a) **WACC**;

    (b) **opex** attributable to the **benefit-based investment**;

    (c) **remaining life** of the **benefit-based investment**; or

    (d) any other costs attributable to the **benefit-based investment**.

    The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**.

Damage to a benefit-based investment

18. The **TPM** must allow Transpower to adjust or end future **annual benefit-based charges** for a **benefit-based investment** where an asset or assets forming part of that **benefit-based investment** are destroyed or substantially damaged.

Allocating annual benefit-based charges among customers

19. The **TPM** must include one or more standard methods for allocating **annual benefit-based charges**.

20. The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.

21. The **TPM** must provide:

(a) that Transpower must use a standard method to allocate the **annual benefit-based charges** for **high-value post-2019 benefit-based investments**;

(b) that Transpower must use Schedule 1 to allocate the **annual benefit-based charges** for the **benefit-based investments** included in Schedule 1;

(c) where these **Guidelines** provide for an adjustment to the Schedule 1 allocations, a method for making that adjustment. That method must be a standard method, simple method or combination of both; and

(d) that Transpower must use a standard method, simple method or combination of both to allocate the **annual benefit-based charges** for any other **benefit-based investments**.

22. A standard method:

(a) must allocate the **annual benefit-based charge** for a **benefit-based investment** between the designated transmission customers expected to benefit from the **benefit-based investment** in proportion to their expected **positive net private benefit** from the **benefit-based investment** over its **remaining life**;

(b) where necessary, may determine expected **positive net private benefits** using one or more reasonable proxies. Such proxies must, in Transpower's reasonable opinion, 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.

23. A simple method:

(a) must be capable of being implemented at a lower cost to participants, including Transpower, than the standard method(s). Cost includes administrative burdens on participants but does not include increases in resulting **transmission charges**;

(b) must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to the designated transmission customers who receive a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had the standard method been applied. However, Transpower is not required to apply the standard method solely for the purpose of making this assessment; and

(c) may exempt designated transmission customers who do not receive a major **positive net private benefit** from a **benefit-based investment** from receiving an allocation of the **annual benefit-based charges** for the **benefit-based investment**.

24. The **TPM** must provide that, save for benefits and costs included at Transpower's discretion, the treatment of benefits and costs used to calculate **net private benefits**, to the extent applicable, in respect of **post-2019 benefit-based investments** under each standard method and each simple method must be consistent with, though not necessarily identical to, 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**, unless Transpower considers there has been a material change since that test was applied.

25. The **TPM** must provide that, once a designated transmission customer's share of the **annual benefit-based charge** has been allocated, that share will not change, save where these **Guidelines** permit otherwise.

26. The **TPM** must provide:

(a) that Transpower may review the allocation of future **annual benefit-based charges** for a **high-value benefit-based investment** if Transpower considers there has been, or expects that there will be, a substantial and sustained change in grid use affecting the **net private benefits** derived by one or more designated transmission customers from the **benefit-based investment**;

(b) that a substantial change in grid use will only have occurred where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges;

(c) a method for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment**; and

(d) a method/s for adjusting allocations in the event that there has been a substantial and sustained change in grid use.

Implementation timeframe for the benefit-based charge

27. The **TPM** must provide for the **benefit-based charge** to apply to **high-value post-2019 benefit-based investments** and **pre-2019 benefit-based investments** to which Schedule 1 applies from the commencement of the **TPM** or the date on which the investment is **commissioned** (whichever is later).

28. The **TPM** must provide for **benefit-based charges** for **low-value post-2019 benefit-based investments** to be phased in as soon as is reasonably practicable after the **benefit-based charge** has been applied to the **high-value benefit-based investments** listed in clause 27 and no later than five years after the commencement of the **TPM**.

29. The **TPM** must provide that the implementation of **additional components**, other than a transitional **peak charge**, must be deferred if necessary in order to expedite the implementation of the **benefit-based charge** for **high-value benefit-based investments**.

Upgrading expenditure

30. **Upgrading expenditure**, in relation to existing **benefit-based investments**, means expenditure that results in an extension to the existing **benefit-based investment's remaining life** or otherwise increases the benefits that **benefit-based investment** is expected to provide.

31. The **TPM** must provide that, where Transpower undertakes **upgrading expenditure**, that **upgrading expenditure** must be recovered using the method prescribed in these **Guidelines** for recovering the **covered cost** of a **post-2019 benefit-based investment** having a capital cost equal to the cost of the **upgrading expenditure**.

32. Subject to clause 31, in recovering **upgrading expenditure** on existing **benefit-based investments**, Transpower may:

(a) treat the **upgrading expenditure** as a new **benefit-based investment**; or

(b) adjust as appropriate the value of the **benefit-based investment**, its **remaining life**, its estimated benefits and the calculation and allocation of the **annual benefit-based charge** for it, in order to reflect the changes caused by the **upgrading expenditure**. An adjustment under this paragraph may alter the **covered cost** and allocation for the overall **benefit-based investment** (comprising the initial **benefit-based investment** and the **upgrading expenditure**). However, such an adjustment is not to alter the requirement to recover the **covered cost** of the initial **benefit-based investment** or the calculation of **net private benefits** for the initial **benefit-based investment**.

Reassignment

33. The **TPM** must provide for a party to make an application to Transpower for **reassignment** of charges:

    (a) where that party has a direct or indirect financial interest in the **annual benefit-based charge** for that **benefit-based investment**;

    (b) where the **benefit-based investment** had an initial value of $5 million or more (with this threshold to be adjusted for inflation); and

    (c) whether or not the **benefit-based investment** has previously been subject to **reassignment**.

34. The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if Transpower considers that the circumstances which led to the **reassignment** are likely to be sustained and:

    (a) for a **pre-2019 benefit-based investment**, the investment's value following **reassignment** would be less than 80% of its current value;

    (b) for a **post-2019 benefit-based investment**:

        (i) where the disconnection of a single party causes the **benefit-based investment's** value following **reassignment** to be less than 80% of its current value; or

        (ii) the **benefit-based investment** has been **commissioned** or otherwise been in operation for the period of time specified in the **TPM** for the purpose of this subclause and its value following **reassignment** is now less than 80% of its current value.

35. In setting a period of time for which a **post-2019 benefit-based investment** must have been **commissioned** in order for it to be eligible for **reassignment**, the **TPM** must provide for that period to be sufficiently long that the prospect of **reassignment** will likely have a negligible impact on the characteristics of the **post-2019 benefit-based investment** that designated transmission customers are incentivised to seek.

36. The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the revision to forecast future demand for **transmission lines services** which gave rise to the **reassignment**.

37. The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist, it must reverse the **reassignment** (that is, restore the value of the **benefit-based investment** to the value that would have applied if the **reassignment** had not taken place) or adjust the level of the **reassignment**, as is appropriate.

38. The **TPM** must provide that, where Transpower determines to carry out **reassignment** with respect to a **benefit-based investment** or reverse a **reassignment**, it must:

    (a) modify the **annual benefit-based charge** for that investment to take into account the change in the **benefit-based investment's** value;

    (b) adjust the allocation of the **annual benefit-based charge** to designated transmission customers to the extent necessary to take into account the change in forecast future demand for **transmission lines services** which led to the **reassignment** or reversal of the **reassignment**; and

    (c) adjust the **residual charge** as necessary to take into account the changes to the **annual benefit-based charge**.

Main component 3: residual charge

39. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers to the extent that they are load to recover any remaining **forecast MAR** not recovered through other **transmission charges**.

40. The **TPM** must provide for the **residual charge** to be allocated:

    (a) in proportion to each designated transmission customer's historical anytime maximum demand, which is to be calculated using data supplied by the reconciliation manager and by:

        (i) taking, in a **pricing year**, the highest value for any trading period which represents the sum of:

            A. the highest net quantity of electricity flow from the grid at the designated transmission customer's grid exit point; and

            B. Transpower's estimate of any concurrent generation by distributed generators or behind-the-meter generation that is indirectly connected to the grid through the designated transmission customer; and

        (ii) taking the average of that value over at least two years ending prior to either 1 July 2019 or the date 10 years prior to the date on which the **residual charge** is to be assessed, whichever is the later; or

    (b) by an alternative method of allocating the charge to designated transmission customers to the extent that they are load, should Transpower consider that the alternative method would better meet the Authority's statutory objective than the method set out in paragraph (a) above.

41. The **TPM** must provide that, in initially allocating the **residual charge** under clause 40, Transpower may adjust the allocation where necessary to accommodate circumstances in which a designated transmission customer has experienced a substantial change in demand due to factors beyond their control or influence. For the purposes of this clause, a substantial change in demand is to be assessed relative to the designated transmission customer's remaining demand.

Provisions relating to adjustments

42. The **TPM** must:

    (a) provide for a process for allocating **benefit-based charges** and **residual charges** in respect of:

        (i) new **large consumers or generators**;

        (ii) existing **large consumers or generators** who establish a new plant or generating unit or increase (where that increase is substantial and sustained) an existing plant's electricity use or an existing generating unit's generation, where that plant or generating unit is directly or indirectly connected to the grid;

    (b) provide that, where a designated transmission customer sells part of its business, Transpower may allocate the designated transmission customer's charges between the original and new owners; and

    (c) avoid creating inefficient incentives for a **large consumer or generator** to shift their point of connection (beyond the ability to do so in the prudent discount policy). The prudent discount policy may apply to circumstances where a **large consumer or**

generator is considering shifting their point of connection, but the **TPM** must include additional provisions to avoid creating such incentives.

The charges may need to be scaled back

43. The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year**:
    (a) applying the other provisions of the TPM would result in Transpower recovering more than its **forecast MAR**; or

    (b) Transpower wishes to recover less than its **forecast MAR**.

44. The **TPM** must provide that, where clause 43(a) applies, charges are to be scaled back in the following order:

    (a) the **residual charge**;

    (b) the **annual benefit-based charge** for **pre-2019 benefit-based investments**; then

    (c) the **annual benefit-based charge** for **post-2019 benefit-based investments**.

45. The **TPM** must provide that, where clause 43(b) applies, Transpower may first scale back the **annual benefit-based charge** for a **benefit-based investment**. However, such a scaling back of the **annual benefit-based charge** must not result in an increase to the **residual charge**.

Main component 4: prudent discount policy

46. The **TPM** must provide for a prudent discount policy that encourages designated transmission customers not to inefficiently bypass the grid, including encouraging **load customers** not to inefficiently disconnect from the grid in favour of alternative supply.

47. The prudent discount must be available where a designated transmission customer can establish that:

    (a) it would be technically and operationally feasible, and commercially beneficial, for the designated transmission customer to undertake the relevant action described in clause 46; and

    (b) the relevant action would be inefficient to implement given Transpower's economic costs of providing the designated transmission customer with access to the **interconnected grid** and the economic costs incurred by the designated transmission customer if it proceeded with the relevant action described in clause 46.

48. The prudent discount must apply for the **remaining life** of the relevant investment, unless Transpower and the party receiving the prudent discount agree to a different period.

Cap on transmission charges

49. Subject to clause 53, the **TPM** must provide for a price cap on each **load customer's** total **transmission charges** excluding:

    (a) any **connection charge**;

    (b) any **peak charge**;

    (c) any kvar charge;

    (d) any charge attributable to investments commissioned or otherwise entering into operation after the end of the 2019/20 **pricing year**;

(e) any **benefit-based charge** in respect of any **pre-2019 benefit-based investment** identified by means of a method established under clauses 62 and 63;

(f) any increase in the **residual charge** due to a **reassignment** of a **benefit-based investment**;

(g) any increase in a designated transmission customer's allocation of the **annual benefit-based charge** for a **benefit-based investment** due to a reallocation under clause 26; and

(h) the application of clause 42.

50. Subject to clause 53, in setting a price cap, the **TPM** must provide for:

(i) any increase in a distributor's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than the amount resulting from the following formula:

B x (0.035 + CPI + L)

where:

B is Transpower's estimate of the total electricity bill for all consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 **pricing year** (expressed in dollars), calculated as:

$$B = C + P*V$$

and where

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the distributor's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

C is the distributor's total line charge revenue for the 2019/20 **pricing year** excluding GST from Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012;

P is the volume weighted average of wholesale energy prices at the distributor's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST, with weights being the gross load as determined by the reconciliation manager; and

V is the distributor's total gross load for the 2019/20 **pricing year**, expressed in MWh, as determined by the reconciliation manager;

(j) any increase in a direct consumer's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than:

B x (0.035 + 0.02 x Y + CPI + L)

where:

B is Transpower's estimate of the total electricity bill of that direct consumer in the 2019/20 **pricing year** (expressed in dollars), calculated as;

$$B = T + P*V$$

and where

Y is the greater of zero and of the number of **pricing years** which have elapsed since the 2019/20 **pricing year** minus 5;

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the direct consumer's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

T is what the direct consumer's total **transmission charge** (including any **connection charge**) is or would have been under the existing **TPM** in the 2019/20 **pricing year**, excluding GST;

P is the volume weighted average of wholesale energy prices at the direct consumer's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST; and

V is the total direct consumer's load in the 2019/20 **pricing year** in MWh, such information to be obtained from the reconciliation manager; and

(k) the price cap to be permanently removed for a particular **load customer** if, in any **pricing year** after the **pricing year** in which **benefit-based charges** are first applied to **low-value post-2019 benefit-based investments**, the cap does not have the effect of reducing the **load customer's transmission charges** subject to the price cap as set out in clause 49.

51. To the extent that the price cap results in a reduction in **transmission charges** for one or more **load customers**, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the **benefit-based charge** for the investments listed in clause 13(b) and the **residual charge** for each designated transmission customer.

52. The surcharge on the **benefit-based charge** and the **residual charge** for a designated transmission customer is to be reduced if necessary and to the extent necessary to ensure that its **transmission charges** subject to the price cap as set out in clause 49 meet the condition in clause 50.

53. The price cap provisions must not prevent Transpower from recovering its **forecast MAR**.

Additional components

54. The **TPM** must incorporate each of the following **additional components**, where including that component would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**:

(a) staged commissioning, as described in clause 55;

(b) charges for assets principally providing connection services, as described in clause 56;

(c) charges for connection assets, as described in clause 57;

(d) a transitional peak charge, as described in clauses 58 to 61;

(e) including additional pre-2019 investments in the benefit-based charge, as described in clauses 62 and 63;

(f) charging for **opex**, as described in clause 64; and

(g) a kvar charge, as described in clause 65.

Additional component A: staged commissioning

55. This component must provide a method for Transpower, at its discretion, to adjust the time profile and allocation of charges over a **benefit-based investment's remaining life** where an investment is **commissioned** in stages so that it sometimes meets the definition of a **connection asset**, in order to best reflect the benefits provided while it is a connection investment relative to the benefits provided after it has become an investment in the **interconnected grid**. The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**, less any **connection charges** already paid.

Additional component B: charges for assets principally providing connection services

56. This component must provide a method to ensure that charges that apply to assets that provide connection services are not affected by connecting those assets to other assets, if they continue to provide principally the services of a **connection asset**, notwithstanding that they do not meet the formal definition of a **connection asset**.

Additional component C: charges for connection assets

57. This component must provide for the method for determining the annual amount to be recovered for each new **connection asset** to align with the method for determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 10 and 11.

Additional component D: transitional peak charge

58. This component must provide a method for determining, in respect of the transitional **peak charge**:

(a) the initial level of the charge;

(b) the designated transmission customers or geographic areas to, or the circumstances in, which it applies; and

(c) how the charge is to be allocated between designated transmission customers.

The transitional **peak charge** may only apply in respect of those geographic areas, circuits or other circumstances which, in Transpower's reasonable opinion, would experience congestion without a transitional **peak charge**.

59. If Transpower determines to include a transitional **peak charge** in the **TPM**, it must include in its outline required under clause 4 of these **Guidelines**, an explanation as to why it considers that grid demand will not be adequately controlled by the other prices including nodal pricing.

60. If the **TPM** includes a transitional **peak charge**:

(a) the transitional **peak charge** must be progressively phased out, such phase-out to commence no later than one year after the transitional **peak charge** is first imposed;

(b) the phase-out of the transitional **peak charge** must result in it being phased out completely within five years of the **TPM** entering into effect. Transpower may, during this phase-out period, temporarily pause the phase-out or increase the transitional **peak charge**, including by reinstating a transitional **peak charge** which has already been phased out, where doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective, provided that the phase-out is still completed within the five year period unless Transpower has obtained the Authority's approval under paragraph (d) below to extend that period;

(c) the **TPM** must include the process for phasing out the transitional **peak charge**, including specifying the maximum transitional **peak charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **peak charge**; and

(d) the **TPM** must include provision for Transpower to apply to the Authority during the phase-out period, to deviate from the maximum transitional **peak charge** that may be levied in any year, the time limit on or duration of the phase-out period. Transpower must provide to the Authority such information as the Authority requires to determine an application under this paragraph.

61. Notwithstanding anything in clause 60 above, after the phase-out period has ended, Transpower may propose to reinstate or introduce a new transitional **peak charge** as part of a review under clause 12.85 of the **Code**. In proposing a reinstated or new transitional **peak charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal.

Additional Component E: Including additional pre-2019 investments in the benefit-based charge

62. This component must include a method for extending the definition of **benefit-based investment** to other **pre-2019 benefit-based investments** in the **interconnected grid** and related services, including transmission alternatives, that contribute to Transpower's **forecast MAR**.

63. If the **TPM** includes such a method, it:

(a) must specify a method for allocating the **annual benefit-based charges** for the **benefit-based investments** between designated transmission customers. The method must be a simple method as described in clause 23;

(b) must provide for the **benefit-based charge** for such **benefit-based investments** to be capped at the present value of the aggregate **positive net private benefits** expected to be derived by designated transmission customers from the **benefit-based investment** over its **remaining life**; and

(c) may include transitional provisions which phase in the relevant charges.

Additional component F: charging for opex

64. This component must include a method for allocating **opex** expended in relation to **connection assets** and assets in a **benefit-based investment** to the designated transmission customers paying charges in relation to that asset or investment. The method must not use a proxy or generalised rule for allocation.

Additional component G: kvar charge

65. This component must include a method for imposing a kvar charge on reactive power.

Interpretation

66. In these **Guidelines**, unless the context otherwise requires it:

2019 Issues Paper means the issues paper prepared by the Authority under clause 12.81 of the **Code** and published by the Authority on [**date**] 2019.

additional component means one of the components required by clause 54 of these **Guidelines** to be included in the **proposed TPM** where Transpower considers that including that component will better meet the Authority's statutory objective than not including it.

annual benefit-based charge means the amount of the **benefit-based charge** to be recovered in respect of a particular **benefit-based investment** in any one **pricing year**.

asset refurbishment has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

asset replacement has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

benefit-based charge means the charge as described in clause 12.

benefit-based investment has the meaning given to it in clause 13.

Code means the Electricity Industry Participation Code 2010, as amended from time to time.

commissioned has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

connection assets means the assets owned by Transpower used to connect a designated transmission customer to the grid**,** and may have a more precise definition in the **transmission pricing methodology** as amended from time to time.

connection charge means the charge described in clauses 10 and 11.

covered cost, in relation to an **benefit-based investment**, has the meaning given to it in clause 14.

electricity market benefit or cost element has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2, as amended from time to time*.*

forecast MAR means, for a **pricing year**, Transpower's forecast maximum allowable revenue as set by the Commerce Commission in the **IPP**, as amended from time to time. The **IPP** for the **pricing year** commencing 1 April 2010 is the *Transpower Individual Price-Quality Path Determination 2020.*

generation customer means a designated transmission customer that is a generator.

Guidelines means these guidelines.

high-value, in respect of a **benefit-based investment**, means a **benefit-based investment** that, at the time it was first **commissioned** exceeded the "base capex threshold" as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time, whether or not the investment would otherwise meet the test for "major capex".

interconnected grid means the grid including the HVDC link but excluding **connection assets.**

IPP means Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act 1986 from time to time. At the date of these **Guidelines** the relevant determination is the *Transpower Individual Price-Quality Path Determination 2015.*

large consumer or generator means an actual or potential user of **transmission lines services** (whether as load or generation) which could reasonably contemplate shifting its point of connection.

load customer means a designated transmission customer that is a distributor or direct consumer.

low-value means, in respect of a **benefit-based investment**, a **benefit-based investment** which does not meet the definition for a **high-value benefit-based investment.**

net private benefit means, for a designated transmission customer:

(a) the value of the private benefits which are consistent with **electricity market benefit or cost elements** that arise from the **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**; less

(b) the value of the private costs which are consistent with **electricity market benefit or cost elements** (but excluding the cost of the **benefit-based investment** itself) that arise from that **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**,

provided that Transpower may, at its discretion, include as part of the calculation the value of other benefits or costs where those benefits or costs are substantial and result from the **benefit-based investment.**

opex means "operating cost" as defined in the Commerce Commission's *Transpower Input Methodologies Determination 2010*, as amended from time to time.

peak charge means a charge, over and above nodal prices and the other **transmission charges** provided for in these **Guidelines**, imposed to influence peak demand for use of the grid.

positive net private benefit means for a designated transmission customer:

(a) the **net private benefit** if it is positive; or

(b) zero if it is not

post-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is first **commissioned** after the publication of the **2019 Issues Paper** (including any part of a **pre-2019 benefit-based investment** to the extent that it is **commissioned** after this date) and which at the relevant time of **commissioning** constitutes base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pre-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is **commissioned** on or before the date of publication of the **2019 Issues Paper** and which at the relevant time of **commissioning** would have constituted base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pricing year has the meaning given to it in the **IPP.**

reassignment means a reassignment of charges from the **benefit-based charge** to the **residual charge** due to a reduction in the value of an asset for the purposes of the **benefit-based charge**, and **reassignments** and **reassigned** have equivalent meanings.

regulatory asset base means, for a **pricing year**, the asset base used to determine **forecast MAR** for the **pricing year.**

remaining life means, for a **benefit-based investment**, the **benefit-based investment's** expected economic life at the time the relevant clause of the **TPM** applies.

residual charge means the charge as described in clause 39.

TPM means the transmission pricing methodology.

transmission lines services has the meaning given to it in the **IPP.**

transmission charges means the charges provided for by the **TPM**, as amended from time to time.

upgrading expenditure has the meaning given to it in clause 30.

value of commissioned assets has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

WACC means, for a **pricing year**, the pre-tax nominal weighted average cost of capital used to determine **forecast MAR** for the **pricing year.**

67. In these **Guidelines**, unless the context requires otherwise, any other term that is defined in Part 1 of the **Code**, and used but not defined in these **Guidelines**, has the same meaning as in Part 1 of the **Code**. Terms defined in Part 1 of the **Code** are underlined in these **Guidelines**.

Q9. What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

Schedule 1 Annual benefit-based charges for the benefit-based investments

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Alpine Energy	3.11%	0.85%	1.49%	2.98%	0.30%	0.24%	0.30%
Aurora Energy	5.71%	1.57%	0.90%	4.48%	0.30%	0.27%	0.30%
Beach Energy Resources (Kupe)	0.03%	0.07%	0.10%	0.08%	0.03%	0.04%	0.03%
Buller Electricity	0.27%	0.08%	0.12%	0.20%	0.03%	0.02%	0.03%
Centralines	0.07%	0.21%	0.24%	0.17%	0.05%	0.01%	0.05%
Contact Energy	2.11%	12.55%	23.98%	0.09%	5.96%	21.25%	5.96%
Counties Power	0.32%	1.06%	1.08%	0.85%	2.62%	1.41%	2.62%
Daiken Southland	0.28%	0.09%	1.38%	0.28%	0.02%	0.02%	0.02%
Eastland Network	0.17%	0.35%	0.56%	0.41%	0.05%	0.00%	0.05%
Electra	2.70%	0.79%	0.95%	0.67%	0.16%	0.14%	0.16%
Electricity Ashburton	1.70%	0.51%	0.76%	1.71%	0.26%	0.15%	0.26%
Electricity Invercargill	2.26%	0.59%	0.27%	2.19%	0.14%	0.12%	0.14%
Electricity Southland	0.12%	0.04%	0.05%	0.07%	0.01%	0.01%	0.01%
Genesis Power	1.22%	3.23%	0.00%	0.03%	3.66%	7.64%	3.66%
Horizon Energy	0.31%	0.36%	0.59%	0.66%	0.05%	0.00%	0.05%
MainPower	3.21%	0.88%	1.28%	2.95%	0.24%	0.20%	0.24%
Marlborough Lines	2.03%	0.45%	0.87%	1.87%	0.15%	0.12%	0.15%
Mercury	0.62%	0.00%	0.00%	0.00%	6.14%	10.53%	6.14%
Meridian	0.23%	33.70%	1.10%	0.05%	7.35%	0.00%	7.35%
Methanex	0.03%	0.06%	0.09%	0.07%	0.03%	0.04%	0.03%
Nelson Electricity	0.28%	0.06%	0.12%	0.23%	0.02%	0.02%	0.02%
Network Tasman	3.06%	0.71%	1.42%	2.57%	0.22%	0.18%	0.22%
Network Waitaki	1.13%	0.36%	0.52%	2.16%	0.13%	0.08%	0.13%
New Zealand Rail	0.04%	0.07%	0.10%	0.08%	0.20%	0.12%	0.20%
Nga Awa Purua JV	0.00%	0.00%	0.00%	0.00%	0.97%	8.00%	0.97%
Ngatamariki Geothermal	0.01%	0.00%	0.00%	0.00%	0.59%	4.86%	0.59%
Norske Skog	0.00%	0.00%	0.00%	0.00%	0.18%	2.47%	0.18%
Northpower	0.67%	1.13%	2.16%	1.78%	5.98%	2.90%	5.98%

Nova	0.10%	0.00%	0.00%	0.00%	0.21%	0.00%	0.21%
NZ Steel	0.30%	0.50%	0.96%	0.85%	2.47%	1.33%	2.47%
NZ Aluminium Smelters	22.04%	7.25%	2.12%	23.59%	1.61%	1.61%	1.61%
Orion	18.22%	4.88%	7.16%	14.69%	1.15%	1.00%	1.15%
OtagoNet JV	1.46%	0.41%	2.01%	2.03%	0.11%	0.11%	0.11%
Pan Pacific Forest Products	0.35%	0.47%	0.76%	0.69%	0.10%	0.00%	0.10%
Port Taranaki	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Powerco	4.02%	6.25%	8.55%	6.70%	1.91%	3.58%	1.91%
Resolution Developments	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Scanpower	0.05%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Southdown Generation	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.01%
Southern Generation	0.09%	0.01%	0.02%	0.16%	0.07%	0.64%	0.07%
Southpark Utilities	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
The Lines Company	0.16%	0.36%	0.47%	0.37%	0.18%	0.49%	0.18%
The Power Company	1.54%	0.34%	8.22%	2.04%	0.13%	0.12%	0.13%
Tilt Renewables	0.26%	0.01%	0.00%	0.00%	0.16%	0.00%	0.16%
Todd Generation Taranaki	0.24%	0.09%	0.00%	0.01%	0.26%	0.00%	0.26%
Top Energy	0.00%	0.24%	0.00%	0.00%	1.09%	0.51%	1.09%
TrustPower	0.01%	0.75%	0.00%	0.01%	0.16%	1.14%	0.16%
Tuaropaki Power	0.08%	0.06%	0.08%	0.07%	0.68%	0.13%	0.68%
Unison Networks	0.63%	1.34%	2.19%	1.60%	0.16%	0.00%	0.16%
Vector	5.51%	10.76%	18.95%	14.37%	51.26%	24.41%	51.26%
Waipa Networks	0.25%	0.59%	0.81%	0.64%	0.33%	1.01%	0.33%
WEL Networks	0.52%	1.13%	1.81%	1.41%	1.13%	2.36%	1.13%
Wellington Electricity	11.83%	4.24%	4.90%	3.21%	0.83%	0.65%	0.83%
Westpower	0.40%	0.09%	0.21%	0.46%	0.05%	0.03%	0.05%
Whareroa Cogeneration	0.10%	0.03%	0.00%	0.00%	0.02%	0.00%	0.02%
Winstone Pulp International	0.17%	0.29%	0.43%	0.36%	0.07%	0.00%	0.07%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Appendix B Reasons for policy positions in the proposed guidelines

Overview of this appendix

B.1 This appendix sets out the policy intent behind the proposed guidelines to inform stakeholders as to our reasons for preparing the proposed guidelines in their current form. It also sets out a number of potential alternative options relating to the details of the proposed guidelines (more high level alternatives are addressed in appendix E) as well as particular consultation questions we encourage stakeholders to address.

B.2 We acknowledge that there are a number of complex design decisions reflected in the proposed guidelines. While this appendix sets out the Authority's current proposal, building on the work we have undertaken to date, we remain open to considering all points of view and encourage submitters to consider all issues fully. Once we receive and consider feedback, we may decide to proceed with an option(s) other than our currently preferred option. We may also choose to combine options (where applicable) or modify them based on stakeholders' feedback. These final decisions on the design of guidelines will be made in light of the feedback received in response to this issues paper.

Overview of the proposal

Main components of the proposal

B.3 There are four main components in the proposed guidelines:

(a) A connection charge. The guidelines in relation to the connection charge are largely the same as under the current guidelines.

(b) A benefit-based charge.[110] This would seek to charge transmission customers for investments in the interconnected grid in proportion to the net private benefit they get from each investment.

(c) A residual charge. This would allow Transpower to recover anything remaining of its maximum allowable revenue.

(d) A prudent discount policy. This would allow for a reduction in a transmission customer's charges in circumstances where that is efficient.

B.4 In addition to the above four components, we are proposing a price cap to limit increases in transmission charges resulting from the proposal.

B.5 The Authority's view is that the connection and benefit-based charges, along with nodal pricing in the spot electricity market, will provide price signals for efficient grid use and efficient investment decisions and thus operate for the long-term benefit of consumers by reducing costs. The residual charge is designed to collect the remainder of Transpower's recoverable revenue with minimum impact on grid use and investment decisions.

Additional components

B.6 Under the proposed guidelines, Transpower would be required to consider whether to include any of the following 'additional components' in its proposed TPM:

[110] This is similar to the area-of-benefit (AoB) charge discussed in the second issues paper. When we discuss the benefit-based charge in reference to past TPM publications, we mean the AoB charge. The former name (AoB) does not now accurately describe the nature of the charge (which does not actually require an area to be defined).

(a) a method for determining how charges are recovered for transmission assets that are commissioned in stages

(b) a method for charging for connection assets that are modified so they would otherwise become investments in the interconnected grid if they continue to principally provide connection services

(c) a method for determining the amount to be recovered for new connection assets that is aligned to the method used for the benefit-based charge

(d) a transitional peak charge[111]

(e) a method for expanding the coverage of the benefit-based charge to include further benefit-based investments commissioned prior to the date of the publication of the 2019 issues paper ('pre-2019 investments'),[112] beyond the initial set of recent high–value investments listed in clause 13(b) of the proposed guidelines[113]

(f) a method for allocating operational and maintenance costs on an actual cost basis (as opposed to the use of allocation rules)

(g) a kvar charge on reactive load.

B.7 The proposed guidelines require Transpower to propose each additional component if, in its reasonable opinion, doing so would better meet our statutory objective than not including that additional component.

111 The draft guidelines in the supplementary consultation paper to the second issues paper made provision for what was called a LRMC charge. This has been dropped and replaced by the transitional peak charge. See the further discussion below at B.306 onwards.

112 The proposed guidelines now include an 'Interpretation' section, as proposed for example by Transpower in its submission on the second issues paper. Terms defined in the interpretation section have the same meaning when used in this appendix, unless the context requires otherwise. This includes the definition for a 'post-2019 investment', which is an investment to the extent that it is first commissioned after the publication of this paper (including any part of a pre-2019 benefit-based investment to the extent that it is commissioned after this date). A 'pre-2019 investment' is an investment commissioned on or before the date of publication of this paper.

113 To clarify: by a grid 'investment', we mean the grid infrastructure that results from an overall project, such as the North Island Grid Upgrade (NIGU) Project, which includes a large number of individual grid 'assets', such as transmission towers, conductors and transformers.

Comprehensive discussion of the proposal

Structure and interpretation

Proposal

B.8 The proposed guidelines have been structured so as to assist in their interpretation.

Discussion

B.9 The structure of the proposed guidelines has been improved from that in the 2016 issues paper so as to aid the reader in interpreting the guidelines. These changes take account of proposals by several submitters.[114]

B.10 The structure proposed broadly follows the structure proposed by Transpower in Annex B to its submission on the second issues paper.[115] For example, the proposed guidelines have a separate interpretation section which defines the key terms used in the proposed guidelines and in this chapter.

B.11 The guidelines include a brief initial section on our policy objectives for the guidelines. This sets out the proposed components of the TPM and explains the purpose of each. We would refer to this section if we needed to consider if the TPM has been implemented in a manner inconsistent with the Authority's policy objective under the 'TPM workability amendment' discussed in appendix F (if that Code amendment is made in the future).

General matters

Proposal

Clauses 1 - 8, proposed TPM guidelines (appendix A)

Discussion

B.12 The purpose of this section is to provide Transpower with guidance on how it is to implement the rest of the proposed guidelines, as well as requiring it to include certain general provisions in the TPM.

B.13 This section provides for Transpower, in developing the TPM, to take into account practical considerations and to provide a proposed TPM which differs in its details from the proposed guidelines where doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective. The reason these measures have been included in the general provisions is to provide greater flexibility to Transpower to develop all aspects of the TPM and to simplify the wording of the rest of the proposed guidelines by removing the need to include such provisions throughout.

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114 For example, the submission by Transpower on the second issues paper and the submission by E Grant Read for Meridian on the supplementary consultation paper. We note that throughout this Appendix there are references to submitters to the Authority's 2016 proposal. While we do not provide a detailed response to all points raised in our consultations relating to the second issues paper, the proposals discussed in this Appendix have developed out of our consideration of the many points raised by submitters (some of which are referenced, where relevant, in this Appendix). If you wish the Authority to consider again an argument or some evidence that you have provided in a previous submission, please feel free to cross refer to the specific place in your previous submission where the point is covered.

115 Clause 2 of Annex B of Transpower's submission.

B.14 Likewise, aspects of the remainder of the proposed guidelines generally allow more discretion than the draft guidelines in the second issues paper. For example, the second issues paper provided a specific fall-back method for allocating the benefit-based charge if the primary method was not practical. Instead, the relevant sections of the proposed guidelines now provide for Transpower to use a proxy for benefits in allocating the benefit-based charge, without specifying what the proxy should be. Similarly, the simple method for allocation of the benefit-based charge is defined separately from the standard method and by reference to the outcome it is intended to achieve.

B.15 The overall effect of these changes is to give Transpower wider discretion in interpreting and applying the proposed guidelines while ensuring any proposed TPM remains consistent with our statutory objective.

B.16 These changes take account of Transpower's submissions that care is needed to ensure the proposed guidelines direct Transpower by laying out clear principles for the TPM but do not unduly foreclose design options and that an overly prescriptive approach risks unintentionally foreclosing development options and adds unnecessary complexity.[116]

B.17 This section also deals with general issues relating to Transpower's reporting in respect of the proposed TPM and for consultation on proposed TPM charges. Transpower would not be required to consult with respect to investments valued lower than $20 million at the time of commissioning.[117] We developed the view (in the course of discussions with Transpower and the Commerce Commission on the workability of the proposal) that this was appropriate in order to reduce administrative burden.

B.18 The Authority considers that it would help customers in their decision making if they are well informed about how their charges are calculated and are able to see how their charges evolve over time. This will in turn increase efficiency, and thus benefit consumers in the long-term, by providing customers with the information necessary to make, or advocate for, the most efficient investment decision. Accordingly, the proposed guidelines include a requirement for Transpower to provide each designated transmission customer with information regarding the basis on which its benefit-based charge and residual charge have been set, including the extent to which the residual charge comprises unallocated opex. They also provide that Transpower is to make it clear exactly how it has calculated a customer's transmission charges, so that the customer could, if it wanted to, take the information and verify the accuracy of Transpower's calculations of its transmission charges.

B.19 The general guidance also provides that in assessing the net private benefit that a transmission customer (for example, a distributor) receives from a transmission investment, Transpower is to include the benefit received by each load or generation party that is indirectly connected through the transmission customer to the grid. That is, any benefit accruing to these parties would be attributed to the distributor. This addresses the issue that those who are actually affected one way or another by the TPM are not necessarily transmission customers. For example, if a transmission investment leads a mass-market consumer to enjoy lower electricity prices, the mass-market consumer is a beneficiary of the investment even though the legal incidence of the benefit-based charge for the investment is borne by the consumer's distributor and even though it is the consumer's retailer which participates in the energy market.

116 Transpower submission on the second issues paper, page 30, and on the supplementary consultation paper, page 30.

117 See discussion from paragraph B.121.

B.20 This section of the proposed guidelines also provides that transmission alternatives and transmission investments are to be treated in a consistent manner. This means for example that benefit-based charges would, if practical, be used to recover the costs of any payments by Transpower in respect of transmission alternatives (including distributed generation). This will ensure that transmission customers have appropriate incentives to weigh up transmission and transmission alternatives.

Q10. Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

Main components

Proposal

Clause 9, proposed TPM guidelines (appendix A)

Discussion

B.21 This clause sets out the main components proposed to be included in the TPM, and also the price cap.

B.22 It also provides that the total recovered by Transpower under these components may not exceed Transpower's forecast maximum allowable revenue (MAR). This is consistent with the TPM's function of allocating the recovery of Transpower's MAR between its customers.

Main component 1: connection charge

Proposal

Clauses 10 and 11, proposed TPM guidelines (appendix A)

Discussion

B.23 We propose that, apart from the matters covered in the additional components, the current guidelines[118] for charging for connection assets would be largely retained.

B.24 The reason is that we consider the current connection charge to be largely consistent with the principles of efficient transmission charging, as discussed in appendix D. This is because it charges parties for the cost of connecting them to the grid. It therefore provides parties with incentives to take connection costs into account in their own investment activity and operations, and to seek the connection option (or an alternative to connection) that most cost-effectively meets their needs.

B.25 These principles are even more important in the context of New Zealand's broader policy goal to reduce carbon emissions. The current connection charge provides parties seeking to electrify load or to build low-emissions generation with the incentive to choose the option

[118] Throughout this paper, references to the 'status quo', 'the current guidelines' or the 'current TPM' should be read as the guidelines and TPM in effect as at the date of publication of this paper.

that achieves lower emissions at lowest cost to the economy as a whole. This should result in lower electricity prices for all electricity consumers over the long run.

B.26 Many submitters on this proposal were broadly of the view that the current connection charge is efficient, and that a change from the status quo would not result in improvements.[119]

B.27 We do propose some related changes in the detail of the guidelines for connection charges to be adopted if, in Transpower's reasonable opinion, they would better achieve the Authority's statutory objective. These are included in Additional Components A to C and F.

Q11.	**Should the current guidelines on connection charges be largely retained or are changes required?**

B.28 We have considered whether any changes are required to connection charges in order to address 'first mover disadvantage'.[120] For example, it may be that it would be efficient in the medium to long term for a new connection investment to be constructed at a scale large enough to accommodate multiple new generators (particularly in a context where renewable generation capacity is growing rapidly). However, the first generator to connect to such an investment may be subject to high charges in the initial period before other generators have connected, and might also bear the risk that the later expected generation connections fail to eventuate. This might inefficiently reduce the number of new generation connections.

B.29 We see three main options:

(a) allow the cost recovery profile for the connection investment to be backloaded (for TPM purposes only)

(b) allow the asset values for the connection investment to be reduced (for TPM purposes only) in the event that the expected connections do not show up

(c) do not attempt to address the issue via changes to the TPM (this is currently our preferred option).

B.30 Option (a) could be used to reduce the connection charges paid by the first generator to connect. The difference in cost would instead be borne by load customers through the residual charge. This would help to address first mover disadvantage. However, it could also lead to inefficient investment decisions. This is because the connecting customer would have less incentive to take into account the costs of transmission in making decisions about its own investment, to the extent it bears a lower proportion of the costs of the grid investment. For example, it could decide to locate in a very remote place requiring an inefficiently large connection investment. This could result in higher costs for the system as a whole (unnecessarily raising electricity prices).

B.31 Option (b) could be used to remove the risk that the later expected generation connections fail to show up from the first generator. The risk would instead be borne by load customers.

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119 For example:

- in submissions on the 2016 TPM proposal, Meridian, Nova Energy, PowerNet, PWC for 14 EDBs
- in submissions on the TPM connection charges working paper published by the Authority on 13 May 2014 (the 'connection charges working paper') Contact (p.1), Counties Power (p.4), ENA (p.6), Fonterra (p.3), MRP (p.1), Orion (p.1), Pioneer (p.1), Transpower (pp.1, 9), Vector (p.3).

120 See, for example, Fonterra's submission on the second issues paper and Transpower's submission to the Electricity Price Review, October 2018, Part Four: Industry: Generation (response to question 14)

This would help to address the first mover disadvantage. However, it could also lead to inefficient investment decisions. This is because it would require other transmission customers to cross-subsidise the connecting customer, so it would have an inefficiently weak incentive to carefully assess the likelihood that the other connection customers could indeed be expected. This could result in overbuilt connection investments, and higher costs for the system as a whole.

B.32 We are not proposing either option (a) or option (b), because of the potential inefficient outcomes noted in the previous paragraphs. So our current preference is not to make any changes to the TPM in order to address the issue; that is, we prefer option (c).

B.33 There are likely to be other ways to address first mover disadvantage that do not involve changes to the TPM. We would be open to considering other potential avenues outside the scope of the TPM review. In this paper we therefore do not discuss in detail any other options for addressing this issue that fall outside the ambit of the TPM.

B.34 However, we do note that Transpower is able to contract with a customer to make an investment outside the standard regulatory framework (that is, the framework governed by the Commerce Commission's Capex Input Methodology for transmission investment and the TPM). The terms of these new investment contracts can be relatively flexible. For example, such a contract could potentially allow the profile of payments for the investment to be back loaded and / or could allow for a customer's payments to be reduced in the event that the expected connections do not show up. This may allow for a more efficient allocation of costs and of risk, compared to options (b) and (a). This is because it may allow for Transpower and its customer to reach agreement on an efficient allocation of both cost and risk, including the risk of the other parties not materialising, between themselves through a process of commercial negotiation. The cost and risk could be shared between the contracting parties, rather than spread across all load customers. This could help to avoid the risks of inefficient connection investments identified above.

B.35 However, we are conscious that addressing first mover disadvantage and achieving the efficient results discussed in the previous paragraph may require changes to other regulations including some that are outside the Authority's jurisdiction. This may be an issue that requires coordination across more than one agency. We will not consider this issue any further here as it is outside the scope of the TPM review.

Q12. Should first mover disadvantage be addressed in the TPM, and if so how?

Main component 2: benefit-based charge

Proposal

Clause 12, proposed TPM guidelines (appendix A)

Discussion

B.36 The proposed guidelines require that the TPM include a benefit-based charge (benefit-based charge).[121]

B.37 The Authority is proposing a benefit-based charge because it would seek to, as far as is reasonably possible:

(a) allocate the cost of each investment in the interconnected grid to those who benefit from it, in proportion to the size of their net private benefit from the investment[122]

(b) fully recover the costs of each investment in the interconnected grid, so such costs need not be recovered through the residual charge (the benefit-based charge would eventually apply across all, not just to a few, grid investments).

B.38 We are proposing that the full cost of each new investment in the interconnected grid be recovered from users of that investment because, as is summarised later in this appendix and is discussed in more detail in appendix D, it provides users of the interconnected grid with better incentives to take into account the cost of providing them with access to the grid

121 Many although not all submissions on the second issues paper supported the introduction of a benefit-based charge, although often with some reservations or qualifications. One reason for this support is that the charge is designed to be service-based and cost-reflective. See, for example, E-Type Engineering, Enernoc, Gore District Council, Grey Power Southland, Invercargill District Council, Market South, McIntyre Dick and Partners, Meridian, Northpower, Nova Energy,, Oji Fibre Solutions, Otago Chamber of Commerce, Otago Southland Employers' Association, Preston Russell Law, Sarah Dowie, South Port New Zealand, Southland Chamber of Commerce, Southland District Council, Southland Manufacturers Trust, Stabicraft Marine, Venture Southland, Winstone Pulp. Others:

- did not favour a benefit-based charge in principle. (For example, Axiom for Transpower considered that the AoB methodology would not have the property of an efficient pricing methodology, which is to elicit desirable behavioural changes before investments are made, and stop undesirable behavioural change after investments are made);
- thought there were practical difficulties with it (for example, Alpine Energy, Unison, Waitaki Power Trust).

We disagree with those who did not favour a benefit-based charge for the reasons discussed in Appendix D and this appendix. We have also endeavoured to design the proposal to take account of the potential practical difficulties (for example, by allowing a proxy for the estimation of benefits).

122 This principle of charging users in proportion to their share of the benefits is consistent with the Authority's decision making and economic framework. For example, the Authority's document *Decision making and economic framework for transmission pricing methodology: Decisions and reasons* states at paragraph 35 that "The Authority's interpretation of its statutory objective takes a net-benefits approach to determining efficiency". In particular, the market-based, exacerbators pay, and beneficiaries pay approaches are all consistent with it. For example, a market-based approach involves a voluntary exchange, which ensures that a customer has the incentive to contract for use of an asset if and only if the benefit it derives from the asset exceeds the cost.

The reason that the Authority prioritises the approaches (in the order of market-based, exacerbators' pay, and beneficiaries pay) is that those ranked higher in this hierarchy are more market-like, in the sense that they:

- devolve to market participants the authority and responsibility for making (and modifying) the investment and charging decisions, as opposed to these being administratively determined.
- sheet home the costs of those decisions to those who make or benefit from those decisions

Those ranked higher are therefore more likely to promote ongoing dynamic and static efficiency gains.

when making their own decisions about their own investment, about using the grid and about whether to support grid investments.[123]

B.39 The Authority considers this reform to be consistent with New Zealand's broader policy goal to reduce carbon emissions. Benefit-based charging would encourage parties seeking to electrify load or to build low-emissions generation to take into account the costs of any upgrade to the interconnected grid that may be required due to their decision. This encourages them to choose the option that achieves lower emissions at lowest cost to the economy as a whole. By avoiding unnecessary cost, this results in lower prices for electricity consumers over the long run. By contrast, incurring unnecessary cost raises the price of electricity, which could discourage consumers and businesses from switching from fossil fuels to electricity.[124]

B.40 The next four sections describe how a customer's annual benefit-based charge for an investment would be calculated.

(a) The next section describes the investments that would be subject to the charge

(b) The section *Benefit-based charge must recover the covered cost of benefit based investments* describes how the total amount (net present value) of the charges for each investment would be calculated

(c) The section *Recovery of the covered cost of a benefit-based investment over time* describes how that total amount would be recovered year by year from transmission customers collectively; that is, it describes how to calculate the annual benefit-based charge for the investment

(d) The section *Allocating annual benefit-based charges among customers* describes how this total annual charge for the investment would be allocated between individual transmission customers.

B.41 Subsequent sections deal with more detailed adjustments and implementation issues.

123 A number of submitters on the supplementary consultation paper agreed that the AoB charge (now the benefit-based charge) is cost-reflective and service-based. For example, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, University of Otago.

However, other submitters on the supplementary consultation paper disagreed. Trustpower and Houston Kemp for Trustpower suggested that the AoB charge is neither service-based nor cost-reflective. They consider it is not service-based because it is not applied to a service that can be isolated from other services provided by the network as a whole, and it is not cost-reflective because it reflects benefits. Transpower suggested that the AoB charge will not provide a price signal. Other submitters did not agree that the AoB charge would send desirable price signals. For example, Employers and Manufacturers Association (Northern), MediaWorks.

We disagree with the second group of submitters for the reasons outlined in this appendix and in more detail in appendix D. For example, we consider that a benefit-based charge for use of the grid is analogous in concept, though not in detail, to the example of charging for a hotel bed-night given in appendix D. Our view is that the benefit of providing such a price signal is clear and is demonstrated by the example that Littlechild gives of the grid investment process in Argentina – see footnote 173.

124 See Productivity Commission, *Low-emissions economy - Final report*, August 2018, p.400 (Finding 13.3). Available at https://www.productivity.govt.nz/inquiry-content/3254?stage=4

Benefit-based charge must apply to benefit-based investments

Proposal

Clause 13, proposed TPM guidelines (appendix A)

Discussion

B.42 In our view, allocating the costs of *future* grid investments on the basis of benefits would promote more efficient decision-making, thus reducing costs and generating long-term benefits for consumers. As is discussed further in appendix D, transmission customers that are required to pay a benefit-based charge for a future grid investment will have an incentive to take transmission costs into account in making decisions about their own investments and use of the grid. They will also have a stronger incentive to engage with the Commerce Commission's decision-making process about proposed grid investments. The efficiency of a benefit-based approach to cost allocation is recognised in the economic literature.[125]

Q13. Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

Should the benefit-based charge apply to past investments?

B.43 However, with respect to past investments we have to make an important design choice. We need to decide whether or not to apply the benefit-based charge to pre-2019 grid investments. This is a difficult decision as the various options have their pros and cons.

B.44 Reflecting this, the views of submitters this subject were also quite mixed. Many submitters on the second issues paper thought historical investments should be included.[126] Of these there was a split between those who thought the benefit-based charge should apply to all pre-2019 investments and those who thought it should apply to a more limited set of investments. Reasons given were varied, but included efficiency concerns, durability

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125 An approach to allocating the cost of transmission investments on the basis of benefit is proposed by W Hogan (2011). All academic references are cited in full in the Bibliography.

Professor Hogan is a leading global authority on electricity markets and transmission pricing. He says

> The attraction of the principle that the beneficiaries pay for transmission investment has dimensions of both fairness and efficiency. The fairness criterion is important especially because the cost allocation principles apply to mandated transmission investments that exploit the power of government to compel participation. The emphasis here, however, is on the effect of cost allocation principles on the efficiency of electricity system framework."

Rivier et al (2013), pg 272 ff makes a similar point. The authors state that:

> Short-term signals given by locational energy pricing such as nodal or zonal prices provide incentives for optimal and efficient system operation and for allocating limited interconnection capacity. Their expected value also provides a useful signal for future investors. Long-term signals, given by locational transmission charges, are needed to share the allowed revenues from regulated transmission installations among grid users, while encouraging new supply and demand-side actors to locate efficiently.

The authors also state (pg 293-294) that "The allocation of the cost of a transmission network among its users must obey some basic principles that result from the combination of microeconomic theory, power systems engineering and sound regulatory practice". Specifically "…[four high level] solid principles' have been established" for the allocation of the cost of a transmission network among its users", the first of which is to "allocate costs in proportion to benefits".

126 Eg, Submission on the second issues paper by Contact Energy , Gore District Council, Invercargill District Council, Oji Fibre Solutions , Nova Energy, Pacific Aluminium, Southland District Council, Unison, Venture Southland.

concerns, the desirability of avoiding 'grandfathering' of charges and the desirability of prices that reflect costs.

B.45 On the other hand, there were many submitters on the second issues paper[127] and supplementary consultation paper[128] who thought the benefit-based charge should be applied only to post-2019 investments. Again reasons given were varied, but included avoiding creating uncertainty, efficiency, durability and the desirability of avoiding wealth transfers.

B.46 The three options that we are considering are as follows.

B.47 The first option would be to apply the benefit-based charge only to future grid investments and recover the costs of past investment through the residual charge. This option (which has been assessed in the CBA[129]) has relatively low implementation costs and would avoid the potential difficulties that might arise in implementing a benefit-based allocation for the costs of existing grid assets. It would still promote more efficient decision-making about new investment in the grid (for example, by encouraging transmission customers to take into account the impact of their decisions on the need for new grid investments). The revenue recovered from load customers via the residual charge would be high initially, but would reduce over time as the value of historical grid investments in Transpower's asset base reduced with depreciation.

B.48 The second option would be to apply the benefit-based charge only to future grid investments and recover other costs from the parties that currently pay transmission charges, in proportion to their current payments. This could be arranged via an alternative specification of the residual charge (payable by all transmission customers) that was allocated in fixed proportions (determined by fixing the current allocation of RCPD and HVDC charges). This is similar to the first option; however it would not involve any initial reallocation of charges. Distortions to grid use would be avoided, as charges would be fixed (as opposed to varying according to grid use as with the RCPD and HVDC charges). Revenue recovered from load and generation customers via this alternative residual charge would reduce over time with depreciation.

B.49 The third option (currently our preferred option) is to include some pre-2019 investments in the list of benefit-based investments.

B.50 If we adopt the third option, we would be diverging from overseas precedent. None of the three independent system operators (ISOs) or regional transmission operators (RTOs) we met in the United States applies a benefit-based approach to recover the costs of existing assets.[130] Instead, the costs of such investments tend to be spread more widely.

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127 Eg, Air Liquide, Auckland Airport, Counties Power, Electricity Ashburton, KiwiRail, Mighty River Power, PWC for 14 EDBs, TECT, Top Energy, Trustpower.

128 Eg, Houston Kemp for Trustpower, Covec, Counties Power, Counties Power Consumer Trust, Northern Federated Farmers, Trustpower, Auckland Airport, Axiom for Trustpower, Trustpower, CEC for Trustpower, Bushnell/Wolak for Trustpower, Professor Yarrow for Trustpower, Vector, Entrust, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower

129 See Chapter 4

130 See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

B.51 Further, when we spoke to Professor Hogan during our visit to the United States, he did not approve of applying beneficiaries-pay to historic investments. Rather, his general view was that it is best to allocate the costs of existing assets in a way that does the least harm and avoids as much distortion as possible.[131] That said, Professor Hogan also acknowledged that where an existing cost allocation for historic investments is grossly unfair or is distorting future investment decisions then a revision may be appropriate. However, in making such revisions, great care had to be taken to avoid causing more harm.

B.52 We engaged further with Professor Hogan on this issue after our visit to the United States. We provided him with a discussion paper setting out the pros and cons of recovering the costs of historical transmission investments through a benefit-based charge.[132] In a subsequent discussion with the Authority Board in May 2018,[133] Professor Hogan said that there was nothing that he was aware of that was inefficient or inappropriate in applying beneficiaries-pay to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered (such as the provisions for reassignment in the case of under-utilised assets). (We also note that the potential for inefficient exit is limited by the price cap. We are unaware of any reasons why the proposal would lead to a risk of inefficient entry.)

B.53 We tested the first option as well as the third option in the CBA, and found the quantified net benefits of $2.729 billion for the first option and $2.711 billion for the third option (the Authority's main proposal). Both these estimates fall within a similarly broad range of around $0.2 billion and $6.4 billion. As explained earlier in this paper, the difference between the two options is not material within the context of the net benefits (a difference of less than 1%). Further, the assessment does not take into account unquantified factors.

