Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM

Decision

10 June 2020

Executive summary

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

The Electricity Authority has decided on new guidelines for transmission pricing.

We expect the new approach to paying for transmission assets will deliver significant benefits to consumers. The 2020 guidelines will give electricity consumers and generators much-improved signals of the cost and value of using the transmission grid. They will stop overly high transmission charges for using electricity at times when consumers most want it and will stop rewarding parties that shift costs on to other consumers for no overall benefit.

The guidelines will also promote the right investment at the right time in renewable generation, transmission and electrification of industrial processes and transport, as we transition to meet New Zealand's low-emissions challenge at least cost to consumers.

The Authority estimates the new approach to transmission pricing will deliver consumers a net quantified benefit of $1.3 billion (within a range of $0.3b–$2.2b) over the next 30 years. This estimate is conservative.

This paper sets out and explains the Authority's decision to introduce new guidelines and responds to issues raised by stakeholders through the consultation process. It also outlines the next steps and timeframes as Transpower develops a new proposed transmission pricing methodology (TPM) in accordance with the new guidelines.

Benefit-based transmission charging

At the heart of the new guidelines is a benefit-based approach — those who benefit from transmission investments will pay for them. Benefits from transmission investments may include better energy prices and reliable energy supply.

Benefit-based charges will replace the main charges under the existing TPM — the regional coincident peak demand (RCPD) and the high voltage direct current (HVDC) charges. The benefit-based charges will cover the remaining costs of seven recent major grid investments; their coverage will also cover grid investments made from July 2019.

A residual charge will recover overheads and unallocated costs and as a transitional measure, the remaining costs of all other historical transmission investments currently in place. The residual charge is expected to reduce over time as new grid investments are captured in benefit-based charges and existing transmission assets are further depreciated.

The residual charge will be allocated to transmission customers based on a historic measure of anytime maximum demand as a proxy for customers' relative size and ability to pay. The allocation will gradually adjust over time to reflect changes in customers' relative size.

Wholesale market electricity prices will work alongside the new charges to manage congestion as a more accurate, responsive and targeted signal of the cost of using the grid. Emerging technologies, real time pricing and new business models are expected to make this an increasingly effective and efficient way to manage grid congestion.

The new guidelines also cover:

- connection charges (largely unchanged)
- a stand-alone cost test for the prudent discount policy
- a transitional congestion charge and other additional components which Transpower must include if, in its reasonable opinion, that would better promote the Authority's statutory objective.

Removing opportunities to avoid charges and barriers to investment

The transmission network is a massive national asset and we want New Zealanders to use the grid to the best extent. This means:

- better signals of the true cost of using the grid — without high transmission charges if the grid is not congested, and grid investments paid for by those who benefit from them
- better use of the grid as New Zealanders take up electric vehicles and electrify process heat
- better investment in transmission — the right amount and at the right time.

The new guidelines support these aims. We disagree with submissions that suggest they are mutually exclusive. The Authority considers a new TPM is necessary to address serious defects with the current approach to transmission pricing. These defects create unnecessary costs for consumers.

The current RCPD charge allocates the cost of existing transmission assets based on how much people consumed at peak in the previous year, regardless of whether there is a grid capacity constraint. It is like having a road congestion charge to discourage people from travelling in places or at times without any sign of travel delay or gridlock. The charge is recognised by many to be overly high.

As a result, the RCPD charge unnecessarily suppresses electricity demand at peak times. It sends a strong signal to customers to invest in technologies such as batteries and distributed generation to avoid paying transmission charges. We have observed and been told this includes running diesel generators to avoid using the grid at potential RCPD times. These generators are expensive to run and unnecessarily increase carbon emissions.

These investments and actions add costs to producing electricity and just shift transmission charges on to other consumers as overall transmission costs still need to be paid for. This ultimately increases the overall cost of consuming electricity in New Zealand.

The current TPM spreads the cost of transmission across all customers, regardless of whether they benefit or not. This is a significant problem because it may cause customers in a region to favour a grid upgrade over more efficient local solutions, such as a demand management technology. This is because the rest of the country will pay for most of the grid upgrade. These inefficient investment choices also increase costs for consumers.

The HVDC charge is also problematic. South Island generators are currently required to pay for all costs of this link between the South and North Islands despite North Island generators benefitting from the HVDC link as well as New Zealand electricity consumers.

In effect, the HVDC charge acts like a tax on South Island generation. It inefficiently discourages investment in South Island generation. Dampening investment in generation pushes electricity prices higher than they need to be. The Authority considers the new guidelines will contribute to unlocking renewable generation in the South Island and lower generation costs for the long-term benefit of New Zealand consumers.

Efficient pricing will deliver significant benefits to consumers

The approach to transmission charges specified in the Authority's new guidelines seeks to resolve these long-standing issues.

One feature is the annual benefit-based and residual charges will be more fixed by design, which significantly reduces the incentive to take actions that shift costs to other consumers. However, having considered submissions the Authority has expanded ways to allow fixed charges to be adjusted under certain conditions to reflect changes in circumstances.

The Authority considers that benefit-based charges should increase scrutiny of proposed transmission investments. Consumers who would benefit and end up paying for a grid investment will have a greater interest in having a say on that investment, to make sure it is fit for purpose and better than alternative solutions. This should result in better information for Transpower and the Commerce Commission on grid investment proposals, solutions that best meet the needs of those who would use the grid investment and greater consumer acceptance of grid investment decisions in their regions.

The Authority also considers greater transparency of who benefits from and who pays the costs of transmission investments will make the TPM more durable.

On the contentious issue of whether to apply benefit-based charges to historical investments, the Authority has adopted its 2019 proposal to apply these charges to seven major existing investments, given it considers this would better promote the efficiency of a new TPM, for the long-term benefit of consumers.

This is on the basis that there is an increasing consensus that the charging methodology for, at the least, existing HVDC assets must change to better reflect benefits.

Further, without making this decision, there is no viable alternative to prevent beneficiaries of new transmission investments paying for those new investments while still paying for a portion of existing geographically remote investments they do not benefit from. The Authority considers that submitters were unable to provide a workable solution to this problem.

The Authority has estimated that the net benefits to New Zealand electricity consumers under the new guidelines will be substantial — with most benefits generated through enabling more consumption at peak times and through lowering average wholesale electricity prices and transmission cost (relative to trends under the current TPM).

The Authority's cost benefit analysis estimates a TPM consistent with the new guidelines will deliver consumers a quantified net benefit of $1.3 billion over the next 30 years, within a possible range of $0.3b–$2.2 billion over the next 30 years. This excludes associated unquantified benefits which the Authority considers would be considerable.

While these quantified net benefits are substantial, the CBA remains just one of the factors the Authority considered in coming to its decision.

Protection for consumers

Some submitters have expressed a concern the Authority's approach will have a negative impact on many consumers. We disagree. Further, the Authority considers it is unreasonable to expect parties currently being charged in excess of benefit to simply keep paying charges that are too high.

The 2020 guidelines will rebalance the transmission charges, not increase them overall. Initially, some transmission customers will pay more and others less than they would under the current TPM.

For most customers the initial impact is modest. In regions that are likely to experience an increase in transmission charges, the increase in the average household bill is estimated to be an average of $19 a year.

The Authority wants to minimise any price shock on household and business consumers. The guidelines include a 3.5 per cent cap on the amount total electricity bills may increase as a direct result of the change (after inflation and volume growth). This addresses the small number of cases where our modelling shows the rebalancing may lead to a larger increase in household electricity bills.

Charges for some industrial consumers will rise significantly. It is likely these consumers have been successful in avoiding transmission costs to date — a rational response to the incentives provided by current transmission pricing, but not the best outcome for New Zealand consumers as a whole. These industrial consumers too will be protected by a cap to allow them to adjust to the new charges. The cap on charges for industrial customers will phase out by increasing incrementally after five years.

The Authority considers this rebalancing of charges will benefit consumers throughout New Zealand. These benefits come from reduced prices and the consumer benefits of increased electricity consumption at peak times, supported by increased generation investment that will result in reduced average prices for consumers.

A new TPM to reflect the change in circumstances

There has been consistent and long-term pressure for TPM reform. The previous TPM came into effect in April 2008 and has been under review since 2009.

The TPM review has been contentious and, based on feedback during consultation, there is no single option that will deliver consensus. The Authority acknowledges the need to end TPM reform has been the one clear and consistent message throughout this process from a wide range of stakeholders.

Most parties agree TPM reform is necessary. Circumstances have changed significantly since 2008 and the current TPM is not fit for purpose.

For example, a significant amount of transmission investment has been commissioned since 2008 and a lot more investment is currently forecast. It is critical we avoid amplifying the inefficient behaviours and outcomes from the current TPM when those new investments are undertaken.

The imperative to reduce carbon emissions will materially change the use of the transmission grid. The potentially high demand for renewable generation and electrification would mean a significant economic transition that relies on grid-supplied renewable electricity alongside other options for low-emissions energy.

More generally, innovation and technological advances are significantly changing the way our electricity system operates and the way people interact with the system. This includes advances in computational power and new technologies including small-scale distributed generation, batteries and intelligent energy management systems that are expected to be very beneficial for consumers and the environment. A TPM needs to accommodate these technologies without distorting incentives. For example, a TPM should not encourage people to adopt new technologies simply to shift transmission charges to others.

In the Authority's view, the new guidelines should be implemented before significant new investment in transmission and generation takes place as part of the transition to a low-emissions economy. The new guidelines will support this transition at the lowest overall cost for New Zealanders.

This review of transmission pricing is one of several Authority projects aimed at enabling an efficient electricity sector in response to a changing environment. The TPM review is one of several pricing projects (with distribution and real time pricing) that seek to achieve more efficient, cost-reflective pricing in which people pay for the service or the product they get.

If transmission pricing, combined with nodal pricing, reflects the true cost, it will send the right signal to potential investors and more accurately reflect where additional supply is required to meet demand. It will also send the right signals to consumers to manage their demand up and down — ultimately allowing them to participate and exercise choice.

Acknowledging the divergent views on the right TPM for the future of New Zealand

The Authority's review process has benefitted from the divergent opinions and analysis put forward in submissions. We have appreciated stakeholders' comprehensive feedback over the years and more recently on the 2019 TPM Issues Paper, through written and oral submissions and workshops.

Some areas are more contentious than others and this decision document provides a thematic response to feedback received from stakeholders on the 2019 Issues Paper and Supplementary Consultation Paper. Our aim is to set out the rationale behind our decision and how submissions have influenced our thinking.

We've considered the concerns and suggestions and made amendments to what we proposed, where we accepted this would be for the long-term benefit of consumers. For example, this decision paper sets out the Authority's decisions to recover the benefit-based charge using depreciated historical cost, to update the residual allocator regularly and to allow a prudent discount to avoid exceeding stand-alone cost. The paper also explains where the Authority has determined not to make changes after considering submissions.

The Authority is clear, however, that no single option will deliver consensus and that while imperfect, the Authority's solution is the best available and materially better than any other viable option. The Authority's view is that submitters were unable to identify an alternative solution that better addresses the flaws in the current TPM for the long-term benefit of consumers.

Next step — development of a proposed TPM

We are very grateful for the level of engagement over the past ten years and we look forward to continuing to work closely with Transpower and stakeholders on progressing the proposed TPM.

The next step is for Transpower to develop a proposed TPM, in accordance with the new guidelines and the relevant sections of the Electricity Industry Participation Code 2010.

Transpower has until 30 June 2021 to do this.

The Authority must then approve the proposed TPM before consulting on it, then determining whether to adopt it into the Code. Transpower would then need to implement any final TPM. We will be working closely with Transpower to ensure the TPM process is carried out in a timely manner on behalf of all consumers.