B.54 Our current view, based on qualitative analysis, is that the third option is the best approach. In particular, we think recovering the costs of some past investments via the benefit-based charge would significantly improve the efficiency of the TPM, for the reasons set out in appendix D (paragraphs D.66 to D.72 below) and for the following related reasons:

(a) It would ensure that customers who do not benefit from these investments would not have to continue paying (through the residual charge) for these pre-2019 investments, whilst also paying (through the benefit-based charge) for their share of the cost of future investments from which they do benefit.[134] Christchurch consumers, for example, could expect to pay the lion's share of the cost of the planned Upper South Island voltage stability project,[135] in addition to paying 9% of the costs of historical projects that benefit mainly North Island consumers.[136] If the charge were applied only to post-2019 investments, it could undermine the viability of some parties

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131 See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

132 Electricity Authority, *Should beneficiaries pay for existing grid assets? Pros and cons of applying an area-of-benefit charge to recover the costs of historical transmission investments*, 8 May 2018

133 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

134 Several submitters to the TPM options working paper (16 June 15) made this point, including for example Orion (p.9) and Alliance Group (p.2). The TPM options working paper is available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374.

135 The planned Upper South Island voltage stability project involves a switching station at Rangitata and a new line to Islington. It is expected to be delivered over 2022 – 2035 at a cost of $283m. Transpower, *Securing our Energy Future 2020 – 2025, Regulatory Control Period 3 Proposal*, November 2018, p.40, Table 10

136 Under the current TPM Orion is expected to pay around $7 million each year towards the costs of just three of the big North Island investments (the North Island Grid Upgrade, UNI reactive support and the Wairakei Ring).

who might be viable if the charges better reflected their share of the costs and benefits of providing them with access to the interconnected grid. It would also result in perceptions of unfairness, undermining the durability (and therefore efficiency) of the regime. This lack of durability could put the overall benefits of the proposal at risk. It would also perpetuate policy uncertainty for investors, and thereby increase the cost of investing, and lead to further resource costs due to ongoing lobbying.

(b) It would address the concerns of some stakeholders with the current TPM that their charges do not reflect the underlying cost of providing them with transmission services and the benefits they receive.

(c) It would discourage rent-seeking behaviour in the future, as it would signal to the market that we are not willing to grandparent historical inefficient regulations. This would reduce any incentive participants have to seek out inefficient regulatory loopholes, as they would anticipate that we would close them when we became aware of them. This would promote dynamic efficiency.

(d) It would improve efficiency by providing information about the value of future investments (as Professor Littlechild noted in his 2016 report).[137]

B.55 Contrary to the views of some commentators[138], changing the charges on pre-2019 investments would not be retrospective. This approach is no different in principle from the government changing the tax rate on existing investments, which is the normal way tax changes are made. The charge would only be retrospective if the *past* charges for the pre-2019 investment were changed. This is not proposed.

To which past investments should the benefit-based charge apply?

B.56 If past investments are to be included, the next decision to be made is to which pre-2019 investments the benefit-based charge will apply. We see several options, as follows. The options are that the benefit-based charge applies to:

(a) all pre-2019 investments except the HVDC assets (and the HVDC charge is retained)

(b) the HVDC assets only (other pre-2019 investments recovered via residual charge)

(c) all pre-2019 investments

(d) a subset of pre-2019 investments including the HVDC (currently our preferred option).

B.57 An important aspect of this issue concerns the treatment of the HVDC assets. Submitters on the second issues paper had mixed views[139] on whether the HVDC assets should be covered by the benefit-based charge.

B.58 One option would be to retain the HVDC charge (and so continue to recover HVDC costs only from South Island generators). An argument for this option would be that South Island

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137 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016, page 14.

138 For example, a submission by PWC for 14 EDBs on the second issues paper. Similarly, we do not agree with the submissions of NZ Steel and Orion that the basis proposed for the residual charge in the second issues paper was retrospective.

139 Several submitters on the supplementary consultation paper (eg, Counties Power, Counties Power Consumer Trust, Unison, Centralines, Trustpower, Yarrow for Trustpower, Houston Kemp for Trustpower) and on the second issues paper (NZIER for MEUG, PowerCo) suggested there is a case for retaining the HVDC charge, for example because it enhances transparency and avoids large wealth transfers for limited and uncertain efficiency gains. On the other hand, NERA for Meridian submitting on the second issues paper thought HVDC assets should be included so as to place generators on a competitively neutral footing.

generators are the key beneficiaries of the HVDC link as it enables them to provide electricity to consumers in the North Island (so arguably the current HVDC charge is already a crude benefit-based charge and so no further change to it is required).

B.59 However, in our view the benefits of the HVDC link need to be re-assessed. The beneficiaries of the HVDC link are now broader than the beneficiaries that were contemplated when it was originally decided that HVDC costs should be recovered only from South Island generators. The change in beneficiaries has come about as the result of operational changes. Changes made since the HVDC was originally commissioned include the commissioning of Pole 3 and the decommissioning of Pole 1, and the establishment of a national reserves market and frequency keeping arrangements. The HVDC link now provides more widely spread benefits such as through its role in the provision of ancillary services.

B.60 Further, in 1996 there was no prospect of additional South Island generation being built. Gas-fired power stations were expected to be the most cost-effective way to deal with anticipated growth in the upper North Island. In recent years this situation has changed, and renewable resources – including South Island generation – are now expected to play a greater role relative to gas generation (as illustrated in the Productivity Commission's Low-emissions economy paper of August 2018[140]). The HVDC link will therefore have widespread benefits, to North Islanders as well as South Islanders, for example by allowing anticipated demand growth to be met efficiently by generation located in both islands.

B.61 Our current view is that these changes mean that it is appropriate to revise the allocation of charges and justify HVDC costs being recovered through the benefit-based charge.

B.62 We are proposing that all HVDC assets be covered by the benefit-based charge, including those that were commissioned before May 2004.[141] These pre-2004 HVDC assets have been included because, unlike other pre-2004 investments, they are relatively easy to identify and because including them will:

(a) ensure that those who benefit from the HVDC link pay for it

(b) ensure that all assets that form part of the HVDC link are charged for it on a consistent basis

(c) promote durability.

B.63 The next question is whether to recover the costs of only the HVDC assets through the benefit-based charge, or whether to extend it to other pre-2019 investments.

B.64 We do not consider it would be appropriate to limit the benefit-based charge to recovering the costs of only the HVDC assets. In our view, recovering the costs of a wider subset of pre-2019 grid investments via the benefit-based charge would better promote the efficiency of the TPM, for the reasons set out at paragraph B.54. These reasons apply as much to transmission assets in the interconnection category as to those in the HVDC category.

B.65 However, we are not proposing to extend the benefit-based charge to *all* pre-2019 grid investments. We currently prefer to apply the charge to a subset largely restricted to recent, major investments. The seven investments in clause 13(b) of the proposed guidelines:

(a) were approved after May 2004 (other than HVDC Pole 2, which is older)

140 Available at https://www.productivity.govt.nz/inquiry-content/3254?stage=4

141 In its submission on the second issues paper, Contact Energy proposed that all HVDC assets should be included in the AoB charge

(b) had an approved value over $50 million at the time the investment was approved

(c) have estimated benefits exceeding their cost.

B.66 We are proposing to restrict the charge's coverage based on date and cost because the benefits of applying the benefit-based charge to pre-2019 investments need to be traded off against the additional costs of applying the benefit-based charge to those investments. The $50 million threshold limits the application of the charge to a relatively small number of investments, which should reduce implementation costs. However, it still captures a large part of the total value of pre-2019 investments that have been approved since May 2004, effectively addressing the issues discussed in paragraph B.54 above. Also, there is relatively good information available for investments approved since May 2004.

B.67 We are proposing to restrict the charge's coverage to those investments that have estimated benefits exceeding their cost for the following reasons. For a pre-2019 benefit-based investment, unlike for an efficient new investment, it is possible that the benefits that transmission customers collectively are now expected to get from that investment might be less than the covered cost. This could occur, for example, because the benefits that the investment is now expected to provide are quite different from the benefits that were expected when the investment was made. We are of the view that it would be inappropriate to set initial benefit-based charges for these investments that exceed the benefits they are now expected to yield. We have put this into practice by choosing initially to apply the benefit-based charge only to pre-2019 investments where we estimate that the benefits exceed the covered cost.[142]

B.68 We are open to the view that it may be preferable for more (potentially all) pre-2019 investments to be subject to the benefit-based charge. We have therefore allowed Transpower (via Additional Component E) to subject more pre-2019 investments to the benefit-based charge if to do so would promote our statutory objective.

Q14. Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

Q15. Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

142 We have also put this into practice by explicitly including a cap on the initial benefit-based charges for any other pre-2019 investment that is included by the application of Additional Component E.

Benefit-based charge must recover the covered cost of benefit-based investments

Proposal

Clause 14, proposed TPM guidelines (appendix A)

Discussion

B.69 For the reasons described above and in appendix D, we are proposing that transmission customers who benefit from a transmission investment would collectively pay a benefit-based charge equal to the covered cost of the investment (as defined below), unless a variation is specifically allowed by the guidelines. This section of the proposal describes how to calculate the covered cost of the investment.

B.70 The costs to be included in the covered cost depend on when the investment is commissioned. For a post-2019 investment, the covered cost is the net present value of the total cost calculated over the entire life of the investment. For a pre-2019 investment, the covered cost is the net present value of the depreciated capital cost in Transpower's regulatory asset base at the time the benefit-based charge is first applied to the investment, the cost of capital on that amount, and all the other costs attributed to the investment from the time the benefit-based charge is first applied to it.[143]

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143 This is consistent with some submissions on the second issues paper that depreciated assets should not be charged for in a way that allows Transpower to recover more than they are worth / recover their costs more than once. For example, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland.

This treatment is different from what would happen in workably competitive markets. As discussed in appendix D, in workably competitive markets, assets would continue to be charged for so long as they continued to provide services. Further, because transmission is a utility-type services, the charges in each year would not depend on the age of the investment providing the service. These charges would continue so long as the investment continued to provide those services, irrespective of its initially expected life. Competition in the product market would then set the level of prices for transmission services to just recover the cost of the assets, including a normal return on capital. If transmission charges were set in this way, they would come to resemble a tilted postage stamp over time (with the critical difference that beneficiaries of new transmission investments would face, and so have the incentive to take into account, the cost of new transmission investments in their decision making).

The different treatment proposed here is necessary in part because, for good reason, the Commerce Commission regulatory regime requires that Transpower recovers no more than the full cost of each new investment. Our view is that, given this, any method of transmission pricing will be imperfect, in the sense of leaving in place some adverse incentive that would be eliminated in an ideal world.

As is discussed in more detail in this section and in appendix D, the treatment we propose here (where the charges recover just the covered cost of the investment from those who benefit from it) ensures that transmission users have an incentive to take account of the cost of the impact on new transmission investment of their own investment and use decisions, and to seek replacement investment only when the benefit to New Zealand of that replacement investment exceeds its cost. However, it means that charges differ from what we would expect to see in workably competitive markets. In particular, it is one reason that Transpower's customers will pay different charges for the same level of service based on the age of the transmission asset supplying them (as Northpower noted in its submission on the supplementary consultation paper) which could lead to inefficient incentives on load and generation when they are making locational decisions. This potential inefficiency is taken into account in the CBA discussed in chapter 4. (Another reason that charges vary with the age of the investment is the way the costs of an investment are recovered over time, as is discussed below).

We consider that it is impossible to eliminate this locational distortion except by spreading the costs of both new and existing investments widely (for example, through tilted postage stamp pricing). However, spreading costs widely would forgo the advantages of applying the benefit-based charge to new investments discussed in this appendix and appendix D.

B.71 The covered cost of the investment therefore includes any cost attributable to the investment. Thus, for example, it would include the cost of site preparation and decommissioning of the investment if that is necessarily incurred as part of undertaking the investment. Allocating expenses to the asset to which they are attributable would better promote efficient grid use and investment (and therefore a reduction in costs, producing long-term benefits for consumers). That is because these costs would then be recovered through the benefit-based charge relating to the investment in question, so the transmission customers that benefit from the investment would face its full cost and take that into account in their decision-making.

B.72 Opex for connection investments is currently spread across connection customers using broad cost allocation rules. In a similar manner, the proposed guidelines will allow Transpower to use broad cost allocation rules to allocate opex to benefit-based investments. Additional component E requires Transpower to consider attributing operating and maintenance expenditure to the investment they are spent on without using a proxy or generalised allocation rule if that would better achieve our statutory objective.

B.73 Transpower's unallocated expenses (mainly overheads) for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16. If any of these overheads are attributable to a benefit-based investment, they would, under this proposal, be included in the covered cost of the investment.[144] In that case, this would reduce the level of unallocated expenses so that it represents, as much as practicable, only true 'common costs'.[145] These would be recovered through the residual charge, as discussed below.

Q16. How should the covered cost of the investment be defined?

[144] Some submissions on the second issues paper proposed this; eg, MEUG, NZIER for MEUG, Southport NZ.

[145] Common costs are costs that are incurred irrespective of the addition of a customer or service.

Recovery of the covered cost of a benefit-based investment over time

Proposal

Clauses 15 - 17, proposed TPM guidelines (appendix A)

Discussion

B.74 This section of the proposal addresses how the total benefit-based charge for an investment would be converted to annual charges (the 'annual benefit-based charges'). This determines when in an investment's life the charges are paid. The annual benefit-based charges for an investment are set so the net present value of those charges is equal to the benefit-based charge for the investment.

B.75 We need to make a number of decisions in this area. We need to decide whether to use the method used by the Commerce Commission or another methodology we call indexed historical cost ('IHC'). And we need to decide which of these methods to apply to future (post-2019) investments, and which to apply to past (pre-2019) investments. There are a number of options, including applying:

(a) the Commerce Commission method for both future and past investments

(b) IHC for both future and past investments

(c) IHC for future investments and the Commerce Commission method for past investments (this is currently our preferred option).

B.76 Submissions were quite mixed on which method is most appropriate and in their reasons for favouring particular approaches.

B.77 Some favoured DHC or opposed IHC because:

(a) DHC would result in market-like outcomes, since workably competitive markets with characteristics like transmission investment are characterised by long-term contracts whose typical features include charges that are higher in the earlier years of the asset's life than in later years and that reflect conditions at the time that the contract was made[146]

(b) IHC would not reflect the realities of a workably competitive market and would be contrary to the approach of the Commerce Commission. This could result in misalignment and divergence from the revenue requirement, and may not pass the test of consistency with clause 12.89 of the Code[147]

(c) the probability of technological change supports charging for a greater proportion of the costs of assets in the near future, when the nature of demand for transmission and distribution services is clearer[148]

(d) for pre-2019 investments, IHC could result in charges for some investments exceeding the cost of the investment, which might be subject to legal challenge[149]

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146 For example, Yarrow for Trustpower submission on supplementary consultation paper, Pacific Aluminium cross-submission on supplementary consultation paper.

147 For example, submission on the supplementary consultation paper by NERA for Meridian Energy, Littlechild for Meridian, Pacific Aluminium, New Zealand Aluminium Smelter.

148 For example, Littlechild for Meridian submission on the supplementary consultation paper, Meridian cross-submission on supplementary consultation paper.

149 For example, submissions on the supplementary consultation paper by: Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type

(e) developing IHC would be unnecessarily complex[150]

(f) arguments for IHC are based on a false scientism and are not informed by pragmatism[151]

(g) if IHC is adopted, the balance between IHC and DHC on each investment will need to be recovered through the residual charge. This impact on the residual charge needs to be taken into account in determining whether IHC or DHC is preferable. Furthermore, the result may not be durable.[152]

B.78 Some favoured IHC or opposed DHC because:

(a) an IHC method is more market-like than DHC[153]

(b) an IHC method for valuing existing assets is consistent with service-based pricing, and in a competitive market, suppliers would charge for services and not individual assets[154]

(c) DHC will not deliver outcomes that are market-like/consistent with competitive markets. This is because charges will be based on the age of an asset, rather than the level of service the asset provides[155]

(d) DHC would result in transmission charges falling as transmission becomes constrained, and as aggregate private benefits and LRMC increase, which would not provide dynamically efficient price signals, and would not be consistent with the beneficiaries-pay principle[156]

(e) using DHC for pre-2019 investments would create an inconsistency between benefit-based investments and connection investments[157]

(f) arguments for using DHC are flawed, as prices in other markets (eg, mobile telephone services) do not depend on the age of the asset providing the service.[158]

B.79 Some proposed that the same method should be used for pre-2019 and post-2019 investments on the basis that calculating the AoB charge (now the benefit-based charge) should be as time-neutral as possible.[159]

Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Contact Energy, E. Grant Read for Meridian, Meridian, NERA for Meridian, Littlechild for Meridian, Pacific Aluminium. In accordance with these submissions, the proposed guidelines provide that the benefit-based charge should recover the covered cost of the investment, which takes account of the depreciation that has already been recovered on pre-2019 investments.

150 For example, submission on the supplementary consultation paper by Axiom for Transpower, Pacific Aluminium,

151 Meridian, cross-submission on supplementary consultation paper.

152 Pacific Aluminium, submission on the second issues paper and cross-submission on supplementary consultation paper.

153 Counties Power and Vector, cross submission on supplementary consultation paper.

154 Houston Kemp for Trustpower, cross-submission on supplementary consultation paper.

155 For example, Vector, Counties Power, cross-submission on supplementary consultation paper.

156 Transpower, cross-submission on supplementary consultation paper.

157 Vector, cross-submission on supplementary consultation paper.

158 For example, Counties Power and Vector, cross-submission on supplementary consultation paper.

159 For example, submission on the supplementary consultation paper by Transpower and cross-submisison on the supplementary consultation paper by PWC for 14 EDBs and Vector.

IHC for future investments

B.80 For each post-2019 investment, we propose that Transpower determine the recovery profile over time for the purposes of the benefit-based charge using a methodology we call indexed historical cost ('IHC').

B.81 Under the IHC approach, Transpower would set the annual benefit-based charges for post-2019 investments by dividing the expected[160] benefit-based charge into equal annual amounts over the benefit-based investment's expected life. This would then be adjusted for inflation. In other words, the annual benefit-based charge for the investment would change over time in line with a price index, unless Transpower makes one of the other adjustments discussed below.

B.82 Transpower would decide on the price index it will use in implementing IHC. This allows Transpower to choose the most appropriate index (for example, one that accounts for technological change).

B.83 The IHC approach we have proposed for future investments is consistent with the way that we think charges would be set in a workably competitive market for utility-type services. As discussed in appendix D, such a market is a useful benchmark, because workably competitive markets are relatively efficient.

B.84 We are of the view that the most reasonable assumption[161] to make is that the services provided by a transmission investment will be roughly constant over its life. This is because for utility-type services, the services an investment is capable of delivering do not degrade as the asset providing the service ages and therefore charges do not reflect the age of the asset providing the service. For example, the hire charges for renting a trailer typically do not depend on the age of the trailer.

B.85 As a result, IHC-based charges (which are roughly constant after adjusting for inflation) better reflect the value of the services provided by a transmission investment across its life, than charges based on depreciated historical cost (DHC), which decline over the asset's life.

B.86 However, the proposed guidelines allow Transpower to propose a different method than IHC in the TPM if it considers that this would better meet the Authority's statutory objective than the IHC method and would still recover the covered cost of the benefit-based investment.

B.87 We have considered whether the proposed guidelines should allow Transpower to recover the covered cost of any particular high-value[162] post-2019 investments in a different way from IHC, if applying IHC would lead to charges that manifestly do not reflect the benefits the investment provides. However, our current thinking is that IHC should be used for all post-2019 investments (unless Transpower identifies a method which better meets our

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160 'Expected' because the charge is set before the actual covered cost (which is what is eventually recovered) is known with certainty.

161 Of course, the services provided by the investment in actuality will not be constant, but may increase or decrease over time depending on the pattern of growth in the grid, in load and in generation. We think assuming IHC is a reasonable approximation.

162 The definition of high-value benefit-based investments would include all major capex under the Commerce Commission's Capex IM. The threshold proposed in the second issues paper was $5m. Some submitters on the second issues paper, such as Transpower, proposed that the threshold should be aligned, as is now proposed, with the threshold under the capex IM. The threshold for major capex under the Capex IM is $20 million, and the definition of high-value investments includes all investments that have a value exceeding that amount (eg, replacement and refurbishment expenditure as defined in the Capex IM).

statutory objective in which case that method would apply to all post-2019 investments). While this may mean that the charges may not reflect the benefits over time, we think there are countervailing arguments:

(a) the benefit-based charge would still reflect the overall benefit those charged for the investment are expected to get over the benefit-based investment's life

(b) once the investment is made, the salient charge for the customer is the total transmission charges the customer faces, and variations in charges for individual investments would tend to average out in those total charges

(c) introducing such a rule would create another arbitrary boundary with the associated costs that that generates.

IHC for pre-2019 investments

B.88 We have also considered applying the IHC method to past investments.[163] The argument for doing so would be that the services provided by a transmission investment will be roughly constant over its life. However, our view is that there are stronger arguments for applying a different approach to past investments. These reasons are explained in relation to the Commerce Commission method below.

Commerce Commission method for pre-2019 investments

B.89 For pre-2019 benefit-based investments, we propose to determine the capital cost and cost of capital recovered in each year so they are the same as Transpower's annual recovery of those capital components under Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act ('the Commerce Commission method'). This then determines the recovery profile of the covered cost over time.

B.90 The Commerce Commission's method currently values assets at their depreciated historical cost (DHC).[164] This means that the capital cost of the assets in an investment at the start of the new TPM would be the DHC of the assets as recorded in Transpower's regulatory asset base (RAB). The value of the assets in every year would be the amount specified in Transpower's RAB at the start of that year. This means the benefit-based charge would recover the capital cost of the investment according to the annual depreciation allowance attributable to the investment in the RAB.

B.91 In that case, the benefit-based charge for an investment in any year would be calculated as the sum of:

(a) the depreciation of the investment over the year[165]

(b) the return on capital for the investment over the year

(c) the operating costs, maintenance costs and other costs (if any) attributed to the investment in the year

(d) any other costs attributable to the investment.

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163 This was proposed by Axiom for Transpower, Castalia for Genesis and Powernet in their submission on the second issues paper. The reasons advanced included that IHC is more service based, and that it would limit price shocks when aging assets are replaced.

164 This is explained in more detail in the second issues paper.

165 If the investment were revalued for some reason, the revaluation would be treated as income (that is, negative depreciation).

B.92 If the Commerce Commission adjusted the Commerce Commission method, the annual charges for pre-2019 benefit-based investment would be adjusted accordingly.

B.93 The Authority considers that the approach is likely to be more efficient than other options, including applying IHC, for five reasons.

(a) It recovers just the total cost of the investment over its life.[166]

(b) It reduces inefficiencies that could result from Transpower possibly needing to scale back its charges (in the event that the rate of grid investment slows in real terms over time), as is discussed below.

(c) It will reduce the inefficiencies that would be caused by a time-varying residual charge if pre-2019 investments were valued using IHC.

(i) If the method used for setting the recovery profile (for either post-2019 or pre-2019 investments) were different from the Commerce Commission method, the residual charge would have to be adjusted over time to allow for the difference between the DHC charges (which are the same as Transpower's recoverable revenue attributable to the investment) and the actual charges. If IHC is used for any investment, the effect of using IHC on the residual charge is positive in the early years of an investment's life and negative in the later years. This is because an IHC-based charge will be lower than a DHC-based charge in the early years but greater in the later years.

(ii) Other things equal, a varying residual charge is less efficient than a constant one that generates the same present value of revenue. This is because the inefficiency generated by a tax-like charge increases more than proportionately with the rate of the charge. Using the Commerce Commission method for pre-2019 investments avoids them causing this inefficiency.

Commerce Commission method for post-2019 investments

B.94 We have considered the option of applying the Commerce Commission method to post-2019 investments as well as pre-2019 investments.[167] This would have the same efficiency benefits as those outlined in paragraph B.93 above.

B.95 However, the Authority considers that for post-2019 investments, on balance, these advantages are outweighed by having annual price signals that better reflect the flow of services delivered by the investment, as discussed above. These efficiencies are likely to be more substantial for future investments, compared to pre-2019 investments, because the prices charged for pre-2019 investments cannot affect whether the investment is undertaken.

166 DHC recovers most of the cost of an investment in the early years of an asset's life, whereas IHC recovers relatively more later in its life. So using DHC for the start of the investment's life and IHC for the end could overall recover more that the total cost of the asset.

167 Submitters who supported using DHC for post-2019 investments had a variety of rationales, as is discussed above. These included that: deviation from the Commerce Commission method had no clear benefits and was complex; that it could cause price shocks when new investments are made; and that consistency with the treatment of pre-2019 investments is desirable. See for example the submissions on the 2016 TPM proposal by ENA, Meridian, NERA for Meridian, Pacific Aluminium, Unison and Vector.

Q17. How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?

Adjustment to charges and recovery of covered cost

B.96 The proposed guidelines allow Transpower to adjust benefit-based charges where, in its reasonable assessment, there has been or will be a material change in the WACC, opex, the expected life of assets or any other costs attributable to the benefit-based investment, as it is likely that these will turn out differently from Transpower's initial assumptions. However, the requirement to recover the covered cost of the investment would remain, for the reasons discussed above.

Charges would continue until covered cost is fully recovered

B.97 Because the annual benefit-based charges must be set before some of the expenditure to which they relate is undertaken, there is likely to be a difference between the costs anticipated when the charges are set and the costs that are incurred in practice. In part this discrepancy can be dealt with by the adjustments described in paragraph B.96 above. However, it is likely that some discrepancy would remain. This means that Transpower would need to include in the TPM some mechanism for ensuring that the covered cost is recovered. For example, it could provide for a wash-up, or it could continue charging the benefit-based charge until the covered cost has been fully recovered, irrespective of the actual life of the investment. The annual benefit-based charge would reduce to the ongoing costs of the investment (such as opex and de-commissioning costs), after all other costs of the investment had been recovered.

Damage to a benefit-based investment

Proposal

Clause 18, proposed TPM guidelines (appendix A)

Discussion

B.98 As is noted from paragraph B.36 above, we intend that the beneficiaries of an investment will pay the covered cost of the investment over its expected life, because this creates efficient incentives for use of the grid and investment and thus long-term benefits for consumers.

B.99 However, in a workably competitive market, it would be unusual for a user to pay charges on an investment that is no longer delivering services to them. We therefore propose that charges may cease or reduce when an asset in an investment is substantially damaged or destroyed. The proposals under the heading *General matters* above mean that Transpower will have to ensure, as far as is reasonably practicable, that the proposal does not create inefficient incentives on transmission users to take actions that result in such a reduction. For example, it might require that charges would reduce only if the damage was caused by an event that nobody could have predicted or controlled.

B.100 Any costs associated with the investment that are no longer recovered through the benefit-based charge due to the application of this provision will instead be recovered through the residual charge.

Allocating annual benefit-based charges among customers

Proposal

Clauses 19 - 26, proposed TPM guidelines (appendix A)

Discussion

Benefit-based charge allocated according to net private benefit

B.101 Transmission investments can have a broad range of benefits. For example:

(a) (for load) access to more and cheaper sources of electricity

(b) (for generators) access to higher-paying, distant customers

(c) reliability benefits (such as a backup source of electricity for load that is reliant on distributed generation)

(d) local voltage support

(e) nationwide benefits from HVDC link (eg, facilitating cross-island provision of ancillary services and price competition between generation).

B.102 This section of the proposal sets out how the benefit-based charge for an investment is to be allocated in proportion to each customer's share of net private benefits from the investment.[168]

B.103 For example, if Transpower were considering a new investment that would strengthen grid capacity to the upper South Island, the benefit-based charge would apply to all expected beneficiaries[169] of that investment. The beneficiaries might include:

(a) upper South Island load, which benefits from improved reliability and from continuing to have their demand for transmission services met in the face of growth in load

(b) lower South Island generation, which is able to export more electricity to the upper South Island

(c) load and generation across the grid which benefits through reduced losses.

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168 As is noted in footnote 125, the approach to allocating the cost of transmission investments outlined in this section is consistent with that proposed by Rivier et al (2013), pg 272 ff. and by W Hogan (2011).

Professor Hogan further comments on page 13

> Note that there is nothing in the transmission investment decision or ex ante cost allocation rule that depends directly on examination of the power flows across individual lines or other transmission facilities. The estimate and comparison with the counterfactual is made at the first stage. This ex ante perspective is unavoidable in evaluating the investment decision. Given the complexity of network interactions, where the power flows across individual lines do not describe actual use or value in any economically meaningful way, the only available methodology based on first principles is to allocate costs according to the same estimates of the benefits the future outcomes. This is consistent with the perspective for the beneficiary-pays principle as described by FERC: "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities" (FERC 2010, p. 91). The cost allocation is made ex ante based on the same analysis that is and must be made before the investment goes forward. The cost allocation does not depend on the ex post utilization that actually occurs, which is difficult to even define much less measure.

169 As provided for under the heading *General matters* above, transmission customers are regarded as agents for parties (both load and generation) indirectly connected through them to the interconnected grid. For example, any benefit that accrues to a distributor's load customer would be attributed to the distributor. Transpower correctly made this point in the comment about clause 13 of appendix B of it submission on the second issues paper.

B.104 Also, the charges each customer faces should reflect its share of the benefits that all beneficiaries would be expected to receive. This would likely mean that upper South Island load and lower South Island generation would pay the most towards the costs of the project, but some of the costs would be borne by other customers expected to benefit.

B.105 As Hogan notes, workable application of the principle could include some spreading of the benefits across different parties at the same location.[170] For example, it may be appropriate to effectively spread the cost of a computer used to bill Transpower's customers across all of its load customers.[171] However, we would expect such situations to be rare for benefit-based investments. For example, the cost of a computer used to manage the HVDC link would be recovered from those who benefit from the HVDC link in the same manner as the link itself.

B.106 We have proposed a benefit-based charge because it allocates the cost of upgrades to the interconnected grid in a way that ensures that those who benefit from the investment pay for it. As is discussed in appendix D, this is relatively efficient because it is consistent with what happens in workably competitive markets. One result is that a user faces incentives which encourage it to take account of the impact on its decisions on the need for grid investments.[172] It therefore provides users of the interconnected grid with incentives to:

(a) take into account the transmission investment implications of their own investment decisions and their decisions about the use of the grid

(b) better scrutinise proposals for new transmission investment.[173]

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170 See page 11 of W Hogan (2011).

171 Indeed, under our proposal, the cost of such a computer would form part of Transpower's overhead costs and so be recovered through the residual charge (ie, spread across all load customers).

172 Some submitters on our earlier proposed area-of-benefit charge appeared to believe that we intend the benefit-based charge to promote coordination of the use of the grid to efficiently defer investment, and point out that it does not have this effect. In particular, some submissions on the 2016 TPM proposal have suggested that a long run marginal cost (LRMC) charge is also required to do this.

Our view is that locational marginal pricing provides this coordination role by efficiently restricting grid use to capacity. We therefore disagree that there is a need for an additional charge, such as an LRMC charge. This is discussed further in appendix E.

173 Submitters on the second issues paper had mixed views on the potential benefits of increased scrutiny. Some (eg, CEC for Trustpower) thought it might have no effect or might actually decrease engagement in the grid investment process. Others (eg, NERA for Meridian) thought it would improve information disclosure and engagement in the grid investment process.

For the reasons outlined in appendix D, we agree with the latter. This is demonstrated by the example that Littlechild gives of the grid investment process in Argentina. He says

> Soon after the new [benefit-based charge] policy was implemented, a Fourth Line from the gas producing area of Comahue to the capital Buenos Aires was proposed but rejected by a majority of market participants. This line was allegedly much needed, and had been widely canvassed under the previous regime. The rejection was perceived as evidence that the Public Contest method did not and could not work. It seemed that transactions costs outweighed the advantages of cooperation between market participants. …
>
> Subsequent and more detailed research has shown that the Fourth Line was expensive, premature and uneconomic. (Littlechild and Skerk 2008b) Delaying its construction was evidence that the Public Contest method did work, not that it didn't work. In the short term, the participants agreed instead to expand capacity by installing capacitors, at a fraction of the cost of a new line. When conditions later made the Fourth Line attractive, the participants worked together well to design, propose and pay for a line that attracted almost unanimous support and was constructed at a significantly lower cost than envisaged in the initial rejected proposal. Subsequently, it became apparent that it was more economic to transport gas from Comahue to Buenos Aires, and build the power stations there, than to build more long-distance transmission lines.

B.107 The Authority considers that these incentives are likely to be better than those provided by the current HVDC and interconnection charges, or any method likely to be feasible under the current guidelines.

B.108 For example, suppose a potential investor in a gas-fired generator was not charged for a transmission investment needed to carry energy from its generator to the point of load, but was charged for the transport of gas. This would encourage them to site the generator next to the gas field, even if it was lower cost overall to locate next to the point of load.

B.109 The Authority's view is that requiring generation customers to pay the benefit-based charge will not cause inefficient pass-through in the wholesale electricity market. This is because the wholesale electricity market is workably competitive. So generators will face competitive pressure to submit offers which reflect their SRMC of generation. While downstream prices may or may not be higher on average than if transmission could be provided costlessly, any higher price would simply reflect the total resource cost of supplying electricity.[174]

B.110 The proposed requirement that the benefit-based charge be allocated according to the net private benefit that the parties are expected to receive from the investment is different from, but related to, the focus of the Commerce Commission's Investment test. The Investment test considers the total expected net electricity market benefits (instead of parties' net positive private benefits).[175,176] The treatment of benefits for the proposed benefit-based charge is required to be consistent with, though not necessarily identical to, the treatment of benefits for the Commerce Commission's Investment Test.[177] This is intended to enhance consistency with the Commerce Commission's regime and to allow Transpower to implement the benefit-based charge in a more cost-effective manner.

B.111 The proposed guidelines provide Transpower with the discretion to include wider benefits, such as environmental or visual amenity benefits. We are not expecting this discretion to be used much, since such benefits are normally dealt with by other processes and regulations. We have included it to allow for the situation where those processes are inadequate and where limiting benefits to electricity market benefits would prevent Transpower from allocating a significant proportion of the benefits from a transmission investment to those who benefit from it. One example might be the benefits in terms of visual amenities and property values (for example) that might arise if Transpower was required to underground transmission lines.

B.112 Consistent with what happens in workably competitive markets, we consider that charges should be set on the basis of net benefits from the investment, that is, benefits minus

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See Littlechild (2011), page 18.

This example also illustrates that, contrary to the suggestion of Axiom for Transpower in its submission on the supplementary consultation paper that customers may not respond to the price signal sent by the benefit-based charge, that at least in some circumstances, customers can and do respond to that price signal.

174 This is discussed further from paragraph D.71 below.

175 , This responds to Transpower's submission on the supplementary consultation paper that the wording proposed there might inappropriately bring in non-electricity market benefits.

176 Major capex involves a specific investment proposal that is considered by the Commerce Commission. The major capex investment test requires Transpower to identify, and the Commerce Commission to assess, expected electricity market benefits and costs that are received or incurred by consumers of transmission services, during the calculation period.

177 In its submission on the second issues paper, NERA for Meridian suggest that this may reduce the costs of implementing the benefit based charge.

costs.[178] This means the benefit-based charge only applies to customers that are expected to receive positive net benefits from the investment.

B.113 Likewise, the charge would not involve compensating parties that suffered dis-benefits from an investment. Compensating parties facing net dis-benefits would:

(a) open the regime up to rent-seeking, as there is no limit to the size of dis-benefits, whereas benefits only need to exceed costs for the charge to apply

(b) increase the rate of the charge, which increases the risk of inefficient behaviour to avoid the charge.

Net load versus gross load for the benefit-based charge

B.114 There is a design choice as to how Transpower should measure demand in order to estimate the benefits of an investment for load customers. There are three main options:

(a) a 'net load' approach: a load customer's demand is measured as off-take at the GXP (we call this approach 'net' as measured demand is lower to the extent that there is injection by distributed generation and/or behind-the-meter generation into a distributor's network or behind a load customer's meter)

(b) a 'gross load' approach: a load customer's demand is 'grossed up' by adding injection by distributed generation and/or behind-the-meter generation

(c) a more flexible approach under which neither of the above approaches is required (this is currently our preferred option).

B.115 The Authority considers the net load approach would be best in most circumstances, as it is likely to provide load customers with appropriate incentives with respect to future investment. This is because a net basis for calculating benefit-based charges better reflects the benefits that customers receive from grid-delivered electricity. That is, a load customer that derives a substantial proportion of its electricity requirements from distributed generation does not benefit from the grid to the same extent as a load customer of similar size that lacks distributed generation. Use of local generation reflects a private judgement that costs of grid supply outweigh benefits. We applied a net load approach in allocating the costs of the seven recent major investments in clause 13(b) of the proposed guidelines.

B.116 However, in some circumstances a gross load approach could be better, as it could avoid a potential efficiency issue. The net load approach has the potential to create an artificial incentive for generation to embed in a load customer's network (and vice versa). This can be seen by considering the following example:

(a) a distribution network that has generation embedded in it

(b) a congestion-relieving investment that benefits the distributor and others is about to be made

(c) the net benefit of the parties is proportional to their net load.

178 The draft guidelines published in the second issues paper made explicit that a party's loss of LCE payment as the result of an investment is a dis-benefit. We have not done so in the proposed guidelines, because it simplifies them and because we think that it is clear that a loss of future LCE is a private cost. If Transpower chooses to apply the benefit-based charge to all pre-2019 investments, then including loss of LCE in the calculation of net benefits would have the effect of ensuring that the cost of the new investment is borne primarily by the parties whose growth in demand led to the investment.

B.117 In this example, the distributor's net load is less with embedded generation, compared to the situation where the generation is grid-connected at the distributor's GXP.[179] As a result, its assessed share of benefits is reduced. Potentially, therefore, this creates an incentive for the distributor to encourage generation to embed within its network.

B.118 This situation may not often be problematic. It is an empirical question as to whether or not the potential inefficient incentive is likely to be material. The Authority considers that the potential incentive is unlikely to have material effects on efficiency, because the costs of embedding can be substantial. However, it cannot be entirely ruled out.

B.119 The Authority prefers a more flexible approach under which neither of the above approaches is required. This is consistent with our less prescriptive approach with respect to the method that Transpower may use to determine benefit-based charges. The expectation would be that, for the purposes of calculating benefit-based charges, Transpower will generally measure a load customer's demand as off-take at the GXP (net load approach). However, Transpower can adopt a gross load approach if it considers the potential inefficiency from adopting a net load approach is likely to be material in any given case and mitigating the problem would be consistent with the Authority's statutory objective. Transpower would need to take any potential inefficiency into account in the detailed design of the benefit-based charge.

Q18. Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

B.120 It is possible for a transmission customer in some scenarios to be an importer of electricity and in other scenarios to be an exporter of electricity.[180] Such a customer may be assessed as benefiting as an importer, an exporter, or both. Transpower will need to separately estimate the share of each customer's charges that are associated with exporting and importing. Further, if this becomes public (e.g. it could possibly do so as part of Transpower's consultation process on the parameters used to calculate TPM charges), then the information would enable distributors to assess the charges arising as a result of distributed generation on their network.

Standard method and simple method

B.121 We propose to differentiate between high-value and low-value post-2019 investments as there are more likely to be net benefits from a more precise allocation of the benefit-based charge for high-value compared to low-value investments.

B.122 There are three broad options for the treatment of low-value investments:

(a) allocate costs via the residual charge

(b) allocate costs via the benefit-based charge using a simple method (currently our preferred method)

(c) allocate costs via the benefit-based charge using the standard method.[181]

179 The same applies with respect to any generation that is located on the distributor's side of the constraint that the investment is relieving.

180 A party providing energy storage services using a battery, for example, would be a load customer when charging its battery and a generation customer when discharging its battery.

181 This was proposed by Orion in its submission on the second issues paper. The Authority considers providing for a simple method is desirable for the reasons discussed here.

B.123 We propose that Transpower include in the TPM two different sorts of methods for allocating the annual benefit-based charges for a post-2019 investment between transmission customers:

(a) a standard method or methods for high-value post-2019 investments

(b) a simple method or methods which may be applied to low-value investments.

B.124 The proposed guidelines specify that the simple method should be simpler than the standard method but is defined by reference to the standard method. Overall, the simple approach may forgo some of the narrowly defined efficiency benefits (ie, ignoring transactions costs) of the standard approach, but it reduces administration and transaction costs.

B.125 We are envisaging that Transpower would be pragmatic in allocating the benefit-based charges for low-value investments, with the method of allocation dependent on the nature of the investment. For example:

(a) Transpower could allocate the charges of a low-value investment between load and generation based on the allocation for a related high-value investment

(b) Transpower could allocate the charges to one or a few expected major beneficiaries (eg, those that would otherwise be expected to be materially affected by constraints)

(c) Transpower could use a rough proxy for benefit (eg, load or historical load) to allocate charges

(d) For an investment that is intended to provide benefits to a specific location, Transpower could allocate all the cost of the investment to load (for an importing region) or generation (for an exporting region) in that region. Transpower proposed a method similar to this (its 'simplified staged approach') in its submission on the second issues paper. (The major difference is that the regions Transpower defined for applying the charges were very broad. In our view, applying the charges to a broad area would be inappropriate for post-2019 investments, and would be inconsistent with the proposed guidelines because it would effectively spread the charges across all load customers within those very broad regions and thus not result in an allocation which broadly approximates the allocation which would have resulted had the standard method applied.[182]).

(e) For an investment that connects two areas, Transpower could allocate the charges to generation in the upstream region and to load in the downstream region.

(f) For an upgrading investment, Transpower could allocate the charges on the same basis as the charges for the original investment, if the original investment were subject to the benefit-based charge.

B.126 As an alternative to using a simple method to allocate the benefit-based charge for low-value investments, we also considered allocating the cost of those investments to the residual charge.[183] This would spread the cost of low-value investments across all load customers, rather than recovering them from the parties expected to receive the majority of the positive net private benefits.

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182 Another key concern that we had with that proposal was that it did not make mandatory the area-of-benefit charge for future investments.

183 Castalia for Genesis proposed this in its submission on the second issues paper.

B.127 In particular, we have considered the argument that low-value and upgrading expenditure is an engineering decision so that the quality and timing of the investment is not influenced by cost. We accept that this may sometimes be the case. However we consider that there will be situations where there are some choices to be made that can and should be influenced by cost considerations. The Authority considers the painting of a wooden house to be an appropriate analogy. While it is clearly necessary to paint the house from time to time to avoid it eventually falling into disrepair, there is still a choice about when to paint it and how to paint it. This choice is influenced by cost considerations.

B.128 For low-value benefit-based investments the incentives to scrutinise Transpower's plans would be weaker. Nevertheless, there will still be stronger incentives than currently exist for Transpower customers to participate during the periods when the MAR and subsequent adjustments to the MAR are determined. In addition, we consider that having a sharp border between the treatment of high-value investments and low-value investments would introduce incentives for transmission customers to seek to have investments sized below the threshold between low-value and high-value investments, for example by breaking investments up into smaller tranches. This has the potential to create significant inefficiencies.

B.129 Instead, applying the benefit-based charge to low-value investments mitigates the potential problem caused by introducing a boundary between low-value and high-value investments.

Q19. Should the guidelines distinguish high-value and low-value investments?

Q20. If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

B.130 There is a further decision to be made in this area, which is identifying the threshold separating low-value and high-value investments. The Authority has identified two options for particular consideration:

(a) $5 million

(b) $20 million (currently our preferred option).

B.131 An argument for a $5 million threshold would be that further efficiencies could be achieved by requiring application of the standard method to more investments. The Authority in its 2016 TPM proposal took the view that there were likely to be net benefits from a more granular allocation of a benefit-based charge to investments valued at over $5 million. At that time the Authority took the view that the risk that the transaction cost involved in a granular allocation of the charge would exceed the benefit from applying the charge was lower for investments over $5 million (compared to investments valued at under $5 million). At this stage there is little evidence available to us to inform this trade-off. So, subject to the possibility of receiving further evidence in submissions, the choice of the appropriate threshold is a matter of judgement.

B.132 The reason we currently prefer a $20 million threshold is that it would reduce administrative burden on Transpower. A key reason for this is that it would align the threshold with the Commerce Commission's threshold for 'major capex', and so would allow Transpower to rely on information produced for the Commerce Commission's Investment Test and other cost-benefit analysis when applying the standard method. These sorts of reasons led several submissions on the second issues paper to propose that the threshold be $20m.[184]

Q21.	**What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?**

Share of benefits determined at time of commissioning

B.133 Under the Authority's current proposal, Transpower would determine the share of the benefit-based charge allocated to a transmission customer for an investment at the time the investment is commissioned. Once Transpower has determined this share, it would not change except in exceptional circumstances. This would be the case even if the actual outcome in relation to the benefits obtained by the customer is quite different from the outcome expected at the time the investment was made.

B.134 The benefit-based charge is fixed in this way so that it does not create incentives for grid users to inefficiently avoid transmission charges by altering their use of the grid. Nodal prices should give the customer incentives to use the grid relatively efficiently. So any other charge that is based on use of the grid (such as a per kwh charge) would risk inefficiently discouraging use of the grid. In particular, if the benefit-based charge was correlated with current grid use in some way, this could encourage transmission customers to inefficiently reduce their grid use to avoid the transmission charge, without having any impact on transmission costs. Similarly, if the benefit-based charge was updated to reflect benefits observed to occur in practice, a customer could take costly actions after the investment had been committed to reduce their share of the benefit-based charge (for example, installing distributed generation partly for the purpose of avoiding charges), even though there is no reduction in grid costs. That would be inefficient.[185]

B.135 The proposed guidelines allow some exceptions to the general rule that the allocation does not change, notably:

(a) a substantial and sustained change in grid use

(b) the entry or exit of a transmission customer

(c) a transmission customer changing its point of connection

(d) a partial sale of a business

(e) adjustments resulting from reassignment.

B.136 Although the share of the benefit-based charge generally remains fixed, the benefit-based charge and the annual benefit-based charges for an investment may vary for a variety of reasons. For example, if a transmission customer disconnects but the fall in use of an investment is not sufficient to trigger a reassignment, then the other customers who paid the benefit-based charge on the investment would see their charges increase correspondingly. Similarly, if any of the costs in the covered cost change (see clause 14 of the proposed TPM guidelines (appendix A)), the charges could change.

[184] For example, Castalia for Genesis, Genesis Energy, PwC for 14 EDBs, Transpower

[185] As Hogan (2011), page 13 says, "The cost allocation is made ex ante based on the same analysis that is and must be made before the investment goes forward. The cost allocation does not depend on the ex post utilization that actually occurs, which is difficult to even define much less measure. This ex ante perspective is particularly significant in the context dealing with uncertainty."

B.137 Furthermore, the charges could vary as a result of any of the changes to an allocation discussed in paragraph B.135 above. For example, if there is a reassignment, the charges would vary both as a result of the reassignment and as a result of any reallocation that results from it, as discussed in paragraphs B.192 and B.193 below.

Allocators for initial set of pre-2019 investments pre-determined

B.138 We have included in schedule 1 of the proposed guidelines an allocation between transmission customers of the costs of each of the seven recent major investments in clause 13(b) of the proposed guidelines The Authority considers that there are three options for the use of this allocation:

(a) the allocation could be purely illustrative, with Transpower being required to determine the allocation for the seven recent major investments

(b) the allocation could be a default option, which Transpower is permitted to depart from

(c) Transpower could be required to set benefit-based charges based on the allocation in schedule 1 (this is currently our preferred option).

B.139 We have proposed setting these allocations because we wish to facilitate the early implementation of the new TPM. Because we expect the new TPM to better meet our statutory objective than the existing TPM, an early implementation would ensure that the gains associated with the new TPM are achieved earlier. After discussions with Transpower on the workability of our proposal, we have come to the view that requiring Transpower to apply our allocation may be expected to reduce the administrative burden and therefore enable earlier implementation.

B.140 We are considering two broad options for determining the allocation of the seven recent major investments in clause 13(b) of the proposed guidelines:

(a) use of the vSPD model – as discussed immediately below (currently our preferred option and the one we have used to produce the current schedule to the guidelines)

(b) use of an approximate regional method – as discussed after the discussion of the vSPD model.

vSPD method

B.141 We are proposing an allocation to each customer in respect of each investment in proportion to that customer's share of the positive net private benefits resulting from the investment, estimated using vSPD (the Authority's version of the Scheduling, Pricing and Dispatch model). In compiling schedule 1 to the guidelines, we estimated the historical investments' benefits based on changes in the price and quantity of energy at various nodes occurring as a result of each grid investment, calculated by running the vSPD model. The method we have used is described in more detail in appendix H.

B.142 We have made every effort to ensure that the method used for the schedule 1 allocation is robust and objective. However, our allocation is not perfect; in producing it we have necessarily made a number of simplifications and judgements. But perfection is not a necessary feature of cost allocation.[186] In our view, the cost allocation for the investments in schedule 1 approximately reflects the distribution of benefits from those investments. The Authority considers that this allocation of costs will result in a more durable TPM compared to the current guidelines.

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[186] See paragraph B.157 to B.167 for further discussion of this point.

Approximate regional method

B.143 We have also considered an alternative method of allocating the costs of the seven major investments in clause 13(b) of the proposed guidelines. This alternative (which we call the 'approximate regional method') involves allocating the costs of each historical investment amongst generators and load based on judgement as to where their benefits approximately fall.

B.144 This method involves grouping beneficiaries of grid investments according to whether they are load or generation customers and also the location of each customer in one of the four regions that Transpower uses to allocate its current RCPD charge: upper North Island (UNI), lower North Island (LNI), upper South Island (USI) and lower South Island (LSI).

B.145 The approximate regional allocation for the historical investments, together with the engineering judgement that underpins that allocation, is set out in the following table.

Table 13 Benefit-based allocation of costs under approximate regional approach

Investment	Proposed allocation		Reasoning: benefits of each investment
	Generators	Load	
North Island Grid Upgrade (NIGU)	30% non-UNI generation	70% UNI load	Reduces constraints between UNI and rest of NZ Allows UNI load greater reliability of supply and lower energy prices Allows non-UNI generation to access higher energy prices
UNI Reactive Support	30% non-UNI generation	70% UNI load	Similar to NIGU, this investment effectively increases the UNI stability constraint limit We have applied same allocation as for NIGU
Wairakei Ring	45% LNI generation, 15% SI generation	40% NI load	Allows LNI generators (and also SI generators to a lesser extent) to access higher energy prices Lower energy prices for load across North Island
Bunnythorpe-Haywards Reconductoring		25% LNI load, 75% SI load	Prevents constraint on southward flow from central North Island to LNI (and on to South Island) during dry periods Lower energy prices for load across LNI and all of South Island
HVDC link	50% SI generation	40% NI load, 10% SI load	In normal (wet) conditions, provides North Island load with lower energy prices and allows SI generation to access higher North Island prices In dry years, lower prices for South Island load Provision of ancillary services: widespread benefits
LSI Renewables	25% LSI generation	75% SI load	Improves access to load for LSI generation Relieves constraint on import of energy into LSI in dry year, reducing dry year prices for LSI load Relieves constraint on import of energy into USI, reducing prices for USI load

Investment	Proposed allocation		Reasoning: benefits of each investment
LSI Reliability	25% LSI generation	75% LSI load	Relieves constraints, allows LSI generation to export greater quantity of energy Increases import capacity and reliability into LSI load

B.146 While the approximate regional method could be seen as a pragmatic and simple solution, we are not proposing it, as we consider that it may create boundary issues and, unlike the vSPD method, it relies on judgement to apply the principle that a customer's charges should reflect its benefits from each grid investment. The vSPD method is also preferable because it gives a finer grained analysis and doesn't spread charges across each region.

Q22. What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

We propose recovering the costs of three historical investments via the residual charge

B.147 The vSPD model has been used to allocate the costs of seven of the major investments commissioned largely since 2004 that had an approved value over $50 million at the time the investment was approved. However, for the remaining three investments that meet these criteria (North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support) our vSPD modelling was not able to identify material benefits for transmission customers commensurate with the costs of these investments.[187] As is discussed in paragraph B.67 we do not consider it appropriate for grid users to pay benefit-based charges that exceed the benefits of the investment for pre-2019 investments, since there is no decision to be made about whether to proceed with the investment.[188]

B.148 There is therefore a decision to be made about how the costs of these three investments should be allocated. We see there being three broad options:

(a) recover all costs of these three investments through the residual charge, rather than the benefit-based charge (currently our preferred option)

(b) use of bespoke methods to allocate costs through the benefit-based charge; for example:

(i) for NAaN: allocate 50% of costs to upper North Island (UNI) load customers (recognising this investment will likely benefit these customers in future given increasing demand in the area) and 50% through the residual charge

(ii) for Otahuhu Substation Diversity: allocate costs to UNI load customers (we calculate around 16% of costs) based on expected (probability-weighted) benefits derived by assuming a probability of a future outage of the Otahuhu substation, and the remaining 84% through the residual charge

(iii) for USI Reactive Support: allocate 50% of costs to upper South Island (USI) load customers and 50% through the residual charge

187 This may in part be a result of calculating the benefits over an historical period.

188 For efficient post-2019 investments, the expected benefits necessarily exceed the expected cost.

(c) a mixed approach under which some proportion of costs are recovered through the benefit-based charge, with the balance being recovered through the residual charge. Depending on the circumstances of each investment, recovery for each investment could be in a range from wholly benefit-based to wholly residual charge, with mixed options in between depending on the outcomes of further analysis.

B.149 We are proposing that the costs of the remaining three investments be recovered entirely through the residual charge, rather than adopting bespoke allocation methods. This is based on our view that relying solely on the vSPD allocation approach is reasonable for pre-2019 investments.

Q23.	**How should the costs of the investments that are not covered by the benefit-based charge be allocated?**

Transpower to develop method for allocating benefit-based charge

B.150 As Transpower has responsibility for developing the TPM, proposing new transmission investments and implementing the benefit-based charge on these investments, we consider that it is appropriate for Transpower to develop the methods for allocating charges (including both standard and simple methods) for post-2019 investments.[189] In particular, Transpower already needs to estimate the electricity market benefits of some investments when it develops investment proposals. In developing allocation methods for the benefit-based charge, Transpower will be able to build on the information generated as part of the investment proposal process to identify the likely beneficiaries of each investment and the relative value of the benefits each is expected to receive.[190]

B.151 In developing its method, Transpower may need to grapple with similar issues to those the Authority has considered in determining its proposed allocation for the historical investments in schedule 1 of the guidelines. For example, the Authority envisages that Transpower may make assumptions about the wholesale electricity prices that would occur in the scenario in which the relevant grid investment is not made (the counterfactual scenario). In doing so it would need to take into account demand response (which is expected to be stimulated by real-time pricing).

Trading off accurate benefit estimation against other considerations

B.152 Transpower would in principle need to consider all the benefits that the grid provides to customers, as outlined in paragraph B.101 above. Some submissions argued it would be difficult or complicated to accurately assess benefits, that the outcome would be sensitive to modelling assumptions[191] and that the outcome might be complex and contentious.[192]

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189 We identified a number of methods on pages 98 and 99 of the second issues paper. There is also a useful discussion of different possible methods in Pérez-Arriaga et al 2014.

190 Hogan (2011), page 2, comments that “In many instances, estimating the shares of benefits is easier than estimating the benefits.”

191 For example, submissions on the supplementary consultation paper by Covec, Counties Power Consumer Trust, Entrust, Northern Federated Farmers, Top Energy, Trustpower, Vector, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Fonterra, Entrust, Transpower, Northpower, Oji Fibre Solutions, IEGA, Pioneer Energy, NZ Energy, Otago Chamber of Commerce

192 For example:

B.153 However, the proposed guidelines allow Transpower to use a proxy for net private benefits in allocating the benefit-based charge between customers under the standard method,[193] provided that, in Transpower's reasonable opinion, the proxy results 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. In addition, the various proposals discussed in the section headed *General matters* above mean that Transpower will need to take account of pragmatic considerations in calculating and allocating benefits.[194]

B.154 On the other hand, the proposals discussed in the section headed *General matters* above, such as the need to avoid incentivising transmission customers to avoid transmission charges in ways that cause economic efficiency, would limit the ways that Transpower will be able to allocate the charges.

B.155 One of the arguments raised against the benefit-based charge has been that, unless a robust way of identifying beneficiaries can be developed, the charge would incentivise parties to argue that they should not be identified as beneficiaries.[195] However:

(a) parties will have a countervailing incentive because, if they claim not to benefit from an asset, Transpower may decide not to proceed with the proposal.

(b) other parties in favour of a proposed investment would have incentives to put forward information to support the opposite case to avoid paying a higher share of the costs of the investment that benefits them.

(c) the proposals discussed in the section headed *General matters* above mean that when Transpower designs the TPM, it will need to take account of practical considerations, such as concerns around robustness (for example, ensuring an appropriate trade-off between accuracy and practicality).

(d) as the methods will be part of the TPM, the only way they could be changed would be through changing the TPM, which the Authority would only approve if doing so promoted the Authority's statutory objective.

- submissions on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Pacific Aluminium, Top Energy, Trustpower, Vector
- submissions on the second issues paper by Axiom for Transpower, EA Networks, Network Waitaki, PWC for 14 EDBs.

193 Transpower's submission on the second issues paper proposed that a proxy be used (Appendix B, clause 8). In its submission on the second issues paper, Bushnell for Trustpower made the point that a proxy could be useful to deal with issues such as these.

194 This is similar to the proposal in the supplementary consultation paper that the standard method must be as accurate as reasonably practical, which was supported by a number of submitters on it, including: PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Meridian Energy, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower. Other submitters such as Axiom for Transpower and Transpower opposed it as being meaningless and unworkable. For the reasons outlined in this section, we do not agree.

195 For example, Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector in submissions on the supplementary consultation paper, and Axiom for Transpower, Bushnell for Trustpower, EA Networks, HoustonKemp for Trustpower, Pioneer, Powerco, Transpower, Unison in submissions on the second issues paper and PWC for 14 EDBs(p.7), Fonterra (p.5), Transpower (CEG) (p.81), Trustpower (Bushnell) (p.5), ENA (p.10), Powerco (p.5), Westpower (p.7), Trustpower (p.17) in submissions on the options working paper.).

B.156 Furthermore, stakeholders would have an opportunity to assist in developing suitably robust methods as part of the consultation that takes place during the development of the TPM. In addition, for high-value investments, the Authority is proposing that Transpower consult with interested parties about important parameters that determine the charges. This consultation should reveal information relevant to establishing the benefits of the investment.

Impact of approximations in estimation of benefits

B.157 Various parties have raised the concern that getting a precise estimate of who benefits from a transmission investment and by how much will be difficult.[196] We agree. Furthermore the precision of the allocation will be affected by:

(a) the need to take account of pragmatic considerations as discussed in the previous section

(b) the use of a simple method for allocating charges for low-value investments.

B.158 This means that the allocation of charges may only approximately reflect benefits, and, that despite the measures taken to improve robustness, there may continue to be a significant range of uncertainty around Transpower's estimates of benefits.

B.159 Some submitters suggested that the benefit-based charge would not provide a forward-looking price signal, because beneficiaries will be unable to reliably estimate the way that charges will change as a result of new investments.[197]

B.160 Other submitters suggested that experts had identified that the AoB charge (now the benefit-based charge) would become less accurate over time, which might lead to a loss of durability.[198]

B.161 In our view, this does not undermine the case for allocating charges according to net private benefit. Perfection and total objectivity are not features of workably competitive markets and should not be expected from the methods for the allocation of the benefit-based charge. Even with a high degree of approximation, we consider that the benefit-based charge would still provide much better incentives for grid users than is possible under the current guidelines.[199]

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196 For example, submissions on the second issues paper by Transpower, Scientia for Transpower, Bushnell for Truspower.

197 For example, submissions on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector, Trustpower, Houston Kemp for Trustpower, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, The Lines Company, Top Energy, Waipa Networks, Westpower, Axiom for Transpower.

198 For example, submission on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector.

199 See Hogan (2011), pages 8 and 14. Hogan explains:

> If [an investment is only just efficient], and the estimate of incremental benefits approximately equals the total cost, it may be difficult to allocate the costs and support the investment well enough to preclude substantial opposition from the supposed beneficiaries. Less than perfect estimation of the benefits and their distribution could be problematic. Even with transmission mandates, this may lead to some such expansions failing to go forward. This would be a loss. From a societal perspective, however, this would not be much of a loss because by assumption the investment is about a net zero benefit.
>
> The more interesting case is where the net benefits are substantially greater than the transmission cost. If voluntary merchant investment is not forthcoming, efficient investment could follow the mandatory route with regulated cost allocation. An important observation is that in these cases cost allocation may by definition not require perfection in the estimation of the benefits or the distribution of benefits. By assumption, in this case there is a substantial excess of benefits F+G+H over the cost TC. Furthermore,

B.162 Furthermore, as Hogan (2011) states:

> Treatment of uncertainty is not simple, but it is unavoidable. The investment decision and cost allocation both can utilize the expected values of benefits and costs across a range of conditions. The scenario analysis is an approximation, but this is not fatal for either the investment evaluation or the cost allocation. The existence of uncertainty does not imply or require cost socialization.

B.163 In principle, this is no different from the uncertainty faced by a private investor undertaking investment in load or generation. That is, net benefits expected at the time the investment is committed may not materialise in practice. It is still appropriate to charge transmission users for the cost of investments made on their behalf, since they will then take that uncertainty into account in making their own decisions.

B.164 An allocation of transmission charges that turns out to be wrong in hindsight is unlikely to cause significant inefficiencies in decisions about access to or use of the grid once the decision is made. Transmission charges are typically a relatively small part of the cost of selling and purchasing electricity, so a substantial change in transmission charges would cause a much smaller change in the charges consumers pay for using electricity. More importantly, a party can only avoid paying the charge for any grid investment if it disconnects from the grid. It would only do that if its total benefit from access to the grid was less than its charges for accessing and using the grid (which is less likely).

B.165 In addition, the benefit-based charge for high-value investments is designed to reduce the chance that charges exceed net private benefits. These design features include:

(a) allocating the charge to both load and generation to the extent they are expected to benefit from an investment

(b) allocating the charge to all or the major expected beneficiaries from an investment

(c) providing for the charge to be recalculated where there is a substantial and sustained change in grid use

(d) allowing reassignment if certain criteria are met

(e) providing for the charge to be recalculated when there is damage to a grid investment

(f) restricting charges on pre-2019 investments to the estimated benefits they provide

(g) providing for a prudent discount in some circumstances where disconnection is otherwise likely.

B.166 The practical challenges of a benefit-based approach are not insurmountable. Each of the three ISOs or RTOs we met in the United States operates a beneficiaries-pay approach which is used to allocate the costs of at least some grid investments. The approach used in these jurisdictions involves modelling the forecast benefits of investments using system planning software models. While the scope of coverage for benefit-based charges and the

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> in the absence of contracts, the regulators have the added advantage that the private interests of market participants diverge from efficient investment in ways that could make cost allocation easier rather than harder.

We agree with Hogan.

NERA for Meridian made the similar point that it is not necessary to aim for a high level of precision in identifying beneficiaries. (submission on second issues paper).

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methods used in these jurisdictions differ from the approach proposed in New Zealand, the benefit-based principle is the same.[200]

B.167 Our assessment is that the difficulties and uncertainties involved in using net private benefits to allocate transmission charges do not undermine the case for allocating benefits in that way.

Substantial and sustained change in grid use

B.168 As is discussed above, in the normal course of events, the allocation of the benefit-based charge for an investment amongst transmission customers would be established when it is commissioned and then not changed.[201] However, there are some circumstances in which it may be appropriate to vary the allocation during the life of a high-value investment, specifically where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges. We expect that these events would be rare. We expect for example that such an adjustment would be no more common than reassignment.

B.169 In workably competitive markets, parties to long-term contracts typically include provisions to deal with substantial changes of circumstances. Often those provisions require the parties to work in good faith to re-establish the commercial basis of their agreement. Although the presence of such provisions can create incentives for opportunistic behaviour, carrying on with manifestly inappropriate arrangements can also create inefficiencies. We have therefore included provision for altering the allocation of the benefit-based charge in such unforeseen circumstances. The TPM must include a proposed method for revising allocations if such a change has occurred. However, no such revisions to charges would be available for low-value investments, in keeping with the need to have a simple benefit-based charge for low-value investments.

B.170 If Transpower did adjust the allocation of the benefit-based charge following a finding that the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges and that such circumstances are expected to be sustained, it would not affect the requirement to recover the covered cost of an investment from the beneficiaries collectively. This is because the proposed guidelines explicitly include the reassignment provision to deal with circumstances where a substantial reduction in use of the investment has occurred.

B.171 The reassessment process should also help address concerns raised by some submitters regarding ‘free riding’ or ‘free-loading’ (for example, the risk that some parties might misrepresent their expected benefits from an investment when it is proposed in order to reduce their level of charges).[202] The Authority is of the view that, to the extent that there would be such problems with the benefit-based charge, such problems would be much less than under the status quo, under which generators do not pay, and cost recovery is spread through the interconnection charge.

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200 Costs have been allocated on a beneficiaries-pay basis for around 50 projects by PJM and five projects by MISO. NYISO has yet to commit a project, but has two ‘public policy’ investments in process with recovery expected to be 75% by beneficiaries-pay and 25% socialised. See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

201 As outlined in paragraph B.96, some of the parameters used to estimate the annual benefit-based charge may change, but this would not alter its allocation between customers.

202 For example, see Bushnell for Trustpower’s submission on the TPM options working paper (p.5).

B.172 There is a risk that a review process could encourage participants to inefficiently avoid the benefit-based charge, because it would give parties incentives to alter their behaviour to demonstrate that they would benefit less from the investment and so reduce future charges for themselves should a review take place. The fact that the timing of future reviews would be uncertain is likely to reduce the likelihood of such behaviour.[203] Nevertheless, to further reduce the chances of such distortion occurring, the proposal limits the circumstances that can qualify as a substantial and sustained change in grid use.

B.173 First, the proposed guidelines provide that before the provision is invoked, there must be a substantial and sustained change in grid use. The TPM must explain how Transpower will determine when such a change has occurred. For example, it may specify a materiality threshold, perhaps defined in terms of a change relative to regional demand.

B.174 Second, the proposed guidelines provide that the circumstances must be outside the range of circumstances factored into the calculations used to allocate the relevant charges. This is because an outcome within the range of circumstances factored into the calculations will have been taken into account in deciding the initial allocation of the benefit-based charge. We anticipate that the investment approval process will continue to contemplate a wide range of scenarios. A substantial change is something that was not factored in to the relevant calculations during that process.

B.175 An example of the latter would be if Transpower had calculated charges using a weighted average of the benefits from two scenarios, one in which some customers experienced rapid demand growth, and another in which customers experienced slower growth. If demand growth turned out to be zero (that is, even lower demand than in the slow-growth scenario), that would be considered outside the range of initial circumstances contemplated and so might trigger a substantial change of circumstances review. But demand growth that was intermediate between that in the two scenarios would not trigger a review.

Q24. Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

[203] For this reason, we do not agree with the submission by Meridian on the second issues paper that the benefit-based charge should be subject to periodic review.

Implementation timeframe for the benefit-based charge

Proposal

Clauses 27 - 29, proposed TPM guidelines (appendix A)

Discussion

B.176 The Authority is proposing the benefit-based charge be implemented in 'one go' to all the high-value benefit-based investments (other than those that are identified as a result of implementation of Additional Component E). This is because the benefit-based charge will initially apply to only a small number of investments, and, depending on the outcome of this consultation process, the share of charges that each designated transmission customer is to pay for each pre-2019 investments (aside from those included via Additional Component E) may have already been determined in schedule 1 of the proposed guidelines.

B.177 We propose that Transpower is to delay the implementation for low-value post-2019 investments and to delay implementation of most of the additional components if that is necessary to facilitate the application of the charge to high-value investments. Although delaying the implementation of the benefit-based charge delays the efficiency gains from these measures, it facilitates faster implementation of the benefit-based charge for new high-value investments, which should achieve the related efficiency gains more quickly. Also, it is likely to be more straightforward to phase in the benefit-based charge for low-value investments after the standard charge has 'bedded in', as this allows time to address any implementation issues before the charge is implemented for low-value investments.

B.178 Nevertheless, we intend Transpower to implement the benefit-based charge for low-value investments as soon as practicable after it is implemented for high value investments. The proposed guidelines state that these charges must be implemented within 5 years of the commencement of the TPM.

B.179 As the residual charge recovers all recoverable revenue not otherwise recovered by the TPM (or a lesser amount determined by Transpower) any revenue foregone from phasing in the simple benefit-based charge method would be recovered through the residual charge.

Q25.	**Should the implementation of the charges for low-value post-2019 investments be deferred, and if so for how long?**

Upgrading expenditure

Proposal

Clauses 30 - 32, proposed TPM guidelines (appendix A)

Discussion

B.180 If Transpower undertook expenditure that is expected to extend the life of an investment beyond its initially expected life (or if it has been previously re-estimated, the re-estimated life) or otherwise add to the benefits from the investment ('upgrading expenditure'), the definition of a benefit-based investment means that the expenditure would be treated as a new benefit-based investment.

B.181 However, treating each upgrading expenditure as a separate investment could result in a proliferation of different benefit-based investments. Accordingly, we propose that

Transpower would also be able to treat the upgrading expenditure as additional capital expenditure on the existing investment. In this case, Transpower would first calculate the annual benefit-based charge for the new combined investment, and allocate the charges across customers on the basis of the present value of the sum of the benefits *previously* estimated for the existing investment plus the additional benefits estimated to result from the upgrading expenditure.[204]

B.182 Transpower would in general not be permitted to make changes to the requirement to recover the covered cost of the investment to be upgraded or to the pre-existing assessment of each customer's benefits from that investment. The reason for this is discussed in paragraph B.133 and B.134 above. However, as outlined in paragraph B.135 above, the proposed guidelines do provide for adjustments in some circumstances (eg, if there is a new entrant).

B.183 While Transpower would be permitted to apply the method in paragraph B.181 above to a pre-2019 investment, it is not obvious how it would do so in practice. The difficulty is that the benefit-based charge for the original investment would be recovered over time using the Commerce Commission method, and the benefit-based charge for the upgrading investment would be recovered using IHC. Instead, Transpower may choose to leave the treatment of the pre-2019 investment unaltered, and treat all post-2019 upgrading expenditure as one or more separate investments that are recovered according to IHC.

Reassignment

Proposal

Clauses 33 - 38, proposed TPM guidelines (appendix A)

Discussion

B.184 The proposed guidelines require Transpower to provide for reassignment of some of the costs of a benefit-based investment from the benefit-based charge to the residual charge.[205] This occurs when a grid investment turns out to be a 'white elephant' and customers make significantly less use of it than Transpower had anticipated initially. This reassignment is achieved by reducing the value of the relevant grid assets for the purposes of calculating benefit-based charges in respect of that investment. The intention is to ensure that the

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204 That is, customer j's charge for the upgraded investment could be calculated as follows:

Let: variables with the subscript j refer to those variables for customer j, and variables without subscripts refer to totals for all transmission customers benefitting from the investment

C(O) = covered cost of the original investment not yet recovered at time upgrading expenditure is commissioned

B(O) = present value of net positive private benefits of original investment originally estimated to be recovered after the date the upgrading investment is commissioned

C(U) = covered cost of the upgrading investment

B(U) = present value of net positive private benefits now estimated to result from the upgrading expenditure

Then the present value of customer j's benefit-based charge

$$= \frac{B(O)_j + B(U)_j}{B(O) + B(U)} * (C(O) + C(U))$$

205 This provision is in place of the provision for 'optimisation' that was included in the 2016 TPM proposal. We have changed the terminology to reduce the confusion that may be caused by the term 'optimisation', which is used in other contexts and has a different meaning. When we comment on the views expressed in submissions on the 2016 TPM proposal on reassignment, we are referring to the views that were expressed on optimisation.

future charges paid by the investment's beneficiaries better reflect the charges they would have paid had the services provided by the investment been more accurately forecast.[206]

B.185 Investments below $5 million are not eligible for reassignment in order to ensure a relatively simple benefit-based charge regime for such small investments. The $5 million threshold is proposed (rather than making the threshold for reassignment the same as the $20 million threshold for high-value investments) to ensure that, for example, relatively small distributors have access to reassignment where they have suffered a reduction in load that is not large overall but that is significant to them.

B.186 A potential disadvantage of reassignment is that it could lead to inefficient grid investment decisions. This is because a customer that would benefit from a proposed grid investment may anticipate the possibility of reassignment in the event that the grid investment turns out to be a white elephant. Such a customer might then have an inefficiently weak incentive to carefully assess the benefits against the costs of the grid investment. This could result in overbuilt investments in the interconnected grid. However, our view is that this effect is likely to be small, as we expect reassignment to be a rare event. As a result, this potential cost is likely to be outweighed by the advantages of the proposed reassignment provisions.

B.187 Reassignment allows transmission pricing to be more like what would occur in a workably competitive market. For example, suppose that a customer disconnected from the grid for some reason. In a workably competitive market, the contractual terms between the supplier of services (Transpower in this case) and the customer would determine whether the supplier or the customer would bear the loss on any investment that was stranded or significantly underutilised due to the disconnection. It would be unusual for other customers of the supplier to bear any of the cost.

B.188 We have proposed the reassignment provisions of the guidelines for the following reasons:

(a) to reflect the reduction in service provided where there has been a significant change in circumstances (such as significant technological development or reduction in demand) such that the 80% threshold is met, and that is likely to be sustained

(b) to efficiently manage the risk of asset stranding (in circumstances where the 80% threshold is met), and so reduce investment uncertainty, by providing customers with an assurance that there is a limit to how much direct additional cost they will have to bear as a result of other customers changing their use of the benefit-based investment.

B.189 For a period of time specified in the TPM (for example purposes, 10 years) after a post-2019 benefit-based investment is commissioned, reassignment would not be available unless a single customer disconnects, causing the value of the investment following reassignment to drop by 20% or more. The different treatment of post-2019 investments from pre-2019 investments is intended to ensure that customers do not seek to have new investments 'gold plated' because they know that reassignment is available. This objective is achieved by specifying that a long period of time must elapse after such a post-2019 investment has been commissioned before Transpower can write it down. This period must be sufficiently long that the prospect of reassignment does not distort incentives.

B.190 Transpower would include a method for determining what the value of the investment would be following reassignment in the TPM.[207] In our view, the considerations under the heading

[206] The reassignment provisions allow for non-transmission customers to apply for reassignment, as submitted by Fonterra in its submission on second issues paper.

General matters above would mean that the procedure for determining the reduction in value may be relatively simple, perhaps using a rule of thumb, even if that means that the reduction is not precise.[208] It might for example adjust the value before reassignment by making an estimate of the degree of economies of scale in all transmission investment, and use that to reduce the value based on the reduction in required capacity of the investment (for example, it might be estimated that a 50% reduction in capacity typically means a saving of 20% in costs).

B.191 If the conditions for reassignment are not met, then the reassignment provisions do not apply, so that Transpower will be required to recover the full covered cost of the investment. For example, if a customer exits but the fall in demand is not substantial enough that the investment's value following reassignment falls to less than 80% of its current value, then the benefit-based charges of other customers are increased proportionally such that 100% of the value of the investment continues to be recovered through the benefit-based charge. Transpower is required to remove reassignment if it is no longer justified.

B.192 If reassignment occurs (so the value of assets in an investment is reduced) the annual benefit-based charge for the investment would be reduced correspondingly, and its allocation would be adjusted to reflect the change in use that led to the reassignment.

B.193 For example Transpower may choose to make adjustments as follows:

(a) To the extent that the reassignment is due to the disconnection of a transmission customer, the benefit-based charge would be allocated among the remaining transmission customers paying the benefit-based charges for the investment according to the net benefits that were originally assessed.

(b) To the extent that the reassignment results primarily from a change in use by a distributor caused by the disconnection or change in use of its customers:

(i) the benefit-based charge is to be allocated among the transmission customers according to the net benefits originally assessed, except that:

(ii) the benefits originally assessed for the distributor would be reduced in accordance with the benefits it is now assessed as getting.

Q26. Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

207 For the avoidance of doubt, this reduction in asset value is for TPM purposes only and has no effect on the value of the asset recorded in Transpower's RAB.

208 This is the reason that we have not referred to optimisation of the investment. Optimisation is normally much more involved than the relatively simple process we are envisaging.

Main component 3: residual charge

Proposal

Clauses 39 - 41, proposed TPM guidelines (appendix A)

Discussion

Function of the residual charge

B.194 The function of the residual charge is to allow Transpower to recover any remaining maximum allowable revenue (MAR) that it is not able to recover from all of the other charges in the TPM. In particular it would recover:

(a) costs attributable to pre-2019 investments in the interconnected grid that are not recovered using the benefit-based charge

(b) Transpower's unallocated costs (including overhead expenses)[209]

B.195 We are considering two options: providing in the guidelines for a single residual charge or for multiple residual charges so that there is a separate residual charge for each sub-component of residual costs (for example, one residual charge for unallocated costs, one for costs attributable to investments in the interconnected grid that are not recovered using the benefit-based charge, one for costs that result from reassignment, and so on).[210] We are currently minded to provide for a single residual charge, as this approach may reduce administrative burden.

Q27. **Should the guidelines provide for a single residual charge or multiple residual charges?**

Design of the residual charge

B.196 The residual charge is not intended to actively influence grid use and investment (including investment in transmission alternatives). It does not need to, because, as is discussed in appendices D and E, this is done by other elements of the TPM and existing institutions, including:

(a) the electricity spot market, which provides efficient incentives for short-term use of the grid via nodal prices (as discussed in appendix D)[211]

(b) potentially a transitional peak charge, which the proposed guidelines provide for if it would better meet the Authority's statutory objective

(c) the Commerce Commission's regulatory regime and the proposed benefit-based charge, which together should limit incentives for inefficient investment by grid users and in the interconnected grid.

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209 Transpower's unallocated costs (including overheads) for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16. Under the current TPM, these costs are recovered from:

- generator customers, through the HVDC charge and the connection charge
- load customers, through the interconnection charge.

210 This has the effect of addressing the proposal by Oji Fibre Solutions (submission on the second issues paper) to have a separate optimisation charge to recover costs arising from reassignment.

211 The real-time pricing (RTP) project is intended to further enhance the efficiency of the spot market.

B.197 Since the mechanisms outlined in the previous paragraph are intended to influence grid use and investment to promote efficient grid use and investment, any additional price signal is therefore likely to cause inefficient use of the grid or inefficient investment.[212] As a result, we have designed the residual charge so that it affects the use of and investment in the grid as little as possible. This will be achieved if a grid user cannot profitably take actions that affect the residual charge it pays. If instead, for example, the residual charge was allocated based on real-time supply or demand, that would encourage grid users to inefficiently alter their grid use.[213] That is why we are proposing the charge be allocated based on a customer's historical electricity demand,[214] rather than its ongoing demand. Specifically, we are proposing the residual allocator could be based on data collected over at least two years ending prior to 1 July 2019. Using a historical allocator gives the customer little incentive to change its use of the grid purely for the purpose of reducing the size of its residual charge.

B.198 The Authority considers that this meets the concerns of those submitters[215] who suggested that the design of the residual charge should minimise inefficient avoidance of charges, but at the same time not discourage efficient consumption decisions.

B.199 We therefore disagree with those submissions that suggested that the residual charge might be more efficient if it sends a price signal[216], for example to adopt non-transmission solutions, to avoid the residual charge, to avoid inefficiently early grid investment or to signal the long-term cost of building network capacity. In our view, any such signal would most likely detract from efficiency.

Q28.	**Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?**

212 This is illustrated by the CBA, which shows that removing the RCPD charge brings forward grid investment, which improves efficiency.

213 See, for example, Hogan and Pope (2017), page 76

214 It is for this reason that we do not agree with those submitters who suggest that the residual allocator should be adjusted more frequently than we have proposed to respond to changing circumstances. See for example PWC for 14EDBs on the second issues paper.

However, we have not included an option of using physical capacity. This takes account of submissions on the second issues paper that using physical capacity would be undesirable, because charges would be based on a level of capacity that is unlikely to be ever fully utilised and that would vary significantly between customers (See, for example, Fonterra, NZ Energy, PwC for 14 EBDs, Waipa Networks, Westpower).

215 For example, submissions on the second issues paper by Pacific Aluminium, New Zealand Aluminium Smelter, Oji Fibre Solutions, Winstone Pulp, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Transpower.

216 See for example, Contact Energy, ENA, KCE, Mighty River Power, NZ Steel, Oji Fibre Solutions, PWC for 14 EDBs See also, for example, submissions on the supplementary consultation paper by Nova, Oji Fibre Solutions, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central.

Allocation of the residual charge

B.200 In determining our proposed default residual allocator, we have considered various measures of historical demand, each of which has pros and cons.

B.201 One choice is whether to allocate based on a peak measure, such as AMD, or a measure of broad usage, such as annual electricity consumption. A potential disadvantage of using AMD is that a load customer might pay less (assuming that the transmission charges were passed through in distribution charges) if it were embedded than it might pay if it were grid-connected. This potential artificial advantage could distort load customers' decisions on location and connection.

B.202 By contrast, an allocator based on annual electricity consumption has the advantage that it treats grid-connected and embedded load customers in the same manner (which would reduce distortion to location and connection decisions). This would address the legitimate concerns of those submitters[217] who considered that AMD disadvantages grid connected grid users relative to those who connect behind, and can therefore benefit from, the averaging implicit in a distributors' AMD. On the other hand, it may have a relatively greater impact on price-sensitive customers (and so distort such customers' decision-making). Large industrial consumers, for example, tend to have a demand profile with less pronounced peaks compared to households, so an allocator based on annual consumption would have a relatively greater effect on an industrial than an AMD allocator.

B.203 We are also considering a two-stage mixed approach to the residual allocator: a pre-allocation between direct connects and distributors using AMD, followed by a further allocation amongst direct connects and amongst distributors using annual consumption. This approach may have the advantages of both impinging relatively less on price-sensitive customers, and also minimising distortions to location and connection decisions by load customers.

B.204 Our current preferred option is to base the residual allocator on historical AMD, as this may reduce the likelihood of disconnection of some large loads. An allocator based on AMD would be less likely (than a MWh allocator) to cause the disconnection of a large industrial consumer (as such consumers tend to have relatively flat load profiles).

B.205 A number of submitters on the supplementary consultation paper either did not support the use of AMD[218] or thought Transpower should be given greater flexibility[219] to design the charge, or thought that the allocator should be RCPD[220]. Various reasons were given, including: that RCPD would limit wealth transfers and that AMD is unworkable in practice, results in illogically high charges, is punitive, is too narrow and is retrospective and so unlawful. For reasons given elsewhere, we do not agree that AMD is retrospective or unlawful. However, in recognition of the fact that we may not have identified the best allocator, we have provided that Transpower may use another method if that would better meet our statutory objective.

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217 For example submission on the supplementary consultation paper by Oji Fibre and Winstone Pulp International.

218 For example, IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, NZ Steel, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower, Fonterra.

219 For example, IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, Meridian Energy, Oji Fibre Solutions, Norske Skog, Auckland Airport.

220 For example, Norske Skog, Nova.

B.206 The proposals discussed under the heading *General matters* above and the heading *Provisions relating to adjustments* mean that Transpower would need to consider the various potential inefficiencies discussed above in the detailed design of the charge. For example, it could calculate the part of a distributor's residual charge attributable to large load connected to it as if the large load was grid-connected at the distributor's point of connection.

Q29. **Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?**

AMD for a customer with multiple points of connection

B.207 If we decide to allocate based on AMD, a further issue arises as to how to measure AMD for a customer that has more than one point of connection. There are two options:

(a) a 'non-coincident peak' measure of AMD, that is, measure demand at the (different) times of highest demand for each point of connection separately and allocate a separate share of the residual charge for each point of connection (then sum to get the customer's overall share of the residual) (This is currently our preferred option.)

(b) a 'coincident peak' measure of AMD, that is, measure demand at the (single) time of highest combined demand for all points of connection within a single 'location' (where location is indicated by the 3-letter location code used by Transpower in its pricing disclosure) and allocate the customer's share of the residual charge on that basis.

B.208 Compared to option (a), option (b) will generally result in a lower measure of AMD – and a lower residual charge – for a customer that has more than one point of connection. This is because the peaks at each point of connection may not occur at the same time. Some parties have submitted that it is reasonable for a customer to be able to take advantage of having a diverse customer base in their location.

B.209 Our view is that the residual charge should be allocated in proportion to a customers' size (and so reflective of their likely willingness and ability to pay). As is discussed in appendix D: decision making framework, allocation of common costs in this way is consistent with what would occur in a workably competitive market. Our current view is that a 'non-coincident peak' measure of AMD is a better proxy for the size of the customer base in a location and its ability to pay charges, however, we are open to considering arguments for the alternative approach.

Q30. **If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?**

Net load or gross load for the residual allocator

B.210 A further choice is whether to adopt a net load or gross load approach to measuring the default residual allocator.

B.211 Some submitters on the supplementary consultation paper[221] thought that we should adopt a net load approach. Some of these submitters thought that the load measure should at least be net of direct generation that is commissioned or committed before the proposed guidelines are finalised. Reasons given included that a gross load would impose a tax on parties with co-generation, and that a decision to invest in co-generation was normally undertaken for good commercial reasons rather than to avoid the charge.[222]

B.212 However, other submitters on the supplementary consultation paper[223] considered that netting off committed direct generation would not be service based or cost reflective.

B.213 Our current preferred option is that the residual should be allocated based on a gross load approach, as gross demand is a better proxy for customers' size (and so their willingness and ability to pay) than net demand. As is discussed in appendix D: decision making framework, allocation of common costs based on this is consistent with what would occur in a workably competitive market. If the operation of distributed generation reduced the residual charge, the allocation would no longer be based on customer size or ability-to-pay. It would also risks creating an artificial incentive for investment in distributed generation over time, in advance of the residual allocator being updated (particularly if updating occurred frequently).[224]

B.214 We do not intend to add back demand response to AMD in calculating gross AMD. While adding back demand response might be desirable in principle for the same reason that adding back distributed generation might be desirable, we accept the views of some submitters on the second issues paper that adding back demand response may be impractical.[225]

Q31. **Should demand be measured using a net load or gross load approach for the allocation of the residual charge?**

221 For example, Fonterra, Nova, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

222 In practice it is impractical to determine the extent to which actions are taken to avoid a charge and actions that are taken for commercial reasons other than to avoid the charge. As a result, we cannot realistically design the guidelines to distinguish between these two different sorts of motivations.

223 For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

224 This means that we are inclined to disagree with those submitters who suggested that the capacity measure should be net of distributed generation; eg, the submissions by Network Waitaki, NZ Energy, Norske Skog, PWC for 14 EDBs on the second issues paper.

225 See for example the submissions on the second issues paper EnerNoc, Orion.

B.215 Finally, if a gross load approach is adopted, there is a question as to whether demand should be 'grossed up' for injection by distributed generation only, or by both distributed generation and behind-the-meter generation. Our current preferred option is that demand should be grossed up for distributed generation and also for behind-the-meter generation, as we see no compelling reason to treat these types of generation differently for these purposes.

Q32. **If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?**

B.216 We have considered whether there is sufficient information available for Transpower to implement a gross load approach in the way we are proposing. The Authority considers that there is data available from the Reconciliation Manager that would meet the requirements of these provisions of the proposed guidelines. The guidelines require Transpower to use this data. The Code already provides for Transpower to request any data from the Reconciliation Manager that it requires in order to set transmission charges.

Q33. **Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?**

Default or predetermined residual allocation

B.217 An alternative option would be for the Authority to determine the initial allocation of the residual charge in advance. We have allocated the residual charge for the purposes of the indicative transmission charges as reported in chapter 5. Under this alternative option, that indicative allocation (with adjustments as appropriate) would become a default or required allocation in the guidelines, for example, by setting out the allocation as a new schedule 2 to the guidelines. We are not currently minded to adopt this option, as we see no compelling reasons to do so and this is a matter of implementation which Transpower is able to address.

Q34. **Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?**

Adjusting the residual allocation

B.218 The guidelines set out a principle that in allocating the residual charge, Transpower should adjust the allocation where a customer has experienced a substantial change to demand due to factors over which they have no control. This principle is intended to allow, for example, a downward adjustment to the AMD of a distributor where a large industrial customer that was previously connected to the distribution network has closed down. An example is the exit of the Holcim cement plant, which reduced demand on Buller Electricity's distribution network. In our view, to charge such a distributor high charges based on a high level of demand, when the industrial customer that caused that level of demand has since closed down, would be perceived as unfair (and so would undermine the proposed TPM's durability).[226]

[226] This addresses the concerns expressed by some submitters on the second issues paper that historical data may not be a good proxy for the customers current size; see for example PWC, Westpower.

Q35.	**Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?**

B.219 The proposed guidelines allow Transpower to propose another residual allocator if that would better satisfy the Authority's statutory objective.[227] In practice, this would mean that a different residual allocator would have to satisfy the proposals discussed under the heading *General matters* above and the heading *Provisions relating to adjustments* These are likely to put significant constraints on any residual allocator that Transpower proposes.

B.220 Transpower could update the residual allocator through an operational review of the TPM, to avoid the allocator becoming anomalous as grid conditions evolve. A number of submitters on the 2016 TPM proposal expressed concerns that allowing for revision of the residual allocator might lead to inefficiencies as grid users altered their behaviour in anticipation of the revision.[228] However, we have provided for this update to be based on the definition of allocator on AMD from the later of 10 years prior to the date of update or the date of publication of the second issues paper. The Authority considers that this should in large part avoid creating inefficient incentives for avoidance of the charge and for inefficient investment in or operation of distributed generation.[229]

Charge would recover overheads

B.221 It is proposed that any remaining overheads and unallocated operating expenses (after the attribution discussed in paragraph B.73 above) would be recovered through the residual charge. Some submitters on the 2016 TPM proposal considered that the overheads should be recovered through the area-of-benefit charge or through a surcharge on all the TPM charges.[230] Other submitters suggested that overheads should be recovered through the residual charge.[231]

B.222 Our view is that the recovery of overheads should reflect how they would be recovered in a workably competitive market.[232] In our view, since the residual charge uses load size as a proxy for ability to pay, it is most appropriate to recover overheads and remaining unallocated operating expenses through the residual charge.

Charge would apply to load only

B.223 Some submitters on the supplementary consultation paper suggested that we should provide for or consider charging the residual to generation as well as load. However, our current preference is that the residual charge would apply to all transmission customers but only to the extent that they are load. Generators would be liable to pay the charge only to the extent that they off-take electricity from the grid. If Transpower proposes an alternative residual allocator, that allocator would need to have the same effect.

B.224 The reason the Authority proposes restricting the charge to load is to avoid inefficiency. Any residual charge that is applied to generation (that is, injection into the grid) would likely

227 This accords with Transpower's submission on the second issues paper, which proposed that Transpower have broad discretion in choosing the residual charge allocator in developing the TPM.

228 For example, Bushnell and CEC for Trustpower, EA Networks.

229 This is also the reason we do not agree with those submitters on the 2016 TPM proposal who suggest there should not be such a lag; eg, Buller Electricity, Fonterra, PwC for 14 EDBs, TECT, Top Energy.

230 For example, Oji Fibre Solutions, Pacific Aluminium

231 For example, Meridian.

232 This accords with the view expressed by Pacific Aluminium in its submission on the second issues paper.

largely be passed on to load in the form of higher energy prices, since new generators would then delay entering until the energy prices they expect to receive would cover their residual charge. That is, on average, prices would rise relative to the no-charge case before the next generator would find it profitable to invest. This means that effectively load customers would likely end up paying much of the charge whether or not the legal incidence of the charge is on load or generation. Since the charge would be passed through in nodal prices, it means that nodal prices would likely be higher, discouraging energy use (compared with the case where the entire charge is on load). The Authority considers that this would be inefficient.

B.225 We therefore do not agree with those submitters on the 2016 TPM proposal who suggest that both load and generation should pay the charge.[233] The reasons given why generators should pay the charge include:

(a) It is desirable to strengthen the locational price signal generators face (Waipa Networks). As is noted above, we consider other charges provide appropriate price signals.

(b) Both load and generation benefit from access to the market (Counties Power). We agree, which is why the benefit-based charge applies to both load and generation.

(c) Competition will limit the ability of generators to pass through the residual charge (EPOC, Norske Skog).

We disagree with these arguments for the reason outlined above.

B.226 The reason the Authority proposes that the charges apply to both load and generators to the extent that they are load is to avoid creating any classification or other difficulties when a customer is sometimes a load customer and sometimes a generator.[234]

B.227 Submitters had mixed views about how specific we should be about the measure of load for this proposal. In its submission on the supplementary consultation paper, Transpower considered that this section of the proposal should be removed, because it should not prescribe that the residual charge be allocated on the basis of load. We believe the proposed guidelines give Transpower considerable flexibility on how to choose the residual allocator, while making clear that the general principle is to avoid applying the residual charge to generators.

B.228 Other submitters on the supplementary consultation paper[235] thought this proposal too vague, because the size of a customer's load can be measured in several different ways. We believe it is desirable to give Transpower flexibility to propose the allocator that it considers best advances our statutory objective, so as to avoid precluding some allocator that may better meet our statutory objective than AMD.

***Q36.* Should the residual charge apply to both generation and load customers, or only to load customers?**

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233 These include Counties Power, ENA, EPOC, Fonterra, Orion, Pacific Aluminium, PwC for 14 EDBs, Waipa Networks, Vector. On the other hand, Contact Energy and Meridian (including NERA) consider load should pay the residual charge.

234 This also addresses the submission of TECT and Top Energy on the second issues paper that parties should be classified from load to injection if their power flow changes on a permanent basis.

235 For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

Addressing dilution of price signals from pass-through of residual charge

B.229 Some submitters have expressed concern the residual charge would be passed through to mass-market consumers through variable consumption charges, which would artificially discourage electricity use. We agree that this could cause inefficient use of the grid. This issue is being addressed through the Authority's review of distribution pricing.

The residual charge is expected to reduce over time

B.230 The amount to be recovered under the residual charge would vary from time to time based on the following factors:

(a) The amount of revenue to be recovered on pre-2019 investments will decline over time as they depreciate.[236]

(b) Transpower could choose to recover an amount through the residual that is less than the maximum it is entitled to (for example, if it wanted to ensure that transmission remained competitive with an alternative, such as solar panels).

(c) If Transpower chooses to extend the benefit-based charge to cover more investments as provided for under Additional Component E*,* then the residual charge would decline correspondingly.

(d) The residual will be affected by differences between the Commerce Commission’s method for valuation of assets and recovery of investment costs over time (DHC) and the approach proposed in this paper (IHC).

(e) Any reassignment would reduce the total of the benefit-based charges, increasing the amount to be recovered via the residual charge.

B.231 Overall, the residual charge is likely to decline over time, as the value of interconnection assets not covered by benefit-based charges depreciates. Conversely, the value of investments covered by benefit-based charges will grow over time.

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236 Revenue recovered through the residual charge will not increase due to new investments in the interconnected grid or upgrading expenditure, as these costs are recovered through the benefit-based charge.

Provisions relating to adjustments

Proposal

Clause 42, proposed TPM guidelines (appendix A)

Discussion

B.232 The purpose of these provisions is to allow for adjustments to be made to the benefit-based and residual charges where circumstances change or else to scale back charges where they would result in Transpower over-recovering its revenue

B.233 Clause 42 of the proposed TPM guidelines deals with large consumers or generators and with the sale of a business.

Charges for a new large consumer or generator

B.234 The proposed guidelines require Transpower to include in the TPM a process for allocating benefit-based charges and residual charges in respect of a new large consumer or generator or an existing large consumer or generator that substantially increases its use of the grid,[237] and therefore also for adjusting the allocation of the benefit-based charges between customers to the extent necessary to take account of the charges paid by the new large customer.[238]

B.235 The proposals discussed under the heading *General matters* above mean that the rules will need to be designed to minimise the chances of inefficiently affecting the customer's decisions about the location and size of its connection and about its use of the grid. In particular, this means that it would be problematic to base the new entrant's transmission charges on its capacity or use of the grid after it enters. If charges were based on this, it would have an inefficient incentive to reduce its capacity or use, purely to avoid the charges.[239] Instead, we think it likely that the charges for new customers will have to be based on a proxy or proxies.

B.236 It is important, once the new entrant has entered, for it to be treated from that time in a similar way to a (possibly hypothetical) existing business that was otherwise identical to the new entrant, but was connected to the grid at the date of publication of the 2019 issues paper. To do otherwise would potentially introduce a production inefficiency. For example, if the new entrant had lower charges than it would have had if it had been an existing business, it might be able to out-compete an existing business (when it might otherwise have been less competitive). This would be inefficient.

B.237 Similarly, the proposed guidelines require Transpower to include in the TPM rules for determining changes to transmission charges for a transmission customer that electrically connects a new large consumer indirectly to the interconnected grid. The reason for making

237 This responds to the submission of Pacific Aluminium on the second issues paper that a customer making a permanent change to its demand should be treated the same as a new customer. Its submission with respect to disconnecting customers is dealt with by the reassignment provisions.

238 This provision deals with the concern expressed by PowerCo in its submission on the second issues paper that the substantial change in circumstances provision may not be sufficient to ensure that the benefit-based charge responds efficiently to the entry of major load and generation. It also addresses the submission by Axiom for Transpower that the previous proposal did not address how customers that enter an area of benefit after an investment has been made would be assigned a share of those sunk assets.

239 Transpower makes a similar point on page 8 of its submission on the second issues paper, although the context is different (namely, the allocation of charges to generation based on average injection).

an adjustment to the distributor's charges when a new large customer connects to a distribution network is that otherwise there would potentially be an inefficient incentive for a large customer to embed in cases where direct connection would have been more efficient. As before, consequential adjustments to the allocation of the benefit-based charges between customers would be necessary to take account of the charges paid by the new large customer.

Adjustment for a large consumer that shifts its connection point

B.238 The proposed guidelines require the TPM to avoid creating inefficient incentives for a large consumer or generator to shift its point of connection from or to Transpower and/or a designated transmission customer.[240] Without such a provision, the proposed TPM could encourage large electricity consumers to shift their connection point in order to avoid or reduce their residual charge and potentially their benefit-based charge. For example, a directly connected industrial customer might be encouraged to disconnect from the grid and embed if this means it would avoid paying transmission charges. This could be inefficient.[241]

B.239 The proposed guidelines do not prescribe how Transpower is to achieve this.[242] The provision could provide, for example, that Transpower would adjust the charges of the affected distributor(s) and the large consumer so that the charges applying to or attributed to the large consumer move with it. For example, in the case of a Transpower customer that will become embedded in a distribution network, the provision could provide that Transpower would increase the distributor's charges by the customer's charges.

B.240 While the prudent discount policy might be one potential tool for addressing these inefficient incentives, our intention is that it is the tool of 'last resort'. Rather than simply reducing charges for any customer that is able to shift its point of connection, Transpower is required to design the other elements of the TPM to avoid creating incentives for customers to shift their point of connection. This means Transpower should not need to have recourse to the prudent discount policy to address this issue.

Adjustment for partial sale of a business

B.241 The proposed guidelines provide that the TPM is to make provision for Transpower to reallocate the transmission charges a transmission customer is liable for if it becomes aware that the customer has sold part or all of its business (eg, industrial plant). Transpower would split the charges between the existing customer and the new owner as appropriate. The purpose of this provision is to ensure that in that circumstance the charges continue to reflect the relative benefit that each party gets from access to the interconnected grid.

B.242 Absent this provision, the contract between the buyer and seller could provide for allocating responsibility for transmission charges, and this could be reflected in the price paid by the

240 This proposal addresses the submission of Refining NZ on the supplementary consultation paper that the cap could result in incentives for users such as the refinery becoming direct consumers.

241 In its submission on the second issues paper, NZ Steel made the point that it might have an inefficient incentive to change its GXPs to allow for consolidation with Counties Power. This proposal addresses this issue.

242 This addresses Transpower's submission on the supplementary consultation paper that the draft guidelines in that paper were too prescriptive on this issue. It also responds to the submissions on the supplementary consultation paper that suggested that the more prescriptive approach proposed there may not be practical. For example, see submissions by PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

new owner. However, this could result in an anomalous situation, for example, where the existing customer retained responsibility for all of the transmission charges relating to that part of the business and the new owner paid Transpower nothing.

The charges may need to be scaled back

Proposal

Clauses 43 - 45, proposed TPM guidelines (appendix A)

Discussion

B.243 These provisions, together with Clause 9 of the proposed guidelines, prevent the total of all transmission charges from exceeding the maximum revenue that the Commerce Commission allows Transpower to recover. If not for these provisions and Clause 9, this could occur as the result of the cost recovery profile that the proposed guidelines would set as the default for post-2019 investments (the IHC approach). This is because the benefit-based charge will eventually extend to all investments in the grid and in the later years of each investment's life, the benefit-based charge would exceed the recoverable revenue attributable to the investment.

B.244 It is also possible that Transpower may decide to recover less than its maximum allowable revenue. For example, it might choose to reduce a particular customer's charges in order to be competitive in the face of emerging technologies that compete with transmission. In that case, it would not be appropriate to recover the charge from other customers by increasing their residual charge.

B.245 We have proposed (in Clauses 43 – 45, proposed TPM guidelines (appendix A)) a way to scale back charges that we consider best promotes our statutory objective.

B.246 There are a variety of methods that Transpower could choose to scale back the benefit-based charges. For example, for pre-2019 investments, it could:

(a) reduce the benefit-based charge pro-rata in order to preserve the relativity between the benefit-based charges in different locations, or

(b) disproportionately scale back the benefit-based charges for those pre-2019 assets that are part of the core grid. This would have the advantage of limiting the scaling back of the charges for non-core grid assets (such as the 110kV network) for which individual ownership contestability is most practicable. This would improve the incentives for efficient ownership decisions about these assets. The main disadvantage of this option is that it would distort locational decisions by providing incentives for generation and load to locate away from the non-core grid.

B.247 Transpower would need to select a method that is consistent with our statutory objective.

Q37. **Are the proposed provisions relating to adjustments appropriate?**

Main component 4: prudent discount policy

Proposal

Clauses 46 - 48, proposed TPM guidelines (appendix A)

Discussion[243]

General rationale for granting prudent discounts

B.249 The economic rationale for granting prudent discounts is that the discounts avoid large inefficiencies in situations that can be characterised as 'win-win'—that is, granting the discount avoids economic inefficiencies arising from the flat-rate nature of the benefit-based charge and residual charge, and avoids other transmission customers paying higher transmission charges.

B.250 For example, it can be better for all transmission customers that an applicant pays discounted transmission charges (exceeding incremental costs) if the alternative is that the applicant would disconnect from the grid and pay no transmission charges. Provided the customer receiving the prudent discount was paying at least its incremental cost, the first scenario is likely to be a better outcome for all transmission customers because the applicant would be making some contribution towards common costs, whereas in the second scenario it makes no contribution, resulting in higher charges for other transmission customers. In effect, the PDP is a practical alternative to applying an efficient Ramsey pricing formula.[244]

B.251 Prudent discounts allow Transpower to reduce its charges to customers when that is considered to be necessary to meet the market costs of an alternative to transmission assets. This is what would happen in a workably competitive market.

A prudent discount would be available to applicants for whom it is privately beneficial to disconnect from the grid and source alternative supply

B.252 This provision largely carries over the policy intent in the current TPM relating to the prudent discount policy (PDP). That is, it provides that Transpower can discount a customer's charges where it is privately beneficial for the customer to undertake a project that will allow it to bypass the existing grid, even though it is not efficient to do so. In addition, the proposed guidelines extend the PDP to situations where it is privately beneficial for a party to disconnect from the grid and source an alternative supply of energy, even though it is not efficient to do so.[245]

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243 There was a large measure of support from submitters on the supplementary consultation paper for retaining the PDP and for extending it as outlined in the proposed guidelines, largely for the reasons discussed here.

244 The second issues paper discussed using Ramsey pricing calculations to allocate the residual charge, as an alternative to extending the PDP to cover the risk of large load customers disconnecting from the transmission grid. However, it concluded that it was impractical.

Partly for this reason, we do not accept the views of those whose submissions on the second issues paper suggested that the need for a PDP indicates that there are problems with the Authority's proposed TPM; eg, Auckland Airport, EMA, Norske Skog, Refining NZ, TECT, Transpower, Vector.

245 The current prudent discount policy does not fully cover this situation, as it explicitly excludes scenarios where a party might source supply from new generation. This is because the definition of 'alternative project' in the TPM means an investment proposed by a customer, which if implemented, would bypass existing grid assets, but does not include proposed new generation.

B.253 Some submitters viewed it as unlikely that industrial load customers would disconnect from the grid and self-supply. Our view is that, in that case, prudent discounts would not be granted to applicants. However, we are aware that the risk of disconnection because of the ability to self-supply is not just a risk in relation to industrial customers. Some distributors also are in a position where self-supply may be a commercially viable option (and if not now, then maybe in the future as a result of changing technology and business models).

B.254 Other submitters expressed concern that prudent discounts might be granted in situations where an application lacked credibility.[246] Submitters were also concerned that the criteria for the PDP might be too difficult to meet.[247] Our view is that these would be matters for Transpower to consider in developing the TPM. Under the proposed guidelines, the TPM would set criteria for assessing applications and calculating discounts under the PDP.

Prudent discounts would apply for the life of the asset unless otherwise agreed

B.255 We have considered two options for the duration of a prudent discount:

(a) this decision could be left unspecified (so that it is to be agreed via commercial negotiation between Transpower and its customer)[248]

(b) the guidelines could specify that it applies for the life of the relevant asset unless the parties agree otherwise (currently our preferred option).

B.256 Some direct consumers have indicated to the Authority that PDPs do not provide enough certainty to make long-term investment and operational decisions.

B.257 Under the proposed guidelines, a prudent discount would apply for the expected life of the asset to which the discount relates, unless a shorter period is otherwise agreed between Transpower and the party receiving the prudent discount.

B.258 This would give a party greater certainty that a prudent discount will be available for the full life of its investment, thus reducing unnecessary uncertainty and promoting efficient investment. It would also reduce the transaction costs involved in assessing applications for new prudent discounts at the end of their term.

Q38. **Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?**

246 For example, PwC for 14 EDBs

247 For example, Contact Energy, Oji Fibre Solutions, Refining NZ

248 In its submission on the supplementary consultation paper, Transpower suggested that the term of a prudent discount should be agreed by the parties, because making the life of the asset the default term effectively forces Transpower into very long-term agreements unless the customer decides otherwise.

Cap on transmission charges[249]

Proposal

Clauses 49 - 53, proposed TPM guidelines (appendix A)

Discussion

B.260 The price cap is intended to limit increases in customers' 'capped transmission charges', being all transmission charges other than the ones excluded by clause 49 of the proposed TPM guidelines (appendix A). Essentially this means the cap limits increases in charges due to the reallocation of existing transmission costs resulting from the proposal.

B.261 One option is for the TPM not to include a price cap. This option would introduce benefit-based charges that better reflect customers' benefits from the seven major investments without delay and for that reason could promote durability and efficiency.

B.262 However the Authority's current view is that the TPM should include a price cap. There are three reasons why the Authority believes a cap is warranted:

(a) Certainty—because the proposed guidelines give Transpower some flexibility (for example, through the provisions discussed under the heading *General matters* above), customers would otherwise be left uncertain as to what their charge would be. A cap would provide customers with relative certainty in advance.

(b) The prudent discount for exit is restricted to circumstances in which customers seek alternative supply (it is not available if a customer goes out of business) — we want to reduce incentives for other forms of inefficient exit (such as a customer going out of business) as a result of the introduction of the new TPM. However, we don't want to extend the prudent discount policy to do this. So an alternative is to use the cap to limit the initial impact of charges by allowing businesses that might otherwise exit time to adjust to the new charges. For a number of direct customers, the cap would be binding and would remain binding for many years.

(c) Limiting potential efficiency effects that might arise from price shocks—limiting the initial impact of the charges would mitigate concerns that the TPM proposal would result in unexpected increases in charges. In particular, some submitters suggested the proposal's wealth transfers could create uncertainty, reduce investor confidence, affect the durability of the TPM, or in some other way have an adverse effect on efficiency.[250] A transition could help address this, to the extent it is an issue.

Options for implementing a price cap

B.263 A price cap could be implemented in various ways. We are considering two options for capping charges.

B.264 The first option (currently our preferred option) would result in the increase in each distributor's capped transmission charges over the transmission charge it pays in 2019/20 being limited to no more than 3.5 percent of the estimated total electricity bill of all of the consumers supplied, directly or indirectly, from the distributor's network in the 2019/20

249 The inclusion of a cap in the guidelines addresses Transpower's submission on the second issues paper that there should be a transition to deal with price shocks.

250 For example, submissions on the second issues paper by EA Networks, Infratil, Mighty River Power, Norske Skog, Transpower, Vector.

pricing year, increased by the rate of inflation plus the percentage increase in the distributor's load (if any) since the 2019/20 pricing year.

B.265 This proposal gives distributors the ability to cap the initial real increase in their customers' transmission charges to about 3.5 percent[251] of their 2019/20 total electricity bill. However, because distributors have discretion in how they set charges, it does not prevent distributors from choosing to disproportionately pass on the increase in charges to particular groups of consumers.[252]

B.266 For each direct consumer, the price cap would result in the increase in each direct consumer's capped transmission charges over the transmission charge it pays in 2019/20 being limited for 5 years to no more than 3.5 percent of the total estimated electricity bill of the direct consumer in the 2019/20 pricing year, increased by the rate of inflation plus the percentage increase in the direct consumer's load (if any) since the 2019/20 pricing year. After 5 years, the 3.5 percent would increase by 2 percentage points per annum (that is, to 5.5 percent, then 7.5 percent etc, until such time as the cap no longer limits the direct customer's capped transmission charges for at least one pricing year). This would ensure that the charges for those customers would become cost-reflective over the long run. This is appropriate as it:

(a) limits the inefficiency that could arise from otherwise similar transmission customers facing different charges

(b) ensures that direct consumers will eventually face cost-reflective charges.