The Authority acknowledges the new TPM guidelines are a significant change. We have made sure there are transitional measures in place to manage the change and provide certainty — for example, a cap on the extent that total electricity bills can rise due to a new TPM and the option for a transitional congestion charge.

For example, the Authority heard stakeholders' concerns about a pricing methodology without a transmission peak charge. We accept there is a risk that demand peaks may not be adequately controlled if the mitigants the Authority is expecting to be in place are not implemented as anticipated.

The Authority is committed to work with stakeholders and Transpower to manage transitional risks. This includes progressing work on a transitional congestion charge as soon as possible, through an industry workshop led by Transpower.

New Zealand and the rest of the world are working through the significant health, social and economic impacts of the COVID-19 pandemic and the outlook is as yet unclear. Increased certainty for new investment is even more important at this time.

The Authority appreciates the extent of the short-term uncertainty but sees no good reason to delay the process of developing a new TPM because of COVID-19 (or other uncertainties, like the outcome of the review of the future of the Tiwai Point Aluminium Smelter). We have no strong reason to believe that a significant negative demand shock would change the conclusion that a TPM, consistent with the 2020 guidelines, would be for the long-term benefit of consumers.

To the contrary, the need for change has become more urgent. The Authority's decision to issue new TPM guidelines puts a full stop on a decade-long review of a TPM that has been a constant source of industry tension. This improves certainty.

The transmission grid is owned and operated by Transpower. The maximum revenue Transpower can recover is set by the Commerce Commission. The Authority sets the guidelines for how Transpower can set its charges to recover the approximately $800m annual cost of building and running the national transmission grid to electricity generators, distributors and direct consumers. This cost is expected to rise to over $1 billion in the next ten years.

Structure of this decision document

Chapter 1 introduces the Authority’s decision on the guidelines and outlines the next steps.

Chapter 2 explains the problem: why the Authority considers improvements to the 2006 guidelines and TPM are necessary and urgent, given the significant inefficiencies caused by the current TPM and significant changes in the industry and the external environment.

Chapter 3 summarises the history of analysis and consultation that informed the guidelines the Authority has now decided on.

Chapter 4 outlines the legal framework for conducting the review; it summarises the Authority’s assessment that there has been a material change in circumstances to justify the introduction of new TPM guidelines and outlines the Authority’s statutory objective and the decision-making and economic framework the Authority has used.

Chapter 5 considers submissions on how the guidelines perform in relation to wider factors such as climate policy objectives.

Chapter 6 explains the ‘Authority’s intent’ section of the guidelines.

Chapters 7-14 explain the Authority’s decisions on the different parts of the guidelines in light of submissions. These chapters reflect key themes in submissions and the Authority’s response to the different points that have been raised.

Chapters 15-16 provide the Authority’s assessment of the likely impacts of implementing a TPM consistent with the 2020 guidelines. They contain results of the cost-benefit analysis, which show the guidelines are for the long-term benefit of consumers and the Authority’s indicative estimate of the impact on transmission charges in the first year of implementation.

Chapter 17 sets out the Authority’s decision on **the process and timeframe** for Transpower to develop a proposed TPM.

Appendix A documents key changes in the methodology and assumptions for the calculation of Schedule one benefit-based charge allocators and estimates of indicative benefit-based and residual charges (to accompany programme files published separately).

Appendix B addresses the main alternatives that have featured in submissions in response to the 2019 Issues Paper.

The guidelines are published as a standalone document.

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1 We have decided to issue new guidelines

2020 guidelines for a new approach to transmission pricing

1.1 The Electricity Authority (Authority) has decided to publish new guidelines (2020 guidelines) that Transpower New Zealand Limited (Transpower) will follow in developing a new transmission pricing methodology (TPM).[1]

1.2 The 2020 guidelines are published on the Authority's website, www.ea.govt.nz.

1.3 The TPM determines how Transpower may charge its customers to recover its maximum allowable revenue in any year for providing access to and use of the national electricity grid (the grid). This revenue is set at $789m in 2020–21 rising to $829m for 2024–25.[2]

Main features

1.4 In broad outline, the main features of the 2020 guidelines are that they require a TPM to include the following:

- a connection charge to recover the cost of assets that connect customers to the grid
- a benefit-based charge to recover the costs of grid investments from parties who benefit from those specific investments
- a residual charge to recover remaining transmission costs
- a prudent discount policy to allow Transpower to discount charges for a customer whose charges would otherwise be inefficiently high or who may otherwise inefficiently bypass the grid (raising costs for all other customers)
- a cap that protects consumers (including directly connected businesses) from price shocks from the initial rebalancing of transmission charges
- seven additional components that Transpower must include in the proposed TPM if that would, in Transpower's reasonable opinion, better meet the Authority's statutory objective, including an optional transitional congestion charge where market and regulatory settings are not yet sufficiently developed to be able to rely on nodal prices and other available tools to efficiently manage congestion on the grid.

1.5 The main consequence of the new guidelines will be to replace the current RCPD and HVDC charges.[3]

1.6 Table 1 provides an overview of each of these components of the 2020 guidelines. Details and a discussion of submissions on them follow in separate chapters below.

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1 The current TPM guidelines are available on the Authority's website and the current TPM is set out in Part 12 subpart 4 of the Electricity Industry Participation Code 2010 (Code).

2 Commerce Commission, 2019, *Transpower Individual Price Quality Path from 1 April 2020* — companion paper to final RCP3 IPP determination and information gathering notices 14 November 2019, www.comcom.govt.nz

3 The guidelines are also consistent with the 2019 Electricity Price Review (EPR)'s final report (p 48) which recommended that transmission pricing changes should: allocate the costs of future grid investments on a beneficiaries-pay basis, reallocate the cost of past grid investments from generators to consumers, or between transmission customers, only if the Electricity Authority can estimate with a high degree of confidence that such a reallocation will result in substantial, long-term benefits to consumers and have a phasing-in period where necessary to avoid price shocks.

Table 1 Key features of the guidelines

Components	Key features of the 2020 guidelines
Authority's intent	This section aims to aid interpretation of the guidelines' substantive clauses.
General matters	This section gives Transpower certain discretion in interpreting and applying the guidelines, for example to take into account practical considerations. It also sets out other provisions which apply in respect of the proposed TPM as a whole.
Connection charge	This charge recovers the cost of connection assets. This component is essentially the same as in the 2006 TPM guidelines.
Benefit-based charge	The cost of grid investments, including the remaining costs of seven recent major grid investments, will be charged to transmission customers who benefit from them. Annual charges will be according to the depreciated historical cost (DHC) method.
Residual charge	This annual fixed charge recovers unallocated costs up to Transpower's maximum revenue and allows for the allocation to be updated regularly based on changes in usage with a lag.
Adjustments to charges and scale back	Charges may be adjusted, e.g. to recognise entry and exit of transmission customers, customers closing one of their plants or selling part of a business, substantial and sustained increases in use or generation of electricity and to avoid incentives to inefficiently shift points of connection.
Prudent discount policy (PDP)	The guidelines provide for a discount on transmission charges of designated transmission customers who would find it beneficial to inefficiently bypass or disconnect from the grid. The policy also allows a customer to apply for a discount if charges exceed efficient stand-alone costs. The duration of a prudent discount is left unspecified.
Transitional cap on charges	The cap is intended to assure households and businesses will not face electricity bill shocks as result of a new TPM and to allow them time to adjust to new charges.
Additional components	*An additional component must be included in the TPM where that would, in Transpower's reasonable opinion, better meet the Authority's statutory objective*
A. Staged commissioning	To adjust charges or reclassify connection and interconnection assets to facilitate efficient staged commissioning of grid investments.
B. Assets principally providing connection services	To ensure connection assets cannot be changed into interconnection assets other than by Transpower investing in other assets to create an interconnection loop.
C. Method for setting connection charges	To align the setting of charges for new connection investments with the method for determining benefit-based charges for post-2019 investments.
D. Transitional congestion charge	To apply when and where grid demand would not be adequately controlled by means such as nodal pricing and administrative load control associated with scarcity pricing. The name of this component has changed to better reflect its purpose.
E. Including additional pre-2019 investments	To apply benefit-based charging to other pre-2019 grid investments and related services, such as transmission alternatives. Allows Transpower to use a standard method or combination of standard and simple methods.
F. Allocating opex	To attribute opex to the asset it was spent on, instead of using broad allocation rules, so that charges for assets better reflect their actual costs.
G. Kvar charges	For imposing a kvar charge on reactive power.

Guidelines will promote the long-term benefit of consumers

1.7 The Authority considers that the 2020 guidelines meet its statutory objective better than the alternatives that have been considered.

1.8 A TPM consistent with these new guidelines will promote the long-term benefit of consumers by promoting:

(a) Competition: for example, by providing a level playing field for generators regardless of location and enhancing competition between grid and non-grid alternatives

(b) Reliability: for example, by giving consumers better signals of the cost and benefits of investments that increase the security and reliability of grid-supplied energy

(c) Efficient operation: for example, by removing charges that inefficiently suppress electricity consumption at peak times and distort choices between transmission infrastructure, demand-response, or generation options.

No alternative considered would better promote our statutory objective

1.9 Over the course of the review, the Authority has considered a large number of alternatives. The Authority considers that none of these are likely to perform better than the 2020 guidelines.

1.10 Appendix B discusses alternatives considered, focussing on those put forward in submissions since 2019. These include an RCPD charge with a weakened price signal, a tilted postage stamp charge, a deeper connection charge, a regional approach, a number of options for incremental TPM reform put forward by Transpower and some options that Trustpower has suggested would be practicable.

1.11 Specific alternatives for a component of the guidelines are discussed within the relevant chapters.

Finalising the TPM review is becoming increasingly urgent

1.12 Getting transmission pricing right is becoming ever more urgent. It is time to resolve the longstanding uncertainty about transmission pricing.

1.13 Longstanding problems with transmission pricing will become more acute as new technologies increasingly provide more opportunities to avoid transmission charges and as investments beckon as part of New Zealand's transition to a low carbon economy through expansion of renewable energy and electrification of the economy.

1.14 These are among the reasons why the Authority is seeking to reform transmission prices. These prices need to send the right signals about the economic cost of using the grid and the cost and value of future investments in the grid, in generation and by those using electricity. As the Minister of Energy and Resources stated in her response to the Electricity Price Review:

> "The electrification of the economy will require significant investment to accommodate an expansion of renewable energy. This requires a transmission pricing methodology that supports the right investments being made in a timely manner."

1.15 Concluding the review will give transmission customers certainty. Most submitters agree the review should conclude and a decision be made. As noted in the Electricity Price Review: "Delays in agreeing on a fair, efficient and lasting transmission pricing methodology risk undermining market confidence and timely investment."

Next steps

1.16 Once the 2020 Guidelines are published (with this decision document, in June 2020), the next step is for Transpower to develop a proposed new TPM and to submit this to the Authority.

1.17 Transpower must submit a proposed TPM to the Authority by 30 June 2021.

1.18 Upon receipt of a proposed TPM, the Authority will then review and consult on the proposal prior to amending the Code to incorporate the new TPM.

1.19 Once the Code is amended, Transpower will calculate, implement and publish new prices consistent with the new TPM, which will take effect from 1 April the following pricing year. The Authority anticipates this to be 1 April 2023.

1.20 Chapter 17, Box 1 on page 111 documents the Authority's decision on the process for Transpower's development of a proposed new TPM.

2 Problems with the current TPM

2.1 Evidence of inefficient behaviours and outcomes caused by the current approach to transmission pricing are necessitating changes in the TPM.

2.2 Some of these factors have been present since the review of the TPM started in 2009. Rapidly changing technology and the implications of ambitious targets related to climate change mean other factors are becoming more pressing over time.