B.267 The cap would be on (and so limit increases in) capped transmission charges rather than on the total electricity bill faced by a direct consumer, even though the cap would be specified in terms of the estimated total electricity bill.[253]

B.268 Transpower has sought more specific guidance on how to implement the cap. In order to address this concern, we have proposed a prescriptive approach to the calculation of the price cap, setting out in the proposed guidelines the data that Transpower must use in setting the cap and the formula that it must apply.[254] The estimated total electricity bill of all of the consumers supplied from each distributor's network and for each direct consumer is to be estimated using data from the reconciliation manager, from the Commerce

251 Because the cap is based on estimated electricity bills, the cap may differ somewhat from 3.5% of consumers' actual bills. However, the difference is not likely to be material.

252 In its submission on the supplementary consultation paper (page 8 and page 16), Transpower comments that "the design of the price cap means Transpower could not provide surety prices would be within the 3.5% price cap." Similarly, other submitters (eg, Vector, Entrust, Pioneer Energy, Otago Chamber of Commerce) note that the price cap relies on retailer pass-through, which may not happen. We agree with these points. The important point is that the cap would give distributors and retailers the discretion to limit the price increases. Whether they choose to or not is a matter for them.

253 This accords with the suggestion of submitters on the supplementary consultation paper who stated that in order to have a meaningful impact, the cap should apply to transmission charges, not to the total retail bill. For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, Nova, Oji Fibre Solutons, The Lines Company, Top Energy, Waipa Networks, Westpower.

254 This also responds to those submitters on the supplementary consultation paper who stated that the cap is unworkable or difficult to apply or too complex possibly because it is highly dependent on assumptions or relies on Transpower being aware of information it may not have access to (for example, the total retail bill of all consumers at a network level). For example, PwC, Alpine Energy, Aurora Energy, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower, Transpower, Ngawha Generation.

Commission's Electricity Distribution Information Disclosure Determination 2012 and from Transpower's own data about transmission charges.[255] In addition, we note that the considerations discussed under the heading *General matters* above mean that Transpower would need to develop a method for implementing the cap which takes account of any remaining practical difficulties in estimating the electricity bill.

B.269 This calculation formula for the estimated total electricity bill leaves out a number of relatively small components of the electricity bill (notably retail margins and metering charges). We have done this to make the estimated electricity bills simple to calculate. The effect is the same as if we had set the cap at a percentage somewhat less than 3.5%. That is, the cap gives distributors whose charges are restrained by the cap greater protection against price increases than the description of the cap would otherwise imply.

B.270 Some submitters on the supplementary consultation paper[256] made the point that there is a trade-off between allowing prices to change quite quickly (so limiting the benefits outlined in paragraph B.262 above), and prolonging the transition period, which potentially delays the efficiency gains from having prices better reflecting costs and, they say, placing an unfair burden on those who subsidise others under the current TPM. Some submitters on the supplementary consultation paper considered a cap would be likely to distort outcomes by shifting costs to others, impacting negatively on durability over time.[257] Other submitters on the supplementary consultation paper supported the introduction of a price cap as a transition.[258]

B.271 Other submitters have proposed different transitional methods than the proposed cap. For example:

(a) amend the existing RCPD charge to give a more suitable locational price signal, develop and introduce an AoB charge, develop and transition the residual charge as a postage stamp charge, develop and introduce LRMC, remove RCPD, and then adjust the AoB charge if necessary[259]

(b) a staged introduction of a new TPM with price increases staggered over several years[260]

(c) a transition from the RCPD charge to the residual charge.[261]

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255 If these data are not available at the time Transpower first applies the cap, it may have to use estimates of them and then apply a wash-up when they become available.

256 For example, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central.

257 For example, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Pioneer Energy, Otago Chamber of Commerce, Counties Power, Counties Power Consumer Trust.

258 For example, Fonterra, Westpower, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central. Genesis Energy, Castalia for Genesis, Transpower, Oji Fibre Solutions also agreed that transitional provisions are desirable.

259 For example, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower.

260 For example, Top Energy, Ngawha Generation.

261 ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Unison, Centralines.

B.272 We accept that some of these approaches would result in a transition similar in nature to that which we are trying to achieve with the cap. However, we cannot see any particular advantage that any of the proposed approaches provide relative to the cap that is set out in the proposed guidelines.

B.273 We agree with the submitters that it is a matter of judgement whether the benefits of the cap outlined in paragraph B.262 above outweigh the costs it imposes such as the muting of the price signals from any new TPM in the interim.[262] However, we believe we have limited any adverse efficiency effect of the proposed cap by applying the cap to the customer's capped transmission charge. Roughly speaking, this means that it would limit the increase in the customer's transmission charges that are attributable to pre-2019 investments in the interconnected grid listed in schedule 1 of the proposed guidelines.

B.274 Specifically, the cap would not apply in regard to charges attributable to assets commissioned after the end of the 2019/20 pricing year, any peak charge or any kvar charge, as doing so would materially reduce the efficiency of those charges. Neither would the cap apply to any increase in a distributor's or direct consumer's charges as a result of reassignment or a review under the substantial and sustained change in grid use provision.

B.275 Of these, the most material exclusions are likely to be the charges attributable to assets commissioned after the end of the 2019/20 pricing year. If these investments are efficient, these charges are not expected to adversely affect any customer, since the charges each customer would pay for them would be less than the benefit it is expected to derive from them.[263]

B.276 The cap would not apply to any benefit-based charge for further assets included as benefit-based investments under Additional Component E. Instead, Transpower would be able to propose a transition for the application of the benefit-based charge to such investments (including a transition that would have the same effect as an extension of the cap to the charges for these investments), if that were consistent with clause 12.89 of the Code. We have not specified the transition, as the appropriate form may depend on the investments Transpower chooses to include.

Q39. **Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?**

B.277 Some submitters on the supplementary consultation paper suggested that the cap should be calculated using transmission charges only, in part because it would be unusual to impose a price cap on transmission costs that is relative to total energy costs.[264]

B.278 We are also considering such an option. In this, the price cap would be the same as discussed above, except that, instead of limiting charges to a percentage of the estimated total electricity bill, the price cap would instead limit increases in capped transmission charges for any transmission customer to no more than some fixed percentage of the

262 This point was also made by Pacific Aluminium and New Zealand Aluminium Smelter in its submission on the supplementary consultation paper.

263 Some submitters on the supplementary consultation paper (eg, Trustpower, Houston Kemp for Trustpower) proposed that the price cap should apply to more than the capped transmission charges. We disagree, for the reasons outlined in this paragraph and paragraph B.273.

264 For example, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Counties Power, Counties Power Consumer Trust, Meridian, Pacific Aluminium, New Zealand Aluminium Smelter.

customer's capped transmission charges in 2019/20 expressed in $/MW (based on the customer's historical AMD). This is a simpler approach because it avoids the need to estimate consumers' electricity bills.

B.279 We are not proposing this option because we consider that the electricity bill is more salient to consumers than transmission charges implicit in it. If we adopted this option, it would make the impact of the proposal on load customers' (and mass market consumers') total bills less consistent, as grid charges make up a different proportion of the total bill for each customer.

Q40.	**Should the price cap be specified as a percentage of estimated electricity bills or in some other way?**

B.280 We considered applying the price cap to generators' charges as well as load customers' charges. Such a cap could be specified as a percentage of generation revenue in 2019/20, with the limit gradually increasing over time (as it does for direct connect customers). This would ease the transition to the new regime for North Island generation customers that currently do not pay transmission charges and would do so under the proposal.

B.281 However, our currently preferred option is to apply the proposed price cap to load customers only. This is because we consider that the concerns about certainty and price shocks that are discussed in paragraph B.262 above mainly arise with respect to the potential impact on consumers (residential, and direct consumers), rather than generators. Generators would not be subject to the residual charge under this proposal (except to the extent of their load), which would limit the adverse impact on generators from our proposal.

Q41.	**Should the price cap apply only to load customers, or to generators as well?**

B.282 We also are considering options for how Transpower might recover any revenue forgone as a result of the operation of the cap.

B.283 Our current preference is to fund the price cap through a percentage surcharge on the total of benefit-based charges for pre-2019 investments and residual charges. This would mean that, to the extent that some customers' increases in transmission charges are capped, the transmission charges of other designated transmission customers (both load and generation) would increase a little compared to what they would have paid but for the cap. This does not violate our proposal that benefit-based charges for any one of these investments should be less than the private benefits from the investment, since we expect that the estimated benefits from the investment would substantially exceed the increase in charges caused by the operation of the price cap.

B.284 The other option we are considering is to fund the price cap out of the residual charge. So to the extent that some customers have their charges capped, all other customers' charges would increase slightly as a proportion of their load.

B.285 We prefer the surcharge on the total of the benefit-based charge for pre-2019 investments and the residual charge because the purpose of the cap is to mitigate any price shock from the new TPM and to create a transition from the current TPM to the new TPM. This is better achieved if generation as well as load bears some of the cost during the transition. We accept that if the surcharge on generators was substantial and persisted for some time, it would likely be passed through to some extent to load in energy prices, and so potentially could cause some inefficiency in grid use. However, we expect this inefficiency to be minimal, both because the surcharge is likely to be small and because we expect the surcharge to diminish over time. Instead of all transmission customers funding the capped amounts, a variation would be for the surcharge to apply only to those who would gain under the proposal, in terms of a reduction in transmission charges. The premise for this option does not take account of the fact that those who would gain from the proposal, in terms of reduced charges, would argue they are currently supporting those who under the proposal would pay more. It may also mean greater allocative inefficiency for longer, compared to a low, flat surcharge on all customers. Thus the Authority does not currently favour this option.

Q42.	**How should the price cap be funded?**

B.286 It may be that after the new TPM is introduced, it becomes apparent that the cap is having little impact on some distributors and/or direct connect customers. In that case there would be little point in continuing with the cap for these customers. Accordingly, the proposed guidelines include a proposal that a customer’s cap be removed if in any pricing year after the year of first application of the benefit-based charge to post-2019 low-value investments, the cap does not have the effect of reducing transmission charges for that customer.

Additional components[265]

Proposal

Clause 54, proposed TPM guidelines (appendix A)

Discussion

B.287 The proposed guidelines require Transpower to propose each additional component if doing so would, in its reasonable opinion, better meet our statutory objective.

B.288 As a result, if Transpower proceeds with any of the additional components, they should have net benefits.

Q43. **Are the proposed additional components appropriate? If not, what changes should be made?**

265 These proposed guidelines omit the proposal in the draft guidelines published with the second issues paper for a 'marginal savings' adjustment mechanism. Many submitters, such as Transpower, were not convinced of the desirability or workability of this proposal. Transpower, for example, considers that it would be better to remove the proposal from the guidelines altogether (Transpower's submission on the supplementary consultation paper, page 14).

Additional component A: staged commissioning

Proposal

Clause 55, proposed TPM guidelines (appendix A)

Discussion

B.289 This proposal relates to investments that are commissioned in stages (staged commissioning), that at some stages meet the definition of a connection asset, but eventually meet the definition of an investment in the interconnected grid. As some submitters[266] pointed out, the treatment of these investments has been clarified in the decision in *Vector Ltd v Transpower New Zealand Ltd* [2014] NZHC 3411. For this reason, it is not necessary to clarify the treatment of these investments in the TPM.

B.290 Charges are based on whether an asset met the definition of a connection asset at the time the charges were being applied, and not on the ultimate configuration or purpose of an asset.

B.291 This creates the risk that participants may have an incentive to seek to avoid staged commissioning, in order to avoid incurring connection charges. Our proposal would make these incentives weaker, compared to the current TPM. Under our proposal, it is likely that the costs of a redesign of the investment (to avoid it meeting the connection definition) would be met to a significant degree by the potential connection customer. This is because it is likely that the costs of the asset, once fully commissioned, would be met through the benefit-based charge, and it is likely that the customer receiving temporary connection services would also be subject to this charge.

B.292 The proposal in clause 55 of the proposed guidelines is intended to assist in mitigating any remaining inefficient incentives to avoid staged commissioning. It does so by allowing Transpower to adjust the split of charges for the investment between the period when it meets the definition of 'connection assets' and the later period after it has become an interconnection asset.

B.293 The benefit-based charges would, over the investment's life, recover the covered cost of the investment less any connection charges already paid for the investment.

266 For example, Transpower's submission on the second issues paper (Appendix B, comment on connection charge at clause 5), PWC.

Additional component B: charging for assets principally providing connection services

Proposal

Clause 56, proposed TPM guidelines (appendix A)

Discussion

B.294 The relevant definitions in the current TPM (in particular, connection link, connection node, interconnection link and interconnection node) rely on the physical and electrical configuration of assets, except in the definition of 'grid asset'.[267] The technical distinction between connection assets and interconnection assets hinges on whether the assets in question form a loop. Generally speaking, 'looped assets' are interconnection assets.[268]

B.295 However, this can create inefficiencies. An example of how this could occur is Waipa Networks' construction of a line between the Te Awamutu and Hangatiki substations. This created a loop with assets that had previously been classified as connection assets and therefore were previously subject to connection charges.

B.296 The new line and associated works (switchgear) were constructed under a customer investment contract (CIC) and costs are recovered under that CIC (not the TPM). However, when the new line was commissioned, the substations and related assets became part of a loop. Hence, it appears that some of Transpower's assets (for example, the Karapiro–Te Awamutu line) became interconnection assets (as defined in the TPM), even though:

(a) the new line that completed the loop is owned and operated by a grid provider other than Transpower (that is, by Waipa Networks) and

(b) the new line is not a grid asset in respect of which the TPM allocates charges.

B.297 If it were not for this additional component, under a TPM that reflected the proposed guidelines, the cost of investments like these might be recovered through the benefit-based charge rather than through the connection charge.

B.298 Waipa Networks submitted that the outcome without this additional component was the correct one, so the additional component is not needed. PwC for 14 EDBs considered that there is a problem, but that Transpower should develop a workable solution, and that the additional component should not be introduced unless it is very clear that it is needed.[269]

B.299 Our view is that the reclassification of investments like these as interconnection assets does not promote efficient investment to the extent that the costs of connection and interconnection assets are recovered differently. For example, if the charges that a customer faces when assets are classified as interconnection assets are less than they would face when the assets were classified as connection assets, it provides an incentive for the customer to have them classified as interconnection assets.

B.300 Further, there are unnecessary transaction costs if the investment is subject to the benefit-based charge when in substance it provides connection services.

B.301 These inefficiencies would be addressed if assets that principally provide connection services (after they are connected by a new line) continued to be categorised as connection assets.

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267 The definition of grid assets identifies the specific assets for which charges in the TPM must be calculated.

268 The exception to this rule is that: small local loops are classified as connection -, not interconnection- assets.

269 Submissions on the second issues paper.

Additional Component C: charges for connection assets

Proposal

Clause 57, proposed TPM guidelines (appendix A)

Discussion

B.302 Currently, Transpower includes all connection investments in a pool, and calculates the charge for each connection asset based on the average depreciation of the pool.[270] The proposed guidelines largely retain the wording of the existing guidelines for connection investments, which would allow Transpower to continue the existing treatment.

B.303 The proposed guidelines may create boundary issues, given that they provide for two distinct classes of transmission investments (connection and interconnection investments), each with a distinct method for determining charges. This could create inefficient incentives for transmission customers to prefer connection investments over investments in the interconnected grid or vice versa. This could come about, for example, because the asset return rate component of the connection asset charge involves valuing connection assets on an average historic cost (AHC) basis, which is different from the approach proposed for valuing assets for the benefit-based charge.[271] Depending on which category was more beneficial for it, a customer could then lobby for a given investment to be configured as either:

(a) a connection investment, subject to the connection charge; or

(b) an investment in the interconnected grid, subject to the benefit-based charge.

B.304 This potential boundary problem would be addressed if the method for determining connection charges in relation to each new connection asset was substantially the same as the corresponding method for benefit-based charges.

B.305 In their submissions on the second issues paper, Fonterra, Meridian and Winstone Pulp supported this proposal. PwC for 14 EDBs was opposed because it considered that it would increase cost and complexity, as well as likely making charges more variable over time. Our view is that if this is the case, the additional component would not be introduced because it would not better meet our statutory objective.

270 This is discussed further on page 76 of the second issues paper.

271 This is discussed in paragraph 7.148(b) of the second issues paper.

Additional component D: transitional peak charge

Proposal

Clauses 58 - 61, proposed TPM guidelines (appendix A)

Discussion

B.306 We have included a transitional peak charge in the proposed guidelines, and have omitted the long-run marginal cost (LRMC) charge that was included in the 2016 TPM proposal. Although that charge was called an LRMC charge, the 2016 draft guidelines allowed wide discretion in the design of the charge.[272] The change in name to peak charge is designed to clarify what the charge is intended to do and how the charge may be designed. As with the corresponding component in the 2016 TPM proposal, this additional component allows for, but is not restricted to, a charge that is initially based on the LRMC of transmission.

B.307 Whether to include a peak charge in the proposed guidelines and, if so, the form of the peak charge is a key design choice in our proposal. The broad context for this decision is that, as is discussed above and in appendix E, we expect that nodal prices, the transmission charges provided for in the proposed guidelines and the Commerce Commission regulatory regime would provide incentives for efficient use of and investment in the grid. So a peak transmission charge may not be necessary.

B.308 We have considered three broad options, which involve including the peak charge as a core component of the proposal, as an additional component or not including it at all.

B.309 Transpower prepared a report on peak pricing for transmission at our request.[273] We have considered this report in forming our proposal on the peak charge. We have discussed our response to the Transpower report and our views about a peak charge in appendix E.

B.310 Our current preferred option is to include it as an additional component, but to make it transitional only. We have included it as an additional component because we think it may have benefits in some circumstances, but these are uncertain, and may or may not be outweighed by potential costs of including the charge.

B.311 In summary, we have included a transitional peak charge because we propose to remove explicit (RCPD) peak pricing from transmission pricing, and because of some other transitional issues. Removing the RCPD charge is a significant change and raises the possibility that there could be a large increase in demand for energy during periods that currently are or could be RCPD peaks.

B.312 In particular, as Transpower noted in its report on peak pricing, the current RCPD charge provides a price incentive on distributors to use load control to limit their offtake from the grid during regional peaks. Most distributors do not currently face wholesale energy prices so it is uncertain how they would react when the RCPD signal is removed. Removal of the RCPD charge might mean that distributors stop (or significantly reduce) their management of demand at times of regional coincident peak demand.

B.313 Where there is no consequent congestion, this would be desirable, since it means that users can access additional energy efficiently.

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272 The major constraint on it was that it had to complement the effect of nodal prices in promoting efficient investment and efficient use of the grid.

273 *The role of peak pricing for transmission,* available at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission

B.314 However, where there is congestion, nodal prices will rise. This will incentivise users to reduce their least-valued energy use. This incentive is likely to become increasingly effective over time, both as a result of the introduction of real-time pricing and as emerging technology and new business models enable energy use to become increasingly price-responsive. As noted in a report appended to Transpower's peak pricing paper, technology can play an important role in enhancing demand response and the ways in which users are able to respond to a change in electricity tariffs may be expected to change over time. [274]

B.315 In the short to medium term however, there is a risk that at some nodes during system peaks demand and supply might not be sufficiently responsive to nodal prices and some other form of rationing might be required. In this circumstance, price rationing is likely to be preferable to quantity rationing since the former tends to target the lowest value energy use.

B.316 As a result, we propose that Transpower could introduce a temporary peak charge, targeted to those areas where it is needed to influence grid use. Since this would be a transmission charge, it can mitigate the concern that distributors might respond to removal of the RCPD charge by abruptly abandoning or reducing administrative demand control.

B.317 Having a transitional peak charge would also allow time for the emergence and uptake of demand control technologies and new business models. It would allow parties such as aggregators time to respond to the eventual removal of the transitional peak charge.

Q44. Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

B.318 We have a number of additional choices to make if the guidelines do include a transitional peak charge.

B.319 First, there is the question of how widely the transitional peak charge would apply. We are proposing that the charge be targeted in its application, that is, it is only to be levied in those geographic areas or on those circuits which Transpower considers could be congested in the absence of such a charge. Our current thinking is that there is no need for a charge in uncongested parts of the grid, and it is undesirable to suppress demand unnecessarily in such locations. Furthermore, since the charge would complement nodal prices, we would expect Transpower only to apply the charge where it considers that nodal prices will not be able on their own to limit demand for transmission use to capacity and that an additional transmission charge would help in controlling demand.

Q45. Should the peak charge be applied only where the grid would otherwise be congested?

B.320 Second, we have a choice to make about when the charge would be applied. Our current thinking is that if the charge is introduced, it would be introduced at the start of the new TPM and would then be progressively phased out. This reflects our view that the peak charge is to limit risks associated with the initial removal of the RCPD charge and that the need for a peak charge will reduce over time as the scope for demand to respond to nodal prices grows (due to RTP and the increasing emergence and uptake of demand control technology and new business models). Our concern is that a permanent peak charge could cause ongoing distortion to the efficient operation of nodal prices.

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274 Frontier Economics, Peak-use charging; A review of price elasticity of demand, October 2018

B.321 We are proposing that, after an initial year of operation, the peak charge be phased out gradually so as to avoid any problems that might result from a sudden reduction in the charge. We are considering two main options for the duration of the phase-out period: 5 years and 10 years. Our current thinking is that Transpower would include in the TPM a plan for phasing out the charge so that it is phased out within 5 years of the TPM entering into effect, after an initial period of operation. The plan would specify the maximum peak charge that Transpower could charge in any year, possibly as a percentage of the initial peak charge.

B.322 We are envisaging that Transpower would monitor developments in real time and adjust the charge to take account of developments as they actually occur. Transpower could for example:

(a) determine a maximum level for the peak charge in selected areas (which reduces gradually to zero over the phase-out period)

(b) set the charge at some level below the maximum for each area, so it has scope to increase the charge temporarily up to the maximum peak charge level if circumstances warranted it, subject to the overall general trend of phasing out the charge.

B.323 Transpower could apply to the Authority to alter any of the parameters of a peak charge. For example, it could seek to extend the phase-out period beyond 5 years or increase the maximum level of the peak charge, if it could show there were net benefits in doing so.

B.324 We have also provided for Transpower to apply to the Authority, as part of an operational review, to introduce (or re-introduce) a peak charge at a later date if that would better meet the Authority's statutory objective. This is to ensure that Transpower does have sufficient flexibility to respond to developments as they occur, while ensuring designated transmission customers have the chance to have input into any such decision.

B.325 We have not included a permanent peak charge in our proposal as a core component or an additional component. We are well aware that some submitters consider that including such a charge in the TPM would better achieve our statutory objective. Because of this, we did carefully consider the possibility of including one, but decided not to propose one. We have outlined our thinking for adopting this approach in appendix E.

Q46. Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

B.326 If the new TPM includes a transitional peak charge, the amount of revenue recovered through the residual charge would automatically fall to make up for the additional revenue generated by the peak charge.

Additional Component E: Including additional pre-2019 investments in the benefit-based charge

Proposal

Clauses 62 and 63, proposed TPM guidelines (appendix A)

Discussion

B.327 We have proposed above that the benefit-based charge would recover the covered cost of each asset in a benefit-based investment.

B.328 Without this additional component, benefit-based investments would be defined to include all future investments and a small number of high-value pre-2019 investments.

B.329 The proposed guidelines require Transpower to include in the TPM a method for extending the benefit-based charge to further pre-2019 assets if that would better achieve our statutory objective.

B.330 Several submissions on the second issues paper[275] and supplementary consultation paper[276] have suggested that the benefit-based charge should be extended to a wider range of pre-2019 assets. Their reasons included:

(a) It involves recovering costs on a beneficiaries-pay basis, and would be cost reflective and service based, rather than through the residual charge.[277]

(b) It is consistent with the finding in the sunk cost working paper,[278] that infra-marginal decisions are as important for efficiency as marginal decisions.[279, 280] In particular, since it is conceivable that the ownership of some parts of the interconnected grid could be transferred between Transpower and other parties, charging users of those assets their full cost could incentivise more efficient ownership decisions. (Ownership

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275 They included Contact Energy, E-Type Engineering, Grey Power Southland, Market South, McIntyre Dick and Partners, Otago Chamber of Commerce, Otago Southland Employers' Association, Pacific Aluminium, Preston Russell Law, Sarah Dowie, Southland Chamber of Commerce, Southland Manufacturers Trust, Stabicraft Marine, Todd Barclay Transpower and Unison.

276 Fonterra, Contact Energy, Oji Fibre Solutions, Pacific Aluminium, New Zealand Aluminium Smelter, Transpower, Top Energy, Ngawha Generation, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central. The following suggested that the charge should recover as much of Transpower's recoverable revenue as possible: Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower

277 Submission on the supplementary consultation paper by Pacific Aluminium and Transpower

278 Transmission pricing methodology: Sunk costs working paper, 8 October 2013.

279 NZAS' submission on the second issues paper.

280 As explained in the sunk costs working paper, a marginal decision is a decision about the last unit (produced) whereas an infra-marginal decision is a decision about all of the units. A decision about investing in a factory to produce a product is an inframarginal decision whereas a decision about how much to produce and sell is a marginal decision.

decisions are infra-marginal decisions, since they involve consideration of more than just the marginal cost of using the assets).[281]

(c) It could reduce potential distortions to efficient location of generation and load resulting from applying the benefit-based charge to only a subset of pre-2019 assets.[282] For example, applying the benefit-based charge to the Wairakei Ring but not to nearby transmission assets may inefficiently discourage a new generation plant from connecting to the Wairakei Ring.[283]

(d) It would reduce distortions from an excessive residual charge. Applying the benefit-based charge to more pre-2019 assets would result in a greater amount of revenue being collected through the benefit-based charge and less revenue being collected through the residual charge. This would lower the rate of the residual charge.

(e) It would reduce wealth transfers, because under our proposal generators would pay the benefit-based charge but not the residual charge.[284] Some submitters have suggested the wealth transfers under the proposal could affect its durability and thus its efficiency.

B.331 Taken together, these reasons suggest there would be merit in considering whether to apply the benefit-based charge to more pre-2019 assets.

B.332 On the other hand, several submitters on the supplementary consultation paper raised concerns on the proposal, including:

(a) it may be difficult to establish meaningful charges[285]

(b) it would be a wealth transfer without efficiency effects[286]

(c) it would compromise static efficiency, and would be unrelated to the rationale of improving dynamic efficiency.[287]

B.333 Transpower would need to take these sorts of considerations into account in determining whether to extend the benefit-based charge to these investments. Transpower would also need to consider the costs of calculating benefits and identifying beneficiaries when considering the coverage of the charge.

B.334 The cost of extending the benefit-based charge to more pre-2019 investments would depend on the method used for allocating the charge. (If Transpower proposes to include this additional component in the TPM, it must also include such a method). As is discussed

281 This assumes that both Transpower and the potential owner will have normal commercial incentives to buy and sell the asset at its true (regulated) economic value; that is at the net present value of net revenues it is expected to generate. We note there may also be other incentives resulting from the Commerce Commission's IPP and DPP regime that may affect decisions to transfer assets.

282 Transpower's submission on the second issues paper, page 25.

283 We acknowledge that this would only reduce, and not eliminate, this potential locational distortion. This issue is discussed more fully earlier in this paper.

284 Unlike the residual charge, the benefit-based charge may not be fully passed through prices and be borne by energy consumers. This is because different generators will face different rates of benefit-based charge. In any case, some pass-through of the benefit-based charge is desirable because it reflects the infra-marginal cost of the associated transmission investments.

285 NERA for Meridian

286 Trustpower, Bushnell/Wolak for Trustpower, Professor Yarrow for Trustpower, CEC for Trustpower, Houston Kemp for Trustpower, EA Networks, Vector, Entrust

287 Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector

earlier, there are fewer benefits and potentially greater costs in applying the benefit-based charge to pre-2019 investments relative to post-2019 investments, and less benefit to accurately allocating the charges, principally because the charges can have no impact on whether the investment is undertaken or not. This means that it is appropriate to adopt a simple method for determining the allocation of benefits from pre-2019 investments. Adopting a simple method would also facilitate applying the benefit-based charge to more pre-2019 assets.[288] In addition, the proposals under *General matters* above require Transpower to balance the benefits of accuracy against various practical issues. This should ensure that the costs of broadening the coverage would be effectively managed.

Q47. Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

B.335 Transpower has indicated that it may not have information on the pre-2019 cost of its older transmission investments. The proposals discussed under the heading *General matters* above make clear that if this is the case Transpower would need to take such practical considerations into account when it establishes the method for determining the charges.

B.336 It may be appropriate for the method for allocating charges for pre-2019 investments to be different from the simple method for allocating low-value investments (despite the criteria being the same). This is in part because the main benefit of a low-value investment is likely to be relatively concentrated geographically, but that is typically not true of larger pre-2019 investments.

B.337 Since Transpower could extend the benefit-based charges to potentially all pre-2019 assets, both the magnitude and the incidence of price increases may differ from that modelled in this paper. Clause 12.89(2) of the Code requires that Transpower's TPM proposal must include indicative prices. This would allow parties to consider the impact of the TPM proposal.

B.338 For any of the investments that Transpower includes under this additional component, it is possible that the future benefits that transmission customers collectively get from that investment are less than its covered cost. If so, the proposed guidelines provide for the initial benefit-based charge to be capped at the estimated net present value of positive net private benefit that the customers are estimated to receive from the investment. This proposal takes account of the fact that, unlike for an efficient new investment, the benefits it is expected to yield may be less than its covered cost at the time the benefit-based charge is first applied to the investment. This could occur, for example, because the benefits that the investment is now expected to provide are quite different from the benefits that were expected when the investment was made.

B.339 If this additional component is included in the TPM, the proposed guidelines provide that the TPM may include a transition. For example, this could be a provision that has a similar effect to the cap discussed under the heading *Cap on transmission charges* above. The reason for providing for this transition is the same as the reason for providing the cap discussed under that heading above.

B.340 The Authority has chosen not to be more specific about the nature of the transition, because the design of the transition is best undertaken once the decision has been made about which additional pre-2019 assets will be subject to the benefit-based charge.

[288] Transpower's submission on the second issues paper proposed that a simple method be used for calculating the benefit-based charge for pre-2019 investments.

Additional component F: charging for opex

Proposal

Clause 64, proposed TPM guidelines (appendix A)

Discussion

B.341 Opex for connection investments is currently spread across connection customers using broad cost allocation rules. As is discussed in paragraph B.72 above the main (mandatory) part of the proposed guidelines would allow Transpower to use broad cost allocation rules to allocate opex costs for benefit-based investments.

B.342 This additional component instead proposes to attribute opex to the asset it was spent on (without use of broad allocation rules or similar). For example, if a building that is part of a benefit-based investment is painted, the cost of painting it would be included in the covered cost of the investment incorporating the building, and recovered from the designated transmission customers paying benefit-based charges in relation to that investment. Charging for opex on this basis will result in charges better reflecting actual costs. This will create an incentive for customers to take the costs actually incurred into account when they consider whether to support maintenance, replacement and upgrading of investments.

B.343 Most submissions on the supplementary consultation paper considered this proposal reasonable, provided it can be carried out cost effectively.[289] However, some submitters were concerned that the allocation would also allocate common costs,[290] which would not be appropriate. Since Transpower would need to satisfy itself that this additional component would better meet our statutory objective before it proposed this additional component, Transpower would need to reassure itself about these points.

B.344 One benefit of retaining broad cost allocation rules is that this is a relatively low-cost method of determining charges. However, the disadvantage of broad cost allocation rules is that they mask the differences in the actual costs of operating and maintaining different assets. This proposal would make connection charges and benefit-based charges better reflect the costs of the relevant investments, and therefore lead transmission customers to support more efficient investment and operational decisions over time. Determining charges in this manner would make the costs more transparent, giving customers the ability to test with Transpower whether they are reasonable. This would help contribute to lower overall costs over time.

B.345 Some submitters have raised concerns that Transpower's customers do not have the ability to scrutinise Transpower's maintenance practices.[291] The Authority considers that making Transpower's opex more transparent will give at least its larger customers additional ability to scrutinise these costs and require Transpower to justify why they are reasonable. Further, distributors have similar businesses to Transpower (albeit operating lower voltage

289 For example, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, University of Otago, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

290 For example, Meridian Energy, NERA for Meridian, New Zealand Aluminium Smelter, Pacific Aluminium.

291 For example, the submission of CEC for Trustpower on the second issues paper

assets) so they are in a relatively strong position to scrutinise Transpower's operating and maintenance practices.

B.346 There is a risk that attributing opex to the assets it is spent on could lead to some customer resistance to maintenance that would extend the life of an asset. However, this seems much less likely than under the current TPM (unless deferring maintenance is in fact optimal). This is because the customers whose charges would incorporate the opex would also have to pay the cost of the early replacement of the asset under the benefit-based charge and potentially the connection charge.

B.347 On the other hand, basing maintenance charges on costs incurred in respect of an individual asset or investment may lead to a concern that parties may be incentivised to seek refurbishments or replacements earlier than is efficient to limit the maintenance charges they would face. Under the section of our proposal relating to the benefit-based charge, we propose that:

(a) following replacement or refurbishment, Transpower would continue to charge the cost of the old investment until that investment is fully depreciated

(b) charges for the capital cost of an asset cease once it is fully depreciated so that the full capital costs in respect of the asset have been recovered.

B.348 This should provide an efficient incentive for Transpower's customers to oppose unnecessary replacements or refurbishments.

B.349 Basing maintenance charges on costs incurred in respect of individual assets or investments may also lead to more efficient incentives around ownership of assets. Under the current rules, there may be an inefficient incentive for transmission customers to purchase feeder lines that are in good condition from Transpower, leaving the poor-condition feeder lines in the common pool. The proposal would reduce this incentive.

B.350 We note that, during the course of consultation on the 2016 proposal, some parties submitted that maintenance costs are negatively correlated to DHC asset values, because maintenance costs increase over time as an asset depreciates in value. This would suggest that DHC or an asset's value would not be suitable allocators for maintenance costs.

B.351 We have included this proposal as an additional component because it is a relatively low-priority issue. This is because maintenance costs are generally a small component of the charges for an asset.

Additional component G: kvar charge

Proposal

Clause 65, proposed TPM guidelines (appendix A)

Discussion

B.352 The Authority currently considers that there would be no immediate, material benefit in introducing a kvar charge. However, it is desirable to provide for the introduction of a kvar charge in case there are net benefits from having it in the future. This would give Transpower the option of proposing a kvar charge at some point in the future, if power factors deteriorate.

B.353 A kvar charge may provide a more efficient means of maintaining power factors than enforcing the power factor requirements in the Connection Code.[292] Like nodal prices, the kvar charge is intended to be complementary to the benefit-based charge that would be imposed if an investment in equipment to correct a power factor is required. A kvar charge would be similar in intent to the nodal transport charge inherent in nodal prices. That is, just as nodal prices reflect the cost of congestion that users impose on others by using the grid, the kvar charge is intended to be a charge levied on those that cause the deterioration in the power factor to reflect the cost that deterioration imposes on other grid users.[293] This cost arises at times when the relevant circuits are congested. As a result it would be desirable to target the charge on these circuits at these times.

B.354 At this stage, our view is that, if Transpower decides to propose a kvar charge, it is best placed to determine the details of the charge.

B.355 Although the TPM can specify how a kvar charge is to be calculated and the circumstances in which it is to apply, it does not need to be specific about what the level of kvar charge is or in which particular regions it will apply. In other words, Transpower can determine the circumstances in which the kvar charge will apply in the TPM, and then determine in real time whether those circumstances apply.

B.356 Transpower, distributors and direct consumers could choose to respond to the kvar charge by installing reactive support equipment, and distributors could also apply a kvar charge to their customers, which some have done. In the case of Transpower, the benefit-based charge would apply to such investments, with the beneficiaries being those who would avoid the kvar charge as a consequence.

B.357 The decommissioning of the Otahuhu B and Southdown power stations may have increased the need for upper North Island dynamic reactive investment. However, if such equipment were necessary, the benefit-based charge would mean that the cost of it would be recovered from those who benefit by not having to pay the kvar charge that would otherwise be imposed.

B.358 Some submitters have expressed the view that improving appliance standards would be likely to provide a more efficient response than kvar price signals. The Authority does not determine appliance standards. However, it can influence such standards through its

[292] We are now intending to pursue separately the related change to the Code to specify a minimum power factor of 0.95.

[293] However, it is unlikely that a kvar charge will be applied in real time in the near future. As a consequence, some approximation, such as a LRMC charge focused on those users whose actions lead to the deterioration in power factor, may be appropriate.

policies, such as the introduction of a kvar charge, which would provide incentives for parties subject to the charge to influence the standards. In any case, except for large consumers, it is likely to be more efficient to deal with reactive load through investment at the transmission or distribution level, than at the end-consumer level.

Q48.	**In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?**

Appendix C Material change in circumstances

C.1 This appendix sets out how the Authority considers there has been a 'material change in circumstances' as contemplated by clause 12.86 of the Code, enabling the review of the TPM.

There have been material changes in circumstances

C.2 Clause 12.86 of the Code states that the Authority may review an approved transmission pricing methodology if it considers there has been a material change in circumstances.

C.3 The Authority considers that material changes in circumstances have occurred since the TPM came into force in 2008, as set out in this appendix.

C.4 The Authority has outlined these material changes in circumstances in earlier TPM review consultation papers, including in the second issues paper.[294] We summarise this previous assessment here, updated to reflect that the changes in circumstances have become more accentuated over time.

C.5 Since the TPM came into force in 2008 we have identified the following material changes in circumstances to prompt a review of the TPM:

(a) **A significant amount of transmission investment has been commissioned since 2008 and a lot more investment is currently forecast.[295]**

The Authority considers that the current TPM was not designed for the boom in recent – and projected – investment in the transmission network that we have seen since 2008. Poor outcomes that are already resulting from inefficient price signals will only be amplified.

Some submitters to the second issues paper have questioned whether new investment is a material change in circumstances – for example Trustpower questioned, if the current TPM is an efficient way to recover regulated revenues of $500 million, why would it no longer be efficient to recover revenues of $1 billion? [296]

The Authority considers that the inefficient behaviours and outcomes caused by the current TPM will be amplified by the scale of the recent and projected growth of the asset base, and thus the revenues to be recovered.

With rapid growth projected in investment and thus costs to be recovered, it will become more likely that other transmission customers will lose confidence in the current pricing methodology. Poor durability creates uncertainty, harms investment decisions and creates incentives for avoiding charges – which lead to inefficient use of and investment in the grid.

294 Section 3 of the second issues paper provided our response to issues raised prior to that time as to whether we considered the threshold was met.

295 Transpower's regulatory asset base (RAB) has increased from a value of from $2 billion in 2005/06 to $4.7 billion in 2018/19. In *Te Mauri Hiko* Transpower forecasts a doubling of electricity demand by 2050, much of which will be met by generation connected to the transmission grid. Further, a high volume of investment is expected to be required in Transpower's fourth and fifth regulatory control periods, due to a large number of grid assets requiring replacement and reconductoring as they come to the end of their economic life. Transpower is projecting a very large uplift in total capex in the years after 2025, according to its November 2018 proposal for Regulatory Control Period 3 *Securing our Energy Future 2020 – 2025*.

296 See Appendix C of Trustpower's submission to the second issues paper (pp 67-75) for a critique of each stated change of circumstance considered material by the Authority.

(b) **The increasing range of technologies available to electricity consumers are fundamentally changing the way people engage with electricity markets**.

There have been significant developments in technology and the electricity sector is on the cusp of transformation as a result of new technology. Small-scale distributed generators, batteries, electric vehicles and intelligent energy-management systems provide households, and commercial and industrial consumers with many opportunities that are already affecting the way they purchase, use, produce and trade electricity. The changes that are currently occurring and the future changes are potentially far-reaching and may change the traditional role of the transmission grid, as they will do for local low-voltage networks.

The current TPM pre-dates this period of innovation. Future scenarios include either:

(i) localised electricity networks predominating, reducing reliance on the transmission grid, or conversely

(ii) ,increased demand for transmission services as transport and process heat electrifies.

(iii) The inefficient price signals under the current TPM risk inefficient grid use and inefficient investments (with some customers potentially avoiding or reducing their share of the cost of the transmission grid, without reducing the cost of the grid). A review of the TPM is essential to ensure the TPM can respond to the opportunities and threats posed by new technologies.[297]

(c) **Advances in computational power.**

As we said in 2016, the reducing costs of computational power mean that there are now more sophisticated methods for measuring transmission services and identifying who is receiving those services.[298] We now take improvements in computational power over the last decades for granted, but arguments against reforming the TPM used to include claimed limitations on data and computational power of systems to manage data. Circumstances have now changed and these constraints have been lifted.

Furthermore, we anticipate that enhanced computational power will lead to further market changes, and these will only increase the importance of efficient transmission pricing. Examples include real time pricing, which will sharpen nodal price signals, and demand response platforms.

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297 Pioneer submitted in response to the Authority's second issues paper that the Authority should undertake a market study on technology to support its material change in circumstances, consistent with Australian and UK practice. Transpower submitted to our supplementary consultation paper to the second issues paper that careful consideration is needed of the implications of emerging technology, and changes in technology do constitute a potential material change in circumstances. We note various studies and strategies released by Transpower in the last three years document and outline the changes that are occurring and the need for the transmission network to respond to them, including: *Battery Storage in New Zealand* (September 2017); *Te Mauri Hiko – Energy Futures* (June 2018); *Transmission Tomorrow – Our Strategy* (December 2018); and *The Sun Rises on a Solar Energy Future* (January 2019).

298 Trustpower submitted in response to the second issues paper that computational power has no effect on the conceptual issues. For example, it does not mean that it is easier to establish the beneficiaries within an interconnected grid, or that a more complex allocation methodology, enabled by greater computational power, is necessarily superior. We acknowledge the point that computational power should have no effect on the conceptual issues. However, it does affect the practicality and breadth of options available, including conceptually simple solutions, in ways that were claimed to not be possible before.

(d) **The regulatory environment has changed significantly.**

The Authority replaced the Electricity Commission from 1 November 2010, and has a different statutory objective under different legislation from the Electricity Commission. The current TPM was prepared on the basis of guidelines that were prepared and approved by the Electricity Commission given its statutory objective. It is appropriate for the Authority to review and consider whether the guidelines and the TPM best promote the Authority's statutory objective.

Further, since 2008 the function of approving grid investments has been transferred from the Electricity Commission to the Commerce Commission and, over time, the Commerce Commission has modified its rules and processes.[299] It is appropriate to ensure that the TPM is more consistent with, and reinforces, the Commerce Commission's disciplines around transmission grid investment.

(e) **New ambitious climate change Government objectives affect the demand for and use of the grid.[300]**

Over the past few years, the Government has announced a series of new targets to reduce New Zealand's greenhouse gas emissions, including most recently announcing a target to reduce New Zealand's carbon emissions to net zero by 2050. We have not stated this driver directly in previous consultations. However it is a material change that is worth highlighting, given the scale of the economic transition that is being signalled by these new climate change objectives.

In order for New Zealand to reach its targets, consumers of all sizes, from households and small businesses to industrial consumers, will need to turn to grid electricity and other options for low emissions energy.

In this regard we also note the significant change to the operating environment in the electricity sector that has already occurred with the introduction of New Zealand's emissions trading scheme in 2008, and its application to the stationary energy and industrial processes sectors from 2010.

As noted above, this increased demand for energy from renewable resources likely requires an upgrading of the transmission grid. This makes it crucial that prices for using the grid (and of accessing distributed energy sources) reflect economic costs, so that households and businesses have appropriate incentives to make good choices about energy use and energy-related investments.

C.6 Submissions in respect of previous proposals have commented on the materiality of these changes over time, including whether the issues identified above constituted a material change of circumstances and whether the Code's threshold has been met.[301] We note in

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299 For example, the Transpower Input Methodologies Determination was originally determined in 2010 (and reviewed in 2016). The Capital expenditure input methodology (Capex IM) was originally determined in 2012 (and reviewed in 2018).

300 The New Zealand Government has announced ambitions targets to reduce New Zealand's greenhouse gas emissions and in May 2019 introduced the Climate Change Response Act (Zero Carbon) Amendment Bill. In August 2018 the Productivity Commission in its *Low-emissions economy* report noted that electricity will need to meet far more of New Zealand's energy needs to achieve low emissions. Transpower's *Te Mauri Hiko* forecast a potential need to double our renewable electricity supply to allow for greater electrification of major industries and transport.

301 For example, the submissions by Frank Ogilvie for NZ Steel, PowerCo and PWC on the second issues paper considered that the issues identified in the second issues paper (and expanded on in this paper) did not constitute a material change of circumstances. Conversely, others (for example, Meridian, Otago Chamber of

this regard that the threshold is focused on whether the Authority considers that there has been a material change in circumstances. In any event, we have considered the various arguments and still consider that there have been material changes of circumstances since 2008, justifying a full review of the TPM.

C.7 Some previous submissions (including in response to the second issues paper in 2016) have argued that, if a material change to circumstance is identified, then the review scope should be limited to matters relevant to that change. The Authority continues to disagree with this position. The Authority's view is that there is no such requirement or limitation on the Authority's ability to review the TPM once the material change in circumstances threshold is met. The Authority considers that it would be unworkable if the Authority had to demonstrate a link between the circumstances and the proposed change in question. Further, elements of the TPM are interrelated and it would be impractical to review some elements that purportedly relate to changes in circumstances and disregard how the TPM fits together as a whole.

Q49. Do you have any comments on the matters covered in this appendix C?

Commerce and the Otago Southland Employers' Association) thought that the issues we identified in the second issues paper did constitute a material change in circumstances.

Appendix D Elaboration of decision-making and economic framework

Introduction

D.1 Section 15 of the Electricity Industry Act 2010 (Act) sets out the Authority's statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

D.2 In the context of transmission pricing, the Authority has interpreted this statutory objective to mean that the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers.[302] This recognises that efficiency and reliability in the electricity industry involve facilitating:

(a) efficient investment in the electricity industry through providing incentives for the most efficient investments to occur at the most efficient time and in the most efficient place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks, or in the demand-side

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution networks, and demand-side management. This means providing incentives for the day-to-day operation of transmission, generation, distribution and demand-side management to involve an efficient trade-off between reliability and cost.

D.3 Efficient investment in the electricity industry primarily relates to dynamic efficiency, while efficient operation primarily relates to static efficiency. The Authority notes in its *Interpretation of the Authority's statutory objective* that, because the Authority's statutory objective requires it to promote the long-term benefit of consumers, the Authority considers that a key focus is to promote dynamic efficiency in the electricity industry, which includes:

(a) taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers

(b) taking into account the durability of the industry and regulatory arrangements, including in the face of high impact, low probability events.

D.4 Where a trade-off between static and dynamic efficiency is required, the above statement suggests that significant weight should be given to the promotion of dynamic efficiency.

D.5 In particular, the durability of the TPM arrangements is relevant to promoting efficiency. A more durable TPM is less likely to result in disputes, in calls to fundamentally change the TPM because of various perceived or actual problems with it, and in fewer unproductive changes to the TPM. This would increase efficiency directly, since all of the activities outlined above have real resource costs. As is noted in the CBA, it would also increase efficiency indirectly, since greater certainty for investors about the future shape of the TPM would lead to more efficient investment in the grid, in substitutes for the grid and in related investment. If a new TPM is durable, the efficiency benefits it brings for consumers are also more likely to be enduring.

302 Interpretation of the Authority's statutory objective, 14 February 2011, available at https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011

D.6 Focussing on overall efficiency means providing incentives for parties to pursue their desired goals at lowest cost to the economy as a whole. This should result in lower electricity prices for all electricity consumers over the long run.

D.7 In 2012 we developed a draft TPM decision-making and economic framework for the TPM review. We consulted on this framework and subsequently published a summary of submissions. Most submitters agreed in principle with the framework, but many raised issues about the application of the framework with some suggesting this implied the framework was unlikely to be practical. We took account of these submissions when we published our paper *Decision-making and economic framework for TPM – decisions and reasons* on 7 May 2012 (DME framework).[303] The Authority has since used the DME framework to guide consideration of the problem definition and to identify options to address those problems.

D.8 The DME framework sets out a hierarchy of charging approaches that we use to identify and assess options for the TPM. The hierarchy gives priority to market-based charges where these are practicable, because workably competitive markets tend to produce more efficient outcomes than other approaches. If market-based charges are not practicable, the hierarchy gives priority to administrative charges, being exacerbators-pay, beneficiaries-pay, and alternative charging options, in that order.

D.9 Submissions on the TPM options working paper continued to express concerns about the practicality of the DME framework. For example, Castalia for Genesis[304] suggested that the DME framework does not provide a tool for assessing options. After considering submissions on the TPM options working paper[305] we took the opportunity to elaborate further on the DME framework in chapter 5 of the second issues paper.[306] Specifically, we elaborated on the relationship between the price signals provided by the TPM and the Commerce Commission's investment approval regime. Our view is that locational marginal pricing (LMP) will, in general, ensure that the use of the grid is efficiently constrained to its capacity. However, even with LMP, inefficient transmission price signals will create an incentive for transmission users to use the grid inefficiently. This could then lead the Commerce Commission to approve transmission investment proposals that are efficient given the use of the grid, but are inefficient overall because grid use is inefficient.

D.10 The conclusion we drew in the second issues paper is that this problem could be mitigated if users were charged appropriately for the full cost of the transmission investment that they benefit from, because they would then take account of the cost of transmission investment to New Zealand when they make their own decisions. Specifically, we concluded that:

(a) transmission prices should, as far as practicable:

(i) recover the cost of delivering the transmission service (ie, be cost-reflective)

(ii) ensure that the cost of the transmission service is charged only to those customers who benefit from the service and in proportion to the benefits that they receive (ie, be service-based)

303 All these documents are available at the following link: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/economic-framework-decision-making/,

304 Castalia. *Transmission pricing methodology: beneficiary pays options*, report to Genesis Energy, March 2014

305 The relevant documents are available at the following link: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374

306 See chapter 5 of the second issues paper.

(b) the pricing methodology should be practicable and involve reasonable transaction costs.

D.11 Some submitters disagreed with this approach. For example, Creative Energy Consulting (CEC) for Trustpower wrote that fixed charges are unfair and impractical, and that a 'forward looking' LRMC charge is required. We disagree, for the reasons outlined in chapter 5 of the second issues paper and the rest of this appendix. In addition, we discuss further in appendix E why we do not consider that a forward-looking charge is justified.

D.12 Other submitters had more specific concerns. For example, some submitters[307] considered that charging Auckland/Northland is not service-based charging, because they have not in fact seen improvements in reliability and/or quality of supply. Similarly, Entrust considered that service-based pricing is an unhelpful concept, because Auckland does not receive a higher quality of service than other parts of New Zealand. However, our modelling suggests that these areas have in fact benefitted from the pre-2019 investments included in clause 13(b) of the proposed guidelines.[308] Pioneer considered that service-based and cost-reflective pricing will only exacerbate the existing 'economic sizing' issues in the grid. However, as the CBA demonstrates, removing the RCPD charge and relying on nodal pricing allows efficient expansions of the grid, which bring net benefits to consumers.[309]

D.13 Still other submitters on the second issues paper thought that transmission costs should be funded equally by all grid users.[310] For example, PowerCo suggested that transmission costs should be recovered using a broad-based, low level, and non-discriminatory allocation, as this is the least distortionary approach. We do not agree with this, because, as described in the rest of this chapter, we consider that charging users for grid investments that benefit them promotes efficient investment, and that charging users who do not benefit from a grid investment for that investment can cause inefficient behaviour.

D.14 On the other hand many submitters supported cost-reflective and service-based pricing.[311] Some considered it will lead to more efficient investment decisions. Others considered it would promote the long-term benefit of consumers. For example, Stephen Littlechild for Meridian considered that our approach of service-based and cost-reflective pricing is consistent with the characterisation of competition as a dynamic process and that the 2016 TPM proposal promoted dynamic efficiency.

D.15 Having considered submissions on the second issues paper, we remain of the view that the essence of the analysis presented in chapter 5 of the second issues paper is robust.[312] We therefore have not repeated this analysis in this 2019 issues paper.

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307 Air Liquide, Northpower, Top Energy and Vector.

308 See appendix A.

309 See chapter 4.

310 For example, Auckland Federated Farmers, Auckland's Heart of the City, Counties Power , EMA, Federated Farmers, Fletcher Building, Newmarket Business Association, Northland Mayoral Forum, Onehunga Business Association, Refining NZ, Ruapehu District Council, South Harbour Business Association

311 Business Central, Canterbury Employers' Chamber of Commerce, E-Type Engineering, Gore District Council, Grey Power Southland, Invercargill District Council , Market South, Meridian, McIntyre Dick and Partners, Nicholas Brown, Otago Chamber of Commerce, Otago Southland Employers' Association, Preston Russell Law, Sarah Dowie, South Port New Zealand, Southland Chamber of Commerce, Southland District Council, Southland Manufacturers Trust, Stabicraft Marine, Venture Southland

312 The discussion in this chapter is also relevant for distribution pricing. However, a key difference in the context of transmission pricing is the presence of the spot electricity market, as it produces nodal prices that influence the use of the transmission grid. The absence of nodal prices in most of the distribution sector means the efficient structure of distribution prices could differ materially from the efficient structure for the TPM.

Q50.	**Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?**

D.16 This appendix discusses efficient transmission pricing and refines the principles set out in the second issues paper and summarised above. If readers would like a more detailed analysis, please refer to chapter 5 of the second issues paper.[313]

An analogy with workably competitive markets

D.17 The Authority considers that workably competitive markets provide an appropriate analogy for efficient transmission pricing. For the reasons set out below, workably competitive markets are reasonably efficient. As a result, prices for transmission services set on a basis similar to that which results in workably competitive markets will also be relatively efficient.

D.18 The remainder of this appendix outlines how prices evolve in workably competitive markets, why this leads to relatively efficient outcomes and therefore what the principles for efficient transmission pricing should be.

Pricing in workably competitive markets

D.19 In a workably competitive market, a business with fixed costs, such as an airline or a hotel, will endeavour to maximise profitability by charging its customers 'what the market will bear'. This means that the business will aim to supply to any customer who will pay more than the extra costs that supplying them causes (ie, the short run marginal cost (SRMC)), provided it expects to have spare capacity. It also endeavours to charge more when demand is high (such as during seasonal peaks).[314]

D.20 Conversely, a customer will only buy the good or service if it values it at least as much as the business charges for it. This means that the benefit to the customer of accessing the product is at least the price the customer pays for it.

D.21 Although each business tries to maximise profitability by charging what the market will bear, competition between suppliers limits the price that the business can charge for the service. If the business is to survive, it must be able to charge enough to recover the capital cost of its investment, its operating and maintenance costs, and a normal return on capital. If at any point in time, the average price it can realise is higher than this, the excess profits being generated make it attractive for businesses to enter or expand.[315] This entry results in extra competition for customers, which will lead to a fall in the average price each business is able to charge. Conversely, if for some reason efficient businesses cannot make a normal return, some businesses will exit or downsize and the reduced supply will allow the remaining suppliers to realise higher prices.

313 The discussion here implicitly assumes that the price signals from the TPM are passed through directly and unaltered to consumers. We are aware that this is inaccurate. For example, most mass market consumers have fixed-price, variable-volume electricity contracts. However, other sections of this paper (eg, the peak charge section of appendix E) explain why this assumption is innocuous.

314 To be precise, the customer always tends to pay the SRMC of the service, where the SRMC is the resource cost of providing them with the service and the opportunity cost of providing them with the service (in terms of not being able to service other customers).

315 To be precise, an average price (and so SRMC) above LRMC implies that a new investment is likely to recover its full costs, so new investment is justified, and vice versa.

D.22 In other words, competition for customers coupled with entry and exit of suppliers drives excess profits (above a normal return) towards zero and ensures that efficient surviving businesses earn around a normal rate of return.

D.23 This means that in workably competitive markets, prices paid by customers are typically no more than the benefit the customers get from the service and on average equal to the cost of providing the service. This is illustrated by the example of hotel bed-nights given in the box below.

An example of a workably competitive market: the market for hotel bed-nights.

During off-peak times, a hotel will tend to set a price that at least recovers the SRMC of providing the bed and most customers prepared to pay this price will be accommodated. During the peak season, the hotel will raise the price of a bed-night, knowing that there will be sufficient customers prepared to pay the higher price and ensure it has few vacancies.

On the other side of the transaction, if a customer is keen to hire a room during the peak season (ie, the benefit it get exceeds the price it has to pay) it will be prepared to pay the higher price because it knows it has to pay the higher price to secure accommodation. Customers who do not value accommodation as much will not be prepared to pay the higher price and will miss out. This is how prices match the amount of accommodation made available to customers to the available capacity, and allocate (or ration) the available accommodation to those customers who value it most.

This example can be extended to accommodation at both a five star hotel and a one star hotel. The average price of a bed in the one star hotel (at the same time and place) will typically be less than that of the five star hotel. This will reflect the differences in costs of providing a five star hotel bed compared to a one star hotel bed. Some customers will value what a five star hotel offers, and be prepared to pay the higher price. Other customers won't and will settle for the bed at the one star hotel or will miss out.

As described in paragraphs D.21 to D.25, entry and exit will tend to ensure that each sort of hotel recovers its full cost of operation over time. That is, over time, the supply of each type of bed (five star and one star) adjusts so that that the average price charged for those beds is typically sufficient to meet the full cost of supplying them, and that capacity is broadly matched to demand.

The example can also be extended to deal with hotels of equal quality at different locations. The average price of a bed in a high-cost location will be more than the average price of a bed in a low-cost location, because it costs more to provide.

These propositions demonstrate the general points that:

at any point in time, the price of a service rations demand for the service to capacity, allocating that capacity to the users who value it most, and

over time, the average price of a service reflects the efficient cost of providing the service.

D.24 The result is to ensure customers get the best deal practicable consistent with efficient businesses staying in business.

(a) When demand is high, available capacity is allocated to consumers who value it most. When demand is low, consumers who are prepared to pay at least the costs they generate get access to the product or service.

(b) If capacity is less than can be justified by the expectation of earning a normal return on capital on the last unit of capacity added, the incumbent providers will make excess profits so there is an incentive for providers to invest in new capacity, and vice versa.

D.25 As a result, capacity is driven towards the maximum that can be justified by the return on capital it generates. At this capacity, the benefit that customers collectively get from the services provided by the businesses is at least the cost of providing those services, and the amount of capacity built is around the amount that customers demand, given the prices charged. These arrangements ensure a reasonably efficient outcome.

D.26 One implication is that the way market prices for the services of a particular asset vary over its life will depend on consumers' preferences for the services provided by a new asset compared to an older one. In particular, if customers are relatively indifferent to the age of the asset providing the service (as they are with the hire of a well-maintained trailer, for example), then the charge for the service will be independent of the age of the asset providing the service. The Authority considers that this is the case for transmission investments.

D.27 Another implication is that a business will continue to charge for an investment as long as the investment continues to provide services (and irrespective of the investment's accounting life), because it can find users who continue to benefit from (and so are prepared to pay for) the services provided by the investment. For the business, the gain it makes from being able to sell the services of an asset that lives longer than originally expected will on average be offset by the losses it incurs on an asset that expires earlier than originally expected.

Pricing of transmission services

D.28 We can derive the principles for regulating prices of a natural monopoly investment like a transmission network by analogy with the way prices are set in workably competitive markets. This is because workably competitive markets tend to be reasonably efficient. As a result, regulating prices for transmission services on a basis similar to the prices that result from the workings of workably competitive markets will also be reasonably efficient.

D.29 The High Court's discussion in *Wellington Airport & others v Commerce Commission*[316] (at page 175) supports the view that regulation should try to pursue the outcomes that would result from workably competitive markets. The Court found that: *"We consider that the outcomes produced in better functioning workably competitive markets are, indeed, the ones to be pursued. The fact that such workably competitive markets may depart in many respects from the markets for regulated services, which are not workably competitive, is the very reason to examine them"*.

D.30 In both the case of natural monopolies and workably competitive markets, the approach is to charge each user of the service at each point in time in accordance with the benefit they

[316] *Wellington International Airport Ltd and others v Commerce Commission* [2013] NZHC 3289.

receive, while ensuring that charges are sufficient to fund efficient investment. With workable competition, competitive entry and exit ensures that users collectively tend to be charged no more than the full cost of production of the service and that all efficient investments are undertaken. With natural monopolies, we cannot depend on competition to lead to this outcome. Instead we rely on regulation to pursue the same end.

Efficient charges for connection investments

D.31 Connection investments are used to connect a transmission customer to the grid.

D.32 The discussion above suggests that for such a connection investment, efficiency requires that the customer is charged the full cost of the connection investment. In this case, as with workably competitive markets, we can rely on each customer to assess for itself whether the benefits it gets from the connection investment compensate them for the cost of the investment and for any risks and uncertainties associated with the connection investment.

D.33 In particular, if the customer privately contracts another party to connect it to the grid, the parties will have the incentive to take into account all of the relevant costs and benefits, in the same manner as parties in a workably competitive market. One example of such a contract is a customer investment contract (that is, an unregulated commercial contract) between Transpower and the customer. This is likely to be efficient.

D.34 This leads to our first principle for transmission pricing:

> *Each user should pay the cost of connecting it to the grid.*

Efficient use of and investment in the grid[317]

Efficient use of the grid

D.35 As with workably competitive markets, the price for using the grid should reflect the cost of using the grid. It should rise during peak periods so that grid use is just restricted to grid capacity and so that the available capacity is allocated to those who get greatest benefit from it.

D.36 It is well established that LMPs can serve this role effectively in the transmission network. For example, the International Energy Agency says that "*Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments.*"[318, 319]

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317 To be clear, in this appendix, we develop principles for transmission pricing by analogy with workably competitive markets because it provides useful insights as to why the principles for transmission pricing established here are appropriate. The principles for transmission pricing discussed here are consistent with the more formal analysis set out in chapter 5 of the second issues paper. They are also consistent with the conclusions of Hogan (2012) and Rivier et al (2013). See footnote 125 for a further discussion of these articles.

318 See International Energy Agency. (2007). The result was first established by Schweppe et al (1988).

Léautier (2019), section 6.4, makes a similar point:

> Suppose producers face LMPs. Competitive equilibrium capacity in market m is determined by the free entry condition E …. Therefore, competitive equilibrium results in optimal [generation] investment. This is simply an application of a general result in economics: if competition is perfect, equilibrium prices lead to efficient production and consumption decisions in the short-term, but also in efficient investment decisions.

See also William W. Hogan (forthcoming)

D.37 The reason is quite simple. LMPs are set to equal the SRMC of supplying or using electricity at each point of connection to the grid. As with the analogy with workably competitive markets, this is the price that by definition ensures that the resource cost of using the grid is met and that, when there is congestion, the use of the relevant circuits is assigned to the highest value use. It immediately follows that, with certain assumptions (discussed further in appendix E), no other peak charge is likely to be as efficient as LMP in restraining grid use to capacity.

D.38 Although this is now well known, it is only in recent decades that LMPs have been practical, as is discussed under the heading *The historical origins of LRMC-based peak charges* in appendix E. Possibly for that reason, many countries have not implemented LMP and are therefore forced to restrict grid use by implementing some peak-based transmission charge (such as an LRMC-based peak charge). As discussed in appendix E, this is typically less efficient than using LMP.

D.39 New Zealand is therefore fortunate to have a relatively complete implementation of LMP in the form of nodal prices:

(a) The scheduling pricing and despatch model (SPD) incorporates all relevant capacity constraints and despatches generation so as to meet demand while taking account of these constraints.

(b) The resulting nodal prices are generally just high enough to ensure that use of the grid is restrained to capacity and that the short-run cost of transporting electricity over the grid (ie, losses and constraints) is covered.

(c) During off peak periods, the short-run price for using the grid (the difference in nodal prices between nodes, or the 'nodal transport charge') is low, reflecting spare capacity.

(d) At peak periods, the short-run price for using the grid is high, so that use of the grid is restrained to its capacity and so that the available capacity is allocated to the most valued use.

D.40 In other words, LMP can fulfil one of the key roles of prices in workably competitive markets. It can restrict the grid use to capacity and allocate that capacity to the most valuable uses. That is, LMP can ensure that, given users' demand for energy and the available grid capacity, use of the grid is efficient.[320]

D.41 There are a number of qualifications to this conclusion, which are discussed in detail under the heading *A peak charge* in appendix E. For example:

(a) there may insufficient price-sensitive demand or supply at a node to allow nodal prices to match the amount of energy supplied at the node to the amount of load

(b) some customers may not face, and so will not react to, nodal prices

(c) nodal prices may not reflect the full SRMC of grid use

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319 We use the term LMPs when referring to prices which meet this 'textbook ideal', and nodal prices when we are referring to how they are applied in New Zealand in practice. In most of the discussion here, we are interested in the cost of transporting energy across the grid (the 'nodal transport charge'), which is the difference between the nodal price at a downstream node and the nodal price at an upstream node.

320 In terms of the DME framework, LMPs are market-based and so come high on the decision making hierarchy, because they are established by the interaction of buyers and sellers in a workably competitive market

(d) arguably, an additional peak charge may be needed to ensure efficient investment by grid users and so efficient investment in the grid

D.42 The conclusion reached in appendix E is that these qualifications do not undermine the arguments presented here. However, they do suggest it may be efficient to supplement nodal prices with administrative load control and possibly a transitional peak charge.

D.43 In summary, as with prices in workably competitive markets, and once known issues are addressed, nodal prices can generally ensure that grid use is efficiently constrained to capacity.

D.44 An important implication of this is that it allows decisions about additions to grid capacity to be de-linked from load and generation developments. That is, LMP can be used to ensure that grid use is restrained to existing capacity, whatever the decisions of grid users. This will allow decisions about whether to upgrade the transmission network to be made purely based on whether the expected benefits from the transmission investment exceed its expected cost, rather than being prompted by the need to allow for things like unexpectedly high load growth.

D.45 Capacity in this context includes all relevant constraints, such as administratively determined grid reliability standards. This means that provided nodal prices are in general effective in restraining demand as described above, investment to meet grid reliability standards can be deferred indefinitely. As a result, it means that these investments can be deferred until they are economically justified. This means that no transmission investment need be made until the benefits to users of the investment are expected to exceed its cost. Thus the substantial net costs to users of inefficiently early investment can be avoided.[321]

D.46 This leads to our second principle for transmission pricing:

> *Locational marginal prices are generally the best means of restricting the use of the grid to its capacity.*

Efficient investment in the grid depends on nodal prices and transmission charges[322]

D.47 In workably competitive markets the average prices that consumers are charged for a service gravitate towards the (efficient) cost of providing them with the service, so that we can be confident that the investment is efficient.

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321 Of course, because of the lags involved in bringing a new transmission investment into use, the decision to undertake a new investment must be made well before the investment is commissioned, meaning that when the investment is actually commissioned, it will likely turn out to be ‘too early’ or ‘too late’.

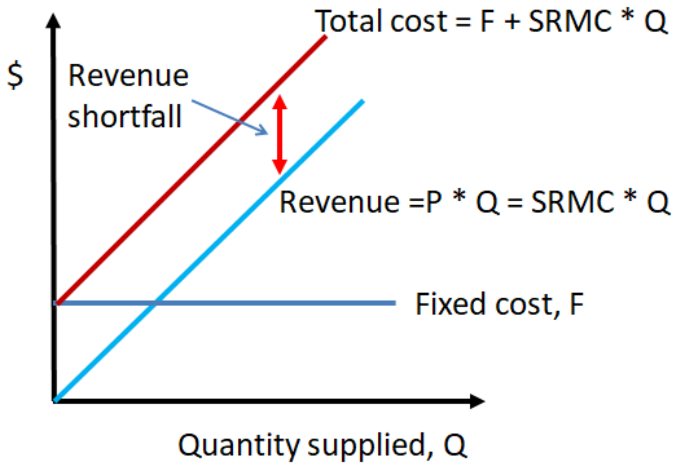
This does not undermine the point being made here that grid investment can be deferred until it is economically justified.

As Hogan (2011) points out, uncertainty like this is inevitable in any commercial investment proposal and must be dealt with (see paragraph B.162).

Nodal prices are beneficial in this regard, as they ensure grid use is restrained to capacity until the new investment is commissioned. They therefore reduce the cost of building the investment ‘too late’ and mean that there is no need to build the investment before the benefits expected from it exceed its cost. (For example it is not necessary to build “early” to mitigate the risk of faster-than-expected load growth).

322 The discussion about investment in this section is consistent with the conclusion in the economic literature on the desirability of marginal cost pricing in decreasing cost industries - see Frischmann et al, 2015. These issues are also addressed in a later and less well known literature on inframarginal economics – see Xiaokai Yang et al 2008.

D.48 However, because there are economies of scale in transmission services, nodal prices[323] are generally insufficient to recover the cost of the investment.[324] This is compounded by the lumpiness of transmission investment.



D.49 This is illustrated by the graph above for a particular case of economies of scale, where there is a fixed cost F of investment (dark blue line) and then a constant per unit cost of production (SRMC = constant – light blue line). Then:

(a) revenue = P * Q = SRMC * Q, where P is the price charged (equal to SRMC) and Q is the quantity supplied (light blue line).

(b) total cost of production = F + SRMC * Q (brown line)

(c) revenue shortfall = total cost less revenue = F (red arrow).

D.50 This means that if we were to rely solely on nodal prices to price use of and access to the grid, users would be charged less than the full cost of supplying them with electricity.

D.51 Charging users less than the full cost of production may lead to inefficient grid investment, as it draws in demand from those customers who would not be willing to pay for it if they were to face prices based on total cost of the investment. Likewise, grid users would also have an incentive to make investment decisions that took into account the nodal prices but not the impact of their decisions on the need for grid investment.

D.52 In the graph above, users would base their decision on the cost they have to pay (the light blue line), even though the cost of supplying them is the brown line.

D.53 In short, customers' decisions are likely to be different from what they would have been had they taken the cost of investment in the grid into account.

D.54 This can be seen from this example: if an investor in a gas fired power station does not take account of their location decision on the need for grid investment, it may locate next to a

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323 More precisely, the rentals arising from the nodal transport charge.

324 This is most easily seen in the extreme case where all the costs are fixed and the SRMC is zero. In that case the unit price is zero and the revenue the investment generates is zero.

The general result can be established as follows. Let P denote the use price, let Q denote usage and AC denote average unit cost.

With constant returns to scale, P=SRMC=AC, the firm's total revenue (which is P x Q) equals total cost (which is AC x Q).

By the definition of economies of scale, SRMC < AC. Hence, P=SRMC means P<AC and therefore P x Q < AC x Q. The revenue deficit would equal (AC - P) x Q if access fees were not charged.

gas field even when it would cost less overall if it were to locate near the source of load. Similarly, it may choose to invest in the gas fired power station when it would cost less overall to invest in some other form of generation (eg, solar and batteries) located closer to the load.

D.55 In both these cases, the cost of generation and transmission in total is greater if the user does not pay the cost of transmission, because consumers collectively have to pay the cost of transmission as well as generation. This means that consumers have to pay more overall for electricity because the investor did not need to take into account of the impact of its decision on the cost of transmission.

D.56 As with workably competitive markets, the solution is to ensure that transmission users who benefit from a transmission investment pay the full cost of the investment. This encourages more efficient investment in transmission by ensuring that grid users, in making their investment decisions, take into account the impact of those decisions on the need for grid investment. In the previous example, the investor in the gas fired power station will take account of the fact that if they locate away from sources of load, they may have to pay for a transmission upgrade to support the transmission of energy to the source of load. This means that the investor has an incentive to choose the investment which costs less overall, which means the cost to consumers of electricity is as low as it can be.

D.57 The point is well made by Coase (1970), page 118:

> A consumer does not only have to decide whether to consume additional units of the product. He also has to decide whether it is worth his while to consume the product at all rather than spend his money in some other direction. This can be discovered if the consumer is asked to pay an amount equal to the total costs of supplying him.
>
> [My] rejection of marginal cost pricing [that is, in our context, charging LMP and recovering the costs of transmission through something like the residual charge or general taxation] reflects the view that it is a mistake to concentrate simply on the marginal conditions when examining a proposal. It is the total effect (in which what happens at the margin is only one factor) which matters.

D.58 Furthermore, provided the grid user cannot avoid paying the charge for a grid investment that benefits them (that is, cannot shift their share of the charge on to another user), the charge will also raise the revenue needed to fund the grid investment efficiently. This is because, at the time the decision to invest is made, the benefits of the proposal to users are expected to outweigh the cost. This means that the expected beneficiaries of the investment would have been prepared to pay for it. Therefore, actually charging them this access fee for the grid is unlikely to lead them to disconnect or otherwise inefficiently alter their behaviour. In contrast, other methods of raising the required revenue, such as taxation, are more likely to be inefficient.

D.59 Charging grid users for new grid investments from which they benefit also has the advantage that it will give users with a significant stake in the investment an incentive to engage with Transpower and the Commerce Commission as part of the Commission's investment approval process and to provide information that could otherwise be difficult for the Commerce Commission to obtain.

D.60 If a particular user does not expect to benefit from a particular investment proposal to the extent envisaged by Transpower, it can be expected to provide that information and to oppose the investment when it expects to receive a benefit from the investment that is less than its share of the cost. It may not reveal this information if charges were to be spread across all transmission customers.[325]

D.61 In short, if users are charged for transmission investments, these are only likely to be sustainable where the benefits to users exceed their costs. This check is particularly important in a time of rapid technological change that is improving the viability of alternatives to supply that do not involve expanding the grid.

D.62 The Commerce Commission is charged with ensuring that grid investment is efficient. The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. It is sometimes argued that this negates the need for a transmission charge on beneficiaries of an investment. We disagree. The Commerce Commission's process and analysis provides for transmission investment that is efficient *given* the decisions of grid users. In the case of the gas-fired power station above, it must provide for grid investment *given* the investor's decision to locate the power station next to the gas field. As a result, even if the Commerce Commission's decision is efficient given grid use, it is still the case that outcomes could be enhanced overall by our proposal.

D.63 The analogy with workably competitive markets also suggests how the charges for a transmission investment should be allocated between transmission customers. As discussed above, in a workably competitive market, those who pay most towards an investment are those who benefit most from access to the investment. The effect is that the total cost of the investment is recovered from all those who benefit from it in a manner that ensures the expected benefit each user receives exceeds the charges it faces.

D.64 Likewise, we propose to allocate charges for a new efficient transmission investment in proportion to the benefit that each transmission user is expected to gain from the investment (a 'benefit-based charge'). This would ensure that the total cost of the investment is recovered and that those who pay for it would be expected to realise greater benefits from it than the charges they pay. Importantly, we consider that this is the only allocation method that provides real assurance of achieving this outcome.[326]

D.65 This leads to our third and fourth principles for transmission pricing:

> *The charges for access to transmission services from a new transmission investment in the grid should recover the total cost of providing the transmission investment.*
>
> *Charges for a new transmission investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment.*

D.66 This leaves open the question of the treatment of existing investments. While the arguments are not as clear-cut for applying the benefit-based charge to existing investments, we are of the view that the balance of arguments favours applying the benefit based charge to existing investments for the reasons set out in the following paragraphs.

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[325] This point is illustrated in footnote 173

[326] As is discussed further below, this does not mean that those users actually do realise benefits exceeding their charges. As with any investment decision, when the future unfolds, the benefit that any user gets from the investment may be quite different from what was assumed when the investment was undertaken. As is normal commercial practice, this risk would be taken into account in assessing how much each user is prepared to pay for the investment (ie, the expected benefits would be adjusted for risk) and so determining whether the investment should proceed.

D.67 The discussion of workably competitive markets above indicates that where users are indifferent about the age of the investment providing a service, charges for the services of old investments will likely be the same as if the investment was new. This means that the principle for charges for existing grid investments discussed above should also apply to existing investments.

D.68 The reason why this is appropriate in transmission is that if the transmission investment was efficient, it means that the benefits to the relevant grid users are greater than the cost of the investment, so that asking them to pay for the investment will not result in inefficiency. Coase (1970) expresses the point at page 118 thus:

> Apparently, what the advocates of marginal cost pricing [ie, in our context charging users LMP but recovering the costs of investment through some other charge, such as the residual charge or general taxation] had in mind was that the Government should estimate for each consumer whether he would be prepared to pay a sum of money which would cover the total cost. However, if it is decided that the consumer would have been willing to pay a sum of money equal to the total cost, then – and this strikes me as a very paradoxical feature of this argument – he will not be asked to do so. ….I found this a very odd feature. …The way we discover whether people are willing to pay something is to ask them to pay it.

D.69 In contrast, as Coase points out, any other way of recovering the costs is likely to impose efficiency costs. In particular, it means that we would be imposing the cost of the investment on some party that does not benefit from the investment. If we imposed the cost on such a party, this could affect how competitive it is in its product market and so its ability to compete against other potentially less efficient businesses. In the extreme, this might cause them to disconnect from the grid and go out of business.

D.70 Furthermore, charging users in this manner for an investment *after* it is made is necessary to ensure that the efficiency benefits relating to new investments described above are realised. Over time, grid users' behaviour before a grid investment is made will likely adjust to reflect the charges they will face for the investment when it is made. If we do not charge the beneficiaries of the investments the full cost of the investment when it is made, then the behaviour of grid users *before* a particular investment is made will reflect this fact. We therefore consider that the best way to encourage users to take account of the full cost of the investment before it is made is to charge those who benefit from the investment the full cost of the investment when (after) it is made.

D.71 Since on average, generators have to charge prices which recover the cost of their investments, the price they charge for energy will on average be higher than it would be if they did not have to pay the transmission charges. This is no different from saying that energy prices will be higher than they would have been if the generator did not have to pay for one of its production costs, such as the capital cost of its plant. It is simply a result of the charges reflecting the resource cost of supply of electricity, in the manner Coase discusses. It is not clear whether the price at the downstream node would be higher as a result of the generator's higher costs, since it depends on which generator is the marginal generator. What is likely, however, is that the prices at the downstream node will be lower than the prices would have been had the transmission investment not been made, provided the investment is efficient. And, at any point in time, provided the market in generation is workably competitive, the generator's offer will reflect the short run cost of generation and not the transmission charges.

D.72 Furthermore, with benefit-based charges for transmission, as with workably competitive markets, charges will also reflect costs.[327] This means that transmission charges will be higher for generators who depend on more expensive transmission investments. As a result, for example, generation that is remote from load would be expected to pay more over time than generation that is closer. So, if such charges are applied (or had been imposed historically) to all grid investments, load in the upper North Island and generation in the lower South Island may over time have paid relatively high charges. Similarly, remote load that is small would expect to pay relatively more than its size would indicate, both because serving it requires a long transmission line and because it is less able to access benefits from economies of scale in transmission compared with a larger load.[328]

D.73 This leads us to modify our third and fourth principles for transmission pricing so that they refer to both existing and new investments, as follows:

> *The charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment.*
>
> *Charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment.*

D.74 Of course it is possible that past investments were not efficient, either because they were never efficient or because the future turned out to be different from what was forecast at the time of the investment. In principle this could mean there is a difference between the share of benefits that a user actually gets and its share of the cost of the investment. We have allowed for this in our proposal by applying the benefit-based charge only to pre-2019 investments where we estimate the benefit from the investment exceeds its cost.

D.75 However, after an investment is made, the choice a user has is whether or not to use the grid (rather than whether to use the particular investment). So the difference between benefit and cost will not cause inefficiency provided each user is charged at least the additional costs that connecting them to the grid causes and provided the charge is not so large as to make it privately profitable to disconnect from the grid; that is, provided the charges are between the incremental cost of and the stand-alone cost of supplying the customer.[329]

D.76 Typically, incremental cost is small relative to stand-alone cost. This means that, in practice, there is wide discretion in the way that charges for existing investments can be allocated without causing material inefficiency. However, there may be cases where

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327 This also means that it is possible to allocate the cost of the investment to different users according to the cost that is 'attributable' to them. One method that is sometimes advocated for allocating costs is the use of Aumann-Shapley values. In essence, Aumann-Shapley values attempt to ensure that those who contribute most to the cost of a common resource pay most for it. They do so by calculating the marginal cost of adding an additional player to the use of a common resource and averaging over all possible orderings of entry. See Young (1994), page 1220.

We propose to allocate according to benefits rather than attributable costs for the reasons outlined in paragraph D.64.

328 The discussion in this paragraph is accurate if, as with workably competitive markets, charges for an investment continue as long as it continues to provide benefits. For good reason, the Commerce Commission regulatory regime instead allows Transpower to recover just the full cost of each investment. This means in effect that, aside from operating and maintenance costs, charges cease once the cost of the investment has been fully recovered. This creates a tension between applying the principle discussed in paragraph D.78 below and the other principles.

329 For a formal explanation of the rule that charges must be between incremental and stand-alone cost, see Young (1994).

inefficiency is a concern. For example, charges for a small load in remote location (such as the West Coast) may approach stand-alone cost. In that case a prudent discount may be desirable to avoid load disconnecting.

D.77 There is one qualification to this discussion. This can best be illustrated by the following example: Suppose a supermarket found that it was facing the prospect of exiting the market because it was unable to compete with another supermarket, and therefore was expected to get less benefit from a transmission investment than its competitor. Giving the former supermarket a lower transmission charge would be no different in principle from exempting it from council rates because it could not otherwise compete with its competitor. Clearly, this could lead to dynamic inefficiency. It is therefore appropriate to ensure that charges for a transmission user should be similar to other competing users after adjusting for their size and location.

D.78 This leads to our fifth principle for transmission pricing:

> *Charges for a transmission user should be similar to those for other competing users after adjusting for their size and location.*

Q51. Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

Recovering any additional costs

D.79 There are a number of reasons why the charges discussed above may not fully recover Transpower's recoverable revenue, including:

(a) the charges would not recover Transpower's overhead and unallocated operating expenses

(b) it may not be efficient to recover the costs of some pre-2019 investments using the benefit-based charge, because the efficiency benefits of doing so could be outweighed by transactions costs.

(c) the proposed guidelines would recover post-2019 investments using a different method (ie, IHC) from the method the Commerce Commission uses in setting Transpower's recoverable revenue, with the difference being absorbed by the residual charge

(d) the proposed guidelines would allow various other adjustments to the other charges, with the difference being recovered by the residual charge.

D.80 Again, workably competitive markets provide a useful guide as to how best to recover these costs. In such markets, costs that are additional to short run marginal cost are recovered by having higher charges for those customers who are prepared to pay more than SRMC (ie, whose use is not much affected by paying more than SRMC). Moreover, since nodal prices and the benefit-based charge are sufficient to ensure efficient use of and investment in the grid, the objective in recovering additional costs is to alter users' behaviour as little as practicable.

D.81 In principle, this suggests levying charges on those who are least price sensitive (that is, whose behaviour is least affected by the charges). However, given the practical difficulties involved, such charges are typically levied on the basis of some measure of size and/or ability to pay.[330]

D.82 However we decide to allocate the charge to recover these costs between consumers, it is desirable that the residual charge be designed so that transmission users view it as a fixed charge. That is, it should be designed so that users have no incentive to alter their behaviour to try to reduce the charge they have to pay. The reason for this is that the other charges discussed above ensure each user has an incentive to use the grid and to invest efficiently. This means that if this charge had an effect on the user's behaviour, it would undermine the effect of the other charges in promoting efficient use of the grid and efficient investment. If, for example, the residual charge were allocated based on the user's current use of the grid, that would encourage grid users to inefficiently reduce their grid use below that suggested by nodal prices.[331]

D.83 Paradoxically, it is likely most efficient – and therefore for the long term benefit of consumers – to apply the charge to load only. The reason is that any such charge that is applied to generation (that is, injection into the grid) would largely be passed on to load in the form of higher energy prices, since new generators would then delay entering until the energy prices they expect to receive would cover the residual charge. This means that effectively load customers would end up paying the charge whether or not the legal incidence of the charge is on load or generation. Since the charge would be passed through in nodal prices, it means that nodal prices would be higher, discouraging energy use (compared with the case where the entire charge is on load). This would be inefficient.[332]

D.84 This leads to our sixth principle for transmission pricing:

> *Any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.*

Conclusion

D.85 This appendix has used the efficiency properties of workably competitive markets to derive principles for the pricing of transmission services that give grid users incentives to behave in ways that ensure efficient investment and efficient use of the grid. This provides grid users with incentives to make decisions that achieve their desired goals at lowest cost to the economy as a whole. This results in lower electricity prices for all electricity consumers over the long run.

D.86 The principles we have derived for the efficient pricing of transmission services can be summarised as follows:

(a) LMP is generally the best means of restricting the use of the grid to its capacity

(b) each user should pay the cost of connecting it to the grid

(c) the charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment

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330 Since general taxation is designed to cause the least practical loss of efficiency, the considerations here are the same as those obtained by following tax policy principles.

331 See, for example, Hogan and Pope (2017), page 76.

332 Economists will recognise this conclusion as being related to that of the seminal article by Diamond and Mirlees (1971) on production inefficiency resulting from the taxation of intermediate goods.

(d) subject to paragraph D.86 (e) below, charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment

(e) charges for a transmission user should be similar to those for other competing users after adjusting for their size and location

(f) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.

D.87 These principles need to be applied taking into account ‘real-world’ considerations such as the need to avoid excessive transaction costs.

D.88 In addition, this analysis has made clear the important point that a decision to commission a new transmission investment can be safely deferred until the benefits from it exceed its cost. In particular, a new investment need not be precipitated by such matters as demand growth or grid reliability unless those considerations provide an economic justification for the investment. This means that the substantial costs of inefficiently early investment can be largely avoided.

Q52. Do you agree with the conclusions of appendix D?

Q53. Do you have any comments on the matters covered in this appendix D?

Appendix E Assessment of alternatives

E.1 As part of compiling this issues paper, and as part of previous consultation rounds,[333] the Authority has considered alternative means of achieving the objectives of its review of the TPM, ie, to ensure that the TPM best meets the Authority's statutory objective. The publication of the proposed guidelines does not, itself, result in any changes to the Code, but the guidelines will, if published, likely ultimately lead to a proposal for a new TPM (and therefore Code amendment). Because this current process may result in Code amendments, the Authority has taken the view that it would be helpful to stakeholders to not only provide a CBA at this time, but also provide an assessment of alternatives now as would also be required for a regulatory statement under section 39 of the Act. In this appendix, we provide a description and discussion of some of the main alternatives we have considered.

E.2 The alternatives covered here are:

(a) a peak charge (as part of our current proposal in this 2019 issues paper or some other alternative)

(b) removing the RCPD charge under the current guidelines

(c) a simplified staged approach

(d) a deeper connection charge

(e) a tilted postage stamp charge.

E.3 We focus first on a permanent peak charge, which we have looked at in detail. We then consider the other alternatives outlined in paragraph E.2. We conclude the section with a list of the other options we have looked at as part of past issues papers, and to which we consider the issues and arguments have already been fully canvassed in these earlier papers.[334]

A peak charge

E.4 We have considered in depth the desirability of including a permanent peak charge, such as a long-run marginal cost (LRMC) charge, in the proposed guidelines. In short, our conclusion is that adding a peak charge would not better achieve our statutory objective. Rather, we have come to the view that nodal prices in combination with a benefit-based transmission charge can provide for efficient use of the grid and for efficient investment in the grid and by grid users.[335]

Submitters' views on a peak charge

E.5 Many submitters on the second issues paper[336] thought that the RCPD charge should be retained or some other form of peak charge (such as a LRMC-based charge) should be

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333 See chapter 9 of the 2016 issues paper and chapter 6 of the 2012 issues paper.

334 Further alternatives, relating to some of the more specific details of the proposed guidelines, are discussed in Appendix B.

335 As is noted in appendix D, we use the term LMPs when referring to prices which meet the 'textbook ideal', and nodal prices when we are referring to how they are applied in New Zealand in practice. In most of the discussion here, we are interested in the cost of transporting energy across the grid (the 'nodal transport charge'), which is the difference between the nodal price at a downstream node and the nodal price at an upstream node.

336 They included Air Liquide, Axiom for Transpower, Buller Electricity, Bushnell for Trustpower, Business NZ, Counties Power Consumer Trust , EA Networks, Eastland Generation, Electric Power Optimisation Centre,

included in the proposed guidelines as well as or instead of the beneficiaries-pay charge to promote overall efficiency in use of the grid and efficient investment in the grid and by grid users. The peak charge is argued to be efficient for a number of reasons, including:

(a) it reduces peak demand (eg, by spreading load, reducing demand), deferring transmission investment

(b) it is incorrect to regard the failure to use full capacity as wasteful

(c) nodal prices are not likely to provide adequate price signals, possibly because differences in nodal prices are small compared to the wholesale electricity prices or because consumers do not see nodal price signals

(d) nodal prices are not durable as they are too sensitive

(e) removing the RCPD-based peak charge could have negative flow on impacts for wholesale prices

(f) removing it would disincentivise load management and investment in load management, including in particular domestic controllable load

(g) it helps lower grid security limits

(h) the RCPD charge is consistent with Ramsey principles

(i) the removal of the RCPD charge would involve significant wealth transfers which would have a chilling effect on investment.

E.6 On the other hand, some submitters[337] did not support a peak based charge in addition to nodal prices. The reasons given included:

(a) not having a peak charge would promote competition

(b) having a peak charge risks incentivising inefficient decisions in investment, including inefficient locational decisions, and potentially inefficiently curtailing load during winter peak periods

(c) having a peak charge would over-signal the benefits of distributed generation.

E.7 Different parties who support some form of peak-based charge have either not specified the details or have proposed different variants of a peak-based charge. The key aspects of their proposed approach typically appear to be as follows.

(a) The charge would be a supplementary transmission charge (rather than, for example, a supplement to nodal prices).

(b) The charge would be based on energy use.

(c) The charge would be levied around times of peak energy use. This could be based on the peak in relevant circuits (rather than a regional or system-wide peak).

(d) The peak charge might be imposed at any peak or only around times the circuit would otherwise be congested (either with or without locational marginal prices (LMPs) on the relevant circuit).

ENA, Fonterra, GBC Winstone, KCE, KiwiRail, Marlborough Lines, Molly Melhuish, Network Tasman, Network Waitaki, Norske Skog, Northpower, NZ Steel, NZIER for MEUG, Oji Fibre Solutions, Orion, Pioneer, Powerco, Powernet, PwC for 14 EDBs, Refining NZ, Top Energy, Transpower, Unison , Vector, Waipa Networks, Winstone Pulp

337 For example, Meridian, NERA for Meridian, Mighty River Power

(e) The charge might be set equal to the expected long-run marginal cost (LRMC) of expanding capacity of the relevant circuit in future per unit of use at peak (possibly adjusted for LMP). Alternatively it might be set at a level judged necessary to restrain the use of the relevant circuit to capacity.[338]

E.8 We define a peak charge as a charge that is imposed around peak use of the relevant circuit and that is additional to the benefit-based and residual charges in the proposed guidelines. It therefore encompasses any of the variants described in paragraph E.7. It also encompasses the LRMC charge that the Authority included in the draft guidelines in the 2016 TPM proposal and in its LRMC working paper.[339]

The historical origins of LRMC-based peak charges

E.9 Given the support for the introduction of a peak charge potentially based on LRMC, we have investigated why early advocates of an LRMC charge chose to support it.

E.10 The early debate preceded the academic discovery of LMP and its use as a basis for establishing an efficient market for sale and purchase of electricity across the grid. Nevertheless, this debate followed much of the reasoning implicit in LMP, and discussed use of LRMC-based charges as a less accurate but more practical alternative to what would later be called LMP. The box below provides a short summary of this history.

Our approach to analysing the case for a peak charge

E.11 We have given careful consideration as to whether the proposed guidelines should provide for a peak charge as a core component or as an additional component and whether this would better achieve the Authority's statutory objective.

E.12 For the reasons discussed below, we have concluded that there is a potential case for a transitional peak charge to mitigate possible risks arising from the implementation of the new TPM but that it would not be efficient to have a permanent peak charge and therefore not to the long-term benefit of consumers.

Transpower's report on the role of peak pricing for transmission

E.13 As part of our consideration of the case for a peak charge, we offered Transpower the opportunity to provide evidence as to whether or not:

(a) the removal of the regional coincident peak demand charge (RCPD) charge would have an adverse effect on the ability to meet peak demand

(b) a charge to control peak demand (such as potentially an LRMC charge) would be economically justified if the RCPD charge were removed.

338 These two approaches are in fact related, if investment in future capacity is efficient. The price necessary to restrain grid use to capacity downstream of the relevant constraint is equal to the short run marginal cost of using energy there. Under certain simplifying assumptions, investment in new capacity is efficient when the average SRMC equals the LRMC of the new capacity. The approaches diverge before load has grown sufficiently to justify new investment, because then the average SRMC is less than the LRMC. See for example Tooth, 2014

339 'Transmission pricing methodology: LRMC charges, published on 29 July 2013, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c13677. While much of the thinking in that paper remains relevant, much of the policy discussion has been qualified or superseded by the discussion in our subsequent publications, including in this 2019 issues paper and in chapter 5 of the second issues paper.

The historical origins of LRMC-based peak charges

Oliver Williamson's paper, Peak Load Pricing and Optimal Capacity[340], sought to determine the optimal price for the transport of electricity as demand increases, and the optimal timing of investment. His optimal price for the transport of electricity is what we would now call the nodal transport charge implicit in LMP (ie, the difference in LMP between nodes).

This analysis was critiqued by Ralph Turvey's paper, Peak Load Pricing.[341] Turvey accepted Williamson's theoretical analysis but criticised it on practical grounds.

The basic notion which he and his predecessors put forward is fully accepted, given his assumptions. This is that the optimum requires price to exceed marginal running cost in periods when demand is high by amounts which will both restrict demand to capacity output in all of those periods and which sums up over them to equal the marginal cost of capacity. In other periods, price must equal marginal running cost.

In modern terms, what Williamson proposed can be interpreted as saying that LMPs should restrict demand to capacity until new investment is justified.

Turvey then goes on to criticise Williamson and others for posing 'ivory tower' solutions that are not practically useful. His critique involves two key elements:

that consumers prefer stable prices but prices in Williamson's analysis would not be stable

that an electricity tariff can have no more than four different prices per year, "except for very large consumers where the expense of recording load hour by hour can be borne".

Both these critiques are no longer valid. Under New Zealand's nodal pricing:

if consumers do value stability in prices sufficiently, retailers have an incentive to provide it through fixed price contracts, which could then be profitable. As is discussed further below, this does not undermine the efficiency benefit of exposing retailers and other parties to LMP.

LMP is feasible and efficient, so there is no need to approximate it with an LRMC based peak charge.

Given the actual conditions in New Zealand today, our view is that Turvey's analysis, as quoted above, indicates that LMP would be what he calls 'the optimum' for pricing the use of the grid – the rationale Turvey advanced for a LRMC charge would no longer apply.[342]

E.14 Transpower responded with the publication *The role of peak pricing for transmission* (Transpower's report).[343]

E.15 We consider that the views Transpower expresses in that report are broadly representative of the views expressed by those who favour providing for a peak charge in the proposed guidelines. Consequently, we provide a detailed discussion of our thinking on Transpower's report and on the desirability of introducing a peak charge of some sort. Our purpose in

340 O Williamson (1966).

341 R Turvey (1968).

342 Of course, the Turvey critique may apply and LRMC based charges may be useful when locational marginal prices are not feasible or practicable. This may be the case for example in imposing a kvar charge to price reactive power or in pricing use of low voltage networks.

343 Our letter to Transpower is included at Appendix A of Transpower, The role of peak pricing for transmission, 2 November 2018, at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission.

doing so is to clarify our position and to provide a basis for submitters to comment on our views.

E.16 Transpower's report builds on three annexes (annexes B, C and D). We summarise each of the three annexes and then draw conclusions.

E.17 Annex B conducts a literature survey of the responsiveness of electricity demand to electricity prices. We are broadly comfortable with its conclusions,[344] which can be summarised as (page 24 of annex B):

> While it is clear that demand for electricity is inelastic [not very sensitive to prices], the literature remains mixed as to whether peak periods are more elastic than off-peak periods, or vice versa.
>
> High peak-use tariffs tend to reduce peak-time demand, and residential customers are more responsive to peak-time prices than non-residential customers.
>
> Consumer responses to peak-use tariffs are much more pronounced in the long term than in the short term.
>
> Demand response effects are much greater where automated or semi-automated response enabling technologies have been applied. It is reasonable to infer that technological change will result in demand for electricity being more flexible and responsive to price signals
>
> These findings suggest that peak-use charging deters peak-time demand and helps with flattening load profiles.

E.18 Annex C analyses what would happen to demand if the RCPD charge is removed and there is no peak charge to restrain demand, so that distributors withdraw a 'modest' amount of load control (around 3% to 7% of peak demand compared to total load control of 20% of peak demand). It then assesses what this would imply if transmission investment is undertaken to meet this increase in demand. This shows that investment would need to be brought forward by 2-6 years to accommodate the increased demand with 90 percent probability.

E.19 As Transpower says, "The analysis presented in Attachment C demonstrates that absent peak pricing, Transpower would need to invest more, earlier, with the consequence that our transmission charges would be higher".

E.20 We infer that Transpower considers that this investment would be inefficient. This is not necessarily so. Such an investment would be inefficient only if the benefit to users of the additional transmission investment needed to accommodate this increase in peak demand is less than the cost of the investment. Transpower makes the point that this would be more likely to be the case if changing technology means that the new investment becomes stranded before the end of its physical life.

E.21 Transpower states that it "remains firmly of the view [that a] peak price signal is essential to avoid grid overbuild." We agree that some form of a peak price signal is likely to be the most efficient way to avoid grid overbuild (the alternative is to rely on administrative load control at peaks).

E.22 In our view the key assumptions made by Transpower in this annex are as follows:

344 However, we note that we have made our own estimates of elasticities for different customer classes during peak and off-peak periods in the CBA of our proposal.

(a) the RCPD charge appropriately signals the economic cost of grid use (noting however that Transpower "has been clear that the current peak price for transmission (RCPD) may sometimes be overly strong"[345])

(b) distributors withdraw some load control in response to the removal of the RCPD signal

(c) the anticipated increase in demand would not lead to an increase in the quantity of generation offered downstream of any relevant constraints, that is, all demand would be met from upstream supply

(d) neither demand nor supply is responsive to the impact of an increase in demand on relevant nodal prices

(e) as a result, the only possible responses to the increased peak that would result from the removal of the RCPD charge would be to: build further transmission investment to meet the demand, to impose another peak charge, or administratively control load.

E.23 Annex D of Transpower's report analyses what would happen to nodal prices and potentially system stability if demand for transmission services is increased by the amount of distributor-controlled load at certain nodes that do not have price-sensitive large loads behind them and there is no additional transmission investment to cope with it. Transpower reports that nodal prices at the times of relevant system peaks would rise substantially (6 to 12 times) and that the scheduling pricing and despatch model (SPD) used to schedule despatch and estimate prices would yield infeasible results. This means that some of the SPD constraints would have to be relaxed or some other form of demand control would be required.

E.24 We view the key assumptions in this annex as:

(a) distributors at the relevant nodes withdraw load control in response to the removal of the RCPD signal

(b) the anticipated increase in demand and in nodal prices is not associated with an increase in the quantity of generation offered and available at the relevant nodes

(c) the anticipated increase in nodal prices does not impact on demand at the relevant nodes (ie, the quantity of energy demanded behaves as if it is completely inelastic).

Our conclusions on Transpower's report

E.25 We are of the view that Transpower's report can be used to inform thinking on the desirability of a peak charge, provided that the assumptions underpinning each of its conclusions are taken into account. Specifically, both the analysis of transmission investment requirements in Annex C and the analysis of nodal prices and grid use in Annex D of Transpower's report are incomplete, as they do not take into account the likely response of both demand and supply to higher nodal prices. We consider that it is desirable to take this into account by reconciling the different assumptions in each of the three annexes. Accordingly, we do so qualitatively in the following discussion.

345 Transpower, The role of peak pricing for transmission, 2 November 2018, Page 6, available at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission

E.26 We conclude that:

(a) demand would likely rise in the first instance if the RCPD charge is removed and not replaced by another peak charge (Annex C of Transpower's report) in part because distributors (or other parties) would likely reduce load control as a result[346]

(b) such an increase in load would (in the absence of another response) necessitate investment in transmission assets being brought forward[347]

(c) however, an expected increase in demand for energy would likely increase nodal prices to the extent there is congestion (as identified in Annex D)

(d) the rise in nodal prices is likely to encourage those exposed to nodal prices to reduce their demand at the relevant node (as discussed in Annex B), and increase supply of energy from generation downstream of the point of congestion

(e) Taking this into account, we consider that:

(i) less transmission will be required than if it was assumed that demand did not respond to nodal prices (as is assumed in Annex C of Transpower's report)

(ii) grid use will be lower than if it was assumed that demand did not respond to nodal prices (as is assumed in Annex D of Transpower's report).

Q54. Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?

E.27 Transpower concludes that a "…peak price signal is essential to avoid grid overbuild." The rest of this section/annex examines this proposition and what that peak price signal should look like.

The nature of a peak charge

E.28 We agree, as Transpower says, that a peak price signal is essential to avoid grid overbuild, to avoid costly administrative load control[348] or both.

E.29 Where we differ from Transpower is in what the peak price signal should look like.

E.30 As is discussed in more detail in appendix D, we consider that it is now well established that, in principle, locational marginal prices (LMPs) can send efficient price signals for optimal short-run use of the grid. For example, the International Energy Agency (2007) says that "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."

346 It is not obvious that distributors would reduce load control if the RCPD charge is removed, as is discussed further in paragraph E.51. However, direct connect customers who currently respond to the RCPD charge may increase their demand for energy, although any demand increase would be tempered by higher nodal prices.

347 Transpower's report implies the timing of this investment is inefficient, but as discussed in paragraph E.20, the investment may not be inefficient.

348 Leaving aside transactions costs, with imperfect information on how grid users value load, any peak charge is typically likely to be more efficient than administrative load control in restricting grid use. This is because it encourages grid users to identify and selectively forego grid use which is less valuable to them than the price imposed by the LMP or peak charge. Other parts of this Annex discuss the effect of transactions costs on this conclusion.

E.31 By definition, LMPs are set at the short-run cost of using energy at a particular location, and efficiently constrain grid use to capacity, provided demand and supply are sufficiently price-sensitive there.[349]

E.32 This means that any peak charge that is different from the LMP, and is effective in reducing demand, must be reducing demand or increasing supply at that location more than is necessary to constrain use to capacity.

(a) Although the peak charge may be targeted at reducing demand in periods when the circuit is congested, it has no effect when the LMP would otherwise (in the absence of the peak charge) have been higher than the peak charge. This is because all the peak charge does is reduce the LMP by an equivalent amount, with no effect on use.[350]

(b) The peak charge can only have an effect on use when the LMP would have been lower (in the absence of the peak charge) than the peak charge. In that case, it reduces the use of the grid to below its capacity.

E.33 Since the peak charge imposes economic costs (the cost of foregone demand or increased supply) when using the additional grid capacity is essentially costless, we consider that the peak charge must reduce the efficiency of grid use. As is discussed further below, we consider that a peak charge can therefore only be justified if nodal prices do not fully reflect the SRMC of grid use, or if the inefficient reduction in grid use is offset by some other efficiency gain.

E.34 In principle, therefore, LMP can efficiently restrain grid use to capacity. However, there are a number of other considerations (such as whether it is cost-effective for users to monitor and respond to LMP) which need to be taken into account before determining whether nodal prices are likely to efficiently ration the use of the grid to capacity in practice.

E.35 In practice, therefore, it is an empirical matter whether LMP is sufficient to efficiently restrain use to capacity and whether a peak charge instead of or in addition to nodal prices would improve efficiency.[351] We discuss further below our assessment of this issue.

E.36 We now examine whether there is any reason to suggest that nodal prices complemented by a benefit-based charge are insufficient on their own to ensure efficient grid use and efficient investment, and if so, whether an additional peak charge is required to promote efficiency.

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349 LMPs may not be able to constrain grid use to capacity if energy demand and supply at any node is not sufficiently sensitive to energy prices. We consider that, with the exceptions discussed in this Annex, if LMPs cannot constrain grid use to capacity because demand for and supply of energy are insufficiently price responsive, it is unlikely that they would be more responsive to any other sort of peak charge. In other words, other peak prices have no advantage over LMPs in this regard. They are also likely to be less efficient than LMPs in the restraint they do put on grid use, for the reasons discussed in paragraphs E.32 and E.33.

Rather, if LMPs cannot constrain grid use to capacity, then administrative load control and/or additional investment in the grid would also be required. Administrative load control would be more efficient to the extent that grid users value the forgone energy use less than the cost of the grid investment, and vice versa. In the former case, the benefit-based charge means that the relevant grid users are likely to favour administrative load control since the cost to them of forgoing energy use is less than the benefit-based charge they would pay for additional grid investment.

350 This reduction in LMPs would occur 'automatically' as generators would lower their offer price and load customers would reduce their use of the relevant circuits during periods when they expect the peak charge to be in operation.

351 For example, the transactions costs of implementing LMP in low voltage systems at the ICPs of mass market consumers mean that currently some other form of peak charge is likely to be more efficient. See Batstone et al, 2017.

Are LMPs and a benefit-based charge sufficient to ensure efficient use and investment?

E.37 There are a number of reasons advanced as to why New Zealand's nodal prices and benefit-based charges on their own may not ensure efficient grid use and efficient investment, and why some other price-based measure such as a peak charge may be required. These are:

(a) relevant parties are not exposed to, or do not respond to, nodal prices

(b) nodal prices on their own are insufficient to restrict grid use to capacity

(c) nodal prices, in conjunction with benefit-based charges, may not ensure efficient investment, even though they can restrict grid use to capacity

(d) in practice, nodal prices will not be allowed to rise high enough to manage congestion.

E.38 We consider each of these arguments in turn in the rest of this appendix. In summary, we conclude that there is a potential case for a transitional peak charge. However, in most of the situations where we consider the case for a permanent peak charge, we consider that the case does not stand up.

E.39 The one possible exception is the argument that a peak charge might be needed to ensure that consumers take into account the effect of their own investment decisions on future transmission investment (discussed below as part of the discussion of the issue at paragraph E.37(c)). This may lower transmission costs and so overall costs. However, the conditions that this charge would need to meet lead us to conclude that such a charge is unlikely to improve efficiency in practice and may well be counterproductive.

E.40 We asked Professor W William Hogan to review an earlier paper which is in effect an early draft of this discussion. Professor Hogan replied in a memo dated 31 May 2018. In it, Professor Hogan looked at the desirability of applying a LRMC based peak charge in practice. We provide selected extracts from Professor Hogan's memo in the box below entitled *Professor Hogan's views on the desirability of a LRMC charge.* He concluded his memo as follows:

> Improvements in the analysis and allocation of the costs and benefits to make better decisions and provide better information would be important. This is a separate subject under the general heading of 'beneficiary pays' cost allocations that we have discussed. But the argument that LRMC is available as part of that package 'does not stand up'.

This analysis by Professor Hogan reinforces the more detailed analysis presented here.

Are all relevant parties exposed to and do they adequately respond to nodal prices?

E.41 There are several reasons to consider that relevant parties may not respond, or may not respond adequately, to nodal prices.

E.42 Households and other small consumers are typically not exposed directly to nodal prices. Typically, these consumers enter into fixed-price variable-volume contracts for their electricity with retailers. Since these expose retailers to price risk, they are likely to cost consumers more on average than spot price contracts. The fact that consumers choose these contracts over (likely cheaper) spot price contracts and that retailers find this profitable means that these arrangements are likely to be efficient.

Professor Hogan's views on the desirability of a LRMC charge[352]

The problems of the LRMC story are fundamental. I would step back from the details of the analysis to emphasize three issues. First, the LRMC analysis typically adopts the relevant description of the transmission system is a single line between two points where the flow on the line is driven by the peak load at the destination. Second, the transmission expansion cost function is essentially well-enough-behaved to be approximated by an increasing marginal cost, e.g. convex. Third, transmission customers are myopic and make their long-lasting investments in future consumption equipment based on the current price.

While these assumptions simplify the framework and almost dictate the need for something like LRMC pricing, the assumptions are not innocuous. If we abandon these assumptions to consider something closer to reality, then the case for LRMC falls away.

The most important lesson we have learned over the many years of studying restructured electricity markets is that the interactions in a complex, interconnected, high-voltage transmission grid have a first-order effect on operations and on the marginal cost of dispatch to meet load at any moment. This fact gives rise to the security-constrained, economic dispatch with nodal pricing as found in the New Zealand market design. … Often the intuition that guides the analysis of a single line is simply wrong in the case of an integrated grid. And using the single line analogy to assign transmission costs leads to perverse behavior. ...

The assumption that the transmission expansion cost function is well-behaved enough to allow marginal analysis to guide efficiency is both critical and wrong. ... Hence, there is an inherent contradiction in making the efficiency arguments for LRMC based on marginal analysis precisely when the marginal analysis does not apply; or in making arguments for LRMC using assumptions which make LRMC unnecessary.

Finally, the assumption of myopic loads and one-part pricing seems unnecessary and wrong. It may be true for some customers, who may also tend to be price inelastic and therefore not much affected by the pricing model. But for large volumes at the margin, that could come from larger commercial and industrial loads, the myopic assumption seems too extreme. …The real challenge is in providing information about the counterfactual and the likely future charges with and without the transmission expansion, rather than imposing on everyone the mandate to be myopic.