2.3 As a result, it is increasingly important and urgent that transmission charges are designed to be efficient so that consumers and suppliers can make electricity consumption and investment decisions that are informed by the true value and cost of grid-delivered electricity. That will contribute to electricity sector outcomes that are for the long-term benefit of consumers.

The current TPM

2.4 The current TPM has three main charges corresponding to the three types of grid assets:

(a) a *connection charge* for connection assets. These are allocated on a user-pays basis and paid by connecting parties

(b) an *interconnection charge* that covers the cost of most of the grid. Distributors and direct consumers pay a share of costs based on their contribution to the 100 highest peaks in a region in the prior measurement year.[4] This Regional Coincident Peak Demand (RCPD) charge allocates total interconnection costs on a ‘postage-stamp’ basis, that is, at the same rate per kW across the country with no regional differentials

(c) an *HVDC charge* for the use of the high voltage direct current cable that interconnects transmission customers between the South and North Islands. South Island generators pay a share of the costs based on their average total energy injected (MWh) across five years (South Island Mean Injection, or SIMI).

2.5 The current TPM also includes a prudent discount policy (PDP), to ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets.

RCPD charge distorts the cost of using transmission

2.6 At around $2,000 per MWh the RCPD charge is overly strong. It will suppress demand whether or not there are grid capacity constraints. This is to the detriment of consumers. It is like having a road congestion charge to discourage people from travelling in places or at times without any sign of traffic delays or gridlock.[5]

2.7 The high RCPD charge causes commercial and industrial consumers to adjust their production processes and others to make investments in distributed generation and other options, such as grid scale batteries, to avoid and shift the charges to others. All this results in large, unnecessary costs for all consumers.

2.8 These problems will worsen as business and residential consumers invest in increasingly affordable technologies (such as batteries and demand management technologies) to try avoiding transmission charges. This shifts more and more of the transmission cost on to fewer consumers who end up paying proportionally more and more.

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4 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.

5 The RCPD charge is also overly strong if positioned as an efficient signal of the future cost of transmission, as some submissions are promoting. By our estimate, it is double the long-run marginal cost (if we assumed that using a single estimate of long-run marginal cost for the country were appropriate).

2.9 With customers' RCPD charges based on their contribution towards peak in prior years and the strong incentives on everyone to reduce their own exposure, customers cannot know for sure what their bill for the next year will be.

2.10 This has been causing significant volatility in transmission bills for Electricity Ashburton and its customers, without the cost of the grid having changed. Horizon Networks also submitted this was an issue. The volatility encourages even more inefficient avoidance behaviours, further increasing costs for consumers.

2.11 Another problem is that the postage stamp allocation of interconnection charges means grid investments in one region are essentially subsidised by all other regions. This tilts customers' preferences toward transmission solutions when capacity constraints arise, compared to otherwise possibly more efficient local solutions such as demand response (including accepting the risk of demand curtailment when grid capacity gets stressed) or local supply and network options.

2.12 Relatedly, an energy-intensive business deciding where to locate its new plant has little incentive to consider the cost of any new investment in interconnection assets needed to support their business — whether this is load or generation — although they do pay for connection assets.

HVDC charge distorts the cost of South Island generation

2.13 Only South Island generation pay the HVDC charge. This charge averaged $150m per annum between 2015/16 and 2019/20 and this year is $92m. The charge is an anomaly as:

- North Island generators and electricity consumers everywhere, also benefit from the HVDC link
- North Island generators do not face an equivalent charge — for example, they do not pay interconnection charges.

2.14 The HVDC charge is like a tax on South Island generation (until recently around 10%, now around 6%). This inefficiently discourages investment in South Island generation relative to North Island generation and supports otherwise more expensive generation in the North Island. That translates ultimately into higher electricity prices for consumers.

Poor incentives to scrutinise grid investments

2.15 The current TPM spreads the costs of interconnection investments across all customers, regardless of where they live. As noted above, customers in a region who would benefit from an investment know most of the costs will be paid for by the rest of the country.

2.16 This creates incentives to submit information in support of such grid investments, even if the price or reliability benefits do not necessarily exceed the cost, or it would be better to delay the investment. The 2019 Issues Paper (p 12) provided the example of pressure from Auckland representatives for regulations to rule out overhead transmission lines, even though undergrounding would be 5-15 times more expensive but knowing Auckland consumers would only pay a minor part of the cost.

The current TPM is not durable

2.17 The Authority considers that these issues explain why aspects of the current TPM have long been unsettled and will become increasingly contentious.

2.18 The postage stamp approach will fuel discontent as people find they are increasingly charged for services that primarily benefit others, given the projected growth in transmission costs.

2.19 The lack of an even playing field — in terms of charges that are linked to the geographic location of generation investments — will also continue to raise the prospect of demands for change and of dispute.

2.20 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 creates uncertainty, which raises the risk and thus costs of long-lived investments.

2.21 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 expressly included as 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 and associated regulatory certainty of the TPM, which may in turn affect the efficient operation of the industry.

2.22 We expect the problems identified will continue to grow 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. In reviewing the TPM, the Authority is therefore looking to address some of these issues as they relate to the pricing of transmission services.

2.23 We acknowledge that aspects of the new guidelines will be contentious. This is inevitable. But the problems under the status quo will grow and that is not sustainable. Following a thorough process of analysis and consultation the Authority is satisfied that the new guidelines will be for the long-term benefit of consumers.

Other issues

2.24 The 2020 guidelines seek to address these headline problems, as well as other problems with the current TPM such as the limited coverage of the prudent discount policy. These are discussed in subsequent chapters.

Submitters' views

2.25 Most submitters agree there are problems to be addressed and agree the RCPD charge is overly-high or otherwise creates problematic incentives that lead to inefficient consumption and investment outcomes and creates problematic volatility in transmission bills that are not cost-reflective.[6] [7]

[6] For example, Buller Electricity, Contact, Counties Power, Distribution Group, EA networks, ENA, IEGA (cross-submission), Marlborough Lines, Mercury, Meridian, New Zealand Wind Energy Association, Ngāti Tūwharetoa Electricity Ltd, The Lantau Group, The Office of the Māori Climate Commission, Transpower, Vector, WEL Networks. Entrust is open to reform of RCPD charges to make them better targeted.

[7] Depowering the RCPD charge, by increasing the number of measurement periods from 100, could reduce but would not eliminate problematic incentives or the excessive volatility in charges.

2.26 Some submitters consider the issues are overstated and that the RCPD works well to reduce demand at peak, to reduce congestion and defer grid investments and to give incentives to be energy efficient.[8]

2.27 There is also an increasing consensus the HVDC charge needs to be addressed.[9] Meridian notes that the HVDC charge has been “highly contentious since 1996 when Transpower first attempted to allocate the costs of the HVDC to South Island generators” (p 3). It states that there is no justification for treating the HVDC investments differently to other interconnection investments or for treating South Island generation as sole beneficiaries. The Distribution Group also makes this latter point. Trustpower considers the impact of the HVDC charge on competition to be well known, and the TPM Group supports The Lantau Group’s view that there is a clear case for realignment of charges.

2.28 Contact and Meridian describe the charge as a tax on South Island generation, with Meridian providing examples of viable renewable generation it suggests are not currently competitive given the transmission charges these would attract. However, Mercury (pages 4-5) disagrees that the existing TPM is an impediment to South Island renewable generation investment and instead points to the consent process, nodal price differences and the potential impact of a Tiwai closure as being more material factors.

2.29 More generally, submitters such as Buller, Contact and Nova Energy agree the problems were correctly identified and Powerco and ENA noted the current TPM had struggled to adapt or keep pace with a changing environment.

2.30 Beyond that there is less agreement between submissions. One group of submitters agreed reform along the lines that the Authority proposed is necessary and increasingly urgent.[10] Another group of submitters thought the problems were not as acute or were not well identified and would be best addressed through incremental reform, possibly through amending the current TPM.

2.31 For example, Meridian considers that submissions indicate “general agreement there are problems with the current TPM.” It agrees with the Authority’s problem definition and considers there is a “clear, well-considered and evidence-based understanding of the key problems with the current TPM” and that these cannot be resolved under the current (2006) guidelines (p 6). It sees reform as an urgent priority (p 4).

2.32 Rio Tinto states that in its reading of the submissions there is a “clear consensus” that the Authority has identified flaws in the existing TPM that lead to inefficient outcomes and that the case for reform is both obvious and urgent (p 4).

2.33 MEUG considers there is an “emerging case for change” and that there is “logic to reducing avoidance behaviour and a pragmatic aligning of payments to beneficiaries.” Winstone Pulp International generally accepts the problem definition (but not the case for changing the cost recovery method for HVDC).

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8 For example, Eastland, Jock Webster, Network Waitaki, Norske Skog, North Otago Irrigation Company Ltd, Oji Fibre, Pan Pac, Sustainable Energy Forum, Waitaki Irrigators Collective Ltd. Trustpower agrees the RCPD charge can be too strong at certain times but that the case for change is weak. Molly Melhuish considers the arguments irrelevant as residential consumers do not face transmission pricing directly. Northpower finds it difficult to envisage the charge’s adverse impacts on mass market consumers. The Lantau Group thought the avoidance behaviour becomes a concern only if the RCPD signal is ‘self-catalysing rather than self-correcting’. (The Authority considers the RCPD charge is not self-correcting. Its structure supports cost-spirals.)

9 However, Entrust described the proposal to shift part of the remaining HVDC cost to consumers corporate welfare. Oji Fibre Solutions considers the initial HVDC investment intrinsic to South Island generation.

10 Including A D Wilson, B Hegan, D Faulkner, D Holz, EIS Group & EIS Holdings, M Dikstaal, Great South et al., I Miller, J Moynihan, J Allison, J van Eeden, Marlborough Lines Ltd, Meridian Energy, Otago Southland Employers' Association, S Clark, T Guy, P & J McKnight, Rio Tinto, Sarah Dowie MP, Southland Chamber of Commerce, South Port NZ Ltd and Southland Disability Enterprises.

2.34 Transpower in its cross-submission notes that “while industry consensus cannot necessarily be expected” it saw “wide support for consideration of more incremental and moderate reform options” (p 5). “The Authority has identified some problems with the current TPM with which we agree. However, in our view, the problems could be dealt with more quickly, more effectively and efficiently than extensive reforms, with less risk and at lower cost by incrementally reforming the existing TPM and guidelines” (chapter 1).

2.35 A similar view was expressed by the TPM Group, The Lantau Group, Norske Skog and NZ Steel. Vector too accepts there is scope for improvement but favours incremental to sweeping reform in the context of a rapidly evolving electricity sector (p 7).

2.36 According to Trustpower, the Authority’s approach to problem definition lacks discipline and lacks evidence.[11] It considers the case made to change the RCPD charge is weak (though in its cross-submission writes it could be improved) and that the “impacts of the HVDC charge on competition …have been identified for more than a decade” (p 21).

2.37 Trustpower thinks change is possible under the 2006 guidelines but that the Authority has “prematurely dismissed reform options [that] would be more proportionate, carry lower cost and risk and better promote the statutory objective” (p 23).[12]

2.38 Energy Trust of NZ disagrees categorically that the problem definition is correct. Ecotricity, Electric Kiwi, energyclubnz, Flick Electricity, Pulse and Vocus submit the Authority should focus instead on more urgent competition issues with bigger gains (e.g. ‘loyalty taxes’).

2.39 More detailed points on aspects of the problem definitions and implications are addressed in subsequent chapters.

2.40 A number of submissions stress that it is time for the review to conclude.[13] The Authority acknowledges the need to bring TPM reform to a close has been a clear and consistent message throughout this process from a wide range of stakeholders.

Conclusions

2.41 There has been consistent and long-term pressure for TPM reform since the current TPM came into effect in April 2008.

2.42 Most parties agree that problems exist with the TPM and need to be addressed and most agree with the nature of the problems we have described (at least with respect to the RCPD and HVDC charges). There are only a few who disagree.

2.43 The Authority notes however that:

(a) parties have varying views on the size of the problem (the cost to consumers of inaction)

(b) parties have a range of views on the best solution, influenced by their views on the size of the problem and which we respond to later.

2.44 Having considered submissions, the Authority is satisfied with the problem definition used for this review of TPM guidelines: the current TPM is flawed and is failing to give electricity consumers and generators efficient price signals about the cost and value of using the transmission grid.

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11 Mercury emphasises it endorses this view in its cross-submission.

12 The Authority does not accept Trustpower’s view (at paragraphs 7.4.3 and 7.5.1) that we have based policy decisions on a few ‘cherry-picked examples’ and that there is a lack of evidence supporting our problem definition. Rather, we have used examples to illustrate the problems that our analysis and our assessment of costs and benefits show are caused by the current TPM (and would be remedied by our proposal).

13 For example, Buller Electricity, Distribution Group, Electricity Networks Association, Great South et al. Meridian, New Zealand Wind Association, Unison and Centralines. Note that expressions of a desire to see a timely conclusion do not also indicate that submitters endorsed the Authority’s proposal.

3 A decade of consultation and analysis

Summary of the major review stages

3.1 The review of the TPM has a long history. The Authority's predecessor, the Electricity Commission, first initiated a review of the TPM in 2009. This work was continued by the Authority and has involved a significant amount of consultation and analysis over the years.

3.2 The decision on the 2020 guidelines is made after careful consideration of submissions, cross-submissions and oral submissions made on the 2019 Issues Paper and the 2020 Supplementary Consultation. The 2020 guidelines build on previous work and submissions received by the Authority, as was noted in the 2019 Issues Paper:[14]

> "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."

3.3 Since the release of the 2019 Issues Paper the Authority provided further opportunities for participants to seek and obtain additional information regarding its proposals and engage with the Authority, including through workshops and responding to questions and requests for information.

3.4 The Authority's consultation, provision of information and engagement since 2019 is summarised in Figure 1.

Figure 1 Authority engagement on TPM since 2019

Jul 2019	Consultation: 2019 Issues Paper Six regional TPM workshops and a workshop on CBA and impact analysis 93 submissions, 18 cross-submissions
Dec 2019	25 oral submissions
Feb 2020	Consultation: Supplementary Consultation Paper 22 submissions
Mar 2020	Authority information paper 'Peak charges under the proposed TPM guidelines' Prof Hogan expert report 'Transmission investment beneficiaries and cost allocation' Concept Consulting report 'Winter Capacity Margin — potential effect of possible changes to transmission pricing'
Apr 2020	Authority information paper 'Response to feedback on the 2019 cost-benefit analysis' and webinar.

14 Electricity Authority, 2019, *2019 Issues Paper* — Transmission Pricing Review, p 3.

3.5 Figure 2 illustrates the major stages of the TPM process from 2009 to 2019. The 2019 Issues Paper at chapter 7 also set out the history of the TPM process in some detail.

Figure 2 Major stages of the TPM Review since inception prior to 2019

Apr 2009	Electricity Commission initiates review
Apr–Dec 2009	Transmission Pricing Technical Advisory Group – report for Electricity Commission
Oct–Dec 2009	Consultation on Transmission Pricing Review high-level options paper
Aug–Sep 2010	Consultation on Transmission Pricing Review stage two options paper
Late 2010	Electricity Authority supersedes Commission and industry participants' CEOs forum conveys emphasis on undertaking TPM review as a priority
Jan 2011	Transmission Pricing Advisory Group established (independent chair, consumers and industry participants)
Jun–Jul 2011	Transmission Pricing Advisory Group consults on its Transmission Pricing Discussion paper. Includes a public briefing session on the paper
Aug 2011	Transmission Pricing Advisory Group report provided to Electricity Authority – recommendations to change the allocation for HVDC costs and to introduce an efficient charge for reactive power uptake
Jan–Mar 2012	Consultation on 'Decision-making and economic framework for transmission pricing methodology review' paper
Oct 2012–Jul 2013	Consultation paper: 'Transmission Pricing Methodology Review: issues and proposal' and a series of forums, a modelling workshop, Q&A workshop, cross-submissions and face-to-face engagement with interested parties
May 2013	Transmission Pricing Methodology Conference attended by the Authority's Board
Sep 2013–Jul 2015	Consultation on 12 working papers resulting from consideration of submissions on the 'Transmission Pricing Methodology Review: issues and proposal' paper
May–Jul 2016	Consultation on the May 2016 'Second Issues Transmission Pricing Methodology' paper (including a briefing and four workshops to interested parties)
Dec 2016–Apr 2017	Consultation on the 'Supplementary Consultation' Paper (including cross-submissions and online question and answer session)
Apr 2017	Decision made to prepare a new CBA
Jul 2017	Preparation of new CBA delayed so new Board members could fully understand the complexities of the TPM review and process to date
Mar 2018	Review and analysis continues. Authority, Commerce Commission and Transpower representatives on transmission pricing study tour to parts of the United States

3.6 We consider that this consultation process has been appropriate and has provided participants with enough time and information to make informed decisions.

Responding to submissions

3.7 In accordance with clause 12.82 of the Code, the Authority consulted on its 2019 proposal, seeking submissions and cross-submissions. Submitters were also invited to provide oral submissions to the Authority's Board and a supplementary consultation was undertaken to in February–March 2020 to explore further options and to address points raised in submissions. The Authority also released information papers on the Authority's thinking on peak charging and the cost benefit analysis in light of submissions on those topics.

3.8 All written submissions, cross-submissions and oral submissions in response to the 2019 Issues Paper and all written submissions in respect of the 2020 Supplementary Consultation Paper, have been reviewed and considered by the Authority's Board in reaching its decision.

3.9 A thematic discussion of submissions, reflecting key concerns raised, is included within each of the chapters below. In preparing these discussions, the Authority has endeavoured to address a range of submissions, with particular emphasis on those raised by a large number of submitters or which tested the robustness of the Authority's reasoning. However, submitters should be assured that, even where a submission is not explicitly mentioned in this Decision Paper, it has been taken into account by the Authority's Board in reaching its decision.

3.10 The Authority notes that its discussions of submissions necessarily compress the information provided. Readers should refer to individual submissions to obtain a full account of submitters' views.

This decision document builds on earlier papers

3.11 This paper summarises the Authority's analysis and the reasons for its decision on the 2020 guidelines, with a focus on how they have changed from the 2019 Issues Paper (which in turn built on the preceding analysis and consultation as outlined above).

3.12 Accordingly, this paper should be read together with the 2019 Issues Paper, the 2020 Supplementary Consultation Paper and the information papers entitled 'Peak charges under proposed TPM guidelines' (and its two supporting papers) and 'Response to feedback on the 2019 cost benefit analysis'. Taken together, these papers explain the reasons for the decision on the Authority's 2020 guidelines.

Further information

3.13 Stakeholders can find all detail on the steps taken towards this decision and the views on previous proposals in the previous consultation papers, presentations and submissions related to the TPM process available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/.

4 The legal and economic frameworks

4.1 This chapter presents and discusses feedback on:

- the legal framework for conducting a review of the TPM
- the Authority's reasons for considering that there has been a material change in circumstances and that the Authority is therefore able to review the TPM
- the decision-making and economic framework that the Authority has used to test our problem definition and potential options against this statutory objective.

The legal framework for conducting a review

4.2 Review of the TPM is governed by Part 12, subpart 4 of the Code.

Threshold for review: a material change in circumstances

4.3 The Code provides two mechanisms for review of an approved TPM, specifically:

- Transpower may submit a proposed variation to the Authority, provided that submission is made at least 12 months after the last approval of the TPM (also known as an operational review) (clause 12.85), or
- the Authority may review an approved TPM if it considers there has been a material change in circumstances (clause 12.86).

4.4 In order to review an approved TPM, the Authority must therefore determine whether, in its view, there has been a material change in circumstances. The Code does not define what is meant by a material change in circumstances. The Authority's view as to whether there has been a material change in circumstances is set out below.

4.5 As to when such a material change in circumstances must have arisen, the Authority considers that it is not restricted to considering only circumstances as they existed when the Electricity Commission first initiated a review of the TPM in 2009.[15] Rather, the Authority takes the view that it is able to consider new material changes arising after this date.

4.6 Where the Authority considers there to have been a material change in circumstances, the threshold required by clause 12.86 has been met and it may review the TPM. Such a review is not mandatory and remains at the discretion of the Authority.[16]

4.7 We also note that, once this threshold has been met and the Authority has determined to review the TPM, the Code does not place any restrictions on the scope of that review.[17] In particular, there are no requirements that the review be limited to matters affected by the material change in circumstances identified by the Authority; such a requirement would be unworkable, particularly given the interrelated nature of the different components of the TPM.

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15 The Authority therefore disagrees with Trustpower which at p 9 of its submission "do not think it is lawful for the Authority to determine a material change of circumstances after it is already well advanced in its review of the adequacy of the TPM [or…] supplement its original determination with other contextual factors as it appears to do in the *2019 Issues Paper*."

16 We agree with NZ Steel's cross-submission at p 6 on this point.

17 Cf Trustpower's submission at p 5, which suggests that there is some ambiguity about this point. For the avoidance of doubt, even if there were such a limitation, the Authority's view is that the material changes in circumstances it has identified are sufficiently far-reaching as to warrant a review of the TPM in its entirety. See Meridian's submission at p 40.

Process for review: the TPM guidelines and process

4.8 Having determined that it considers there to have been a material change in circumstances, the Authority is able to review the approved TPM, including the TPM guidelines.[18] While a review of the TPM will not always involve a review of the TPM guidelines, in some cases such a review will be necessary in order to fully review the TPM under clause 12.86.

4.9 Clauses 12.81 to 12.83 of the Code govern the preparation of:

- the process for development and approval of the TPM
- the guidelines to be followed by Transpower in preparing the TPM.

4.10 Specifically, these provisions require the Authority to:

- prepare an Issues Paper on the process and guidelines
- consult on that Issues Paper
- decide on and publish the process and guidelines.

4.11 Passing new TPM guidelines does not constitute a Code amendment. As such, it is not subject to the consultation requirements set out in the Electricity Industry Act 2010.[19] Of course, this does not prevent the Authority from providing additional information where it considers this may assist participants and seeking their views on such information (as it has done with providing a cost benefit analysis in this case) to inform and support the Authority's decision-making.

4.12 In accordance with the Code requirements for review of the TPM and development of new guidelines, the Authority:

- released its 2019 Issues Paper on 23 July 2019 (which built on and was informed by analysis and consultation in the preceding 10 years). Further supporting materials for participants' information were subsequently released in August 2019
- consulted on that paper between 23 July and 1 October 2019
- provided for cross-submissions between 1 and 31 October 2019
- heard oral submissions in December 2019
- undertook supplementary consultation between 11 February and 3 March 2020.

4.13 This decision paper represents the Authority's decision on the TPM guidelines and process.

The Authority's statutory objective

4.14 As a Crown entity, the Authority must act consistently with its statutory objective. In addition, clause 12.81(2) of the Code requires that the process and guidelines be developed in accordance with the Authority's statutory objective.

4.15 The Authority's statutory objective at s15 of the Electricity Industry Act provides that:

> 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.

4.16 In preparing new TPM guidelines, the Authority has considered and developed the guidelines in accordance with its statutory objective.