Improvements in the analysis and allocation of the costs and benefits to make better decisions and provide better information would be important. This is a separate subject under the general heading of "beneficiary pays" cost allocations that we have discussed. But the argument that LRMC is available as part of that package "does not stand up.

E.43 In this case, it is likely that retailers will endeavour to manage that risk by entering in to a contract with a counterparty (such as a generator), so that the price risk is shifted to a party that is better placed to respond to nodal price variations.

E.44 This means that, even though the mass market consumer does not respond to nodal prices, the behaviour of other parties compensates for this so that grid use responds as if they do.

E.45 Even if relevant parties are exposed to nodal prices, it may be that there are barriers preventing them from acting in response to those prices. In particular, nodal prices are

352 Extracts from the memo from Professor Hogan to Carl Hanssen dated 31 May 2018.

volatile and not finalised in real time, and the transaction costs of responding to prices may be too high.

E.46 Under current nodal pricing, nodal prices are volatile and are not finalised until after the relevant transactions have taken place. Price-sensitive parties will respond to their expectation of prices – the concurrent 5-minute real time indicative prices normally provide a good indication of final prices. However, the actual prices may be significantly different, particularly at times of system stress. As a result, it cannot be guaranteed that demand for use of a congested circuit will be restrained by the nodal price.

E.47 However, we do not consider this to be an argument for peak charges, as, in our view, they don't solve this problem efficiently. They are harder to set to restrain grid use to capacity, since they must be set administratively in advance and are unlikely to be revised on a near real-time basis (or even every half-hour by half-hour).

E.48 If either the time delay could be eliminated or the volatility reduced, that would enable parties to more efficiently respond to nodal prices. We expect that real time pricing (RTP) [353] will eliminate the time delay and mis-pricing by making sure that the nodal prices are known at the time that the transaction occurs.

E.49 It may also be that it is not cost-effective for some consumers to respond to nodal prices. That is, the savings involved from monitoring and responding to nodal prices mean that it is not worth consumers doing so. If this is true for nodal prices, we think it is likely to be equally true for a peak charge.

E.50 At the moment, distributors can use administrative load control to reduce all relevant consumers' load and so mitigate the transactions costs issues of consumers responding individually to a peak charge. They have an incentive to respond to the current RCPD charge because they pay transmission charges. However, as Transpower notes, distributors are not exposed to nodal prices. Transpower therefore appears to consider it likely that distributors will respond to the removal of the RCPD based charge by (potentially abruptly) reducing load control.

E.51 We agree that this risk is real[354], but consider it overstated for the following reasons.

(a) Distributors are likely to have some incentive to act in the best interests of their customers. In particular, some distributors are consumer trusts which can be expected to take into account the interests of consumers connected to them.

(b) It seems likely that the time of a distributor's peak will tend to be correlated with the time that relevant transmission circuits are congested. In that case, distributors may control load on the circuit as a by-product of managing their own networks.

(c) With the introduction of RTP, distributors will have some incentive to bid demand control into the market (as some currently do with interruptible load).

E.52 Furthermore, we know that, overall, demand is, to varying degrees, responsive to prices. We have seen some large industrial firms responding to the RCPD transmission charge by,

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353 Details of the real time pricing project are available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/

354 It is a potential risk because an abrupt increase in load may cause challenges in managing the grid, as discussed in Transpower's report, and because it may lead to a greater need for administrative load control, as discussed in Transpower's report and in footnote 349. The increase in load may nevertheless lead to an increase in efficiency, including efficient investment in the grid, as discussed in paragraph E.20.

for example, shifting their load to off-peak periods and installing DG. This is reflected in the estimates of price elasticities in Transpower's report discussed above.

E.53 More importantly, we are expecting to see increasing demand response. First, businesses like Enernoc are already providing demand response services and we expect (and are taking policy measures to facilitate) technology, new business models and other innovation to increasingly allow consumers to behave as if they are actively monitoring and responding efficiently to nodal prices.[355] In particular, we expect over time:

(a) retailers and other aggregators to manage small consumers' load for a share of the nodal price savings that it generates

(b) improving technology (eg, increasing cost-effectiveness of battery technology and information technology) is likely to make it easier for consumers to respond to changing nodal prices, including through automated services that reduce transaction costs of responding to changing prices in real time.

E.54 As Annex D of Transpower's report states, 'demand response effects are much greater where automated or semi-automated response-enabling technologies have been applied. It is reasonable to infer that technological change will result in demand for electricity being more flexible, and responsive to price signals'.

E.55 Second, we are intending to implement shortage prices in the RTP project, which will encourage transmission customers to bid demand control into the electricity market.

E.56 Thus we consider that there are several reasons to expect that households and other consumers' load will become increasingly responsive to energy prices over time. This will likely also lead to nodal prices becoming less volatile and so more predictable.

E.57 In summary, we can see some reasons for caution in the short term about removing the RCPD price signal, with these concerns abating over time as: distributors' behaviour is revealed, RTP beds in, retailers and other aggregators take steps to manage small consumers' load, and various other innovations make it easier for load to respond to nodal prices.

Are nodal prices on their own sufficient to restrict grid use to capacity?

E.58 In principle, LMPs are the most efficient prices for restricting grid use.

E.59 However, nodal prices in the NZ electricity market do not meet this ideal. Aside from the reasons discussed in paragraphs E.41 to E.57 above, the most plausible reason that nodal prices will not restrict grid use to capacity is that they do not fully reflect the SRMC of use of the grid. For example, as discussed in chapter 5 of the second issues paper, nodal prices currently do not fully reflect scarcity prices.

E.60 This provides a plausible argument for a peak charge to buttress the signal given by nodal prices.

E.61 However, since we already have nodal prices (and so incur their ongoing administrative and compliance costs), we consider that a better response is likely to be to address the source of the problem, which is an inadequacy in nodal prices. This is likely to be more efficient, both because (as is discussed earlier), it is better targeted than a peak charge and because

355 Over time, these responses are likely to increasingly compete with distributor's own load control with consequent benefits to consumers.

the additional administrative and compliance costs are likely to be lower than those for an additional new charge.

E.62 Addressing the current deficiencies in nodal prices is a key objective of the RTP proposal.

Q55. Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

Do nodal prices that restrict grid use to capacity ensure investment is efficient?

E.63 Although LMP may be the most efficient prices for restricting grid use, overall efficiency also requires that investment is undertaken efficiently.

E.64 The Commerce Commission regulatory regime is designed to ensure that grid investment is undertaken efficiently, given the demands that users place on the grid.

E.65 Several parties submitting on the second issues paper considered that a LRMC charge would encourage efficient investment, possibly by encouraging more efficient use of the grid.[356]

E.66 In general, we disagree, for the reasons discussed in appendices B and D. In summary, the proposed benefit-based charge is designed to charge grid users for new grid investments in proportion to the benefits they get from the investment. This is intended to promote efficient investment by grid users, by encouraging them to take account of the impact of their own use and investment decisions on the cost of new grid investment. It also encourages grid users to seek new investment in the grid when it is efficient, and to participate in the Commerce Commission investment approval process.

E.67 However, there is one situation where this approach may not provide incentives for efficient use of the grid and efficient investment. This situation can be seen by considering the situation where there are multiple beneficiaries of a future grid investment, with each grid user being small in the sense that its own decisions do not much affect the timing of or need for grid investment.

E.68 In that case, if grid users could coordinate, they might collectively agree to make current investment decisions that increase their own costs but more than compensate for that by reducing the need for or deferring the timing of future grid investment. That is, they would co-optimise their own investment decisions with grid investment decisions.

E.69 However, if they can’t coordinate their investment decisions, each user will realise that its own decisions cannot much affect the grid investment decision. Each user will therefore take the grid investment decision as given (pre-determined), and optimise its own investment given its forecast of that grid investment decision and the associated future energy prices. This decision may well be different from the decision the user would have made had it been able to coordinate its decision with those of other grid users, as discussed in paragraph E.68 above. This is the so called ‘tragedy of the commons’ situation

[356] For example, ENA, Oji Fibre Solutions, Orion, Transpower.

identified by Transpower in its earlier submissions (for example, Axiom for Transpower[357]), and which is implicit in the Transpower's report (footnote 343).[358]

E.70 In this circumstance, it is possible that imposing a peak charge on each grid user over and above nodal prices may encourage each grid user to take account of their decisions on the timing of grid investment and so in effect coordinate their use of the grid. In other words, the charge could potentially have the same effect with respect to grid investment as LMP have in coordinating grid use. This is our understanding of the reasoning of those who favour a 'forward-looking' LRMC charge for use of the grid.

E.71 While we accept that there is a theoretical case for such a charge, we think that there are more considerations to take into account in setting the peak charge than the LRMC of the future transmission investment. The box *'Tragedy of the commons' related incentive problems* below discusses these other considerations in the context of a particular example of the 'tragedy of the commons' problem.

E.72 Taking account of these other considerations would likely mean that the optimal peak charge to co-optimise users' investment decisions with grid investment would be less than LRMC, would vary over time, might reduce as the time for efficient new transmission investment approaches, and might be negative.

E.73 Setting a peak charge which takes account of all these considerations would seem to be at best complex and difficult. Even if LRMC can be estimated robustly, it does not seem practical to establish how big the peak charge should be and when it should apply. On the contrary, there is a very real risk of getting it wrong in ways that reduce efficiency below that which would be achieved without any such charge. Such issues would need to be overcome to establish the case for a peak charge better meeting our statutory objective.

E.74 These conclusions are reinforced by the practical considerations that Professor Hogan refers to in his memo summarised in the box above.

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357 Axiom, Economic review of second transmission pricing methodology issues paper: a report for Transpower, July 2016.

358 A related concern is that small consumers are exposed to nodal prices but don't accurately anticipate them so they make long-lived investment decisions which will eventually cause congestion and higher prices, but they do not take that into account because they do not know that this will happen. As is noted above, in most cases small consumers are likely to be on fixed price contracts which in effect price in average nodal prices and shift the price risk to more sophisticated parties that can be expected to take these considerations into account. However, even if a consumer does face nodal prices, and naively predicts that the nodal transport charge will be about zero (as it is when the relevant circuits are not congested), they will be making a reasonable prediction, since that will be true once a congestion-relieving transmission investment has been made.

‘Tragedy of the commons’ related incentive problems

The tragedy of the commons problem can be illustrated by considering a single user of a transmission investment[359] who is considering whether to expand its plant now (which would require an immediate transmission upgrade) or to defer expanding until next year (which would allow the transmission upgrade to be deferred for a year).[360] We assume that the user is rational and bears all the relevant costs and benefits of the transmission upgrade.

Because the user alone affects the timing of the transmission investment by its investment decision, the user has the incentive to take account of all relevant costs and benefits in making its decision on when to expand its plant (including the reduction in nodal prices and the loss of LCE caused by the transmission upgrade). That is efficient.

This is no longer the case where there is more than one user. This can be seen by considering the case where there are multiple ‘small’ users.[361] In that case, each user takes account of its proportion of the same costs and benefits as the single user. In particular, because it faces the benefit-based charge, it takes account of the cost of the transmission investment in the same manner as the single user. However, there is one key difference. The user correctly assumes that its energy use decision does not influence the timing of the transmission investment. The user forecasts when the transmission investment, if any, will take place and then treats that time and the associated benefits and charges as a given (pre-determined) in its own decision making. As a result, the user’s private calculation differs from that of the single user in the previous paragraphs. In particular, it will not take account of:

(a) the present value of the savings that would result from deferring the transmission investment if users collectively deferred their plant expansion[362]

(b) the benefit from increased energy use that the user would get from an earlier expansion of the transmission investment[363]

(c) associated changes in LMP and LCE.

That is, the users’ investment decision involves different costs and benefits, which could cause the sum of individual users’ decisions to deviate from the efficient decision that the single transmission user would make. This is an example of the”tragedy of the commons” problem.

The annualised value of the term in (a) above is around the (annualised) LRMC of the investment. So, ignoring (b) and (c) above, if we charged the users collectively a variabilised annual charge equal to LRMC for the use of the grid, then each user would take that into account in its decision about whether to expand its use of the grid. This would give the user

359 For the purposes of illustrating the point, we are ignoring the fact that a transmission investment used by a single user would likely be a connection investment.

360 The relevant user in this situation is the person who actually bears the charge. In the case of a price-controlled distributor, the users are the distributor’s end users rather than the distributor.

361 By ‘small’, we mean that each user’s use is small relative to the aggregate use of the circuits involved. For ease of exposition, we assume all these small users are the same. Even if the users are larger, there will still be the same kind of inefficiency discussed here, but it will be less marked.

362 Note however that the small user does have an incentive to take account in its decisions of the fact that its cost of transmission will increase when the transmission investment takes place, since it pays the benefit-based charge for the investment (and users collectively pay the cost of the investment).

363 Each user would face a counterfactually higher LMP where the transmission build is deferred a year, which would restrict its use of energy, so that users collectively optimally restrict their use of the circuit to capacity.

an added incentive to defer its plant expansion so as to avoid the LRMC charge on its expanded use of electricity.[364] This would help overcome the 'tragedy of the commons' problem with respect to (a) above. That is, imposing a LRMC charge would incentivise each small user to in effect take into account the present value of the deferring transmission costs in making its investment decisions.[365]

However, there are some other issues to be taken into consideration. These are that:

- LMPs will rise as the relevant circuits become congested, which already encourages users to reduce their use of the relevant circuits.
- The prospect of a benefit-based charge for the new investment already provides an incentive for the user to reduce their use of the transmission asset.[366]
- There are also costs to deferring grid investment that the user does not take into account (ie, the foregone energy use in point (b) above).[367]
- LMP should ration grid use to the available capacity, and so if a peak charge is effective in reducing grid use, it will inefficiently reduce grid use below capacity, as discussed in paragraphs E.32 and E.33 above.
- An LRMC peak charge cannot be set to send efficient signals about the benefits of deferring grid expansion to both short- and long-lived investments that users might make. For example, suppose an LRMC peak charge is imposed early enough that it is able to provide users incentives relating to the benefits of deferring grid investments when they make long-lived investments. Then it would over-signal with respect to short-lived user investments, because many such short-lived investments would be fully depreciated before the transmission investment is made (and so the investments would be inefficient). The opposite would be the case if the LRMC peak charge was targeted at short-lived investments.

All these considerations would likely mean that the optimal peak charge to co-optimise users' investment decisions with grid investment would likely need to be less than LRMC, would vary over time, might reduce as the time for efficient new transmission investment approaches, and might be negative.

Q56. Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

364 Since it is not important to the discussion, we do not pursue here the question of the optimal way of sharing the LRMC charge between users. Our view is that the discussion in appendix D would provide a useful way of considering this issue.

365 This rationale for an LRMC charge is quite different from the arguments advanced by the authorities who initially proposed an LRMC charge, as discussed above.

366 That is, the user will recognise that its charge for the future investment will be proportional to the benefit it is assessed to get from the investment, which will give it an incentive – other things being equal – to reduce its use of the relevant circuits so as to reduce its future charge. This is efficient to the extent it reduces the cost of future grid investment by encouraging the grid user to permanently reduce its grid use (eg, if it encourages the user to install more energy efficient equipment). However, it is inefficient if the saving in charges is different from the grid costs saved or if the grid user is temporarily changing its use to give a misleading impression of its likely future grid use. The proposed guidelines require Transpower to design the TPM to limit these inefficiencies as far as is reasonably practicable.

367 The benefit the user gets from earlier expansion is near zero when the circuit is uncongested and (ignoring LMP and LCE) rises to around LRMC when the investment is justified.

Would nodal prices be allowed to rise high enough in practice?

E.75 As well as the issues discussed above, we have considered a number of other issues relating to the possibility that in practice, nodal prices do not or cannot rise high enough to reflect the impacts of additional demand on congestion, and a peak charge might therefore encourage more efficient grid use.

E.76 The first concern is that **when grid capacity is limited, administrative load control may be used to manage congestion**, even though nodal prices, if they had been allowed to operate, may have been sufficient to constrain the use of the grid to capacity.[368]

E.77 Under current arrangements, the effect of this would be to reduce nodal prices even though the consumers whose load is controlled may value the use of electricity foregone at more than the nodal prices that actually eventuate. In this situation, it might be better to control load with a peak charge, since that could induce a reduction in demand or an increase in supply where capacity would otherwise be constrained.

E.78 With RTP, this issue will no longer arise. The intent is that under RTP, administrative load control would take place only when scarcity prices have been triggered. Thus, nodal prices would signal the loss of use caused by administrative load control. This is likely to be more efficient than a peak charge, because:

(a) nodal prices would signal the cost of administrative load control only when that load control is actually necessary.

(b) the prospect and actuality of high nodal prices is likely to trigger additional energy supply and demand response, reducing and potentially eliminating the need for administrative load control.

E.79 The second concern is that **high nodal prices will cause the public to lose confidence in the sector and are therefore not a sustainable approach to signalling costs of use**. However, fluctuations in nodal prices are not new. There have been high and volatile nodal prices in the past driven mainly by energy costs. As is noted above, many small consumers choose to shelter themselves from price volatility by entering in to fixed-price variable-volume contracts, and it is likely that this practice will continue. Furthermore, with the introduction of the benefit-based charge, sophisticated users who are subject to high and volatile nodal prices arising from transmission constraints will be aware that the nodal prices are expected to cost them less on average than inefficient transmission investment to forestall them.

E.80 The third concern is that **users may never see the full costs of their actions because investment is usually triggered 'early'**, before nodal prices have risen to levels commensurate with signalling that additional investment would be beneficial.[369]

E.81 In particular, one view is that the grid reliability standard (GRS) is an administrative standard that may require Transpower to propose and the Commerce Commission to approve investments that would not pass a cost-benefit analysis and therefore are inefficient. It might be thought that a peak charge is desirable to defer such investments until they are efficient.

[368] As discussed in footnote 349, it may be efficient for the system operator to undertake some administrative load control if the relevant parties are not sufficiently sensitive to prices.

[369] Hogan and Pope (2017) make the point that this occurs in the Texas electricity market. Their conclusion is similar to ours: that is, the rules should be adjusted so that transmission investment does not take place inefficiently early.

E.82 If this were so, a better solution may be for us to amend the GRS so that it takes account of the all the economic benefits and costs (including reliability) of such investments.

E.83 However, if this is not practical, at least in the short term, a peak charge could be used to restrict grid use to avoid breaching the reliability standard and triggering the investment until it is economically justified. This would have the effect of turning the administrative GRS into an economic test, since it would mean that use of the relevant circuits would be constrained to capacity by the peak charge until the investment is justified by the reliability and other benefits that it provides.

E.84 Furthermore, the beneficiaries of the investment would have an incentive to support such a peak charge, since it means that the investment would be deferred until the expected benefits to them from the investment exceed the benefit-based charges they would pay for it.

E.85 However, any administrative rule that would otherwise result in inefficiently early investment can be included as a constraint in SPD. The result would be that nodal prices would rise to reduce grid use to avoid breaching the administrative rule. Since nodal prices can generally constrain grid use to capacity, and since they can be supported by efficient load control (as discussed in footnote 13) transmission investment need not be undertaken inefficiently early. Furthermore, LMP would be more efficient than a peak charge, since they would ensure that load is reduced only when needed and only to the extent needed to avoid breaching the GRS.

E.86 If despite this, a decision was made to undertake a transmission investment inefficiently early, it would point to flaws in the transmission investment decision-making process and not to flaws in nodal prices. Accordingly, the appropriate policy response would be to adjust that process.

E.87 Overall, therefore, we see no reason why nodal prices cannot manage congestion efficiently, so practical considerations do not justify the introduction of peak charges.

Q57. Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

Conclusion: A permanent peak charge?

E.88 In summary, our view is that nodal prices, enhanced by RTP, are the most efficient pricing tool for limiting the use of the grid to capacity. In most circumstances they are likely to be as effective as, and more efficient than, any other peak charge, in doing that.

E.89 This does not preclude the possibility that it may be efficient to operate some administrative load control as well, at least in the short term.

E.90 However, we expect that technological developments, new business models and other innovations will mean that load becomes increasingly responsive to nodal prices over time and responding to nodal prices will become cheaper. This is likely to make nodal prices less volatile, to flatten load profiles and to make nodal prices increasingly effective in restraining grid use to capacity, so that administrative load control is needed much less frequently.

E.91 The Commerce Commission’s regulatory regime is designed to promote efficient grid investment given grid use, and the benefit-based charge gives transmission users an incentive to take into account the cost of transmission investments in making their own investment decisions.

E.92 As is discussed above, there is a potential case for incorporating a permanent selective peak charge for restraining grid use below capacity so as to promote efficient investment by grid users; that is, to deal with the ‘tragedy of the commons’ issue. However, in practice, such a charge is not likely to improve efficiency once other relevant considerations are taken into consideration.

E.93 As a result, on balance we do not consider there is a case for a permanent peak charge in the TPM to assist in limiting grid use to capacity, or to promote efficient investment. We have therefore not included a permanent peak charge in the proposed guidelines.

Transitional issues

E.94 We do, however, see possible reasons for caution in the short term. These reasons include:

(a) Distributors may respond to the removal of the RCPD transmission charge by abruptly reducing or stopping load control at peaks, unless they are given some incentive to continue with load control.

(b) The expected benefits of RTP in making nodal prices transparent in real time, in stimulating demand response and in limiting premature administrative load control may take time to emerge and may not emerge as expected.

(c) Technological developments (eg, batteries and automated demand control technologies) and market based arrangements (eg, the emergence of demand aggregators) to make mass market load more responsive to nodal prices will take time to become important.

E.95 We consider that a transitional peak charge may be an appropriate and proportionate response to these concerns. Accordingly, we have included an additional component in the proposed guidelines providing for a transitional peak charge.

Q58. Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

We have considered other options

Addressing RCPD charge problems in a manner consistent with the current guidelines

E.96 Under this option the TPM would be reformed in a way that is consistent with the existing guidelines. This could occur if Transpower decided to undertake an operational review of the TPM to remove the RCPD charge. It could also occur through the Authority's review of the guidelines (for example, if we made the guidelines more restrictive in a way that required Transpower to reform the current RCPD charge).

E.97 A large number of submitters to the second issues paper and supplementary consultation paper supported retaining the status quo or revising the TPM under the current guidelines in some way (though not necessarily removing the RCPD charge. For example, some suggested amending the number of periods over which the interconnection charge is calculated, if the interconnection signal is too strong).[370]

E.98 The Authority considers that variations that are consistent with the current guidelines would be lawful, practicable, and would recover Transpower's costs.

E.99 Because the RCPD charge can reduce use of grid circuits even when they would not be congested in the absence of the charge, the RCPD charge results in inefficient use of the grid.

E.100 In the CBA, we have considered retaining the current pricing methodology but with RCPD required to be calculated using all trading periods so that the RCPD charge becomes a MWh charge. A charge based on load is likely to have a similar effect to a small sales tax on energy sales. It is therefore likely to substantially ameliorate the inefficiency caused by the RCPD charge. As a result, this option is likely to be more efficient than the status quo.

E.101 However, the cost of new investment would continue to be spread across all transmission users. This means that the beneficiaries of a new investment would not face their share of the cost of the investment. As a result, users would have an incentive to ignore the impact of their own decisions on investment and on use of the grid. This means that it does not achieve the various efficiency gains resulting from the benefit-based charge, as described in appendix B. For example, a new investor in generation would not take into account the effect of where they locate on the need for new transmission investment. As a result we consider that this option is likely to be materially less effective than our current proposal at addressing problems with the status quo.

E.102 This reasoning is consistent with the results of the CBA, which shows that replacing the RCPD charge with a load-based charge is more efficient than the current TPM (net benefits of $1.8 billion) but less efficient than our current proposal ($2.7 billion, within a range of $0.2 billion to $6.4 billion).

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370 For example, the following parties supported this option: Air Liquide, Alpine Energy, Aurora Energy, Buller Electricity, Centralines, Counties Power, Counties Power Community Trust, EA Networks, Eastland Network, Electra, Employers and Manufacturers Association (Northern), ENA, Girdwood Consulting for Trustpower, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Newmarket Business Association, Ngawha Generation, Northland Inc, Northland Mayoral Forum, Northpower, NZ Steel, Oji Fibre Solutions, Onehunga Business Association, Orion, Otago Chamber of Commerce, Pacific Leadership Forum, Pioneer Energy, Powerco, Powernet, PwC for 14 EDBs, Refining NZ, Scanpower, South Harbour Business Association, TECT, The Lines Company, Top Energy, Trustpower, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, and Westpower.

E.103 For these reasons, the Authority prefers our current proposal in this 2019 issues paper to addressing RCPD charge problems in a manner consistent with the current guidelines.

A simplified staged approach

E.104 This option was described by Transpower in its submission to the second issues paper.[371] It was also supported by a number of submitters on our supplementary consultation paper.[372]

E.105 Under this option, the TPM guidelines would require a TPM with several different charges, implemented in stages:

(a) a simplified benefit-based charge payable by load applying to most existing interconnection assets to replace the RCPD charge.

(b) the simplified benefit-based charge be recovered as a peak charge that is LRMC-like (based on use) and designed to promote efficient use of grid assets that are not connection assets

(c) a continuation of the existing HVDC charge[373]

(d) a fixed residual charge to recover Transpower's remaining recoverable revenue.

E.106 In addition, it would include as additional components to be implemented if justified:

(a) a non-simplified benefit-based charge applying to new investments over a certain threshold

(b) the replacement of the HVDC charge with extended locational prices for generation.

E.107 This option would potentially also include some of the optional features of the proposal put forward in this 2019 issues paper.

E.108 A key feature of this option is that it could be implemented in stages.

E.109 As is discussed above, we are of the view that a peak-based charge, in addition to nodal pricing would likely detract from efficiency. Instead, therefore, we analyse the proposal with the peak based charge replaced with a fixed charge based on some form of proxy for benefits.

E.110 In addition, we consider the proposal including the additional component related to the HVDC charge. We assume that this would be allocated to generation customers on some basis that is not related to their current or future use of the grid, because otherwise it would inefficiently affect their use of the grid. With this proviso we consider that the proposal would better reflects the long term costs of providing transmission services to generation, and is therefore likely to improve efficiency.

E.111 We first consider the proposal without the additional component relating to the non-simplified benefit-based charge.

E.112 The Authority considers that this revised simplified staged option is lawful, practicable, and would recover Transpower's costs.

371 Transpower's submission is available at: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

372 For example, this option was supported by the following parties: IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, Mercury, and Genesis Energy.

373 This is not clear, but appears to be implied on page 6 of Transpower's submission on the second issues paper.

E.113 We also consider that the simplified staged approach is simpler and would likely have lower implementation costs than our current proposal.

E.114 However, we consider that this option is likely to be less effective than our current proposal at addressing problems with the current TPM. In particular it is likely to be less efficient than our current proposal in relation to non-HVDC costs. This is because the beneficiaries of an investment would not face their share of the cost of the investment. The proposal would therefore not achieve the key benefits identified in Appendix B from having a benefit-based charge. In particular, grid users would make their own use and investment decisions without taking account of the impact those decisions have on grid investment. For example, a new investor in generation would not take into account the effect of where they locate on the need for new transmission investment.

E.115 For this reason, we consider that it would be desirable to implement the additional component relating to the benefit-based charge as well as the additional component related to the HVDC charge.

E.116 We consider that, provided the area over which benefits were calculated was relatively granular, this option would provide load customers with a charge that better reflects the long-term costs of providing transmission services to them, and is therefore likely to improve efficiency, relative to the current TPM.

E.117 However, we are of the view that it would not be as efficient as the proposal set out in appendices A and B. This is because:

(a) Generation customers would face none of the cost of new transmission investments from which they benefit. As a result, the various benefits outlined in appendix B from applying the benefit-based charge to transmission customers would be foregone for generation customers.

(b) Load customers would face the full cost of transmission investments, even though it is likely that generation customers are likely to benefits to some extent from the investment. This could result in various inefficiencies. For example, load customers may oppose an investment that is efficient overall.

(c) The benefit-based charge would only apply to major investments. This means that load which benefits from the investment would pay for all of a major investment but potentially only a small proportion of a non-major investment that is only slightly smaller. This sharp boundary could create various inefficiencies, as discussed in appendix B.

(d) It would only partially address the problem that beneficiaries of post-2019 investments would be asked to pay for those investments while being asked to continue to pay for the pre-2019 major investments that benefit others. Our view is that this will create durability problems, as discussed in appendix B.

(e) The broad regional approach proposed for existing investments would create boundary issues and potentially consequent implementation difficulties.

E.118 All these issues could be mitigated by adjusting the details of the policy. However, we consider that these adjustments would move the policy towards the policy described in Appendices A and B of this issues paper.

E.119 For these reasons, we prefer the proposal in this 2019 issues paper to the simplified stage approach.

A deeper-connection charge

E.120 The Authority considered this option in detail in the second issues paper. Under this option, the new TPM guidelines would require that the interconnection and HVDC charges be replaced by a residual charge and a 'deeper-connection' charge. This option is similar to our current proposal, but with a deeper-connection charge instead of benefit-based charge.

E.121 The deeper-connection charge would be calculated by:

(a) determining the concentration of load users and generation users of an asset, based on electricity flows[374]

(b) using those concentration values to determine the total deeper-connection charge, if any, to be allocated to load and generation for the asset

(c) allocating the deeper-connection charge for the asset based on physical capacity or share of flows (for load), and share of flows (for generation).

E.122 The Authority considers the deeper-connection option is lawful, practicable, and would recover Transpower's costs. We also consider it is likely to be more efficient than the status quo. In particular, customers would have stronger incentives to take account of the impact of their own decisions on investment and on use of the grid. This means that it would achieve some of the various efficiency gains resulting from the benefit-based charge, as described in appendix B. This is because the main parties paying a deeper-connection charge for an asset would be aligned with the parties receiving transmission services from the asset. For example, transmission customers liable for the deeper-connection charge for a new investment would have stronger incentives to scrutinise transmission investments than they would under the current TPM, where the costs of an investment are spread across all load in the case of interconnection and South Island generators in the case of the HVDC. We consider this would lead to more efficient decisions by transmission customers in relation to their use of the grid.

E.123 However, there are disadvantages to this option that are less likely to arise under our current proposal. In particular:

(a) customers who pay the deeper-connection charge may be charged more than the benefit they receive. The charge could be designed to minimise the chance this would occur (for example, by excluding assets from the charge where this is likely to occur, and by allowing assets to be 'optimised'). However, some distortions are likely to be inevitable

(b) the deeper-connection charge is likely to be less effective at promoting efficient investment. In particular:

(i) it would only partially recover the costs of most assets

(ii) it would not apply to some assets at all, even though the beneficiaries of those assets may not be particularly difficult to identify

(iii) it would be poor at promoting efficient investment in new large assets, as the charge would be poorly aligned with the distribution of benefits from such investments. This is because the addition of large assets to the grid can materially alter power flows over other parts of the grid (altering the deeper-connection charges for those assets). It can materially alter nodal prices around

374 The concentration indicator would be the Herfindahl-Hirschman Index, a commonly used measure of concentration.

the grid, but the deeper-connection charge ignores the benefits that arise from those pricing effects even though they would be benefits that users would be prepared to pay for

(c) the identification of deeper-connection assets and the parties subject to the charge is quite complex and is likely to result in distortions to behaviour. In particular, the proposal to periodically review the charge, while having the benefit of ensuring charges remain somewhat service-based, has the disadvantage of creating incentives which encourage grid users to inefficiently alter their grid use. The Authority would seek to design the charge to minimise such distortions, however some distortion is likely to remain

(d) the deeper-connection charge creates a locational distortion for distributors, generators, and direct-connect transmission customers

(e) the deeper-connection charge is likely to result in higher transaction costs than the current proposal.

E.124 We prefer the proposal in this 2019 issues paper to the deeper-connection charge because of the disadvantages of the deeper-connection charge that are set out above.

A tilted postage stamp charge

E.125 Under this option, the new TPM guidelines would require that the TPM consist of a connection charge, and an interconnection charge and HVDC charge set on postage stamp basis, but with the rate of the charge varying between regions. The 'tilt' of the charge, or the distribution of charges to different regions, would be set with reference to the long-term cost of providing transmission services to different regions (or an approximation of that cost). A tilted postage stamp option was supported by several submitters to the second issues paper and the supplementary consultation paper.[375]

E.126 Various versions of the tilted postage stamp proposal have been proposed. One variant of the tilted postage stamp option would be new TPM guidelines that require the TPM consist of a connection charge, an LRMC charge and a postage stamp residual charge. The combination of the postage stamp residual charge and the LRMC charge would provide the 'tilt', ie, the differential in charges between regions.

E.127 We consider here a charge which is not related to customers' energy use and under which the cost of new investment is recovered from all designated transmission customers in proportion to their existing transmission charges. While different versions of the tilted postage stamp proposal would have different efficiency effects, the direction of the effects identified below would be the same relative to the current TPM and relative to the current proposal.

E.128 The Authority considers the tilted postage stamp option is lawful, practicable, and would recover Transpower's costs. We also consider it is likely to be more efficient that the status quo. This is because:

(a) it better reflects the long term cost of providing users with access to the grid, and so encourages them to take account of those costs in making their decisions

375 For example, the following parties expressed support for this option: CEC for Trustpower, EA Networks, and Trustpower,

(b) it avoids charging customers based on their energy use, and so largely avoids creating an incentive for customers to inefficiently alter their grid use to reduce their transmission charges.

E.129 However, this option is likely to be less effective that the current proposal at addressing the problems identified with the current TPM. The main reason is that it does not align the charges transmission users pay for new investments with the costs of those investments. This means that it does not yield the efficiency gains expected from the benefit-based charge, as set out in appendix B. For example, it is likely to lead to inefficient investment and grid use by transmission customers and so grid investment that may be efficient given grid use, but is inefficient overall.

E.130 The Authority considered and did not favour this option when we prepared our second issues paper.[376] On further consideration, we have not changed our assessment of this option compared to the current proposal.

We have also considered, and do not favour, a range of other alternatives

E.131 During the course of earlier consultations and in earlier issues papers, the Authority has considered a range of other options for reform as well as the status quo. Some of the options considered are:

(a) several options proposed by the TPAG (2011)[377]

(b) ten options considered in the Authority's first issues paper (2012)[378]

(c) four different types of beneficiaries-pay options considered in the beneficiaries-pay working paper (2014)[379]

(d) the LRMC charging options considered in the LRMC working paper (2014)[380]

(e) three options considered in the TPM options working paper (2015)[381]

(f) two alternative options considered in the Authority's second issues paper (2016) (that is, an SPD-based charge and a broad-based, low-rate charge for each island or four transmission pricing regions combined with a broadly levied HVDC charge)[382]

E.132 We do not prefer any of the options listed above relative to the current proposal for a variety of reasons, including either because they are not lawful, are not practicable, deliver lower net benefits, or would not further the Authority's statutory objective. On further

376 Further analysis of the option is presented in paragraphs 9.28 – 9.34 of the second issues paper.

377 The Transmission Pricing Advisory Group (TPAG) was an ad hoc advisory group established in 2011 to recommend a preferred transmission pricing option. The TPAG's report is on our website: https://www.ea.govt.nz/development/advisory-technical-groups/disestablished-groups/transmission-pricing-advisory-group-2011-disestablished/.

378 The first issues paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c2119. Alternative options are considered in chapter 6.

379 The beneficiaries pay working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c7492.

380 The LRMC working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c13677.

381 The TPM options working paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374.

382 The second issues paper: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

consideration, we have not changed our assessment of these options discussed in the earlier papers.

Q59.	**Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?**
Q60.	**Do you have any comments on the matters covered in this appendix E?**

Appendix F Potential changes to the Code

F.1 In this appendix we set out three potential Code amendments that we consider to be consistent with the Authority's TPM guidelines proposal (including potential drafting of the Code amendments).

F.2 These changes would be to:

(a) amend Part 14 of the Code to specify a methodology that Transpower must use to allocate loss and constraint excess (LCE)

(b) amend Part 6 of the Code to adjust the avoided cost of transmission (ACOT) provisions to be consistent with the proposed guidelines

(c) amend the Code to allow the Authority to further review an approved TPM if its implementation is found to be unworkable or if it has been implemented in a manner inconsistent with the Authority's policy objective.

F.3 These potential Code amendments logically accompany our proposal to amend the TPM guidelines. The first two in particular would be consequential to the adoption of the proposed TPM guidelines. While we are minded to propose these amendments in the near future, because these Code amendments are linked to adoption of the proposed guidelines and a consistent TPM, we are not proposing that the Code be amended at this stage.

F.4 Rather, we present the Code changes now to encourage comment on our proposal as a whole. Subject to consideration of feedback, we would consult again on whether to adopt the Code changes (if they are still considered necessary) alongside any future proposed TPM developed by Transpower.

Potential Code amendments and discussion

Code change 1: LCE amendment

Description[383]

F.5 Amend the Code[384] to provide that:

(a) a grid owner must allocate any LCE (including residual LCE) it receives in a year:

(i) amongst investments in proportion to the LCE generated by each investment (including investments whose cost is recovered through the residual charge); and

(ii) in respect of each investment, amongst customers in proportion to the transmission charges they pay in that year in respect of that investment.

(b) this allocation is deemed to be the prevailing methodology for distribution of LCE payments for the purposes of the benchmark agreement.

383 We asked Transpower about the workability of these proposed code amendments. As part of its commentary on this, Transpower indicated that it considered that it would be more efficient for the clearing manager to allocate LCE for FTR settlements to the FTR manager, and residual LCE directly to purchasers, and that it had submitted this to the Authority's consultation in March-April 2019 on its *Proposal for the design of the remaining elements of real time pricing* (refer: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972). We will be considering that point as part of that consultation.

384 Refer to the proposed Code amendment drafting annexed to this appendix.

Discussion

F.6 As discussed in appendix D, workably competitive markets provide a natural analogue for establishing efficient pricing in the interconnected grid. If the market for grid investments were workably competitive, owners of grid investments would charge users the SRMC of transporting energy across individual grid circuits, and the resulting nodal transport charge (the difference between nodal prices at the ends of the circuit) would tend to both efficiently ration the grid circuit to its capacity and provide the owner of the grid circuit with a normal return on capital.

F.7 Likewise, nodal prices are set in the spot market and generate a financial surplus. The surplus on a circuit in any trading period is approximately the difference in prices between the two nodes of the circuit during the trading period multiplied by the amount of energy that flows between the two nodes during the trading period. These surpluses are used to create a pool of funds called the LCE.

F.8 However, unlike in workably competitive markets, the nodal transport charge yields insufficient revenue to cover the cost of the investment. This is because transmission exhibits economies of scale, as is discussed in footnote 324. As a result a second charge is necessary to recover the transmission owner's total costs.

F.9 Nevertheless, as paragraph F.6 above notes, the nodal transport charge is the natural analogue to prices in workably competitive markets. The resulting LCE is generated through the operation of the wholesale market for electricity, and therefore is preferred to administratively determined charges as outlined in the Authority's DME framework.[385]

F.10 However, the benefit-based charge is intended to recover the total covered cost of the investment. If Transpower were also to receive the residual LCE for the investment, it would recover more than the expected cost of the investment, and transmission users who benefit from the investment would collectively pay more than the expected cost of the investment. This is inconsistent with what would tend to happen in workably competitive markets, because in those markets excess profits tend to zero as new entrants take advantage of the excess profit opportunities.

F.11 Instead, in order to best seek to mirror the workings of a workably competitive market, the residual LCE from an investment needs to be assigned to those who pay charges in relation to the investment, so there is no over-recovery from customers. This can be achieved by crediting the residual LCE generated by each transmission investment to the Transpower customers who pay transmission charges in relation to the investment.[386] In particular, Transpower would credit:

(a) LCE generated by each connection investment to the customer or customers who pay connection charges for that investment.

(b) LCE generated by each benefit-based investment to each customer who pays a benefit-based charge for the investment in proportion to the share of charges they pay for the investment.

(c) LCE generated by investments whose cost is covered through the residual to customers that pay the residual charge, in proportion to the share of the residual charge that each customer pays.

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385 Electricity Authority, *Decision-making and economic framework for transmission pricing methodology – decisions and reasons*, 7 May 2012.

386 The economic effect of this treatment is similar to that of the treatment proposed in Hogan (1991).

F.12 There is one qualification to this. Before Transpower receives the LCE generated by the grid, clause 14.16 of the Code requires that some of it is first used by the FTR market and the balance remaining after that process is transferred to Transpower for use as LCE. It is this sum that would be allocated by Transpower as described in the previous paragraph.

F.13 The Authority considers that the potential Code amendment is efficient because it parallels the workings of workably competitive markets by ensuring that customers pay charges in relation to an investment that are expected to recover the full cost of the investment, and it avoids cross-subsidisation of other investments. As explained in appendix D charges which best parallel those in workably competitive markets are likely to be efficient.

F.14 Under our potential Code amendments, because the allocation method specified in the Code would be Transpower's 'prevailing methodology' under the Benchmark Agreement, no amendments to the Benchmark Agreement would be required.

F.15 LCE payments do not reduce the amount of transmission costs recovered under the TPM, but LCE payments offset transmission customers' individual transmission charges. This means that the incentives for customers are the same as if LCE payments did reduce the amount of transmission costs recovered under the TPM. So transmission users effectively face nodal prices and the benefit-based charge net of LCE.

F.16 This means that load that stands to benefit from lower nodal prices as a result of a proposed investment would assess the extent to which the benefits from lower nodal prices and a greater volume of electricity transported exceeded the reduction in LCE. Similarly, generation that stands to benefit from higher nodal prices as a result of a proposed investment would assess the extent to which the resulting benefits from higher nodal prices and the greater volume of electricity transported exceeded the reduction in LCE.

F.17 We therefore expect that transmission customers would only support the investment where they expect that the net private benefits from changes in electricity prices and volumes would exceed the transmission charges they would incur and the LCE they would otherwise receive if the investment did not proceed.

F.18 Consider, for example, a benefit-based investment that is expanded to cater for the growth of one load customer but which would also supply another load customer whose demand is static. The investment would benefit the customer whose demand is growing as they would be able to receive increased volumes of electricity as their demand grew. Taking into account LCE prior to and after the investment, they are likely to receive net benefits from it, and therefore be willing to pay for it, because any reduction in LCE resulting from the investment would be more than offset by the benefits they would receive from lower prices and the volume of electricity supplied by the transmission investment continuing to meet their demand. Customers with static demand do not receive the same benefit from the investment, because the reduction in nodal prices is likely to be largely offset by the reduction in LCE that they would have received if the investment was not undertaken.[387] Since the calculation of benefits in this example takes into account LCE as well as the benefits from lower prices and greater transmission volumes, the benefit-based charge would be paid relatively more by the party whose load was growing.[388]

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387 This would not be the case if the cost of the existing investment is recovered through the residual charge, since then the reduction in LCE would be spread across transmission customers.

388 The effect of this for benefit-based investments is to make the benefit-based charge more like an exacerbators-pay charge and less like a beneficiaries-pay charge, as described in the DME framework. The DME framework makes clear that exacerbators-pay charges are preferable to beneficiaries-pay charges.

F.19 Some submitters on the LCE working paper were concerned that the potential Code amendment would result in undesirable volatility. However, we consider that allocating LCE to participants who pay for specific assets is unlikely to increase the volatility of charges those customers face. As is the case under the current TPM, customers would receive a credit note against transmission charges.

F.20 Several submissions on the LCE working paper raised concerns about distortions to behaviour if LCE was allocated to specific assets.[389] However, those submissions were originally made in the context of a TPM guidelines proposal which meant that small changes to the behaviour of transmission customers could have led to material changes in transmission charges.

F.21 Under the current proposal, we consider that this is not an issue since the LCE allocated to a user would be based on the transmission charges it pays, which under the guidelines proposal is largely unaffected by its use of the grid at a particular point in time. So a user must pay the nodal transport charge to transport another unit of energy across the grid but its share of the LCE is unaffected by its use of the grid.

F.22 The LCE working paper[390] raised the possibility of extending the averaging period over which LCE was allocated (eg, annually rather than monthly) to limit any distortions to nodal prices and therefore behaviour, caused in relation to allocation of LCE.[391] We are not considering extending the averaging period. The Authority considers that the concern expressed in the LCE working paper would likely be irrelevant under the current proposal because the allocation of the charge for each investment would be fixed when the investment is made (save where the proposed guidelines allow allocations to be changed).

F.23 However, even if it were not, we do not consider the issue to be material. Under the current TPM, South Island generators that pay HVDC charges receive LCE attributed to the HVDC link. If this potential approach to the allocation of LCE gave rise to a risk of distortions to nodal prices sufficient to extend the averaging period, this would also be the case under the current TPM in relation to the HVDC, but there is no evidence of such a problem.

Q61. Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

Code change 2: Clarifying changes to the ACOT regime

Description

F.24 Amend Part 6 of the Code to clarify that distributors:

(a) are required to make ACOT payments to owners of distributed generation in respect of transitional peak and kvar charges (if these are included in the TPM)

[389] For example, the following submissions on the LCE working paper: ASEC (p.6), Genesis (p.4), Powerco (p.2), Transpower (p.1)

[390] Transmission pricing methodology: Use of LCE to offset transmission charges: Working paper 21 January 2014, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c7493.

[391] Paragraph 7.16, p.22, and paragraph 8.25, p.27.

(b) are not required to make ACOT payments to owners of distributed generation in respect of benefit-based charges, residual charges and/or connection charges.

Discussion

Background

F.25 Part 6 of the Code requires distributors to make avoided cost of transmission (ACOT) payments to owners of distributed generation that cause a reduction in transmission costs,[392] provided that:

(a) the distributed generation was installed before 6 December 2016

(b) the distributed generation appears on a list published by the Authority under clause 2C(1) of Schedule 6.4 of the Code (based on Transpower analysis aimed at identifying distributed generation required to meet the Grid Reliability Standards).

F.26 The Commerce Commission's rules allow price-controlled distributors to recover from their customers (through regulated distribution charges) payments that are made in accordance with Part 6 of the Code (that is, ACOT payments).[393]

F.27 The proposed TPM guidelines would change the basis for ACOT payments. Currently, ACOT payments are based on reductions in distributors' RCPD charges due to the operation of distributed generation. However, if our current proposal for the TPM guidelines comes into effect, distributors would no longer pay RCPD charges. Instead, they would pay other charges, including:

(a) charges with largely fixed allocations such as the benefit-based charge, residual charge and connection charge

(b) variable charges (if these are included in the TPM) such as a transitional peak charge (Additional Component D) and kvar charge (Additional Component G).

F.28 The Authority indicated in its 2016 decision on the distributed generation pricing principles that further refinement of the ACOT arrangements was to be expected. Given the close links between transmission pricing and ACOT, we anticipate that there may soon be a need to clarify the ACOT arrangements under a new TPM.

ACOT for variable charges may encourage efficient operation of distributed generation

F.29 In our view it may be consistent with the Authority's statutory objective for ACOT payments to be made for avoiding either or both of the transitional peak and kvar charges (if these are included in the TPM).

F.30 There is a key distinction in the proposal between two types of charges:

(a) variable charges (the transitional peak charge and the kvar charge), which are intended to influence customers' use of the grid (as they relate to transmission costs that vary based on customers' use of the grid)

(b) charges with a largely fixed allocation (the benefit-based charge, residual charge and connection charge), which are not intended to influence customers' use of the grid.

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392 In this context distributors have interpreted transmission costs as transmission charges.

393 Some payments to owners of distributed generation are made by distributors under private contracts that do not directly refer to the Part 6 requirements. These payments may also be recovered by price-controlled distributors through regulated distribution charges.

While the precise amount of these charges may vary over time, customers' allocations should largely remain fixed, subject to provisions of the proposed guidelines addressing exceptional circumstances.

F.31 If the variable charges are included in the TPM it may be efficient for the price signals they send to be passed on to distributed generation, if that would encourage efficient operation by distributed generation that could reduce variable costs. ACOT payments based on reductions in distributors' transitional peak and kvar charges might allow this.

F.32 We are also considering whether to make further changes to Part 6 of the Code so that all distributed generation would be treated alike. The attached drafting of the Code allows for this. If we were to make such changes then:

(a) there would be no distinction between distributed generation based on the date of installation

(b) the lists of ACOT-eligible distributed generation published by the Authority under clause 2C(1) of Schedule 6.4 would not be needed, and would have no further effect.

F.33 The argument for making these further changes would be that ACOT payments in respect of variable charges should be payable to all distributed generation, regardless of the date of installation and of whether or not they appear on the lists of covered distributed generation published by the Authority under clause 2C(1) of Schedule 6.4 of the Code. The reason would be that any distributed generation that is able to reduce distributors' transitional peak charge and kvar charge would – by definition – reduce variable transmission costs, because these variable charges would be designed to accurately reflect variable costs, unlike the existing RCPD charge.

ACOT for fixed charges is not efficient

F.34 The Authority considers that it would not be consistent with our statutory objective for ACOT payments to be made for avoiding transmission charges with a largely fixed allocation (fixed charges). In particular, we consider that ACOT payments based on reductions in fixed charges would not encourage efficient operation by distributed generation, would not provide incentives for distributed generation to operate at particular times and would not reduce variable transmission costs. This is the case for all distributed generation, regardless of the date of installation and of whether or not they appear on the lists published under clause 2C(1) of Schedule 6.4.

F.35 Because customers' allocations of the fixed charges will generally remain constant (save in exceptional circumstances set out in the proposed guidelines), it appears unlikely that distributors would be liable under the existing Code for ACOT payments in respect of these charges as the distributed generation's connection would not enable the distributor to avoid transmission costs. However, the wording of the existing Code may lead to some uncertainty on this point. On the basis of this uncertainty, owners of distributed generation may seek ACOT payments based on reductions in distributors' benefit-based charges and potentially residual charges.[394] So we are considering an amendment to Schedule 6.4 to make it clear that ACOT would not be payable in these circumstances.[395]

394 This possibility was raised by Transpower in its submission on the supplementary consultation paper (page 37).

395 Transpower raised this option in its submission on the supplementary consultation paper (page 38) , in which it said: "One thing the Authority could do, if a benefit-based charge is adopted, is to amend Schedule 6.4 to define ACOT as avoided LRMC charges only i.e. no ACOT for avoidance of benefit-based or residual charges."

F.36 In our view ACOT payments in respect of the benefit-based charge and the residual charge are not required in order to encourage efficient future investment in distributed generation. In most cases the wholesale market will provide sufficient incentives for investment in distributed generation that efficiently reduces transmission network costs. Further, Transpower is able to contract with potential investors in distributed generation whose operation could efficiently reduce or defer transmission network costs. The Commerce Act 1986 provides incentives for Transpower to provide transmission services at lowest cost, which may be via non-transmission solutions.

F.37 Further, retaining ACOT payments with respect to fixed charges could lead to inefficient avoidance behaviour if transmission customers expect charges to be re-calculated. For example, consider a distributor that expects charges for a pre-2019 grid investment to be recalculated due to a substantial and sustained change in grid use. There is a potential risk that it might contract with an investor to build new distributed generation mainly for the purpose of arguing that its benefit-based charges for that pre-2019 grid investment should be reduced (in circumstances where the distributed generation would not otherwise have been built). This would not lead to savings in transmission costs (as the avoided charges relate to a pre-2019 investment) but the distributed generator might attempt to argue that, under the current drafting of the Code, it should nevertheless be entitled to ACOT payments.

F.38 We note that in designing its benefit-based charge, Transpower should take into account any potential inefficiency from this source. If it considers the potential inefficiency is likely to be material it could address this by adopting a gross load approach to measuring demand in certain circumstances.[396] Under a gross load approach, the transmission customer's charges would not be reduced by building distributed generation.

Problem addressed by the amendment

F.39 If transitional peak charges or kvar charges are included in the TPM, it would be efficient for distributed generators to be rewarded for avoiding these charges. However, under the proposed guidelines, it is intended that other charges will be designed so that they are not avoidable. The default provisions in the Code for payments to distributed generators for ACOT would therefore not apply in respect of these charges:

(a) the purpose of the residual charge is to recover residual revenue with minimal distortion to transmission customers' decisions about grid use or investment. The residual charge is designed to be a fixed charge, so that it affects the use of and investment in the grid as little as possible.

(b) once Transpower has determined the share of the benefit-based charge allocated to a transmission customer for an investment, that share would not change except in exceptional circumstances. The benefit-based charge is fixed in this way so that it does not distort use of the grid.

F.40 The allocation of residual and benefit-based charges may need to be revised over time, albeit infrequently. In the case of the residual charge this is likely to involve a recalculation of the volumes used to allocate customers' charges (such as lagged AMD).

F.41 The prospect of revisions to charges could give rise to an expectation of ACOT payments related to possible reductions in transmission charges from reduced grid demand volumes, even though any changes in charges would not reflect a change in economic costs of

[396] See discussion at paragraphs B.114 to B.119.

transmission or, equivalently, benefits from efficient reductions in grid demand. This risks costs from inefficient operation of existing generation and also disputes about the eligibility of distributed generation for ACOT. The Authority's proposed amendment would seek to resolve such issues by making clear when ACOT payments are available.

Q62. Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?

Code change 3: TPM workability amendment

Description

F.42 Amend clause 12.86 of the Code to add that the Authority may review an approved transmission pricing methodology if it considers that the transmission pricing methodology, or some part of it, has:

(a) become unworkable in its implementation; or

(b) been implemented in a manner inconsistent with the Authority's policy objective contained in the guidelines.

Discussion

F.43 This amendment would prevent the unlikely situation arising where some unforeseen issue prevents the guidelines being implemented in the manner intended. For example, it may be that after the TPM has been approved, in the course of implementing the TPM, Transpower identifies that some aspect is unworkable. Of course, given the process that precedes implementation, the prospect of this is remote but, given the complexities of the subject matter, it is still a possibility. If an issue did arise and if we were dealing with an ordinary piece of Code, the Authority could propose an amendment to address the problem. However, this would not be possible in the case of the TPM, because of the Code requirement (Clause 12.86) that the Authority may only review an approved TPM if there has been a material change in circumstances.

F.44 The Authority considers that this amendment would reduce uncertainty, since it reduces the chances that the TPM cannot be implemented or is implemented in a way that is inconsistent with the intent we have expressed in the guidelines proposal.

Q63. Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

Q64. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

Annex: Potential Code amendment drafting

Schedule 6.4, clause 2 amended and clauses 2A to 2C revoked

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation**. To avoid doubt, **incremental cost** is net of—

(i) ~~if the **distributed generation** is included in a list **published** by the **Authority** under clause 2C(1),~~ transmission costs that ~~an efficient **distributor** would be able to avoid~~ would be able to be avoided as a result of the **electrical connection** of the **distributed generation** (being a peak charge or kvar charge but not including any area-of-benefit charge or residual charge imposed by the **transmission pricing methodology**)~~at the **nameplate capacity** specified for that **distributed generation** in the list~~; and

(ii) **distribution** costs that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**:

(b) costs that cannot be calculated (eg, avoidable costs) must be estimated with reference to reasonable estimates of how the **distributor's** capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the **distributor** as a result of the **distributed generation** being **electrically connected** to the **distribution network** were, and deducting the costs that would have been incurred had the generation not been **electrically connected**. In this case, if the costs differ from the costs charged to the **distributed generator**, the **distributor** must advise the **distributed generator** and recover or refund those costs after they are incurred (unless the **distributor** and the **distributed generator** agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant **asset** replacement or upgrade, the connection charge attributable to the **distributed generator's** actions or proposals is payable by the **distributed generator** before the **distributor** has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the **distributor** is not obliged to incur those costs until that payment has been received:

(e) if **incremental costs** are negative, the **distributed generator** is deemed to be providing network support services to the **distributor**, and may invoice the **distributor** for this service and, in that case, the **distributed generator** must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine **maintenance**, the connection charge attributable to the **distributed generator's** actions or proposals may take the form of a periodic charge:

(g) *[Revoked]*

(h) after the connection of the **distributed generation**, the **distributor** may review the connection charges payable by a **distributed generator** not more than once in any 12-month period. Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) if multiple **distributed generators** are sharing an investment, the portion of costs payable by any 1 **distributed generator**—

  (i) must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and

  (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a **distributed generator** has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all connection charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:

(l) if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the **distributor**. The refund—

  (i) must take into account the relative expected peak of each **distributed generator's** injected generation; and

  (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial connection of that **distributed generator**:

Non-firm connection service

(n) to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain** connection and **lines** services to **distributed generators** in accordance with their **connection and operation standards**.

~~**2A Transpower to provide reports to Authority in relation to distributed generation**~~

~~(1) **Transpower** must, by 15 March 2017 (or such later date as the **Authority** may allow), provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(2) **Transpower** must, by 30 August 2017, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(3) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(4) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(5) In this clause and clause 4,—~~

~~(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—~~

~~(i) commencing at 38°02'S and 174°42'E; then~~

~~(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then~~

~~(iii) proceeding north along the 175°27'E line of longitude; and~~

~~(b) Lower North Island is that part of the North Island not referred to in subclause (a); and~~

~~(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and~~

~~(d) Lower South Island is that part of the South Island not referred to in subclause (c).~~

~~**2B Authority to review Transpower's reports in relation to distributed generation**~~

~~(1) The **Authority** must, as soon as practicable after receiving a report from **Transpower** under clause 2A,—~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(2) If the **Authority** declines to approve the report,—~~

~~(a) the **Authority** must, as soon as practicable,—~~

~~(i) advise Transpower of its reasons for declining to approve the report; and~~

~~(ii) direct Transpower as to how it should amend the report before resubmitting it; and~~

~~(b) **Transpower** must amend the report in accordance with the **Authority's** direction, and resubmit the report to the **Authority**,—~~

~~(i) for the report provided under clause 2A(1), within 10 **business days**; and~~

~~(ii) for reports provided under clauses 2A(2), (3), or (4), within 20 **business days**.~~

~~(3) The **Authority** must, as soon as practicable after receiving a resubmitted report from **Transpower**,—~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(4) Subclause (2) applies to the resubmitted report as if it were the report originally provided under clause 2A.~~

~~**2C Authority to publish list of distributed generation**~~

~~(1) The **Authority** must, after approving a report provided by **Transpower** under clause 2A, **publish** a list of **distributed generation** for the relevant region for the purposes of clause 2(a)(i).~~

~~(2) A list **published** under subclause (1) must include—~~

~~(a) only **distributed generation** that is connected as at 6 December 2016; and~~

~~(b) the **nameplate capacity** of the **distributed generation** as at 6 December 2016.~~

Clause 12.86 amended

12.86 Review by the Authority

The Authority may review an approved **transmission pricing methodology** if it considers that:

(a) there has been a material change in circumstances; or

(b) the **transmission pricing methodology**, or some part of it, has:

(i) become unworkable in its implementation; or

(ii) been implemented in a manner inconsistent with the **Authority's** policy objective contained in the guidelines published under clause 12.83.

New clause 14.35A inserted

14.35A Allocation of loss and constraint excess

(1) A **grid owner** must allocate any **loss and constraint excess** (including **residual loss and constraint excess**) it receives in a year:

(a) amongst investments in proportion to the **loss and constraint excess** generated by each investment (including investments whose cost is recovered through the residual charge); and

(b) in respect of each investment (other than those whose cost is recovered through the residual charge), amongst customers in proportion to the transmission charges they pay in that year in respect of that investment

(c) in respect of investments whose cost is recovered by the residual charge, amongst customers in proportion to the residual charge they pay in that year.

(2) This allocation is deemed to be the prevailing methodology for distribution of **loss and constraint excess** payments for the purposes of the **benchmark agreement**.

Appendix G Response to some criticisms

G.1 We have responded throughout this paper to various submissions we have received on previous TPM publications. This appendix provides further context by noting and responding to some criticisms a number of submitters have made of the Authority's approach to review of the TPM, in particular with respect to:

(a) the review process

(b) the basis of the Authority's position and the regard the Authority has had for commentary by submitters and external consultants.

G.2 This appendix is in part prompted by a meeting Authority staff held with members of the 'TPM Group'[397] who met with Authority staff in February 2019. The group members presented their concerns relating to past TPM review processes and sought further engagement with the Authority going forward.

G.3 In February 2017 Counties Power, Counties Power Consumer Trust, Entrust, EMA, Federated Farmers of New Zealand Auckland and Northland Provinces, Trustpower and Vector submitted a report prepared by Dr John Small of Covec, titled *Expert review of expert reviews of transmission pricing methodology reform proposals* (the Covec report).[398] The Covec report was commissioned by the TPM Group, because this "group of stakeholders was concerned the Authority had not fully engaged with the expert advice it had received in its review of the Transmission Pricing Methodology (TPM), and its process to develop replacement TPM Guidelines."[399]

G.4 Members of the TPM Group asked (when they met with Authority staff in February 2019) if the Authority could provide its views on the matters raised in the Covec report. We agreed it would be useful to do so, and agreed to make this summary of our views available with the 2019 issues paper. We think this is useful for all submitters because, 10 years since a review of the current TPM was first initiated, it is useful to reflect on the process we have been through to date. It is also useful to present and explain some of the arguments and counter-arguments that we have considered over time with respect to some of the main policies that we continue to propose.

The Covec report

G.5 The Covec report is a collation of and commentary on views from approximately 60 consultant reports produced as submissions or for submitters to Authority consultations for the transmission pricing review from 2012 to 2016. During this time the Authority presented two major proposals or issues papers (in 2012 and 2016) and a series of working papers over about a dozen consultations.

G.6 The Covec report does not address the earlier work conducted as part of the transmission pricing review. In particular, it does not address the work of the Transmission Pricing Advisory Group (TPAG), which published a discussion paper in 2011, or the Electricity Commission, which published a consultation paper on high-level options in 2009 and a

397 At the time of publication of the Covec report, the TPM Group members were Counties Power, Counties Power Consumer Trust, the Employers and Manufacturers Association (EMA) Northern, Entrust, Federated Farmers Auckland, Northpower, Top Energy, Trustpower, and Vector.

398 Small, J, *Expert review of expert reviews of transmission pricing methodology reform proposals*, Covec, February 2017. Published under *Submissions* at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c16277https://www.ea.govt.nz/dmsdocument/21882

399 *Ibid,* page 3.

Stage 2 options consultation paper in 2010. The Authority's analysis and proposals used this earlier work as an input into our work, along with work by the Transmission Pricing Technical Group and the New Zealand Electricity Industry Steering Group.

A concern that the Authority has not considered expert views

G.7 A key theme, and a genesis of the Covec report, is the concern that the Authority has not engaged with expert advice presented in consultant reports. For example, it states:

> "For the most part, the EA's style throughout this process has been to avoid citing particular critics. Instead it has tended to refer to 'submissions' in the aggregate, without identifying particular arguments made by individual experts, claim they have been considered and then reiterate the EA's view. This style is unfortunate in the current context, where there is a substantial weight of expert opinion that opposes the EA's desires: it suggests that the EA is not actually engaging with the submissions."[400]

G.8 We acknowledge that we have not always cited either proponents or critics of the proposal in our TPM consultation papers. However, the Authority must and does consider all views submitted to it, expert or not, provided by consultants or provided directly by submitters. Not citing specific submitters or their consultants does not equate to ignoring their views in formulating our thinking on transmission pricing.

G.9 In fact, the thinking that has underpinned the TPM review proposals has been heavily informed by the insights from expert economists and consultants, as well as other submissions. For example:

(a) the concepts of benefit-based charging and the approach to calculating benefits follow the approach suggested by Professor Hogan in 2011[401]

(b) the concept of an area-of-benefit charge originated from Castalia in its report for Genesis Energy on the beneficiaries pay working paper[402]

(c) our scepticism about the value of a long-run marginal cost (LRMC) or some other peak charge, given New Zealand has 'gold standard' marginal pricing incentives (nodal pricing), was informed by a report from Professor James Bushnell (on behalf of Trustpower) on the options working paper.[403] Our consideration of an LRMC charge followed submissions from the Electricity Networks Association (ENA)[404] and Transpower[405] on the beneficiaries-pay working paper.

G.10 The views of external consultants and other stakeholders have also influenced the Authority's process. For example:

400 *Ibid*, paragraph 301.

401 Hogan (2011).

402 Castalia. *Transmission pricing methodology: beneficiary pays options*, report to Genesis Energy, March 2014.

403 Bushnell, J. *Equity and efficiency implications of New Zealand's Transmission Pricing Methodology options*, August 2015.

404 ENA, submission on TPM beneficiaries-pay working paper, 25 March 2014.

405 Transpower, submission on TPM beneficiaries-pay working paper, 25 March 2014.

(a) the Authority decided to publish and seek submissions on a series of working papers[406] in response to submissions on the first issues paper from October 2012 and at the subsequent TPM conference in May 2013

(b) the Authority's decision to produce and publish the sunk costs working paper[407] was in response to submissions by the Competition Economists Group (CEG) on behalf of Transpower[408] and other submitters who argued that altering charges on sunk costs cannot produce efficiency gains and could result in efficiency losses.

Criticism of the policy development process

G.11 The Covec report criticised the Authority for failing to follow a 'disciplined' policy process in conducting the TPM review.

G.12 It is important to consider the longevity of the review and the extent to which each consultation has built on earlier work when looking at the policy process.

G.13 Review of the TPM has involved a conventional policy process consisting of establishing objectives, identifying problems, developing options, identifying a preferred option and testing this with cost-benefit analysis. The 2016 issues paper followed this approach and so does this 2019 issues paper.

G.14 Some aspects, like objectives, problems with charges, and the nature of options were first articulated by the Authority as far back as early 2012 when we released our consultation paper on the TPM decision-making and economic framework.[409]

G.15 Where issues were identified with aspects of the review during consultation, such as with the problem definition or cost-benefit analysis, the Authority has sought to respond to those issues. The problem definition has been refined over time partly in response to submitter feedback. For example, in their submissions on the first issues paper, Mighty River Power and Transpower submitted that the Authority's analysis had not established that there were inefficiencies with the interconnection charge.[410] In response, the Authority presented detailed analysis in the problem definition working paper,[411] followed by extensive further analysis of this issue in the options working paper[412] and in the second issues paper[413].

Explanation of long-standing elements of the proposal

G.16 The Covec report stated that the Authority was intent on pursuing three consistent 'goals' throughout the review:

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406 The working papers are available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

407 Electricity Authority, Working Paper – Transmission pricing methodology: Sunk costs, October 2013

408 CEG, *Transmission pricing methodology – economic critique*, February 2013.

409 Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, January 2012. Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c6767

410 Mighty River Power submission on first issues paper, Appendix A, page 3. Transpower submission on first issues paper, Appendix A, page 4.

411 Electricity Authority, *Transmission pricing methodology: Problem definition relating to interconnection and HVDC assets: Working paper,* 16 September 2014. See in particular pages 42-57, 59-62, 65-83, 100-103.

412 Electricity Authority, *Transmission pricing methodology review: TPM options: working paper*, 16 June 2015, pages 16-23.

413 Electricity Authority, *Transmission pricing methodology: issues and proposal, Second issues paper,* 17 May 2016, pages 52-71.

(a) removing the HVDC charge

(b) creating a charge based on the benefits of individual transmission investments

(c) extending this charge to existing grid assets established since 2004.[414]

G.17 Regarding these three 'goals' as identified by the Covec report, we explain below the origin of our position on each:

(a) The proposal to remove the HVDC charge arose in response to problems first identified by the TPAG in 2011, which were accepted by the Authority.[415] Transpower's 2015 operational review addressed some of these problems (namely, the distortion to operational efficiency from the HAMI charge). However, the Authority considers that the problem of distortion to investment in South Island generation remains.

(b) The proposal to introduce a beneficiaries-pay charge based on benefits of individual transmission investments reflects the views of international experts, such as Professor William Hogan, that charging on the basis of benefits is an effective approach to promoting efficiency.[416]

(c) We first proposed to apply the benefit-based charge (which at the time we called the 'area-of-benefit' charge) only to new investments in the options working paper ('Application B') in 2015. After considering submissions on that paper, we then proposed (in the second issues paper) to apply the charge to existing post-2004 investments valued at more than $50 million, along with Pole 2 of the HVDC, as well as new investments (ie, 'Application A' in the options working paper). In our supplementary consultation paper we proposed adding an additional component, which would allow the charge to be applied across *all* historical investments.

During our preparation for this 2019 issues paper, we sought the opinion of Professor Hogan on the issue of applying benefit-based charges to historical assets. Professor Hogan said there was nothing that he was aware of to suggest that there was anything inefficient or inappropriate in applying beneficiaries-pay charging to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered (such as provision for reassignment in the case of under-utilised assets).[417]

We emphasise that, while the proposal in the 2019 issues paper also includes benefit-based charges on post-2004 investments and Pole 2, our views on this matter (and indeed our views on any matter that is the subject of this proposal) are not fixed.

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414 Small, J, *supra* note 2, paragraph 295.

415 TPAG, *Transmission pricing discussion paper*, 7 June 2011.

416 See also Perez-Arriaga et al (2013), Lévêque (2003), chapter 7.

Some external consultants who submitted on the Authority's second issues paper have also agreed in principle with beneficiaries-pay charging, such as Compass Lexecon, even if they did not agree to applying such charges to historical assets. In particular, in paragraph 6 Compass Lexecon states: "The use of a beneficiaries-pay principle for new investments ... may promote dynamic efficiency by making beneficiaries accountable for the expansion of the grid as long as the approach is based on defining charges proportional to net benefits and granting beneficiaries the ability to block investments." Schoeters, MA, Spiller, PT, for Compass Lexecon, *Transmission pricing mechanism in New Zealand: An analysis of the Electricity Authority's proposed options*, prepared on behalf of Vector, 11 August 2015. Appendix to Vector submission on TPM second issues paper.

417 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

G.18 Accordingly, these are all elements of our proposal but are not goals in and of themselves. The Covec report stated that a substantial weight of expert opinion is against the adoption of these elements. We outline below some of the – in our view – more persuasive arguments against these elements of our proposal and our responses to them.

Arguments relating to removing the HVDC charge

G.19 Professor Yarrow, quoted on page 69 of the Covec report, said the Authority should not be responsive to lobbying:

> "…Application B (or an alternative approach that reflects outcomes in relevant, workably competitive markets in a similar way) has the following, two attractive features: Its adoption would signal that the EA has been relatively unresponsive to past lobbying…. Its adoption would signal that the potential gains from lobbying (aimed at securing redistributive benefits in future policy exercises) could be expected to be lower than has previously been the case."[418]

G.20 We think the argument about responsiveness to lobbying cuts both ways: in relation to both those lobbying for and against the status quo. We do not consider that lobbying is always a negative, as we do want parties to tell us about problems. However, we agree that we should not take any action or decision simply in order to placate any party. Ultimately, any future decision on whether to retain or remove a particular charge, such as the HVDC charge, or introduce new charges must be based on which path best promotes the Authority's objective.

G.21 The key question with respect to the HVDC charge is whether retaining or removing it would deliver net benefits. We consider that removing the HVDC charge would achieve efficiencies by reducing the disincentive to generation investment in the South Island currently caused by the HVDC charge.[419]

Arguments relating to introducing a benefit-based charge

G.22 The three main criticisms we have heard about charging according to benefit are that:

(a) it would introduce new distortions to use of the transmission network and investment

(b) it is not practical

(c) it is complex.

Distorting use and investment?

G.23 Bushnell and Wolak (2017) state:

> "Allocating the costs of networks according to the concept of beneficiaries pay can be an attractive principle until one recognizes that any assignment of fixed network costs distorts behavior – either in the short term (through changes in operating behavior), or long term (through changes in investment incentives), or both. While we consider this approach more reflective of social or regulatory policy than of markets,

418 Yarrow, G, *Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology*, February 2017, Appendix D to Trustpower submission on Second issues paper: supplementary consultation, page 14.

419 We did consider addressing this problem by restricting the HVDC charge to existing South Island generation only but rejected this option because it would undermine competition.

there are nonetheless appealing equity aspects to the notion that one can assign costs to those who gain the most.

However, if the entity that benefits most from an upgrade, and therefore pays the highest per kWh cost to use the grid, is also the one most able to take actions [to] reduce the amount it pays for the grid, then a 'beneficiaries pay' principle can lead to very inefficient energy and ancillary services market outcomes. The risk is that charging parties too much, or in an inefficient way, can undermine the very benefits upon which the case for the upgrade were predicated. One does not want to discourage use of expensive infrastructure simply as a consequence of attempting to recover sunk costs."[420]

G.24 Bushnell and Wolak acknowledge that the Authority is attempting to avoid distorting use by making benefit-based charges largely fixed and independent of use.[421] Accordingly, their primary concern about distortions from application of the benefit-based charge relate to distortions to investment.

G.25 All TPMs will distort both use and investment to some degree. We acknowledge too that charging according to benefit will result in locational differences in transmission charges, which may affect investment decisions. We treat this as a cost in our CBA. In our CBA in chapter 4, we estimate the magnitude of the potential distortion from load and generation not locating in regions with recent investments in capacity. According to our CBA, there *is* likely to be such a distortion, but the costs associated with that distortion are likely to be outweighed by the increases in efficiency resulting from the introduction of the benefit-based charge.[422]

G.26 We think those locational differences in transmission charges will, over time, better reflect the underlying costs of providing transmission services to different regions. We think those differences could promote more efficient investment over the long term, eg, by requiring an investor in wind generation to take into account the relative transmission costs of investing at a location close to or distant from load.

G.27 We also note that those, such as Bushnell and Wolak, who reject benefit-based charging advocate continuing to apply connection charges.[423] As we explained in chapter 5 of the second issues paper, our economic rationale for charging beneficiaries of an investment is analogous to that for requiring customers of connection assets to pay connection charges. At a high level, the key difference between the connection charge and benefit-based charges is how the beneficiaries are identified: connection uses a physical definition while the benefit-based charges use a calculation of benefit. As far as the charges themselves are concerned, they are very similar: both charge for an investment to supply identified beneficiaries and the rate of the charge recovers the cost of the investment from those who benefit from it over its life.

G.28 Accordingly, our proposal could be considered as an extension to the boundary for determining connection assets and therefore connection charges. While we acknowledge the concerns around the benefit-based charge distorting grid use and investment, these same concerns should also apply to the connection charge. Since these concerns do not

420 Bushnell, J and Wolak, FA, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, page 8, Appendix F to Trustpower submission on TPM supplementary consultation paper

421 *Ibid.,* footnote 7.

422 See chapter 4.

423 Bushnell, J, and Wolak, FA, *supra* note 24.

outweigh the benefits in the case of the connection charge, we think the same should also be the case with the benefit-based charge.

G.29 Submitters, such as Bushnell and Wolak, have pointed to the HVDC charge as an example of why a benefit-based charge is problematic because of the divergence between forecast and actual benefits over time.[424] Hogan (2011) addresses this uncertainty point head on. As he says, "Treatment of uncertainty is not simple, but it is unavoidable…. The scenario analysis is an approximation, but this is not fatal for either the investment evaluation or the [benefit based] cost allocation."[425] He also makes the point that the benefits must be determined as part of the decision about whether or not to invest, irrespective of how the investment is actually paid for. He suggests that, "In many instances, estimating the *shares* of benefits is easier than estimating the benefits."[426] *[emphasis added]*

G.30 In addition, Bushnell and Wolak's citation of the HVDC charge as an example of the problems with beneficiaries-pay charges does not take into account the relationship between the HVDC investments and HVDC charges. In particular, when the HVDC charge was first introduced and applied to South Island generators it recovered the costs of Pole 1 and Pole 2, from which South Island generators were clear beneficiaries. Since then, Pole 1 has been decommissioned, Pole 3 has been commissioned, and it provides additional services including round power that were not provided by Poles 1 and 2.

G.31 As a result, the beneficiaries and the share of benefits may have changed but the parties subject to the HVDC charge have not changed. Our proposal avoids the problem of replacement investment providing different services over time to different beneficiaries by charging according to forecast benefits from the replacement investment. In particular, there would be separate benefit-based charges for investments that change the life or the benefits of the original investment. This means that, if the beneficiaries and flow of benefits from a replacement or upgrade investment change, this is reflected in the benefit-based charge for that investment.

G.32 Submitters identifying concerns about distortion to use and investment from the benefit-based charge have suggested that investments in the interconnected grid should be recovered through a charge based on Ramsey pricing (where customers are charged at a rate inversely proportional to their sensitivity to changes in price).[427] This is on the basis that such a charge least distorts behaviour in economic terms (assuming that the charge does not have any value in signalling the cost of users' decisions). Although, with this assumption, a Ramsey charge is in some sense optimal, we are not aware of any situation where Ramsey pricing is applied in practice in its pure form.

G.33 Our proposal does, in fact, incorporate elements of Ramsey pricing, in the form of an expanded prudent discount policy, which would provide a discount to a customer's charges (including the benefit-based charge) where they could demonstrate the charges would distort their investment decisions.

G.34 We agree that spreading the charges across grid users in some way that approximates Ramsey pricing would avoid the distortions that Bushnell and Wolak identify. But it does have a cost. The cost is that users would not face, and so would not take in to account, the

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424 *Ibid*.

425 Hogan, WW, *supra* note 5.

426 *Ibid*.

427 E.g. Creative Energy Consulting, *A response to Meridian's submission to the TPM consultation,* September 2016, Appendix C to Trustpower submission on TPM supplementary consultation paper.

costs in terms of transmission investment that their own decisions generate.[428] We have discussed the impact of this in incentivising inefficient investment both in this paper and in the second issues paper. Our assessment is that the inefficiency identified by Bushnell and Wolak is likely to be outweighed by the increases in efficiency resulting from the introduction of the benefit-based charge.[429]

G.35 This is the heart of the 'marginal cost controversy' debate between Coase and the marginalists.[430] Consistent with our position, Frischmann *et al* (2015) concluded in a review article on this debate that: "The arguments marshalled by Coase (and his contemporaries) not only succeeded in this particular debate, as we shall see, but more generally served as part of the foundation for various fields of modern economics".

G.36 We note that Creative Energy Consulting criticised NERA's citation of the Coase article as backing two-part tariffs and benefit-based charges on the basis that Coase only advocated such charges where costs were attributable to individual customers but not when there are common costs.[431]

G.37 We agree that Coase's formal analysis assumed costs were clearly attributable to individuals, but consider that Coase himself thought the principle more broadly applicable. For example, in the same article, he refers to establishing prices for use of a bridge,[432] and elsewhere he comments "[My] rejection of marginal cost pricing reflects the view that it is a mistake to concentrate simply on the marginal conditions when examining a proposal. It is the total effect (in which what happens at the margin is only one factor) which matters."[433]

G.38 In any case, our proposal does attribute the cost of transmission investments to particular customers, namely those who benefit from it. For example, we do not consider investments such as NIGU are 'common costs', as the technology, location and scale and therefore cost are clearly attributable to particular customers.

Practical?

G.39 With respect to the practicality of the benefit-based charge, the Authority considers that it has demonstrated that it is practical to calculate charges based on benefits on multiple occasions, including in the current proposal. We do, however, appreciate the issues raised by Scientia Consulting about the sensitivities of benefit calculations to assumptions and the impact of investment dependencies on benefit calculations.[434]

G.40 However, our assessment is that the sensitivities that Scientia examined were not marginal. Further, as noted by Hogan (2011), uncertainty is a fact of life and needs to be addressed in the investment decision.[435] Accordingly, we have consistently considered that calculation of benefit-based charges needs to take into account this uncertainty. This could occur, for example, through the use of scenarios.

428 They will only do that if they face a benefit-based charge.

429 See also Appendix B.

430 Coase, RH (1946), pages 169-182.

431 Creative Energy Consulting, *supra* note 31, page 10.

432 Coase, RH, *supra* note 34.

433 Coase, RH (1970).

434 Scientia Consulting, *Technical evaluation of AoB approach used in the TPM second issues paper*, July 2016, Appendix E to Transpower submission on TPM second issues paper.

435 Hogan, WW, *supra* note 5.

G.41 Further, under the Commerce Commission's capital expenditure (capex) input methodology, in 'major capex proposals' and applications to the Commission for approval of 'listed projects', Transpower is required, to the extent reasonably possible, to provide a quantitative estimate of the benefits from the investment expected to be delivered to Transpower's customers.[436] This should mean that for those large grid investments Transpower can draw on the analysis required for this task to assist it with the calculation of benefit-based charges.

G.42 Further, the fact that charges based on benefits have been applied in the United States, Chile and Argentina demonstrates that it is practical to apply benefit-based charges.[437] Each of the three ISOs or RTOs we met in the United States operates a beneficiaries-pay approach which is used to allocate the costs of at least some grid investments. While the scope of coverage for benefit-based charges and the methods used in these jurisdictions differ from the approach proposed in New Zealand, the benefit-based principle is the same.[438] We therefore consider that the practical challenges of a benefit-based approach are not insurmountable.

Complex?

G.43 In most cases we propose a customer's share of charges would be calculated just once under a benefit-based charge. Exceptions would be rare. In contrast under the current TPM a customer's share of the interconnection or HVDC charges is recalculated annually – which, as evidenced by recent changes to Electricity Ashburton's transmission charges for 2019-20, can cause substantial price volatility year on year.

G.44 We think submitters' concerns about complexity relate mainly to the method we have used to calculate benefits. We have used the vSPD model, a model virtually identical to that used to operate the wholesale market, and which wholesale market participants should be familiar with. We have used the vSPD model to calculate proposed charges for seven recent major investments in this proposal.

G.45 The approach used by the three ISOs or RTOs we met in the United States involves modelling the forecast benefits of investments using system planning software models, which are of a similar (or greater) order of complexity to the vSPD model.

G.46 Furthermore, in response to this concern, we propose that Transpower may use a simpler method for smaller investments in designing the TPM, and may use proxies even under the standard method. This is likely to make the charges less accurate in reflecting benefits. Nevertheless, we consider that these charges will be relatively efficient despite this potential inaccuracy.

436 Commerce Commission, *Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination),* consolidated version as at 1 June 2018, clause 7.5.1(1)(b).

437 Both Argentina and Chile calculate capacity charges using an area-of-influence method. Schoeters, MA, Spiller, PT, *supra* note 20, pages 42-43,

438 Costs have been allocated on a beneficiaries-pay basis for around 50 projects by PJM and five projects by MISO. NYISO has yet to commit a project, but has two 'public policy' investments in process with recovery expected to be 75% by beneficiaries-pay and 25% socialised. See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018. Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/release-of-joint-report-beneficiaries-pay-in-usa/

Applying benefit-based charges to seven major investments

G.47 The aspect of our proposal that has been most subject to debate is applying benefit-based charges to some recent major investments. We emphasise that our proposal *does not* involve retrospective charges – that is, changes to historical charges that customers have already paid. Our proposal *only* involves changing future charges. The main arguments submitters have advanced against applying benefit-based charges to some historical investments are that such charges would:

(d) distort behaviour while being unable to alter the efficiency of those investments

(e) introduce unfairness and so undermine, rather than promote, durability.

G.48 With respect to distortions to behaviour, the general tenor of submitters' concerns is reflected by the following comment from Bushnell (2015):

> "…it would be inappropriate to use such supplemental charges [such as the AoB charge] to recover the costs of investments that have already been made. This could only distort current behavior, and have no impact on the grid investment itself as those investments, and their costs, are sunk. Therefore, the goal of economic efficiency is best served by the 'Application B' option, which would place less capital costs from existing investments under the new pricing regime."[439]

G.49 As discussed above, we have attempted to design the proposed benefit-based and residual charges to minimise distortions to use, as distinct from investment, from application of these charges. In addition, we are proposing a transition that would limit the size of the impact of application of the benefit-based charge to some historical investments, and therefore further limit distortions to behaviour.

G.50 Minimising distortion is not the same as spreading the charges uniformly across all customers. As is noted above, we have sought to follow the approach first advocated by Coase (1946) of imposing charges for investments attributable to particular customers (ie investments that benefit particular customers) on those customers,[440] ie beneficiaries.

G.51 We acknowledge concerns that the proposal to apply benefit-based charges to recent investments could impact investment going forward, as, for example, Axiom (2016) describe:

> "There can be no dynamic efficiency benefits gained from signalling to generators that it is cheaper for them to locate in areas where assets are 'older'. Regardless of whether assets are old or new, their costs are sunk. This distinction can therefore only give rise to dynamic inefficiency." [441]

G.52 While we recognise this risk (and have quantified the dynamic inefficiency that Axiom refers to in our CBA), we consider that in some respects our proposal reduces such dynamic inefficiency. In particular, we think replacing the HVDC charge with benefit-based charges on all beneficiaries of HVDC Pole 2 and 3 will to some extent address the long-standing problem that the current HVDC charge provides an excessive disincentive to generation investment in the South Island. This includes regions with a lack of generation and generation competition, notably the upper South Island.

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439 *Supra* note 7, page 2.

440 See Coase (1946) op. cit.

441 Axiom Economics, Economic Review of Second Transmission Pricing Methodology Issues Paper, A report for Transpower, July 2016, page 29.

G.53 More generally, we think judgements about dynamic efficiency need to consider both positive and negative effects. Accordingly, while applying a benefit-based charge may provide disincentives for generation to invest in areas where existing investments are subject to the charge, the benefit-based charge will also mean that generators need to consider the future transmission investment implications of locating in other areas as well. We also agree with Professor Littlechild that not applying the benefit-based charge to historical investments would mean foregoing the benefits of providing information about the value of future investments.[442] We think the overall effect will be to promote more efficient investment rather than detract from it.

G.54 Moreover, the Commerce Commission regime for major capital proposals and listed projects is now designed to approve only investments that reflect efficient costs of a prudent supplier.[443]

G.55 To the extent that previously-approved investments were efficient, the beneficiaries of the investment would have been prepared to pay for them because the benefits to them would have exceeded the cost. That means the benefit-based charge would not cause them to exit.[444] The same cannot be said if we instead choose to recover the cost of the investments through Ramsey-like charges. That will recover the cost of the investment from some parties who get little or no benefit from it. If the charge were poorly reflective of Ramsey principles, which we think is the case with the interconnection charge calculated on the basis of RCPD, the magnitude of the charge might be sufficient to cause them to exit when they would have been viable but for the charge.

G.56 We have also argued that applying the benefit-based charge to existing investments will promote durability. If this does result in a more durable TPM, this should reduce uncertainty, which should be beneficial for investment and therefore promote dynamic efficiency. Some submitters, however, consider applying charges to historical investments will increase disputes and uncertainty rather than reduce them. For example, Creative Energy Consulting criticise the durability of this approach as follows:

> "But, by including some historical assets, but not others, within the AOB regime, by drawing a 'line in the sand', the EA has just created some new grounds for claims of unfairness: for example, from customers in Northland, who appear to be paying for the majority of the cost of the assets that serve their region, through the new AOB charge and, in addition, a share of the older assets serving all other regions, through the residual charge." [445]

G.57 In our view, the question of whether a TPM is more or less durable is a matter of judgement. Our assessment is the prospect of new investment in some areas affects the

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442 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016, page 14.

443 The Commission's capital expenditure input methodology was reviewed and amended in 2018. See Commerce Commission, *Transpower capex input methodology review: Decisions and reasons* (29 March 2018).

444 Coase (1970), *supra* note 38, points out the absurdity of not charging for these investments:

"Apparently, what the advocates of marginal cost pricing had in mind was that the Government should estimate for each consumer whether he would be prepared to pay a sum of money which would cover the total cost. However, if it is decided that the consumer would have been willing to pay a sum of money equal to the total cost, then – and this strikes me as a very paradoxical feature of this argument – he will not be asked to do so. ..I found this a very odd feature. …The way we discover whether people are willing to pay something is to ask them to pay it."

445 Creative Energy Consulting, *Review of the Electricity Authority's TPM second issues paper,* July 2016, page 23, appendix to Trustpower submission on second issues paper.

durability of any TPM. In particular, we think durability would be undermined if beneficiaries of these new investments have to pay for these as well as help pay for large recent investments in other areas they don't benefit from. Meanwhile, the actual beneficiaries of those large recent investments would only have to pay part of the costs of the investments they benefit from, further undermining durability.

G.58 We think there are several factors that reduce the impact of our current proposal with respect to applying benefit-based charges to historical investments. First, under the Commerce Commission's input methodology that establishes a total revenue cap for Transpower, Transpower is able to recover more of the costs of an investment early in its life.[446] In the case of the seven large historical investments we propose be subject to benefit-based charges, since most of them were commissioned in the early part of this decade, a significant portion of the costs will actually already have been paid by customers that are not the primary beneficiaries.

G.59 Second, we are no longer proposing to apply benefit-based charges to three of the historical investments that we proposed applying the area-of-benefit charge to in the second issues paper. For two of these, Otahuhu GIS and NAaN, any benefits would be likely to flow mainly to upper North Island customers but, since the estimated benefits do not exceed the costs, we propose to recover the costs of these investments through the residual, so these costs would also be spread between the primary beneficiaries and other customers.

G.60 Finally, as we note above, we have included:

(a) a transition mechanism to manage the impact of moving to recover the costs of these investments from beneficiaries

(b) an additional component to allow Transpower to apply the benefit-based charge to all historical investments, which would mean that all customers would pay for the investments they benefit from. This component can be implemented if, in Transpower's reasonable opinion, it would better meet the Authority's statutory objective.

Is there evidence of a problem of inefficient transmission investment?

G.61 A theme of the Covec report is that the Authority has failed to present evidence that the existing TPM does not promote efficient investment.

G.62 In our view, it is reasonable to presume – and is a standard assumption in economics – that parties, in deciding what is best for them, will take into account charges they pay as a consequence. If transmission charges are substantially less than the costs to New Zealand imposed by those parties' decisions, it can be presumed that on occasions decisions will be made that are in the parties' self-interest but which impose net costs on New Zealand.[447]

446 Under the Commission's Asset Valuation input methodology that applies to Transpower for the purposes of information disclosure and the setting of the revenue cap, the regulatory asset base (RAB) is not subject to indexation, which results in the investment being recovered earlier than if it had been indexed. This contrasts with the input methodologies for electricity distributors, where the RAB is indexed.

447 Coase (1970), *supra* note 38, makes this point with respect to decreasing marginal cost industries like transmission: "Note that marginal pricing [ie, in our context, pricing using LMP without a benefit-based charge] makes it impossible for consumers to choose rationally between two alternative uses of factors that are required for production but do not enter the marginal cost" page 118.

G.63 There are examples of likely inefficient grid investments. When analysing the benefits of the post-2004 large historical grid investments (those with costs exceeding $50 million), to identify benefit-based charges, we were not able to identify net benefits for three of the investments: North Auckland and Northland (cost $473 million), Otahuhu GIS (cost $106 million) and Upper South Island dynamic reactive (cost $55.2 million). These investments were all approved by the Electricity Commission.[448] While we note the benefit calculations we have conducted for these investments were historical and only considered benefits early in the lives of these investments, the lack of net benefits at this point raises questions around the efficiency of the timing of construction at the very least.

G.64 That several such major investments — with a total cost of more than $500 million — may have costs exceeding benefits confirms there are legitimate questions about whether the transmission pricing regime is fit-for-purpose, and effective in supporting the transmission investment approval regime. This is for two main reasons.

G.65 First, under the Commerce Commission regime, if the Commission approves a transmission investment, then Transpower is able to recover the costs of that investment under the TPM, subject to the application of incentive mechanisms in the Commission's capital expenditure input methodology.[449] As a result, apart from amounts that are shared between Transpower and its customers under the incentive mechanisms, the risk of the investment failing is transferred from Transpower to its customers.

G.66 Charges that spread the costs widely reduce incentives on customers to scrutinise investments, even if they are inefficient or inefficiently risky, or to present useful information on more efficient alternatives. The Commerce Commission's major capex and listed projects grid investment approval processes provide a robust method to test the costs and benefits of those larger investment proposals. However, this process would be enhanced if customers had incentives to reveal information that more accurately reflected a proposal's net benefits or considered the merits of alternatives.

G.67 Second, the cost-benefit analysis reported in this issues paper provides evidence that the existing TPM likely does not promote efficient investment. For example, our modelling of investment behaviour by load customers demonstrates that the existing RCPD charge could be expected to cause inefficient investment in batteries that would be made mainly to avoid the RCPD charge.

G.68 The Covec report emphasises the opinion of Professor Yarrow that when a firm, such as Transpower, is subject to economic regulation the firm has incentives to design efficient prices, and a greater ability to do so than the regulator, as it has better information about its customers. However, this view does not take into account two important factors.

G.69 First, if Transpower does not charge only those who benefit from an investment the cost of the investment, transmission users (who may or may not be Transpower's customers but may include consumers to whom charges are passed through) will have an incentive to

448 Investment approval documentation for these investments is available at: NAaN: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/; Otahuhu GIS: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/otahuhu-substation-diversity-proposal-history/; USI reactive support: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/grid-development-proposals-archive/ige-applications/upper-south-island-reactive-support-history/

449 Commerce Commission, *Transpower capex input methodology review: Decisions and reasons* (29 March 2018), page 33, Figure 5: Overview of new capex incentive regime.

undertake inefficient investment, because they will treat the cost of additional transmission investment caused by those decisions as minor to the point it is not relevant to their own investment decisions.

G.70 This can be demonstrated by considering the location decisions of gas-fired generators who could potentially face both electricity and gas transmission costs. Under the status quo, except for the costs of connecting to the grid, North Island gas-fired generators only need to consider gas transmission costs (but are not charged electricity transmission interconnection costs). As a consequence, gas-fired generators tend to locate close to their source of gas. However, if they also had to face the transmission costs, they may decide to locate closer to the customers they are supplying with their generation.

G.71 Second, like any firm, Transpower's incentives are to maximise its profits.[450] Under its regulatory regime it can do this by increasing its revenue, because the more revenue it receives the greater its profits will be. Building more assets can increase revenue. In our view, the current TPM facilitates this because a load customer that benefits from an interconnection investment does not have to pay the full cost of the investment.

G.72 This is reinforced by the fact that, under the current TPM, aside from the HVDC, generators pay nothing towards interconnection investments, regardless of the extent to which their location decisions impact on interconnection asset costs.

G.73 The Covec report implies that the Authority does not trust the Commerce Commission's ability to screen investments, and that the Authority does not provide any supporting evidence of inefficient investments actually having been approved.[451]

G.74 The review of transmission pricing is not a question of trust in or effectiveness of the Commission's process. It is about achieving efficient transmission pricing signals. We are concerned about the consequences of an inefficient *pricing* regime (which the Authority is responsible for). Inefficient transmission pricing affects:

(d) investment by generation or consumers, which may be inefficient if their decisions do not reflect the cost of transmission

(e) transmission investment via:

(i) investment and use decisions by users of the transmission grid, which will affect the timing, location, nature and scale of transmission investment

(ii) the extent to which transmission customers have incentives to support or oppose transmission investments.

G.75 We have already discussed how investment and use decisions by users would affect demand for transmission investment. With respect to the second proposition, the quality of a regulator's decision is clearly influenced by the information they have available to them.[452] On that point, we consider that the current RCPD charge is structured in a way that:

(a) encourages transmission customers to support a grid investment option that they would individually benefit from, even if it is not the best solution, and

450 In fact, pursuit of profitability is a statutory objective. Transpower is a state-owned enterprise and, accordingly, its financial objective is to "operate as a successful business" and "be as profitable and efficient as comparable businesses that are not owned by the Crown", State-Owned Enterprises Act 1986, section 4(1)(a).

451 Small, J, *supra* note 2, paragraph 13-19.

452 This result has also been well established in economics since the publication of the seminal article by Jensen and Meckling (1976).

(b) provides little incentive for transmission customers to provide Transpower and the Commission quality information that would assist in the scrutiny of a grid investment proposal.

G.76 By contrast, we would expect our proposal to provide strong incentives for stakeholders to provide information to ensure the investment decision was of high quality. This would mean that the Commission's process would be better supported by transmission pricing.

Distinction between the guidelines and the TPM

G.77 The Covec report queried the 'very detailed' nature of TPM guidelines proposed by the Authority and questioned what the Authority's rationale was for presenting a high level of detail. It stated: "As Professor Yarrow has noted, regulators of natural monopolies … frequently take the view that the regulated firm knows best how to design its charges. This is because the regulated firm (i.e. Transpower) interacts directly with its customers on a regular basis and therefore has superior information to regulators about the most efficient ways to earn revenue."[453]

G.78 The implication is the guidelines should be less prescriptive and perhaps Transpower is in a better place to determine the detail in the TPM.

G.79 We have considered this point carefully and consider that the appropriate level of prescription varies, considering:

(a) who has the best information and incentives to design, develop and/or implement a workable TPM based on the guidelines?

(b) what are areas that must be reflected in the final methodology to ensure the Authority's policy intent is most likely to be achieved, and where is flexibility needed to enable adaptation?

G.80 The proposed guidelines in this issues paper reflect these considerations by varying the level of prescription from relatively prescriptive (as in schedule 1) to relatively high level, as in the principles set for Transpower in clause 1. The proposed 2019 guidelines reflect detailed feedback from Transpower staff on an earlier draft of the guidelines in order to improve their clarity and workability.

Submissions have led to substantial changes to the TPM proposal

G.81 The Covec report suggests that the Authority has been rigid in its views about transmission pricing, and that certain aspects of our proposal remain unchanged despite opposing expert views.

G.82 It is true that we have continued to propose to move to a beneficiaries-pay approach instead of the existing HVDC and interconnection charges, for the reasons discussed above.

G.83 It is also true, however, that we have changed our position about many aspects of our proposals to a substantial degree over time. In doing so we have been influenced by the views of external consultants, among others. Such changes include:

(a) changing from calculating benefits from an ex post to an ex ante (forecast) basis[454]

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[453] Small, J, *supra* note 2, paragraph 24.

[454] Castalia, *supra* note 6, Trustpower submission on beneficiaries-pay working paper, section 6.2. We note, in particular, the following from Trustpower's submission on the approach to applying beneficiaries-pay charges,

(b) removing the cap on benefits for calculating charges[455]

(c) changing the method of calculating the residual charge from a variable to a fixed basis[456]

(d) changing from applying the residual charge to generation and load to just load[457]

(e) proposing and then withdrawing the deeper connection charge[458],[459]

(f) proposing[460] and then withdrawing a LRMC charge[461]

(g) introducing the ability to include a transitional peak charge[462]

(h) introducing the ability to apply the benefit-based charge across the entire grid rather than limiting it to large post-2004 assets[463]

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which is reflected in the design of the benefit-based charge: "If the Authority intends to persist with a beneficiaries-pay charging methodology, Trustpower considers it should select a pricing approach which is based on long-term forecasts of benefits and beneficiaries. If necessary, this could provide for charges to be recalculated periodically as and when there are changes to the use of the grid…. [W]e would expect charges to be based on offsetting benefits calculated over the lifetime of a transmission asset, over a range of potential scenarios. Only parties with offsetting benefits would be charged." Paragraphs 6.2.1, 6.2.3, page 12.

455 Bushnell, J, *Efficiency and cost recovery for transmission network investments*, March 2014. Appendix to Trustpower submission on beneficiaries pay working paper; Meridian submission on beneficiaries pay working paper; Orion submission on beneficiaries pay working paper.

456 Transpower submission on the TPM first issues paper; ENA submission on the TPM first issues paper. These parties submitted that the Authority needed to be clear about whether the residual should incorporate a pricing signal or should be non-distortionary. For example, the Orion submission on the first issues paper stated: "If the objective is indeed minimizing distortion in use of the grid, as opposed to efficient peak avoidance, an allocation based on market share would seem to be more appropriate." (page 21).

457 Unison submission on first issues paper; Redpoint, *Evaluation of New Zealand transmission pricing review against international experience,* 18 February 2013, Appendix to Trustpower submission on TPM first issues paper,

458 The deeper connection charge was developed, at least in part, in response to criticisms that charging options higher on the Authority's DMEF had not been considered, eg see PwC for 21 EDBs, submission on beneficiaries-pay working paper, paragraph 11.

459 While the deeper connection charge was considered in the second issues paper, it was not proposed as the cost-benefit analysis used for that paper (which was subsequently discredited) indicated lower net benefits. As outlined in chapter 9 of the second issues paper, also influencing the decision not to proceed with deeper connection were that:

- customers could face deeper connection charges exceeding private benefits — see CEG for Transpower, submission on options working paper, page 72)
- it was less effective than the area-of-benefit charge at promoting efficient investment — the following submissions, amongst others, identified issues relating to inefficient investment from the deeper connection charge: CEG *ibid*,, Castalia for Genesis submission on options working paper, pages 16, 18, 19, Scientia for Transpower submission on options working paper, pages 19-20, ENA submission on options working paper, page 9, CEG, ibid., page 5, Marlborough Lines submission on options working paper page 8
- the identification of assets and parties subject to the charge was complex and likely to result in distortions to behaviour — see the following submissions on the options working paper: Buller, page 6, Counties Power, page 13, ENA pages 8-9, EPOC, page 12, Genesis, page 6, Castalia for Genesis, pages 16, 19, CEG for Transpower, page 70, Orion, page 6, Pioneer, pages 2, 3, The Lines Company, Tauhara No. 2 Trust, page 3, Scientia for Transpower, page 13,14, 19-20, Trustpower, page 14.

460 ENA, *supra* note 8, Transpower, *supra* note 9.

461 Bushnell, *supra* note 7.

462 The decision to include a transitional peak charge was influenced by Transpower's submission on the supplementary consultation paper that not having an RCPD-based or LRMC charge could affect demand response, which could in turn impact on reliability and system security.

463 NZAS submission on the second issues paper; Transpower submission on the second issues paper.

(i) introducing transition mechanisms[464]

(j) proposing and then withdrawing an extension to the prudent discount policy to address inefficient exit.[465]

G.84 In addition, numerous other changes have been made to our proposal and the draft guidelines in response to comments from submitters.

G.85 The Covec report does not reflect the substantial changes to the Authority's proposal over the course of the review (beyond acknowledging some changes). The Authority considers its approach of tallying supporting or opposing views from external consultant reports submitted throughout the course of the review to be inappropriate in two respects:

(a) Our proposal has changed over time as noted above. The tallying fails to acknowledge this.

(b) More importantly, the Authority considers any issues raised in submissions by external consultants and other submitters alike on their merits, not in terms of numbers for or against. The Covec report in fact reinforced exactly this point. It found that most external consultants criticised the Authority's decision-making and economic framework or its elaboration in the second issues paper. However, the Covec report agreed "… with NERA's view that this chapter is 'not contentious from an economics perspective'."[466]

The Authority is proposing a TPM that it has assessed best meets the statutory objective

G.86 We agree with Covec that there is no perfect TPM. Our proposal reflects trade-offs between different efficiency objectives.

G.87 The Covec report, by its tallying of external consultant views, implies however that there is consensus amongst external consultants. But submissions including from external consultants have expressed a broad range of views on particular TPM approaches. Our review of submissions showed a wide range of views from submitters and their external consultants on whether, for example, the TPM should:

(a) have an LRMC or another peak charge

(b) be based on benefits and, if it is, how this should be calculated

(c) include a residual charge on generation and, if so, to what

(d) apply to specific investments

(e) apply to historical investments and, if it does, which ones

(f) remove the HVDC charge

(g) specify the calculation of the residual charge.

464 Fonterra, submission on beneficiaries-pay working paper, paragraph 12.6.

465 The following submissions submitted that this proposed extension of the prudent discount policy would increase inefficiency: Genesis Energy, Top Energy, Counties Power, Molly Melhuish, Fonterra, Castalia for Genesis, King Country Energy (KCE), Pioneer, Vector, EA Networks, Unison, Orion, HoustonKemp for Trustpower, Mighty River Power, Powerco, Transpower, Trustpower, PwC (for 14 EDBs), Electric Power Optimisation Centre.

466 Small, J, *supra* note 2, page 119.

G.88 Regardless, it is not the number of submissions for or against that determines our approach to an issue but the substance of the position each submission is expressing.

G.89 We have discussed above what has influenced our thinking in proposing the benefit-based charge and applying it to new investments and some historical investments. In addition to the issue of the investments to which the benefit-based charge is applied, other matters on which external consultant views were advanced include:

- whether an accurate assessment of beneficiaries is appropriate
- whether a fixed capacity measure is appropriate for benefit-based and residual charges
- whether the cost allocators are appropriate
- whether it is appropriate to include distributed energy resources in the assessment of capacity.

G.90 Where appropriate, we address external consultant opinions on these matters in the 2019 Issues paper in the discussion about our proposal. For the most part, this relates to external consultant opinions on the second issues or supplementary consultation papers, as the proposal has changed significantly from that in earlier papers, in part because of responses to consultant opinions. However, we make the following general observations with respect to these matters:

G.91 *Accuracy of assessment of benefits:* Some external consultants, as cited by Covec, have questioned the practicality of estimating benefits and whether an accurate assessment is appropriate.

G.92 As noted at paragraph A.42 above, our discussions with the US jurisdictions who have applied beneficiaries-pay charges for several years confirm it is practical to apply a beneficiaries-pay approach to allocate the costs of transmission investments (acknowledging that our proposed approach is not identical to the approach adopted in US jurisdictions but is broadly similar).467

G.93 In relation to accuracy, we agree with the comment from NERA cited in paragraph 282c of the Covec report that precision of calculation of benefits is not necessary to achieve material efficiency gains relative to the status quo.

G.94 *Use of a fixed capacity allocator:* Comments on the second issues paper cited by Covec relate to whether allocation on the basis of fixed capacity will allow charges to reflect benefits over time. Deciding on an allocation method involves a trade-off between avoiding distortions to behaviour from the charge and reflecting the change in a party's circumstances over time. Our proposal attempts to make this trade-off by charging in a relatively rigid way but also providing mechanisms that allow adjustments to reflect certain changes in circumstances.

G.95 *Appropriateness of cost allocators:* The comments cited by Covec relate to whether it is appropriate to remove the RCPD charge. As we comment elsewhere, including in the 2019 issues paper, we think nodal prices should be the primary mechanism for incentivising efficient use of the grid.

G.96 We note the comment by James Bushnell cited by Covec (paragraph 290a) that peak usage may be an appropriate proxy of the allocation of costs and benefits, "particularly if it

467 Electricity Authority, Commerce Commission, Transpower, June 2018, *supra* note 43.

reasonably captures the conditions triggering those costs". As we have commented at length throughout the TPM process, we do not consider the RCPD charge reasonably captures the conditions triggering transmission costs. Further, to the extent it does, it undermines the effectiveness of nodal pricing. However, because of concerns raised by Transpower and other submitters about potential unintended consequences from removal of the RCPD charge, our proposal includes an additional component that provides for introduction of a transitional peak charge.

G.97 We also note comments by some submitters that the current RCPD charge reflects Ramsey pricing principles.[468] We think this relationship is very weak. A charge that follows Ramsey pricing principles should not involve significant distortions to behaviour, but the current charges do the opposite: substantial investment targeting avoidance of the RCPD charge, withdrawal of interruptible load during RCPD periods and avoidance of the RCPD charge in regions with falling or flat demand.

G.98 Our approach is to design a residual charge that seeks to minimise incentives to inefficiently alter use and rely on nodal pricing to provide signals about use that reflect the real-time state of supply and demand on the transmission network.

G.99 *Inclusion of distributed energy resources in calculation of the residual charge:* We propose to calculate a load customer's share of the residual charge based on demand "grossed up" for injection by distributed generation or behind-the-meter generation as we think this better reflects customer size, and therefore ability and willingness to pay for transmission costs. It also provides better assurance that load customers will not be encouraged to invest in distributed generation or batteries just to avoid charges.

Conclusion

G.100 In conclusion, we have considered matters raised in submissions we have received to date, including those identified in the Covec report, and will carefully consider submissions made in respect of this 2019 issues paper.[469] We have altered our proposal in response to various issues validly raised. However there are also some issues or arguments raised in submissions that we do not accept, including those identified by Covec that criticise our policy process, for the reasons outlined above.

G.101 As well as detailed consideration of submissions, we also sought the views of Professor Hogan to identify whether there were any problems with our proposal with respect to the application of the benefit-based charge to recent major investments that would necessitate us changing our approach. However, he identified no such problems.

G.102 Our decision on whether to confirm our proposal will, however, depend on the outcome of our consideration of submissions on the 2019 issues paper. The submissions we receive will be subject to thorough analysis before we make our decision.

G.103 We continue to be open to persuasion by submissions presenting arguments of substance, from all and any parties – whether a stakeholder or an external consultant. While we have chosen in this section to focus on matters raised within the Covec report in particular, these points are merely illustrative of the many views put forward in the course of this review.

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[468] For example, Creative Energy Consulting, *supra* note 31, page 20.

[469] Please note, as we have said elsewhere in this 2019 issues paper, if you wish the Authority to consider again an argument or some evidence that you have provided in a previous submission, you are welcome to cross refer to the specific place in your previous submission where that point is covered.

G.104 We have arrived at the proposals in the 2019 issues paper after thorough consideration of the views of all stakeholders, not limited to the ones put forward in the Covec report by consultants.

G.105 We currently consider that while no TPM proposal can ever be perfect, on balance our proposal as presented in this 2019 issues paper would promote the Authority's statutory objective including by promoting the creation of a TPM that would be in the best long-term interests of consumers for the foreseeable future. However, we do not claim to have achieved perfection and we look forward to considering submissions as to how our 2019 proposal can be improved.

Q65. Do you have any comments on the matters covered in this appendix G?

Appendix H Method and assumptions: impact modelling and proposed benefit allocation

H.1 This appendix provides a description of the methods and assumptions we have used to produce:

(a) the information on indicative year-one transmission charges in chapter 5

(b) the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).

H.2 The Authority invites submitters to provide feedback on key assumptions and modelling decisions we have made in determining the allocation of benefit-based charges. In some cases we have considered alternatives before adopting a particular approach. We have included questions around the options considered in this appendix.