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18 Cf Trustpower p 5.

19 We note that, if the Authority determines to proceed with the accompanying Code amendments discussed in the 2019 Issues Paper (see Appendix F), these would be subject to the usual Code amendment processes.

4.17 The link between the Authority's statutory objective and its application with respect to designing the guidelines was considered in the Authority's Decision-Making and Economic (DME) framework for its TPM review[20], which complements and provides additional guidance on, but does not replace, the direct application of its statutory objective.[21]

4.18 The Authority considers that the benefits of the guidelines tie directly to all three limbs of its statutory objective for the long-term benefit of electricity consumers by promoting:[22]

(a) competition: for example, by providing a level playing field for generators regardless of location and enhancing competition between grid and non-grid alternatives

(b) reliability: for example, by giving consumers better signals of the cost and benefits of investments that increase the security and reliability of grid-supplied energy

(c) efficient operation: for example, by removing charges that inefficiently suppress electricity consumption at peak times and distort choices between transmission infrastructure, demand-response, or generation options.

4.19 The 2020 guidelines do this by promoting:

(a) competition[23] — for example, replacing the HVDC and RCPD charges with fixed-like benefit-based and residual charges supported by nodal prices:

(i) provides a level playing field for generators regardless of location and between new and existing generators, by equalising the basis for charging generators

(ii) enhances competition between grid and non-grid alternatives through better signals of the cost and value of transmission

(iii) encourages innovation and investment and therefore competition, for the benefit of consumers given better signals of the cost and value of energy alternatives

(b) reliability — for example by providing improved:

(i) consumer trade-offs between security and cost, given better signals of the marginal cost of increased security and reliability of grid-supplied energy and non-grid alternatives

(ii) investor certainty and consumer confidence, which will promote appropriate investment by electricity users in, for example, demand response capability

(c) efficient operation — for example through:

(i) removing price distortions that inefficiently suppress electricity consumption at peak times and result in cost shifting (and costs incurred in doing that)

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20 See https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/economic-framework-decision-making/ and the *2016 and 2019 Issues Papers*

21 Cf Trustpower p 8.

22 Vocus and Electric Kiwi suggested the Authority adopt an approach to interpreting the "long-term benefit of consumers" that is consistent with the Commerce and Telecommunications Acts and recognise wealth transfers impact on consumer-benefits and not just efficiency.

23 The Authority agrees with Trustpower at p 7 that the competition limb is also very relevant, including for the reason promoted by Bushnell and Wolak at p 8 of its submission, as is the reliability limb. We acknowledge there are mechanisms in the wider regulatory framework to allow for non-wire substitutes. But as explained in this paper the Authority considers the existing TPM undermines these. The 2020 guidelines level the playing field, to complement those wider mechanisms and so promote competition, including competition in the provision of substitutes for transmission lines (in addition to promoting the other limbs of the statutory objective).

(ii) encouraging grid users to provide better information on the need for and value of, investment in transmission infrastructure, compared to other options (such as demand-response, or accessing higher cost energy options)

(iii) recovering allowable revenues for sunk costs and overheads in a way that least distorts electricity consumption or investment behaviours

(iv) encouraging choices by transmission customers about electricity consumption or generation that take into account their full share of future transmission costs

(v) durable pricing arrangements as costs of transmission are allocated to customers in proportion to net private benefits and RCPD charges — the cause of significant year-to-year unpredictability — are removed.

4.20 For the avoidance of doubt and consistent with the discussion above, the Authority therefore does not accept the suggestion that it has given primacy to the third 'efficient operation' limb of its statutory objective, or that it has reduced the three limbs of its statutory objective into a single 'overall efficiency' objective and so has misinterpreted its statutory objective as Trustpower suggests.[24]

4.21 Some submitters consider that the Authority's proposal is inconsistent with its statutory objective generally (e.g. NZ Steel p 7, which notes in particular the impact of rule changes and wealth transfers creating investment uncertainty) or in its detail (e.g. Rio Tinto). The Authority disagrees and its reasons are discussed further below.

4.22 A number of other participants raised concerns regarding the Authority failing to consider wider matters based on its interpretation of its statutory objective. For example, submitters have told us that the Authority should consider the impact of its TPM guidelines on climate change mitigation efforts and the transition to more renewable energy,[25] fairness, energy affordability, wellbeing, child poverty, regional economic development and the impact on Māori.[26] These wider factors are discussed in the next chapter.

4.23 The Authority notes that, while it is required to act consistently with its statutory objective, including in developing the guidelines, this does not necessarily prevent it from considering other factors, where in doing so it is continuing to act consistently with its objective. For example, the Authority notes that it is expected to consider the matters outlined in the Government's Enduring Letter of Expectations — to Statutory Crown Entities.

4.24 Indeed, the Authority has considered wider factors. For example, the Authority also considers that the guidelines better support a transition to a low-emissions economy, at least cost to consumers, than does the current TPM. (e.g. see chapter 5). And while fairness is not explicit in the Authority's statutory objective, the Authority has the long-term interests of consumers at the centre of its decision-making and perceptions of fairness may be relevant for example where they raise concerns about the durability of a proposal.

24 Trustpower pages 6–8.

25 See chapter 5 and footnote 48.

26 Electra, Entrust (suggesting the proposal would be corporate welfare (p 1) and hurt the regions (p 3), Northland Regional Council et al. (noting any additional financial burden would exacerbate poor economic and social outcomes in the north), Fonterra p 3, Grey Power p 2, Lower Waitaki Irrigation Company, Mahitahi Hauora, Mercury (cross submission), Network Waitaki pages 13-14 and Appendix 3, North Otago Irrigation Company, One Double Five Whare Awhina Community House, Refining NZ p 2, Taitokerau Education Trust, Tauhara North No. 2 Trust (noting increased charges impair the ability to deliver employment and community programmes), The Lines Company p2, and WEL Networks. Electra considered broader business and social impacts should be considered (p 8). By contrast, Great South et al note there are currently disadvantaged consumers in Southland who are paying inefficiently high prices but that the TPM is not how to address social policy issues.

A material change in circumstances

What we consulted on

4.25 Before the Authority may review an approved TPM it must consider that there has been a material change in circumstances (see paragraph 4.3). In this section we set out our reasons for considering that there had been a material change in circumstances.

4.26 The 2019 Issues Paper outlined the Authority's reasons for considering that there had been material changes in circumstances since the TPM was introduced in 2008. This reflected the position outlined in previous Issues Papers and previous submissions.

4.27 In particular, we identified the following as material changes in circumstances:

(a) A significant amount of transmission investment has been commissioned since 2008 and a lot more investment is currently forecast

We noted that the current TPM was not designed for the boom in recent — and projected — investment in the transmission network that has occurred since 2008, with Transpower's regulatory asset base increasing from $2 billion in 2005/06 to $4.7 billion in 2018/19 and forecasts predicting a further doubling of electricity demand by 2050.[27]

As a result, the Authority considered that the inefficient behaviours and outcomes resulting from the current TPM would be amplified by the scale of recent and expected growth in investment. In particular, with the rise in projected investment and therefore costs to be recovered under the TPM, it would become more likely that transmission customers would lose confidence in the current TPM, creating uncertainty and harming investment decisions and encouraging the avoidance of charges.

(b) The increasing range of technologies available to electricity consumers are fundamentally changing the way people engage with electricity markets

The Authority considered that there have been significant developments in technology, with the electricity sector on the cusp of transformation as a result of new technology, including small-scale distributed generators, batteries, electric vehicles and intelligent energy-management systems. We noted that such technology was already changing the way in which households, commercial and industrial consumers purchase, use, produce and trade electricity and that current and future changes were potentially far-reaching and may change the traditional role of the transmission grid.

The Authority considered that the existing TPM pre-dated these developments and that future scenarios could include either reduced reliance on the transmission grid as a result of localised networks predominating or else increased demand for transmission as sectors such as transport and process heat electrify. Again, the inefficient price signals created by the existing TPM could create issues going forward by encouraging inefficient grid use and investment.

(c) Advances in computational power

We noted that advances in and the reduction of costs of computational power have allowed more sophisticated approaches to measuring (use of and demand for) transmission services and identifying who is receiving those services. As such, while limitations on data and computational power of systems had previously been used to

[27] Transpower 2018, *Te Mauri Hiko — Energy Futures;* more recently 2020 Whakamana i Te Mauri Hiko — *Empowering our Energy Future* revised this to 68% having factored in demand-side efficiency gains.

argue against TPM reform, these constraints have generally been lifted, enhancing the practicality and breadth of options available.

In addition, we noted that greater computational power will likely lead to further market changes, increasing the importance of efficient transmission pricing. Examples we gave included real time pricing sharpening nodal price signals and demand response platforms.

(d) The regulatory environment has changed significantly

We noted that the Authority, with its different statutory objective and legislative regime, had replaced the Electricity Commission on 1 November 2010. The existing TPM was prepared based on guidelines prepared and approved by the Electricity Commission in light of its particular statutory objective. As such, the Authority considered it appropriate to review and consider whether the TPM and the guidelines, best promote the Authority's statutory objective.

In addition, we noted that since 2008, the function of approving grid investments had been transferred from the Electricity Commission to the Commerce Commission, with the Commerce Commission having modified its rules and processes over time. We therefore considered that it was appropriate to ensure that the TPM is more consistent with and reinforces, the Commerce Commission's processes.

(e) New ambitious climate change Government objectives affect the demand for and use of the grid

We further noted that the Government has announced a series of new targets to reduce New Zealand's greenhouse gas emissions over the last few years, including most recently announcing a target to reduce New Zealand's carbon emissions to net zero by 2050.[28] We considered this was a material change worth highlighting, given the scale of the economic transition that these new climate change objectives signalled. In particular, we noted that for New Zealand to reach its targets, consumers of all sizes, from households and small businesses to industrial consumers, would need to turn to grid electricity and other options for low-emissions energy.

We also noted that significant change to the operating environment in the electricity sector had 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.

Some scenarios[29] suggest that electrification of transport and industrial processes could double electricity demand, although that is just one scenario among many. We noted that, regardless of which scenario plays out, it is 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.

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28 The Climate Change Response Act (Zero Carbon) Amendment Bill, which was noted in footnote 300 to the *2019 Issues Paper*, was subsequently passed and came into force in November 2019.

29 For recent scenarios, see Transpower's *2018 Energy Futures — Te Mauri Hiko*, Transpower's *2020 Whakamana i Te Mauri Hiko — empowering our energy future*, MBIE's *2019 Electricity demand and generation scenarios*, Business Energy Council 2019 *New Zealand Energy Scenarios* https://www.bec2060.org.nz/

Submitters' views and our assessment

4.28 While a number of submitters considered reform of the TPM to be necessary and urgent, relatively few directly addressed the issue of whether there has been a material change in circumstances permitting review of the TPM under clause 12.86. This may be because submitters had responded on this subject previously; such submissions were taken into account in the production of the 2019 Issues Paper and are not repeated here.