H.3 The Authority has published on the Authority's Electricity Market Information (EMI) website a set of files showing the calculations and technical notes on the methods used.

Method to calculate indicative customer charges in chapter 5

H.4 The primary task of chapter 5 is to show (indicatively) the change in the allocation of Transpower's annual costs among its customers in the first year if the proposed guidelines were implemented via a new TPM, compared to the allocation under the current TPM.

2022 is assumed to be the first year of pricing under a new TPM

H.5 The pricing year 2021/2022 (referred to as 2022) is assumed to be the first year of pricing under a new TPM. This assumption is conservative in the sense that it results in relatively large year-one impacts. The first year of pricing may be later than 2022. If this is the case, the depreciated value of the seven major historical investments subject to the benefit-based charge would reduce further and the impact of the change in charges that is due to those investments would be less than shown in chapter 5.

H.6 Transmission charges are set out only for the first year of a new TPM. The purpose is to show the immediate change caused by the shift to a new TPM and the resulting reallocation of the costs of historical investment in the grid. It is more difficult to show expected charges in subsequent years of a new TPM. This is because each year Transpower would allocate new expenditure via the benefit-based charge. The impact of this on customers' charges would depend on which customers Transpower identified as benefiting from that new expenditure.

H.7 Transpower has provided us with estimates of its breakdown of annual revenue for each benefit-based investment for 2022 (based on RCP3 forecasts). Transpower's expected total revenue requirement for 2022 is sourced from the Commerce Commission's draft decision on Transpower's revenue for RCP3.[470]

Transpower's customer list

H.8 A list of Transpower's current customers was sourced from the information on customer charges disclosed by Transpower under the Commerce Commission's Information Disclosure regulation.

470 Transpower's individual price-quality path from 1 April 2020 – Draft decisions and reasons paper – 29 May 2019. Available at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020?target=documents&root=102833 .

H.9 Those customers' points of connection (POCs) have been identified, with some adjustments based on Transpower's advice. In the few instances where multiple customers are connected to the same POC we have allocated benefits (and charges) between customers in proportion to volume (load or injection).

H.10 Charges are estimated for Transpower's customers only as these are the only parties that Transpower can charge directly. We have not estimated the impact of the proposed changes to the TPM on distribution charges.[471] That is a matter for each distributor. For example, Pacific Steel is owned by NZ Steel and is a customer of Vector. Any effects a new TPM based on the proposed guidelines would have on distribution charges incurred by Pacific Steel would be a matter for Vector. So we have not taken this into account in estimating transmission charges for NZ Steel.

We first estimate charges under the current TPM

H.11 To estimate the indicative impact of a new TPM on charges, we first estimated customer charges that would apply under the current TPM for 2022.

H.12 The starting point for this estimate is the customer charges provided in Transpower's disclosure under the Commerce Commission's Information Disclosure regulation for the most recent available year (2019/20).[472] We used this information to set the estimated allocation of the RCPD charge and of the HVDC charge in 2022. That is, we have assumed that the allocation of the RCPD charge and of the HVDC charge would be the same in 2022 as in 2019/20. This is based on an assumption that customer behaviour would be unchanged.

H.13 We needed to take into account the expected reduction in Transpower's revenue requirement for 2022 (as compared with 2019/20). To ensure that the total of estimated charges is equal to Transpower's revenue requirement for 2022, we applied the 2019/20 allocations to the 2022 revenue. We did this separately for interconnection revenue and HVDC revenue. This is because interconnection revenue and HVDC revenue are expected to decline at different rates between 2019/20 and 2022.

H.14 Our estimate of customer charges under the current TPM in 2022 is imperfect, as:

(a) customer usage or generation in 2022 would likely vary from the levels we have assumed to some extent

(b) Transpower's revenue for the benefit-based investments and its revenue relating to other costs recovered through the residual charge could turn out to be different to the estimates it has supplied[473]

(c) it does not account for changes to the allocation method for the HVDC charge (discussed below).

H.15 We have not taken into account changes to the allocation of the HVDC charge resulting from the gradual transition from a Historical Anytime Maximum Injection (HAMI) basis to a

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471 Similarly, we have not estimated the impact of the proposed changes to the TPM on the further allocation of transmission charges by other transmission customers (such as directly-connected industrials) to other businesses connected to their networks.

472 Transpower Information Disclosure Schedules F1-6, G1-8, SO1, Disclosure Year, 30/06/2018, sheet F6 titled 'Revenues', 'Current Year +2' (Forecast year), being the pricing year to 31 March 2020.

473 Transpower's revenue for regulatory control period 3 (RCP3) (for 2020/21 to 2024/25) will not be finalised until November 2019 according to the Commerce Commission website. Refer: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020.

South Island Mean Injection (SIMI) basis.[474] This migration would be complete by 2022. We did not adjust for this as it is unlikely to result in a material distortion to charges. Note that the change to the allocation of the HVDC charge only affects South Island generators.

We then calculate indicative charges under the proposal

H.16 We have estimated indicative customer charges that could apply under a TPM based on the proposed guidelines for 2022. To do this, we have calculated allocations of the charges that would apply under such a TPM (including the benefit-based charge and the residual charge) and applied those allocations to Transpower's expected revenue requirement for 2022.[475]

H.17 **The allocation of the connection charge is the same as in 2019/20.** We split out the connection charge and apply it to customers in the same proportions as were disclosed for the most recent available year, with a reduction in the charge to account for the expected change in Transpower's expected revenue requirement for RCP3. Under the Authority's proposal the guidelines with respect to the connection charge would not change materially. We therefore assume the way Transpower would calculate the connection charge would not change (so we did not model changes to the connection charge).

H.18 **We have calculated the benefit-based charge for seven major investments.** Transpower provided a breakdown of the estimated depreciated value of the seven major investments listed in clause 13(b) and schedule 1 of the proposed guidelines, and operating and maintenance costs attributable to those investments for years up to 2024/25. These were used to determine the modelled amount to be recovered in 2022 for each of the seven major investments in schedule 1 (as set out in Table 14below).

Table 14: Indicative amount recovered for each of the seven major investments

Investment	Modelled amount recovered ($m in 2022)
NIGU	60.5
HVDC (Poles 2 and 3 combined)	98.9
LSI Renewables	2.7
Wairakei Ring	9.1
BPE-HAY reconductoring	6.5
UNI dynamic reactive support	4.9
LSI Reliability	2.4

H.19 The modelled amount to be recovered in 2022 for each of the seven major investments was then allocated according to the percentage of benefit for that investment proposed for each customer in schedule 1 of the proposed guidelines. The method we used to determine the percentages in schedule 1 is discussed below under the heading "Method to calculate the allocation of benefit to schedule 1 investments".

474 Following Transpower's operational review 1 (which took place over 2014 – 2015) a decision was made to change the allocation of the HVDC charge from HAMI (a peak charge) to SIMI (a volume-based charge). In the 2019/20 pricing year HVDC charges are allocated 25% according to HAMI and 75% according to SIMI. Refer: https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/operational-review-1.

475 To calculate $/MWh charges for 2022, we needed to estimate 2022 volumes. To do this, we took recent consumption figures (over the 2014 – 2018 period) and increased consumption / injection for each customer (load / generation) by 1% per annum.

H.20 **We calculate the residual charge.** The residual charge recovers any of Transpower's regulated revenue that is not recovered by either the connection charge or the benefit-based charge.[476]

H.21 For the calculation of indicative residual charges, we have assumed that the residual charge is allocated based on gross anytime maximum demand (AMD),[477] for each POC/Network for each of the four years from 1 July 2014 to 30 June 2018. We calculated the average of the four years for each POC/Network. The 4-year average smooths out outliers in any single year.

H.22 We used data available from the Reconciliation Manager (reconciliation data file 010) to measure half-hourly demand, as we consider this to be the most robust source of half-hourly gross demand available.

H.23 The AMD calculation is on a 'gross' basis. This means any distributed generation connected to the distribution network is not netted off against demand. For example, if for years 1, 2, 3 and 4 respectively, a POC/Network had maximum demand of 10, 15, 20 and 25 MW, and distributed generation in those same trading periods of 0, 5, 10, and 15 MW, the gross AMD at that POC/Network would be (10+15+20+25)/4 MW.[478]

H.24 As mentioned earlier, there are some instances where there are multiple customers behind a POC. In these circumstances the split between customers is determined by combining 'POC' and 'Network' in the reconciliation dataset (ie, POC/Network). For example, POC WHI0111 comprises two networks: Contact Energy and Pan Pacific Forest Industries. By creating a separate POC/Network reference for each (WHI0111_CTCT and WHI0111_PANP), the AMDs can be calculated separately for each customer.

H.25 Where a customer has multiple POCs, that customer's gross AMD will be the sum of the gross AMD of each POC. An alternative approach would have been to pool demand for each customer across locations and calculate the AMD of the pooled demand.[479]

H.26 Where a customer has multiple networks, AMDs for each of the customer's networks were then rolled up into a total AMD for a Transpower customer. Adjustments were made based on information provided by Transpower. Where we have needed to make important assumptions and apply judgement in particular cases, we have recorded these and published them on the Authority's EMI website.

We compare charges under current TPM and the proposal and apply the cap

H.27 We compared the indicative charges for each transmission customer under the proposal to the charges estimated for the current TPM. This gives us the 'raw' impact of the policy change on customers. This raw impact is published on the Authority's EMI website.

H.28 We then applied the price cap calculation as provided for in the proposed guidelines.

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476 Transpower also earns a comparatively small amount of income from notionally embedded agreements (NEAs) and prudent discount agreements (PDAs). In the 2019/20 pricing year, this was disclosed as $3.04m.

477 AMD is the trading period with the highest demand (in MW) measured at each POC and network over a pricing year. There are instances where there is more than one network (and customer) at a POC

478 By contrast, net AMD would be (10+10+10+10)/4. Note however that once the distributed generation is subtracted from the maximum load for each trading period, the net AMD periods might change, for example, to periods when distributed generation was not running.

479 Refer appendix B.

Method for allocation of benefit to seven major investments

H.29 This section describes the modelling approach we used to generate the percentages in schedule 1 of the proposed guidelines. The percentages are the portion of benefit (and charges) proposed to be allocated to each customer for each of the seven major investments listed at clause 13(b) of the proposed guidelines. Below we set out the data inputs, key decisions and assumptions made that materially impact the allocation, the alternative options we considered, and the modelling steps.

Beneficiaries were identified using vSPD

H.30 The vectorised Scheduling, Pricing and Dispatch tool (vSPD) is used to identify the beneficiaries of each of the transmission investments in schedule 1. The vSPD model emulates real market half-hourly price and quantity outcomes at approximately 250 nodes across New Zealand's transmission network.

H.31 The approach for identifying the beneficiaries and estimating benefits involves running the vSPD model:

(a) with the investment in question (the factual case)

(b) without the investment in question (the counterfactual case).

H.32 Changes in prices and quantities due to the investment can then be determined at each of the approximately 250 nodes in each half-hour trading period by comparing vSPD results in the factual case with those in the counterfactual case.

H.33 Running the vSPD model requires making input assumptions. In many cases we have applied judgement in selecting an appropriate assumption – particularly in respect of describing the counterfactual case (that is, what would have happened over the long term had the investment in question not been built).

H.34 If removal of the investment (running the vSPD model in the counterfactual case) results in a constraint on the system, this creates price separation between nodes on each side of the constraint. That is, the nodal price downstream of the constraint increases to ration the use of the system to its capacity. In that case, the investment provides load downstream of the constraint with lower electricity prices and better reliability due to the removal of a constraint. Investments in transmission also reduce electricity losses and this provides loss benefits. Loss benefits are typically distributed fairly evenly across the grid.

H.35 The following steps illustrate the approach taken using vSPD for each half hour (refer Figure 20 below for a simplified illustration of the benefit calculation).

(a) Step 1: Solve the final pricing schedule with transmission asset(s) in place (solve 1).

(b) Step 2: Calculate the benefit (producer surplus) to injection and off-take participants (consumer surplus) at each node using the scheduled quantities and prices from solve 1.

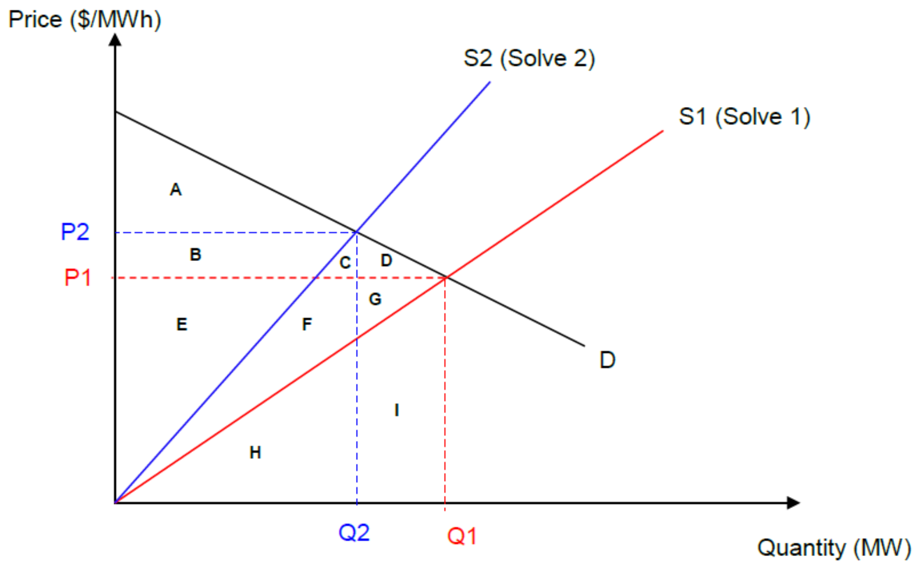
(c) Step 3: Remove the transmission asset(s) and re-solve the final pricing schedule (solve 2). Refer to the section on VPO below for a discussion of this process.

(d) Step 4: Re-calculate the benefit to injection and off-take participants at each node using the scheduled quantities and prices from solve 2.

(e) Step 5: Calculate the change in benefit for each participant at each node due to the removal of the transmission asset(s) (from solve 1 to solve 2). Refer to Figure 20.

(f) Step 6: Those participants with a positive change in benefit at a node from Step 5 are classified as beneficiaries with the calculated change indicating the extent of the benefit.

Figure 20: The calculation of benefits using vSPD



	Solve 1	Solve 2	Change
Demand (offtake)	A + B + C + D	A	B + C + D
Supply (injection)	E + F + G	B + E	F + G - B

We use data from a 'typical' historical year to model benefit

H.36 We have assumed that the distribution of benefits over a recent historical period (2014 – 2018) is a reasonable proxy for the likely distribution of forward-looking benefits of the investments under consideration. This means we have made no adjustments to reflect either demand growth or new grid-connected generation.

H.37 This approach differs from the modelling that supported the 2016 proposal, for which we developed a future scenario (taking a base year and then increasing demand and generation investment to account for growth over time). The Authority considered submissions on that proposal that made the point that the modelling was overly complex. In response, for the 2019 proposal we have simplified the approach by using historical data.

H.38 Our approach is pragmatic. For a future grid investment, it is feasible to forecast a factual and counterfactual scenario. However, this task is much more difficult for a historical investment. In the latter case, the design of a robust counterfactual would involve unravelling all subsequent investments in generation and on the demand side that had been made since the grid investment was built, and then creating a replacement investment sequence that would have occurred under the alternative (counterfactual). This would be a complex undertaking and given the level of assumptions required, it could lead to spurious accuracy.

H.39 The estimate is robust to changes or unusual circumstances that occur in any single year, as we have used multiple separate years of data and averaged the results, to provide a reasonable range of scenarios indicative of a 'typical year'.

H.40 The Authority considered two options for defining the recent historical period:

(a) a two-year modelling period ending 30 June 2018

(b) a four-year modelling period ending 30 June 2018 (currently the Authority's preferred option).

H.41 The Authority chose to estimate benefits using market data over four years and averaged the results from the four separate years (from 2014/15–2017/18). (The Authority also decided to use the same four-year timeframe as the basis for allocating an indicative residual charge.) The Authority considers that this four-year modelling period averages out variances from annual and seasonal patterns, without being too outdated. The advantage of using the two-year period would be that it would mean relying on the most recent data only. However, the four-year data profile more closely matches the decade-long hydrological profile. This means it is more likely to produce results that are representative of long-term benefits. This option would best promote the long-term benefit of consumers, as in the Authority's view – for the reasons set out above – the resulting allocation between customers is more likely to approximate the distribution of the benefits of the investment (compared to a two-year modelling period).

Q66. Over what period should we undertake the vSPD modelling?

Determining the counterfactual scenarios

H.42 Determining the appropriate counterfactual is an important decision, because it affects both the estimated benefit of undertaking the investment (and so whether it is assessed to be efficient) and the distribution of benefits (and so who pays benefit-based charges in respect of the investment).

Fixed or variable virtual price offer (VPO)

H.43 Our vSPD modelling method requires making assumptions about the wholesale electricity prices that would have occurred in the scenario in which the relevant grid investment was not made (the counterfactual scenario). We call these assumptions the virtual price offer (VPO). The Authority considered two options:

(a) a fixed VPO (fixed at $500/MWh)

(b) a variable VPO as described below (currently the Authority's preferred option).

H.44 A VPO fixed at $500/MWh is based on the assumption that a diesel peaker would have been built to support reliability when there is not enough transmission and local generation to meet demand. The Authority does not consider this assumption to be realistic where demand growth is substantial over time, as it is not plausible that demand growth would have been served over a sustained period by expensive peaking generation.

H.45 Developing a counterfactual for an existing investment such as the North Island Grid Upgrade (NIGU) necessitates taking a view on what would have happened if that investment had not been commissioned. For example, perhaps:

(a) diesel peakers would have operated to cover shortages in Auckland

(b) several Auckland-based generators that closed in the factual scenario would not have closed in the counterfactual, and instead would have continued to offer in at their short run marginal cost (SRMC)

(c) Taranaki-based peakers that (in the factual) use the North Island Grid Upgrade to deliver their electricity to Auckland might not have been commissioned or might have been built at different locations.

H.46 The Authority's view that without NIGU a longer term solution would have been found at a cost much less than $500/MWh.

H.47 Our preferred option (variable VPO) is to assume that wholesale prices would have been a maximum of 20% higher in the counterfactual scenario compared to the factual scenario in which the grid investment was built. This assumption is based on experience that sustained prices much higher than 20% over the average are typically not observed. The variable VPO assumption also takes into consideration the absence of demand response in the vSPD model runs, and expectations around increasing levels of demand response over the life of the investments (discussed below). Some customers may reduce their demand in response to high prices, and in particular, very high prices. Further, the variable VPO assumption addresses a simplification of vSPD whereby generator offer tranches, which are an input into vSPD, are fixed. In practice, generators would likely change their offers in response to changing market conditions, or where a transmission line becomes unavailable.[480]

H.48 Lastly, available indications of the future cost of alternatives to transmission (including batteries and distributed generation) also suggest a price in this range is appropriate.

H.49 In the Authority's view, a variable VPO would best promote the long-term benefit of consumers, as – for the reasons set out above – the resulting allocation between customers is more likely to approximate the distribution of the benefits of the investment (compared to a fixed VPO).

H.50 We modelled the benefit-based charge under both the variable and fixed VPO options to enable interested parties to analyse customer impacts of the Authority's preferred option and the alternative option. The results of this modelling are available on request. The Authority currently considers that a variable VPO is the most appropriate approach for the initial benefit-based charge. We look forward to receiving submissions on this matter.

Further discussion of the VPO

H.51 As an investment becomes more fully utilised there would be increasing levels of unserved energy on the downstream side of an investment in the counterfactual case (without the investment), which we price at the level of the VPO. As the quantity of energy subject to the VPO increases, this provides scope for investment in less expensive forms of generation in the counterfactual case. For example, if there are only a few trading periods where VPO is assigned, either this would be left as unserved energy and priced at the value of lost load (VoLL), or a diesel peaker would be brought in at around $500/MWh. As an asset becomes more fully utilised and there are a high number of trading periods where VPO is applied in the counterfactual, this provides the case for a gas-fired peaker to enter, or even less costly forms of base-load generation, priced at around $70/MWh.

H.52 An important point to note is that, the higher the VPO price is in $/MWh, the greater the total benefits from an investment as calculated in vSPD and the higher the benefit to load

[480] Variable VPO does not affect high prices in the counterfactual case unless removal of the investment being assessed leads to unserved energy in the counterfactual. Sometimes vSPD generates high prices in the counterfactual because, where there is a capacity shortage, higher generator offers (from a generator's offer tranche) might be dispatched in the model. We dealt with prices we considered infeasible by removing them in post processing.

(versus benefit to generation). If an existing investment has barely been utilised, the appropriate VPO price may be on the high side. In this case a greater share of the benefits of the investment would accrue to load customers. As the asset becomes more fully utilised, the appropriate VPO price drops, and a greater share of the benefits would accrue to generation. Logically, an investment that is only required during the highest peaks provides benefits related to reliability – and load customers tend to benefit more from reliability than do generation customers.

H.53 For a post-2019 investment, the development of an appropriate VPO assumption will be more important. However, it is also likely to be less problematic. The Authority considers that developing a VPO assumption for a new investment would require less judgement than that for an existing investment. This is because under the Commerce Commission's regulation, Transpower is required to consider alternatives to transmission investment. A future cashflow comparison of the grid solution and a non-transmission alternative could be used to inform a VPO assumption for future grid investments.

Q67. Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

Demand response

H.54 We have not adjusted prices in the counterfactual to take account of potential demand response to the higher prices resulting from the absence of the grid investment.[481] The Authority's view is that this approach results in reasonable estimates of benefit, as we have made various adjustments to address the prospect of unreasonably high prices, including:

(a) the VPO assumption (both variable and fixed) essentially caps higher prices where there is unserved energy in the counterfactual, providing an effect not dissimilar to demand response

(b) in circumstances where VPO does not apply, we dealt with prices we considered infeasible by removing them in post processing

(c) we reduced the effect of outliers in the modelling through separately calculating benefits over four years and then averaging those benefits. For example, in a dry year South Island load benefits substantially from the HVDC (prices in the counterfactual are high), but this only occurred in one year of the four years in the modelling period.

Gross vSPD versus net vSPD versus traditional vSPD

H.55 The Authority's proposal is that the application of the benefit-based charge to the seven major investments be carried out on a net load basis. By this, we mean that we recognise distributed generation (or other generation that is permitted to be netted) behind a point of connection, so that its injection would 'net' off against total demand. For example, if a network's demand is 100MWh, but 50MWh of this demand is supplied by local generation connected behind the point of connection, then the net demand at that point of connection would be 50MWh, whereas gross demand would be 100MWh.

481 The CBA takes into account demand response. Further, previous vSPD modelling included demand response assumptions for two customers. The vSPD modelling for the 2019 proposal does not, and explicitly avoids bespoke adjustments. Bespoke adjustments will be considered following analysis of information in submissions, as outlined in the section titled, 'Treatment of approved/committed distributed generation, entries and exits, and other adjustments.'

H.56 In the Authority's view a net load basis for calculating benefit-based charges for the seven major investments would best promote the long-term benefit of consumers, as it better reflects the benefits that customers receive from grid-delivered electricity. That is, a load customer that derives a substantial proportion of its electricity requirements from distributed generation does not benefit from the grid to the same extent as a load customer of similar size that lacks distributed generation.[482]

H.57 Half-hourly prices and generation/load volumes that are key inputs into vSPD are based on the volumes that the wholesale electricity market 'sees', ie, bid and offers, half-hourly settlement volumes and prices across the 250+ POCs. A 'traditional vSPD' approach automatically nets generation against load if a generator does not 'offer in' to the wholesale market. Thus, a traditional vSPD approach does not actually 'see' distributed generation that does not offer in – it 'sees' only a reduced level of demand at any POC that non-offering-in distributed generation sits behind.

H.58 However, where a generator offers in, often as required by the system operator who has some discretionary powers in this area, its generation volumes will not net off against any load. The offering-in generator will be separate and distinct from the load POC, and vSPD will calculate supplier surplus-related benefits to the extent that the generator benefits from transmission investments in the benefit-based charge.

H.59 Many of the generators that offer in to the wholesale market are grid-connected generators, and therefore would not net against load under a net vSPD approach. However, some of the generators are distributed generation or in some instances, grid-connected co-generation.

H.60 The Authority is proposing a net load approach for applying the benefit-based charge to the seven major investments – that is, to allow certain generation (primarily distributed generation), to net against the load in the network that generation sits behind. For example, a generator connected to Powerco's distribution network (ie, a distributed generator) would net off against Powerco's load and have the impact of reducing Powerco's consumer surplus or level of benefit from benefit-based investments. It is important to note however that a generator in, say, Powerco's Wairarapa network, would not be permitted to net off against a Powerco load in Powerco's Taranaki network, because Powerco's benefit from the grid in respect of its Wairarapa network relates to net load in the Wairarapa district only, independent of load or generation located in Taranaki.

H.61 To implement netting in vSPD, we have analysed the generators that offer in to the wholesale market, and applied judgement to determine which of these generators to net off against their respective loads.

H.62 We developed the following rules to support this judgement:

(a) Generation that is not grid-connected generation is to be netted against load at the relevant POC.

(b) Where there is insufficient load at the POC, netting is allowed against any load at the same physical location (physical location being identified by the first 3 letters of the POC, ie, ABY is Albany).

(c) Where there is not enough load to fully offset the generation at the same physical location, judgement is to be applied as to which POCs in the same network as the

482 See appendix B.

generation the remaining generation is to be netted against.[483] This is to ensure that the load customer's share of charges reflects the net benefit it derives from the grid.

H.63 For generators where judgement was required to determine whether netting should be permitted, we applied the following conditions:

(a) Partially embedded generation to be fully applicable for netting (100% netting permitted).

(b) Notionally embedded generation to be treated as grid-connected generation if it does not meet the definition of distributed generation in the Code.

(c) Grid-connected co-generation to be fully applicable for netting, but only against the grid-connected industrial load it is co-located with.

H.64 Prices are calculated half hourly in vSPD, giving rise to half hourly benefits (consumer surplus and producer surplus). In order to calculate net vSPD we made several manual netting adjustments across POCs and recalculated benefits. The recalculation of benefits was applied annually rather than half hourly, with revised benefits being calculated as a proration according to changes in annual quantities. For example, if demand at a POC was reduced by half due to a netting adjustment, the corresponding revised benefit was reduced by half. This approach makes two assumptions:

(a) first, that prices will not change on account of the netting

(b) second, that there is a linear relationship between volume and benefit.

H.65 While these assumptions do not strictly hold in practice, we consider these assumptions to be reasonable. The adoption of Net vSPD has reduced the estimated charges for the following distributors and direct-connects: Alpine Energy, Aurora Energy, Electricity Ashburton, Horizon Energy, Network Tasman, Norske Skog, NZ Steel, OtagoNet JV, Powerco, The Lines Company, The Power Company, Unison Networks, WEL Networks, Wellington Electricity, Westpower, and Whareroa Cogeneration Limited.

Q68. Do you agree with the approach we have taken to netting distributed generation? Do you agree with the application of the netting policy for particular generator(s)? If not, please provide information on particular generator(s) so that we can consider whether to amend the netting arrangements.

Investments initially subject to the benefit-based charge

H.66 The seven major investments that we propose to be initially subject to the benefit-based charge are listed at clause 13(b) of the proposed guidelines and in Table 15

H.67 As discussed in appendix B, the vSPD model has been used to allocate the costs of seven of the major investments commissioned since 2004 with an approved value over $50 million at the time of approval. For the remaining three investments that meet these criteria (North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support) the vSPD modelling was not able to identify material benefits for transmission customers commensurate with the costs of these investments.[484]

483 This would be POCs where there is no constraint expected between them and the relevant POC.

484 See appendix B.

Table 15 Investments modelled as being subject to the benefit-based charge

Investment	Reference
NIGU	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/
HVDC (Poles 2 and 3 combined)	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/
LSI Renewables	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/
Wairakei Ring	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/
BPE-HAY reconductoring	http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/bunnythorpe-haywards-a-and-b-lines-conductor-replacement-investment-proposal/
UNI dynamic reactive support	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/ This investment has been combined with the North Island grid upgrade investment so there is no dedicated vSPD run for this investment.
LSI Reliability	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/

H.68 The Authority decided to group Poles 2 and 3 of the HVDC on the basis that they essentially provide a single function. Note that we do not necessarily envisage that Transpower would be grouping new investments or new investments with existing investments for post-2019 investments. This is because parties considering whether to support a *new* investment would likely consider the incremental benefits and incremental costs of the new investment.[485]

Modelling scenarios provided

H.69 In addition to presenting modelling of the Authority's core proposal, we have provided some alternative options for parties to consider.

H.70 In the '2019 Proposal impacts modelling' Excel file, refer to columns W and X in the sheet titled 'Results'.[486] By changing the number selected in cells X3 and X9, parties can switch between the eight combinations of the options listed below.

485 That is, they would consider the benefits they get from the grid augmented by the existing investment against the benefits they get from the grid notLCE refunded includes LCE and residual LCE that is paid to Transpower. This is not the same as the LCE generated by the assets and investments, because some LCE is used to fund the FTR market in the first instance.

H.71 Benefit-based charge alternatives modelled:

(a) Net vSPD benefit-based charge, with variable VPO (the proposal)

(b) Net vSPD benefit-based charge, with fixed VPO at $500/MWh

(c) Traditional vSPD (no manual netting applied), with variable VPO

(d) Traditional vSPD (no manual netting applied), with fixed VPO at $500/MWh

H.72 Residual charge alternatives modelled:

(a) Gross volume on load (MWh pa)

(b) Gross anytime maximum demand (AMD) (the proposal).

Treatment of approved/committed distributed generation, entries and exits, and other adjustments

H.73 Our proposed charges, indicative charges and other impacts modelling are calculated using data from 1 July 2014 through to 30 June 2018. For historical benefit-based investments we consider that using historical data as modelling inputs provides a reasonable proxy for the future benefits parties will receive over the life of investments. For the residual charge we consider that historical data provides a reasonable proxy for customer size.

H.74 However, we will consider submissions where parties consider that the ex-post data or modelling outputs require adjustment. Examples of the types of matters we anticipate parties may wish to specifically consider in their submissions are:

(a) for an entering or exiting customer, or where an entering or exiting embedded customer, will cause or has caused, a material ongoing change in demand (or generation)

(b) where a material problem with the data is identified, for example, to address a 'double counting' issue.

H.75 There is an exception to the ex-post (historical) data only rule – where large new distributed generation/netting generation has been consented, is financially committed and is intended to be commissioned by the time a new TPM is in place. Where distributed generation/netting generation that met these conditions was identified, we reduced half-hourly load at the relevant POC in vSPD by the amount of generation expected (in essence, netting), before running vSPD. Note this relates to the benefit-based charge only as the residual charge is a gross charge, and thus no netting is permitted.

H.76 The Authority has identified two large distributed generators that met the conditions:

(a) We reduced net load at Kaikohe to account for the 31.5 MW Ngawha expansion, expected to be commissioned in 2020/21. However, the adjustment was subsequently backed out on the basis of this new generation being grid-connected. We did not calculate vSPD charges for the expected new grid-connected generation, because we do not expect Ngawha to receive net benefits from investments included in the benefit-based charge, and because we have not adjusted charges for entering or exiting customers.

(b) We reduced net load at Kawerau to account for the 20 MW Te_Ahi_O_Maui geothermal that is consented/financially committed and is expected to be in place by 2022.

Q69. Do you consider that the data or modelling outputs used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide detailed reasoning/quantitative calculations.

Technical details of the TPM vSPD beneficiary simulation

H.77 For the TPM beneficiary simulation, we use data from July 2014 to June 2018 (four years of data) to estimate the benefit gained at each grid location (GXP/GIP).

H.78 In most cases, the factual case is the same as final pricing cases during this four year period. However, the value of lost load (VoLL) is adjusted in each case according to the respective counterfactual case.

H.79 In all simulations, Te_Ahi_O_Maui geothermal is added and assumed to be always at 90% capacity of 20 MW. Consistent with the netting policy, this generation is permitted to be netted off against load at Kawerau. vSPD calculates this automatically as Te_Ahi_O_Maui reduces load at Kawerau.

H.80 In all simulations, Ngawha2 stage 1 geothermal is added and assumed to be always at 90% capacity of 28 MW. Note, we decided to adjust NgaWha expansion on the basis that it would be grid connected and not distributed generation. The original adjustment has been manually backed out of the vSPD output files. This adjustment is undertaken using half-hourly data, in Excel.

Factual case simulation

H.81 This section describes the simulation of the factual case.

H.82 The factual case is the case where all grid upgrade projects (GUPs) have been built and are in service. The factual case is based on data from July 2014 to June 2018, with the exception of the Lower South Island (LSI) reliability project where the project was built and completed within the July 2014 to June 2018 timeframe.

H.83 For the special case of the LSI reliability project, transmission data is modified to simulate both the factual and counter factual cases (case without grid upgrade project).

H.84 The factual case is essentially the SPD case between July 2014 to June 2018 with new embedded generation added as mentioned above.

H.85 In case of HVDC, only the energy market is modelled.

H.86 In case of LSI reliability, transmission data is modified as if the LSI reliability grid upgrade project is in place.

No NI grid upgrade project (NIGU) simulation

H.87 The North Island Grid Upgrade (NIGU) Project to provide a secure supply of electricity to Auckland and Northland was officially completed in December 2012.

H.88 The factual case is final pricing case.

H.89 In order to approximately model the old grid before the NIGU project, the following was applied:

(a) The penalty for energy deficits is fixed to VoLL.

(b) The following transmission lines that are built for the NIGU project are removed from the system (PAK_T1, PAK_T2, PAK_T3, 'PAK_WKM_1 & 2, OTA_PAK_3 & 4, PAK_PEN_3 and HOB_PEN_1).

(c) Note that HOB_PEN_1 belongs to the North Auckland and Northland grid upgrade project. However, we needed to remove it to avoid overloading on the 110KV transmission line in the case of no NIGU.

(d) We removed the new NIGU substation (PAK2201, BHL2201, BHL2202).

(e) We added back the old 110KV substation at Pakuranga (PAK1101).

(f) We added back the old transmission lines and transfomers (ARI_PAK_1, PAK_PEN_1, OTA_PAK_1, PAK_T5 and PAK_T6)'

(g) Capacity and parameters applied for the old transmission lines and transformers are as of 21 July 2009.

(h) We redefined the upper North Island stability constraint as it was on 21 July 2009 with a limit of 1000 MW (or 1120 MW to be more optimistic).

(i) Ramp-rate constraints are ignored.

(j) A virtual generator is added at OTA2201 with 'unlimited' capacity and offered at either a fixed price of $500/MWh or at a variable price defined by historical prices at OTA2201.

No North Auckland and Northland grid upgrade project

H.90 The North Auckland and Northland (NAaN) project reinforced transmission into the Auckland Region and across the harbour to North Auckland and the Northland Region. It added a new 220 kV of transmission capacity to the National Grid by providing 37 km of underground cable between the Pakuranga, Penrose, and Albany substations.

H.91 The NAaN project was officially completed and the connection was commissioned in February 2014.

H.92 The factual case is the final pricing case with the same VoLL ($3000/MWh) as the counter-factual (no NAaN grid upgrade) case.

H.93 In order to approximately model the old grid before the NAaN grid upgrade, the transmission line between the Hobson street substation and the Wairau road substation (HOB_WRD_1) is removed so that demand in North Auckland and Northland is served through old transmission lines between the Otahuhu and Henderson substations.

No Wairakei Ring grid upgrade project simulation

H.94 The Wairakei Ring grid upgrade project was officially completed in June 2014.

H.95 The factual case is final pricing case.

H.96 In order to approximately model the old grid before the Wairakei Ring upgrade, the following is applied:

(a) The penalty for an energy deficit is fixed to VoLL.

(b) The new transmission line between Whakamaru and Wairakei (WKM_WRK_1) that was built for the Wairakei Ring project was removed.

(c) The capacity and parameters of the following transmission lines were adjusted back as they were on 21 July 2009. (ATI_OHK_1, ATI_WKM_1, OHK_WRK_1, THI_WKM_1, THI_WRK_1, PPI_THI_1).

(d) Note that THI_WKM_1, THI_WRK_1 and PPI_THI_1 are similar to WKM_PPI_WRK_1, WKM_PPI_WRK_2 and WKM_PPI_WRK_3 respectively.

(e) We re-applied old winter permanents constraints such as:

(i) ATI_OHK.1__WKM_PPI_WRK.1__:S__WKM_WRK__OHK__LN

(ii) ATI_OHK_1_W_P_1

(iii) ATI_WKM.1__WKM_PPI_WRK.1__:S__WKM_WRK__ATI__LN

(iv) ATI_WKM_1_W_P_B_z

(v) OHK_WRK_1_W_P_2A_z

(vi) OHK_WRK_1_W_P_A_z.

H.97 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines in all trading periods.

H.98 Ramp-rate constraints are ignored.

H.99 A virtual generator is added at OTA2201 with ‘unlimited’ capacity and offered at either a fixed price of $500/MWh or at a variable price defined by historical prices at OTA2201.

Lower South Island renewables grid upgrade

H.100 The Lower South Island (LSI) renewables grid upgrade increases the capacity mainly on four transmission lines (LIV_WTK_1, AVI_WTK_1, CYD_ROX_1 and CYD_ROX_2).

H.101 The project was staged with CYD_ROX_2 capacity doubled in April 2014, CYD_ROX_1 capacity doubled in February 2015, AVI_WTK_1 capacity doubled in June 2015, and lastly LIV_WTK_1 capacity doubled in May 2016.

H.102 There are other works around this project, but these are ignored to simplify the simulation.

H.103 The factual case is final pricing case.

H.104 In order to approximately model the old grid before the LSI renewable upgrade, the following was applied:

(a) The penalty for the energy deficit is fixed to VoLL.

(b) The capacity and parameters of the following transmission lines were adjusted back as they were on 21 July 2009 (LIV_WTK_1, AVI_WTK_1, CYD_ROX_1 and CYD_ROX_2).

(c) We re-applied the old winter permanents constraints such as:

(i) AVI_WTK_1_W_P_1A

(ii) AVI_WTK_1_W_P_2A

(iii) CYD_ROX_1&2_W_P

(iv) LIV_WTK_1_W_P_1A

(v) LIV_WTK_1_W_P_2A.

H.105 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines for all trading periods.

H.106 Ramp-rate constraints are ignored in counter-factual cases.

H.107 Virtual generation is added at OTA2201 and INV2201 with ‘unlimited’ capacity and offered at either a fixed price of $500/MWh or at variable price defined by historical prices at OTA2201 and INV2201.

Lower South Island reliability grid upgrade

H.108 The Lower South Island (LSI) reliability grid upgrade increases the transmission capacity in/out and through the Lower South Island 110 KV grid. The changes included increased capacity on the 220KV/110kV transformers at Halfway Bush (HWB), Roxburgh (ROX) and Invercargill (INV). A new 220KV/110kV transformer was also built at Gore (GOR).

H.109 The factual case is based on the final pricing case with new transformers added if they were not in place (ie, due to commissioning during the analysis time frame).

H.110 In order to approximately model the old grid before the grid upgrade, the following was applied:

(a) The penalty for energy deficit is fixed to VoLL.

(b) The 220kV/110kV transformers at HWB, ROX and INV were replaced by old transfomers based on data at or before July 2014.

(c) The 220kV/110kV transformers at GOR were removed.

(d) We re-applied old winter permanents constraints such as:

(i) EDN_INV_1_W_P_1

(ii) ROX_T10_W_P_1.

H.111 In order to simplify the simulation run, we applied the winter capacity and constraints for these lines for all trading periods.

H.112 Ramp-rate constraints were ignored.

H.113 A virtual generator was added at GOR0331 with ‘unlimited’ capacity, although this was not required in the simulation.

Bunnythorpe-Haywards transmission replacement

H.114 Two 220kV transmission lines were decommissioned and replaced with like-for-like transmission lines.

H.115 The factual case is based on the final pricing case.

H.116 In order to approximately model the grid without these two transmission lines, the following was applied:

(a) We removed the BPE_HAY_1 and BPE_HAY_2 transmission lines.

(b) The Wellington stability constraint limit was reduced to 700 MW.

(c) The Paraparaumu (PRM) substation was connected back to Pauatahanui (PNI).

H.117 Ramp-rate constraints were ignored.

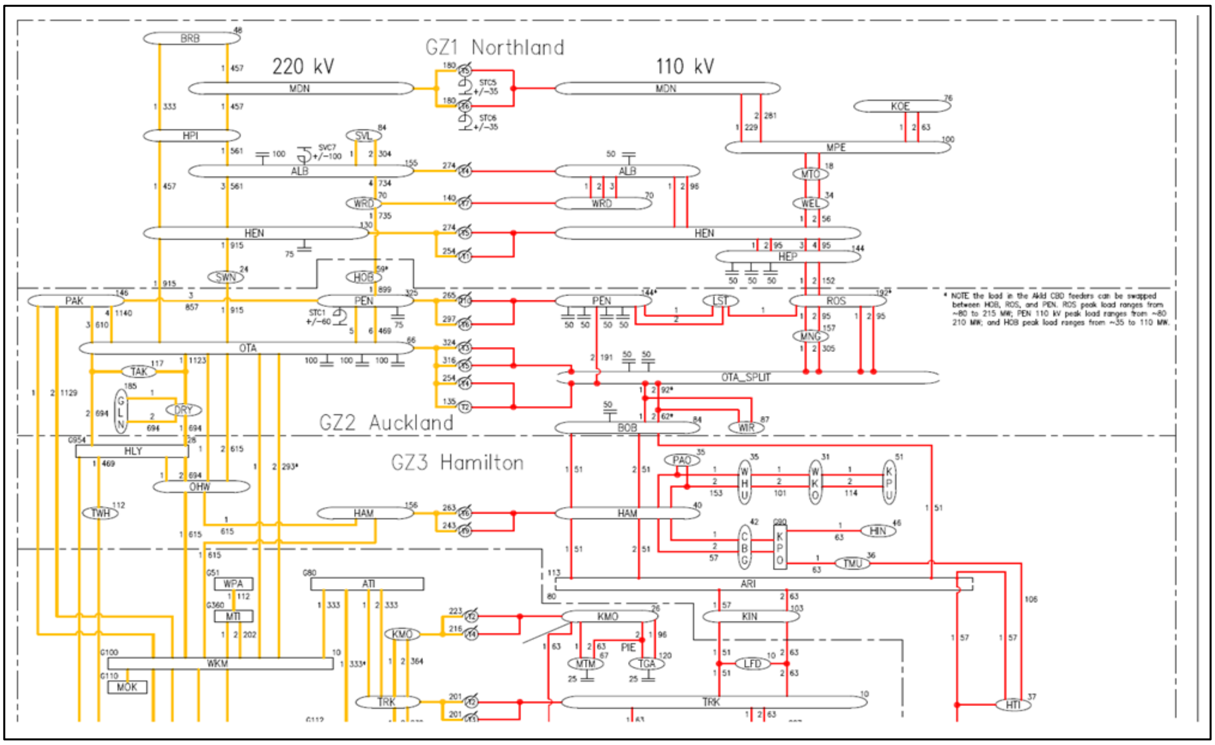
H.118 Virtual generation was not required.

Infeasibilities

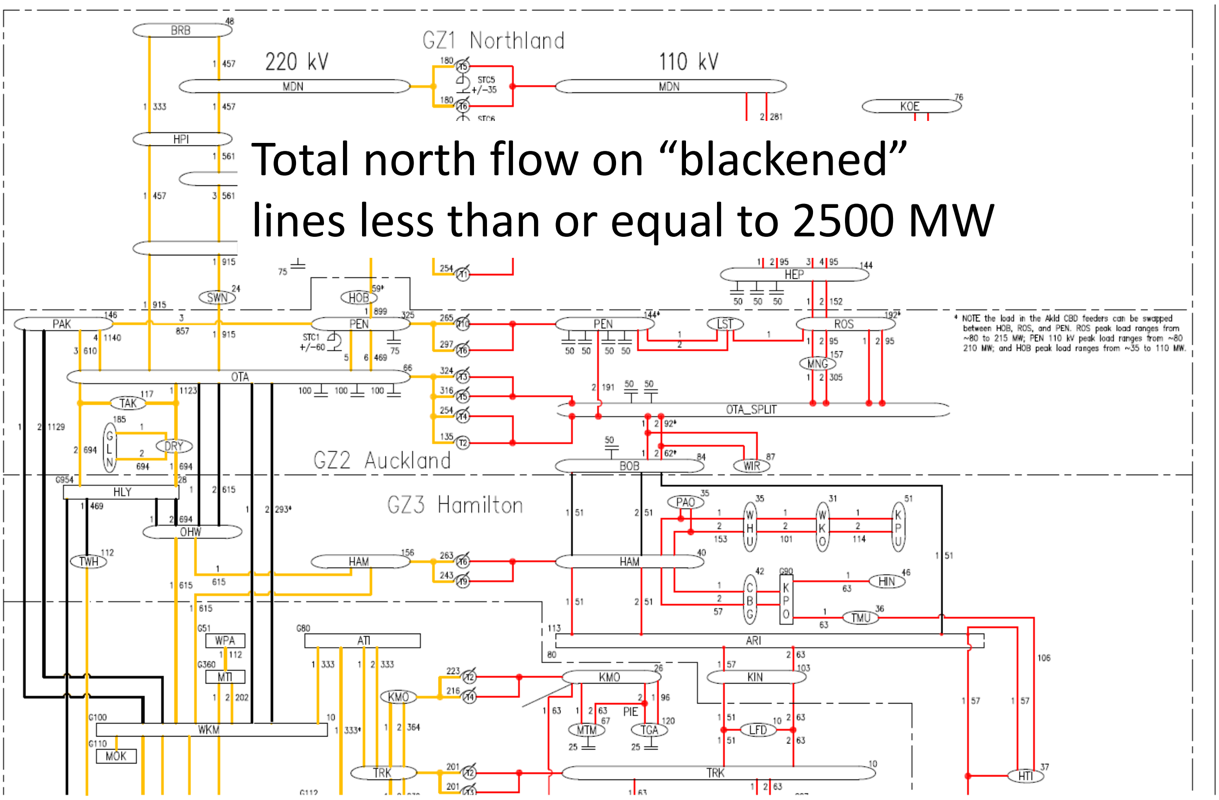
H.119 Grid configuration ‘with and without’ the transmission investment being assessed is modelled in vSPD to best approximate actual grid configuration, and the grid configuration that would be in place if the investment being assessed had not been undertaken. This involves taking out transmission assets and putting back in what was there before, with other adjustments, as required. Due to the complexity of grid configuration and its gradual development over time, vSPD sometimes calculates infeasible prices. In the final vSPD run we dealt with any remaining infeasible prices (prices above $10,000/MWh) by removing them in post processing.

An example of the application of the vSPD factual versus counterfactual simulation to the North Island grid upgrade

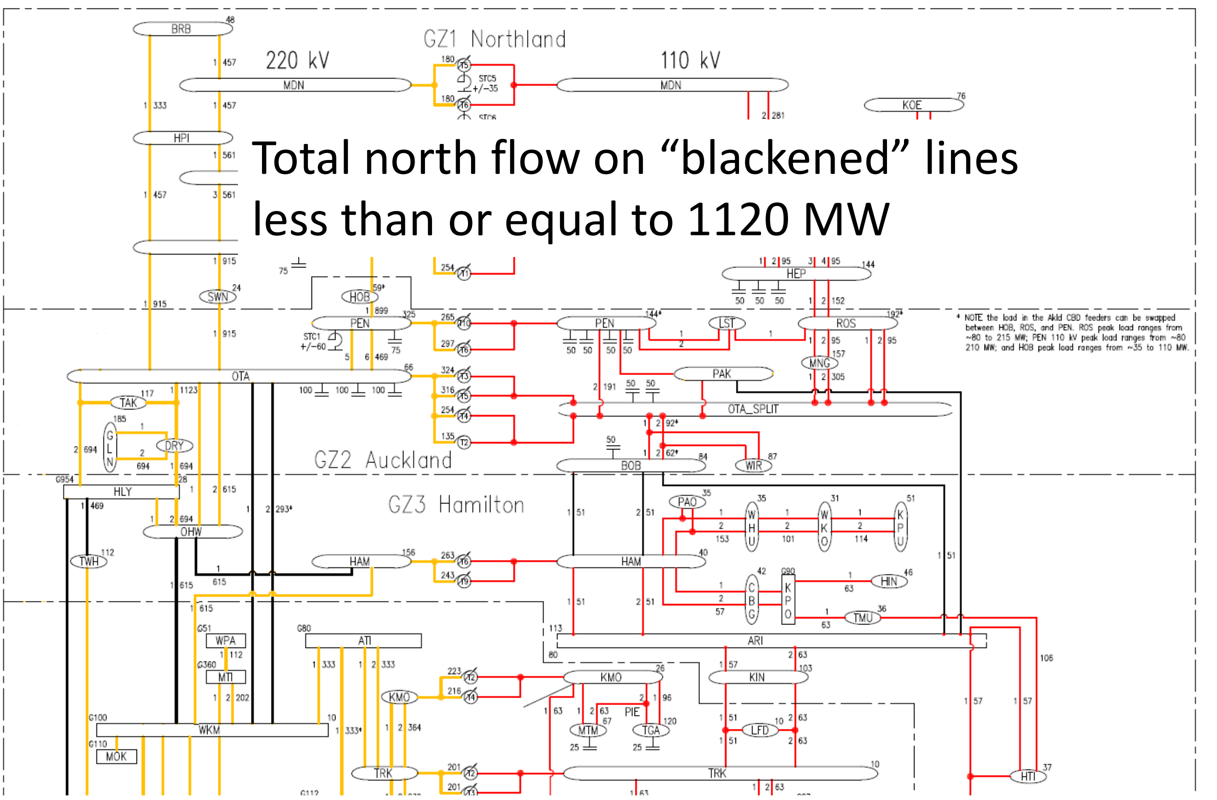
With NIGU



With NIGU constraint



Without NIGU



Modelling of indicative loss and constraint excess

H.120 Under the potential Code change on LCE that we are presenting for comment alongside the Authority's proposal, LCE revenue would be allocated to each of the connection assets and groups of assets or investments in the interconnected grid (including benefit-based charge investments and investments with costs recovered through the residual charge). LCE revenue is effectively treated as a partial refund of transmission charges to transmission customers. The allocation contemplated under the potential Code change would effectively reduce the revenue recovered in respect of each grouping of assets or investment in proportion to the LCE generated by that grouping of assets or investment.

H.121 The allocation of LCE to benefit-based investments has been modelled on an indicative basis and is available on the Authority's EMI website. This allocation has *not* been used in either the allocation of major investment costs in schedule 1 or the modelling of indicative charges for the proposal. The LCE allocation to benefit-based charge investments is provided for informational purposes only.

H.122 For this indicative modelling, the magnitude of the LCE funds used to offset transmission charges is sourced from information available on Transpower's website.[487] The LCE that could be refunded to benefit-based investments was identified using SPD, whereby each investment is defined as a bundle of SPD branches, and SPD calculates the LCE generated by each branch. A significant amount of LCE would be refunded to the HVDC ($7.5m) and the North Island grid upgrade ($5.5m). Total LCE is currently around $50m per annum.

H.123 The refund of LCE to connection assets was not modelled. Total LCE refunded to connection assets is normally around $5 to $6 million per year.

Q70. In addition to the specific questions above, do you have any other comments on the matters covered in Chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).

487 Aavailable at: https://www.transpower.co.nz/industry/revenue-and-pricing/pricing. LCE refunded includes LCE and residual LCE that is paid to Transpower. This is not the same as the LCE generated by the assets and investments, because some LCE is used to fund the FTR market in the first instance.

Appendix I Questions to assist submitters

You are welcome to comment on any matter relevant to the Authority's proposal, including on any part of the issues paper, including the appendices and supporting technical materials.

We have posed some questions throughout the 2019 issues paper including in the appendices to help prompt answers to specific details. These questions are repeated here.

Please do not feel that you need to limit your responses to the consultation questions or that you need to answer them all. Instead these questions can be treated as a guide and you may wish to answer any you consider are important. Please explain your answers in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Chapter 2

I.1 Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

Chapter 3

I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines?

Chapter 4

I.3 Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?

I.4 Do you have any comments on the matters covered in chapter 4?

Chapter 5

Refer Questions I66-I67.

Chapter 6

I.5 How long should Transpower have to complete its development of the TPM and why?

I.6 What checkpoints (if any) should the Authority set in the TPM development process?

I.7 How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

I.8 In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

Appendix A

I.9 What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

Appendix B

General matters

I.10 Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

Connection charge

I.11 Should the current guidelines on connection charges be largely retained or are changes required?

I.12 Should first-mover disadvantage be addressed in the TPM, and if so, how?

Benefit-based charge

I.13 Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

I.15 Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

I.16 How should the covered cost of the investment be defined?

I.17 How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?

I.18 Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

I.19 Should the guidelines distinguish between high-value and low-value investments?

I.20 If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

I.21 What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

I.22 What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

I.23 How should the costs of the investments that are not covered by the benefit-based charge be allocated?

I.24 Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

I.25 Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

I.26 Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

Residual charge

I.27 Should the guidelines provide for a single residual charge or multiple residual charges?

I.28 Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?

I.29 Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

I.30 If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

I.31 Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

I.32 If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

I.33 Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

I.34 Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

I.35 Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

I.36 Should the residual charge apply to both generation and load customers, or only to load customers?

Other

I.37 Are the proposed provisions relating to adjustments appropriate?

I.38 Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?

I.39 Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?

I.40 Should the price cap be specified as a percentage of electricity bills or in some other way?

I.41 Should the price cap apply only to load customers, or to generators as well?

I.42 How should the price cap be funded?

I.43 Are the proposed additional components appropriate? If not, what changes should be made?

I.44 Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

I.45 Should the peak charge be applied only where the grid would otherwise be congested?

I.46 Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

I.47 Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

I.48 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?

Appendix C

I.49 Do you have any comments on the matters covered in this appendix C?

Appendix D

I.50 Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?

I.51 Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

I.52 Do you agree with the conclusions of appendix D?

I.53 Do you have any comments on the matters covered in this appendix D?

Appendix E

I.54 Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?

I.55 Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

I.56 Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

I.57 Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

I.58 Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

I.59 Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

I.60 Do you have any comments on the matters covered in this appendix E?

Appendix F

I.61 Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

I.62 Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?

I.63 Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

I.64 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

Appendix G

I.65 Do you have any comments on the matters covered in this appendix G?

Appendix H

I.66 Over what period should we undertake the vSPD modelling?

I.67 Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

I.68 Do you agree with the approach we have taken to net distributed generation? Do you agree with the application of our netting policy for particular generator(s)? If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.

I.69 Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.

I.70 In addition to the specific questions above, do you have any other comments on the matters covered in Chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A).