4.29 Of the few submissions that did address whether there has been a material change in circumstances, most agreed that a material change in circumstances had occurred since the current TPM was adopted.[30] For example, Meridian submitted that each of the changes identified in the 2019 Issues Paper represented a material change and taken together, there is clearly a material change in circumstances justifying a full review of the TPM.[31]

4.30 In addition, other submitters recognised issues identified by the Authority as material changes in circumstances, including acknowledging:

- the impact of electrification, including the electrification of private vehicles[32]
- the need for renewable generation investment to achieve New Zealand's climate change goals[33]
- the impact of transformative technologies more generally[34] which as they become more affordable will likely increase participation by consumers and others
- the Electricity Industry Act 2010 which changed the regulatory environment.[35]

4.31 By contrast, Trustpower submitted that the factors the Authority has identified in its 2012 and 2019 Issues Papers did not amount to a material change in circumstances, either collectively or individually. It agreed that changes are occurring, but disagreed these require fundamental reform of the TPM, including because such changes were known at the time the TPM was developed.[36] Trustpower also suggested that the Authority's identification of advances in computing power as a material change relate to its preference for a more granular asset-based beneficiaries-pay pricing approach, rather than any flaws in the current methodology.[37]

4.32 The Authority does not agree that the extent of the changes which have occurred were known at the time the current TPM was drafted. The scale and potential of technological change in the electricity industry, particularly distributed energy resources, were not anticipated at this time. While there were of course indications that, for example, investment in transmission assets would grow and the importance of climate change policy may increase, the scale and implications of these changes were not anticipated when the current TPM was drafted.

4.33 As noted above, the Authority also considers it is not restricted to considering material changes in circumstances which had arisen by the time the Electricity Commission

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30 Energy Trusts of New Zealand p 10 (noting that Energy Trusts of New Zealand favour higher level issues being addressed prior to the TPM process), Meridian p 39, Rio Tinto p 33, Cf Trustpower p 9 and following.

31 Meridian pages 39–40.

32 Countries Power Ltd p 3.

33 Mercury p 1. Mercury did however suggest that the current TPM was not an impediment to this.

34 Energy Trusts NZ p 2.

35 Molly Melhuish p 3. Melhuish considers the proposal to favour bulk electricity over local energy development.

36 Trustpower p 10.

37 Trustpower p iii.

commenced its review of the TPM in 2009 and that it can consider material changes which occurred after this date.[38]

4.34 For the avoidance of doubt the Authority's view is that, even if the assessment was undertaken as at 2009, it would still consider there to have been a material change in circumstances and thus the threshold required by the Code would still have been met.

Material changes in circumstances have occurred

4.35 After considering submissions, the Authority maintains its view that material changes in circumstances have occurred since the TPM came into force in 2008. Specifically, the Authority considers its views summarised above were correct. The Authority therefore considers that the threshold provided for review of the TPM in clause 12.86 of the Code has been met.

The decision-making and economic framework

What we consulted on

4.36 The 2019 Issues Paper retained and elaborated on the 2012 decision-making and economic (DME) framework to test our problem definition and potential options.[39] Both the DME framework and the 2019 elaboration are intended to be an aid to interpreting, but do not replace, the Authority's statutory objective.

4.37 The DME framework sets out a hierarchy of charging approaches that we use to identify and assess options for new guidelines. This hierarchy:

- gives priority to market-based charges where practicable, principally because workably competitive markets are dynamic and so tend to enhance competition, provide the levels of reliability that consumers want and promote static and dynamic efficiency
- otherwise the preference in order is for exacerbators-pay, beneficiaries-pay, then alternative charging options.

4.38 Appendix D of the 2019 Issues Paper discussed previous submissions on the application of the DME framework and the relationship between: the wholesale electricity market's nodal prices, the Commerce Commission grid investment approval regime and transmission charges that are cost-reflective, service-based (or as we term it benefit-based) and practicable with reasonable transaction costs.

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38 However, even if the Authority was limited to considering material changes which had arisen by 2009, the Authority considers that there would still have been a material change in circumstances as:

- a Ministerial review of the electricity market had taken place in 2009 which led to the introduction of the Electricity Industry Bill into the House at the very end of 2009. This subsequently led to changes to the regulatory arrangements with the Authority replacing the Electricity Commission and responsibility for approving grid investments being assigned to the Commerce Commission
- legislation implementing the Emissions Trading Scheme was passed in September 2008, with further amendments occurring in 2009. The ETS introduced a price signal to incentivise a reduction in carbon emissions (thereby also supporting investment in renewable generation), with particular impacts for the electricity sector given the ETS captured emissions from stationary energy and industrial processing activities
- an updated Government Policy Statement on Electricity Governance was issued in May 2008, with changes including documenting the target of 90% of electricity being produced from renewable sources by 2025 and requiring consideration of the need for grid upgrades to transport renewable electricity. A further updated GPS was issued in May 2009, emphasising accelerated prudent transmission grid investment to enhance security of supply.

While the TPM came into force in 2008, this was the culmination of a longer process and reflected a pricing framework which has been in place since the late 1990s.

39 For a detailed exposition of the DME framework readers are referred to the *2019 Issues Paper* Appendix D.

4.39 Drawing on the analogy of workably competitive markets the Authority derived principles for the pricing of transmission services to give effect to the Authority's statutory objective:

(a) locational marginal prices are generally the best means of restricting the use of the grid to its capacity

(b) each user should pay the cost of connection to the grid

(c) the charges for access to transmission services from a transmission investment should recover the total cost of providing the transmission investment

(d) subject to (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.

4.40 In what is essentially the seventh principle, the Authority also noted that these principles need to be applied taking into account 'real-world' considerations such as the need to avoid excessive transaction costs.

4.41 These principles deliver, as Professor Hogan put it, a two-part pricing structure with variable congestion charges and fixed access charges assigned on a beneficiary-pays basis, which adheres to first principles and can accommodate workable implementation.[40]

4.42 In addition, this analysis made clear the important point that, with efficient pricing in place, a decision to commission a new transmission investment can in principle be safely deferred until it is economically justified. In particular, unless there are other regulatory or administrative constraints, these price signals mean that a new investment need not be precipitated unless the expected benefit of the investment outweighs its expected cost. This means that the substantial costs of inefficiently early investment can be largely avoided.

Submitters' views and our assessment

Decision-making and economic framework

4.43 Many submitters did not comment specifically on the DME framework or the elaboration of it (as opposed to the Authority's proposal based on it). This perhaps reflects the period of time that has passed since the DME framework was first published and previous consultations on it and its elaborations.

4.44 Among submitters who did comment, some are supportive of the DME framework and its elaborations used by the Authority.

4.45 Meridian (p 41) notes that:

> "The DME framework and its elaborations are useful tools for identifying and evaluating different options and have been used appropriately by the Authority to date for that purpose.
>
> The DME framework should not, however, be treated as a strict hierarchy of preferred methods of charging. That is because pragmatism is required in developing an acceptable TPM. Trade-offs will be required between competing requirements that a TPM will address. Nor does the DME framework replace the Authority's ultimate test,

40 Hogan, WW, 2020, *Transmission investment beneficiaries and cost allocation: New Zealand Electricity Authority Proposal*, at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/

which is to determine the pricing option that best meets the Authority's statutory objective."

4.46 Other stakeholders are not supportive of the DME framework. Trustpower thinks the DME framework has not served the Authority very well, as indicated by the Authority's progressive elaboration of the framework (p iv) and is based on the wrong premise of promoting the overall efficiency of the electricity industry (p 14), which inappropriately subsumes the three separate competition, reliability and operational efficiency limbs of the Authority's statutory objective (p 6) — as discussed above.

4.47 The Authority does not agree with these critiques.

4.48 For example, Trustpower (p 19) repeats CEC's 2016 conclusion (for Trustpower) that the Authority had turned the DME framework on its head 'without justification' by preferring a 'beneficiaries-pays' instead of an 'exacerbator-pays' LRMC method. We disagree. If transmission services could be provided through a workably competitive market with devolved decision-making, that would most likely be the best means of delivering long-term benefits to consumers. But this is not practical with current technology. Instead, a regime that is modelled on the features of a workably competitive market (as encapsulated in the principles outlined above) is most likely to be the best means of pursuing the long-term benefits of consumers.[41]

4.49 Trustpower further suggests that the workably competitive markets analogy may not provide much insight and references Bushnell and Wolak in suggesting it is a somewhat artificial construct in the case of a monopoly transmission provider (p 15) and that the best evidence as to how a transmission company operating in a workably competitive market would price its network is largely the current TPM (p 16).

4.50 Likewise, Mercury (p 13) suggested that the workably competitive market analogy is not particularly helpful or relevant and suggested that the Authority's main rationale for this approach was to justify applying the benefit-based charge to historical investments (though it considered this was inconsistent with economic theory).

4.51 Norske Skog (p 5) disagreed with the conclusions of Appendix D of the 2019 Issues Paper and suggested that in certain circumstances inefficient grid investment may be best overall.

4.52 Transpower suggests that while workably competitive markets can provide a useful analogy in considering pricing for a natural monopoly, it does not follow that charges should be set on the basis of estimated benefits as customers (who cannot choose an alternative provider) would bear the cost if Transpower gets it wrong (Transpower p C19).[42] Likewise, Rio Tinto (p 33) considered that relying on an analogy with workably competitive markets can provide useful insight for policy development but is not a solid basis for choosing one pricing method over another.

4.53 Our view is that workably competitive markets tend to support the long-term benefit of consumers and so can provide useful insights into properties of regulated markets that are likely to be consistent with our statutory objective. As the High Court found in *Wellington International Airport Ltd and others v Commerce Commission* (p 179):

"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

41 For the reasons described in Appendix D of the *2019 Issues Paper*. See also footnote 85 on p 39 of the *Second Issues Paper*.

42 That concern would seem to apply regardless of pricing methodology and other mechanisms are in place to protect customers from such harm, such as the scrutiny of grid investments and the prudent discount policy.

markets may depart in many respects from the markets for regulated services, which are not workably competitive, is the very reason to examine them." [43]

4.54 We also agree with Transpower and Rio Tinto that the use of workably competitive markets analogy is helpful but not definitive. While we used the analogy of workably competitive markets in the 2019 Issues Paper to provide such insights, this was explicitly based on earlier analysis. As Professor Hogan's report[44] makes clear, our analysis is solidly based on robust analysis of various factors and provides "the missing piece in a workably and economically efficient two-part pricing scheme".

4.55 Another concern raised by Transpower is: "We do not consider the content of Appendix D of the 2019 Issues Paper to be an "Elaboration of [the] decision-making and economic framework". It appears the Authority has effectively replaced the DMEF with new tests that the TPM be "cost-reflective" and "service-based"." [45]

4.56 Similarly, Trustpower[46] infers that the progressive elaborations appear "to have implicitly acknowledged the defects in its assessment framework."

4.57 This misconstrues the objective of the DME framework, chapter five of the Second Issues Paper and Appendix D of the 2019 Issues Paper. As is clear from all three documents, we consider that they are consistent with each other and are intended to clarify what the statutory objective means in practice in the context of transmission pricing. It is also clear they are not intended to replace the statutory objective and that the latter would take precedence if there were any conflict between them.

Pricing principles for efficient pricing of the interconnected grid

4.58 Meridian consider the six principles for transmission pricing outlined in paragraph 4.39 are consistent with cost-reflective and service-based pricing.

4.59 Trustpower and others do not share this view. In particular, Trustpower cites CEC which suggests the proposal does not meet the conditions of being intuitively reasonable, having a clear trajectory and having sufficient flexibility and adaptability. It instead supports a higher level set of principles previously described by the Authority as "a close adaptation of its statutory objective" (p 13).

4.60 We do not accept the views of those who consider that the six pricing principles are inconsistent with, or do not elucidate, the Authority's consideration of its statutory objective. Specifically, we maintain the view that the above pricing principles are relevant to the TPM guidelines. More generally, as discussed above, we consider that the efficiency properties of workably competitive markets provide a useful analogy to infer 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.

4.61 As part of our quality assurance process, we commissioned a report from Professor Hogan (see footnote 40) on the Authority's conclusion and of the various critiques of it. Professor Hogan was supportive of the Authority's analysis. As he says (p 3), "the Authority's approach of following the guidance from first principles leads to the design of a beneficiary-pays system that is both intuitive and consistent with competitive market design for generation and load" and with LMPs in place, "the Authority's proposal provides the missing piece in a workable and economically efficient two-part pricing scheme."

4.62 Professor Hogan also examined some of the more substantive critiques of the Authority's analysis. His overall conclusion about these critiques is as follows: "The various criticisms

43 Wellington International Airport Ltd and others v Commerce Commission [2013] NZHC 3289.

44 See footnote 40.

45 Transpower p C18.

46 Trustpower p iv and p 18.

of the Authority's proposal are either incorrect or are based on implicit assumptions that do not apply to the real transmission system."

4.63 For example, he considers that the various critiques that the Authority's pricing principles should include some form of Ramsey pricing[47] are based on an implicit assumption of one-part pricing, whereas the Authority's proposal is explicitly based on two-part pricing. He concludes (p 8) that the Authority's proposal "follows the same dictates as Ramsey pricing, but applies the analysis to a two-part pricing structure and the result supports efficient investment."

Our decision

4.64 After considering the submissions received, the Authority considers its elaboration of the DME framework and the principles for pricing transmission services it derived in the 2019 Issues Paper are appropriate.

4.65 The 2020 guidelines are designed to promote competition, reliability and efficient operation of the electricity industry for the long-term benefit of consumers.

[47] For example, Bushnell and Wolak 2017 p 7, Creative Energy Consulting 2019 p iii, Mercury Energy p 13 and The Lantau Group 2019 p 11.

5 Wider considerations

The 2020 guidelines support a transition to low emissions

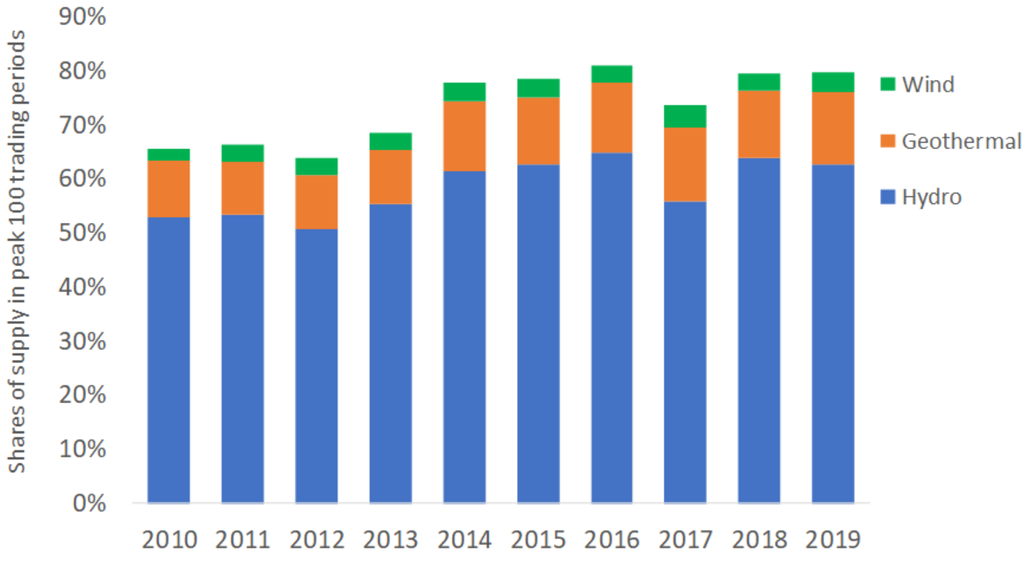
5.1 A number of submitters thought the 2019 proposal did not support climate and renewable energy policies.[48] Some argued the increase in peak electricity demand following removal or the RCPD charge would mean more fossil fuel generation, increasing carbon emissions.[49]

5.2 The Authority considers that the 2020 guidelines do support the climate policy objective of a transition to a low-emissions economy at least cost.

Renewable generation already meets 80% peak demand and this will grow

5.3 Thermal generation is not the only nor the best option to meet peak demand (unlike many other jurisdictions): renewables already meet 80% of peak demand. Reliance on renewables has grown over time, displacing higher-cost thermal generation (Figure 3). The Authority expects this trend to continue. For example, hydro generation met 63% of demand at the 100 highest peaks in 2019. Its share has been growing over time.

Figure 3 Share of renewables at peak is increasing (100 peak periods)



Source: Electricity Authority

48 Entrust, ETNZ, Northern Regional Council et al p 3, Fonterra pages 3, 5, Golden Bay Cement, Independent Electricity Generators Association pages 6-7, King Country Energy p 2, Mercury (as cost reallocation may deter future North island geothermal investment), Network Waitaki, NZ Steel, NZ Wind Energy Association p 5, Ngāti Tūwharetoa, Northpower (p 11), Office of the Māori Climate Commission, Oji Fibre Solutions, Refining NZ, solarcity, Tauhara North No. 2 Trust, The Sustainable Energy Forum, Transpower p 6, Trustpower, Vector, Waitaki Irrigators Collective Ltd, Whangarei District Council and Zero Carbon Nelson Tasman. Molly Melhuish suggests the proposal seeks to suppress consumer investments to reduce (peak) demand.

By contrast, Meridian notes these concerns are unfounded and overly simplistic (p 4 cross-submission). Great South et al. thought the HVDC charge locked New Zealand into a future with North Island fossil-fuelled generation … out of step with … emission reduction targets (p 2).

49 This increase in peak demand due to the proposal is very minor (around 1 per cent over the top 800 hours) in the context of the 68% demand increase by 2050, under increased electrification, that is projected in Transpower's *2020 Whakamana i Te Mauri Hiko — Empowering our Energy Future*.

The economics favour renewables

5.4 An increase in demand at peak need not translate to higher emissions. Renewables have a cost advantage over fossil fuel generation. They operate at lower cost than gas or other fossil fuels, particularly when emissions pricing increases and so will logically be used to serve increased demand before gas peaking is turned on.

5.5 While some thermal generation (360 MW) is consented and expected in the near term, the majority of currently consented and planned new generation is for wind — just under 1700 MW (Figure 4).[50]

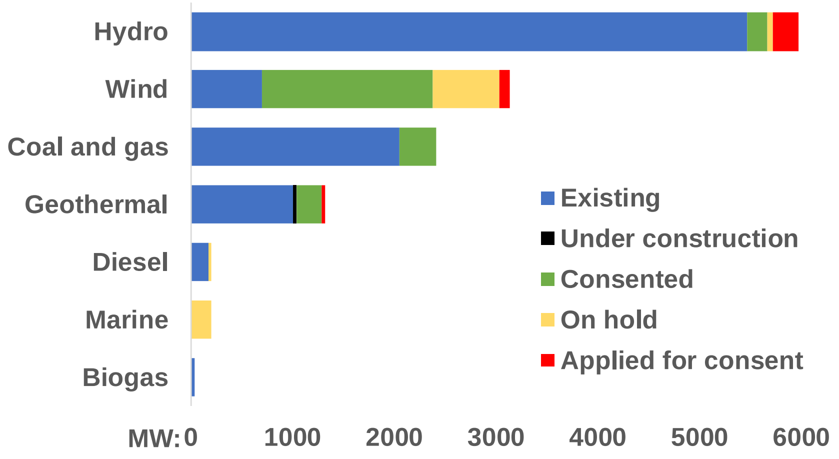
5.6 Renewables' cost advantage will improve further over time with:

(a) ongoing reductions in the cost of renewable technologies (e.g. wind, solar)

(b) expected increases in the emissions price faced by gas, coal and diesel generators.

5.7 Given these broader trends and that 88% of currently proposed generation projects are renewables, it suggests generation entering the market in future will be overwhelmingly renewable and that this generation will be used to meet any increased peak demand.

Figure 4 The majority of proposed generation capacity is from renewable sources



Source: Electricity Authority, EMI, Operational capacity, Q1 2020

The guidelines will unlock renewable generation

5.8 The Authority's guidelines will put all generation on an even footing, regardless of location. Currently, South Island generation pays all the HVDC charges, although North Island generators also benefit from the link as do consumers.

5.9 Replacing the HVDC charge with benefit-based charges will unlock investment in South Island renewable generation options. Opening up hydro generation in the South Island is a good complement to the expansion of wind and solar, to deal with the intermittency of those sources. Examples of proposed South Island renewable generation projects (consented or are on hold) include the Wairau scheme (70.5MW), Arnold River (46MW), Rakaia/Lake Coleridge (16MW), Pukaki (35MW), North tunnel at Waitaki (240MW) and Hurunui wind generation (76MW) — totalling a potential additional 484MW.[51]

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50 MBIE's *Energy in New Zealand 2019*, p 17. Consented capacity indicates plant that could be built in the future. The greatest share of currently consented capacity is wind. Total new wind generation capacity is over 45 per cent of current national hydro capacity. The generation mix will change if the Taranaki Combined Cycle 377MW gas-fired plant is closed or refurbished in 2022.

51 EMI dataset: '20190924_Proposed_generating_plant.xlsx' at https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_fleet/Proposed

5.10 The 2020 guidelines will enable South Island renewables to participate in the market without a disproportionate burden from transmission charges that currently have the effect of supporting otherwise higher cost options. Access to lower cost generation overall is for the long-term benefit of consumers.

Removing incentives to run diesel generators during peak hours

5.11 Some submissions[52] argued that removing the RCPD charge will discourage investment in distributed generation, co-generation or battery storage, stymieing process heat electrification and the goal of 100% renewable generation by 2035.

5.12 The Authority does not agree with those submissions. Distributed generators do not have significantly lower emissions than grid connected generators.[53] In fact, by removing the overly strong RCPD charge, the 2020 guidelines remove the financial incentive to run diesel generators in order to avoid peak charges and shift costs to others.

5.13 For example, Marlborough Lines submitted that under the current charging methodology mobile diesel generators are operated to offset network load at suspected Upper South Island peak times. It stated this is inefficient given the increase in emissions and cost of operating these generators even when there is significant spare capacity in the local and regional transmission network. This use of diesel generation is a direct result of the incentives the RCPD charge creates.

5.14 The 2020 guidelines should not discourage efficient investment in distributed generation. Instead, the 2020 guidelines put distributed generation on an even footing with other generation and demand response. This means lower costs to consumers overall.

5.15 Removal of the RCPD charge does, in our view, reduce the scope for 'avoided cost of transmission' (ACOT) payments compared to the past, as benefit-based and residual charges would not vary with use.[54] Distributed generation is still likely to command higher wholesale prices to supply local demand, but only where the transmission network is constrained, i.e. where the distributed generation becomes highly valuable. In such situations Transpower could also contract distributed generation to operate during peaks to defer transmission investments where that is efficient.

The guidelines support a least cost transition to a low-emissions economy

5.16 The Authority considers it is important to get the TPM right ahead of the significant investment in transmission that may be needed in the years ahead to support the transition to a low-emissions economy.

5.17 Fonterra (p 3) suggested that the guidelines will increase their transmission charges and that this will slow or even stop their investment in renewable energy or process heat electrification. The Office of the Māori Climate Commission was concerned that benefit-based charges would suppress new renewable projects, especially geothermal available in a few finite locations (p 2).

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52 For example, Entrust p 2, IEGA p 7, and solarcity. The Authority disagrees with solarcity that the Authority is opposed to these technologies – see paragraphs 5.14 and 5.20.

53 Grid-connected supply in 2020 to-date was 79% renewable/21% non-renewable. Distributed generation (in terms of capacity at May 2020, rather than supply) was 63% renewable/37% non-renewable.

54 It may be useful for the Authority to clarify the position on ACOT payments via a future Code amendment. The 2016 amendment to distributed generation pricing principles restricted the scope for regulated ACOT payments, however the Authority indicated in the *2016 decision paper* that further refinement of the ACOT arrangements was to be expected. Appendix F of the *2019 Issues Paper* discussed a potential Code amendment to clarify that distributors (a) are required to make ACOT payments in respect of transitional peak and kvar charges (if such charges are included in the TPM) and (b) are not required to make ACOT payments in respect of benefit-based charges, residual charges or connection charges. However, no such amendment has yet been proposed.

5.18 The rebalancing of transmission charges to be benefit-based will mean that some customers will pay more for the grid services than they do now. Currently, interconnection costs are spread on a postage stamp basis which means grid investments built to service one group of customers are paid for by other parties who do not benefit from those grid services. Those other parties currently face inefficient barriers to invest in renewable generation or process heat electrification.

5.19 Further, the Authority considers that if new grid investments need to be made to enable renewable investments, the system of benefit-based charges means that those charged for grid investments would benefit from them and be better off than without them.

5.20 Transmission pricing is not the vehicle to tilt the playing field in favour of any technology or location. But the Authority considers that the 2020 guidelines will result in efficient transmission prices, so generators, industrials and other consumers can factor transmission costs correctly into their decisions. This ensures transmission pricing does not interfere with emissions pricing and plays its part in a least cost transition to a low-emissions economy.

Consistency with distribution pricing principles

5.21 Some submissions question whether the guidelines are consistent with the Authority's distribution pricing principles.[55] These questions relate mainly to the absence of a peak transmission charge and how the low fixed charge regulations limit distributors' ability to pass on the benefit-based and residual charges as fixed charges.[56]

5.22 The Authority considers the guidelines are fully consistent with the distribution pricing principles. Like the distribution pricing principles, the TPM guidelines (and the pricing principles discussed at 4.39) seek to achieve:

(a) a signal of the economic costs of using grid services, reflecting differences in services provided to consumers and encouraging efficient network alternatives

(b) recovery of the shortfall using charges that signal economic costs, in a way that least distorts transmission network use

(c) charges that are subsidy free (e.g. by allocating the costs of transmission assets to customers on a benefit-basis)

(d) charges that are responsive to requirements and circumstances of end users so charges reflect economic value, for example via the prudent discount policy

(e) transparency in deriving and applying charges and having regard to transaction costs (e.g. pragmatic approaches) and consumer impacts (e.g. transitional arrangements).

5.23 There will be differences in implementation between the guidelines and distribution pricing principles. This is because there is no system of nodal pricing beyond the grid exit points. Nodal prices explain why the Authority has not included a permanent peak transmission charge in the guidelines. The absence of distribution-level nodal prices explains why the Authority considers time-of-use pricing might be (not must be) how distributors can constrain — as efficiently as is currently feasible — demand to available network capacity, if there are congestion risks.

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55 The distribution pricing principles are included in the Authority's July 2019 decision paper: *More efficient distribution prices principles and practice*, at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/

56 See, for example, Electric Kiwi, ENA pages 5 & 8, Independent Electricity Generators Association p 8, Network Waitaki p 10, NZ Wind Energy Association p 10, Orion p 7, Pioneer p 6, Powerco p 3, The Lines Company, Transpower chapter 20, Trustpower p 21, Vocus p 4, WEL Networks p 1 and Wellington Electricity Lines Ltd.

5.24 Orion highlight that whilst the guidelines require a benefit-based charge for specific investments and a residual based on historical AMD shares, a distributor does not have the ability to charge retailers or their customers in either of these ways.

5.25 The Authority does not expect distributors to pass through transmission charges to their customers in this manner. Distributors will have to decide how best to allocate fixed annual charges among their customers, guided by the distribution pricing principles.

5.26 Other submitters, such as the ENA, Network Waitaki, Powerco and The Lines Company, consider the low fixed charge regulations are a barrier to pricing reform. Powerco (p 3) notes it "restricts and distorts the ability of distribution pricing to reflect" fixed transmission charges.

5.27 The Authority acknowledges the low fixed charge regulations currently restrict distributors' pricing options.[57] However, it is also the case that only a portion of distributors' revenues come from residential consumers who qualify for low fixed charge tariffs, so progress can be made on distribution pricing reform.

Consistency with best practice regulation

5.28 A number of submitters thought the 2019 proposal does not meet best regulatory practice, either directly or indirectly because of questions around the adequacy of the problem definition, assessment of alternatives, or the cost benefit analysis.

5.29 Good regulatory practice involves, among other things, being clear about objectives and the problem to be solved, evaluation of costs and benefits, an assessment of alternatives and open and transparent processes including consultation and supporting Treaty of Waitangi obligations.[58]

5.30 These concepts are entirely consistent with the requirements for consultation on the TPM guidelines in the Code and the process the Authority has adopted to date. The Authority has followed and will continue to follow, the requirements of the Code and Electricity Industry Act 2010 as it works toward a Code change in relation to the TPM.

5.31 Northpower (pages 2, 4) and Refining NZ (p 2) consider the Authority's proposal failed to meet the 'basic tenets' of best regulatory practice, which they define as addressing a material and enduring problem, doing so with the smallest intervention possible and being based on robust economic foundations and a sound CBA. Northpower thought the Authority had met none of these conditions (p 4) and instead concludes pragmatic incremental adjustments would be consistent with good regulatory practice (p 30).

5.32 Trustpower implies the Authority has not followed sound regulatory practice (paragraph iv) because it considers the Authority has not correctly identified problems or taken a disciplined approach to problem definition (p 5), considers that the Authority's assessment of alternatives has been inadequate and does not consider the CBA to provide a reasonable estimate of net benefits (p 53). Axiom for Transpower repeatedly states the Authority's review has "fallen short of best regulatory practice in numerous respects" (pages 69, 103 and 150).

5.33 NZ Steel considers the proposal fails to meet principles of good regulatory practice, because its outcomes are not predictable and consistent, it is not proportionate, fair or equitable — as it creates wealth transfers from NZ Steel shareholders (p 7), reallocates costs of past investments (p 17), is inconsistent with the Authority's statutory objective (for

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57 The Government's response to the Electricity Price Review has indicated these regulations are under review.

58 The Government has published its expectations about good regulatory practice and stewardship that it expects "regulatory agencies … will have regard to and give appropriate effect to … within the bounds of their agency resources and mandates". (p 1). https://treasury.govt.nz/sites/default/files/2015-09/good-reg-practice.pdf.

example by penalising efficient load shifting (p 7) and because the review process itself creates regulatory uncertainty.

5.34 Mercury considers (p 5 cross-submission) there is room for improvement with respect to Treaty of Waitangi obligations and the achievement of a regulatory initiative in the lowest cost manner. It suggests the Authority's proposal may not comply with Treaty of Waitangi obligations because it may lead to negative effects for those Māori in areas of the North Island with interests in geothermal operations and will require additional consultation (p 7).

5.35 It also endorses Trustpower's view that more proportionate reform options have been prematurely dismissed (p 5) and that a systematic impact analysis "would naturally have led the EA to identifying that the benefits could be substantially achieved by making small amendments" (p 7). The Lantau Group made similar comments.

5.36 The Authority agrees with the vast majority of what submitters suggest is needed for a good regulatory decision. But their critique of our decision is wrong. The Authority instead considers there is a clear problem definition, there has been extensive consideration of alternatives and it has sought and provided evidence that the proposal will produce material net benefits. Reasons for the Authority's views are expanded on in other places in this paper, but here we point out that:

- there is a clear problem definition (set out in chapter 2), with elements first identified by the Electricity Commission and developed through multiple rounds of consultation and analysis
- there has been extensive consideration of alternatives and the cost benefit analysis considers a reasonable set of alternative options. It is entirely unremarkable and common practice that the Authority — having considered qualitatively a long list of alternatives — shortlisted options to test the relative merits of those stronger options. Beneficiary-pays is based on good robust economic thinking. The CBA has absorbed the full critique of a range of experts and comes out well in the positive
- the Authority's qualitative and quantitative analysis has not found support for the proposition of some submitters that small or incremental changes will substantially achieve the objectives and benefits the Authority is pursuing. The nature of the problem and challenges facing New Zealand such as the transition to a low-emissions economy indicate an incremental change are not likely to be sufficient
- expectations for good regulatory practice do not limit reform options to those that are low-cost, low-risk, or incremental (and such options have been considered as part of the Authority's analysis)
- the Authority's actions and approach have been predictable (Meridian at p 16 notes in its cross-submission that the proposal "has been amply signalled and represents an evolution of the Authority's thinking over the years"); in particular, progressively removing incentives that encouraged inefficient investment in the past is likely to decrease, rather than increase, uncertainty[59]
- participants are treated in a consistent and equitable manner, with for example transmission investments being charged on the basis of benefits and the residual charge being based on the same objective measure for all transmission customers and a transitional cap on the amount total electricity bills can increase as a result of implementing a TPM consistent with the guidelines
- the Authority acknowledges the possibility the guidelines may have a negative effect for those in poverty or on Māori in areas of the North Island with interests in geothermal operations, but these impacts are small compared to the long-term

[59] See paragraph B.54 of the *2019 Issues Paper*.

benefits of the proposal on all Māori consumers and all other consumers from getting transmission pricing right (see also next section)

- the Authority has followed a significant and robust process of consultation over many years and has modified its views and proposals in light of feedback.

Consistency with government wellbeing objectives

5.37 Some submitters expressed the view that the 2019 proposal worked against wider government policy objectives relating to regional development and poverty, wellbeing and living standards policy objectives.

5.38 The Authority acknowledges energy hardship is a challenge for a group of New Zealanders.[60] The Electricity Pricing Review (EPR) made eight recommendations relating to energy hardship. These recommendations did not suggest the anticipated TPM reform was a problem for or inconsistent with addressing energy poverty.

5.39 Instead, the recommendations focussed on initiatives such as expanding community-based assistance, providing more financial help to those in energy hardship, boosting energy efficiency in the homes of those in hardship, ending the prompt payment discount and ways to provide those in social housing or on welfare assistance better electricity deals.

5.40 Submitters told us they thought that poorer communities would face the biggest increase in transmission charges without any change in level of service.[61] We acknowledge submissions — including oral submissions by those representing communities and whānau — on poverty and energy poverty challenges.

5.41 In particular, the Authority noted during oral submissions that some representatives for community groups had been left with the impression that their electricity bills would rise by large amounts. We want to set the record straight on that.

5.42 The Authority has been sensitive to the impact on consumers from the initial rebalancing of transmission charges that will be a result of implementing the 2020 guidelines.

5.43 In particular the new guidelines provide that each transmission customer's total transmission charges cannot rise by more than 3.5% of its total 2019/20 electricity bill (taking account of inflation and load growth; see chapter 13). This provides protection against bill shock to consumers.

5.44 In the districts where charges would rise, the impact in the first year on the average residential electricity bill should be less than 40 cents a week. In other words, this impact will be modest for residential consumers. Further, the rebalancing of charges means that in other districts charges would fall by an equivalent amount.

5.45 Even so the Authority is aware that the impacts of introducing new guidelines will not be the same across the country, or different demographic groups.

5.46 The Authority tested whether there is a clear relationship between impacts (the change in initial indicative charges in the short-run and the long-run measure of change in consumer benefit) and:

- the proportion of the population who identify as Māori (using census response data) in each distribution network

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60 More than 100,000 households were spending more than 10 per cent of their income on power in 2017, *Electricity Pricing Review* (2019), p 18.

61 Including Tauhara North No. 2 Trust, Northland Regional Council et al, Mahitahi Haurora, Network Waitaki, One Double Five Whare Awhina Community House, and Taitokerau Education Trust. See also footnote 26

- the average deprivation index score for the population in each distribution network (using Otago University’s NZ Deprivation Index).

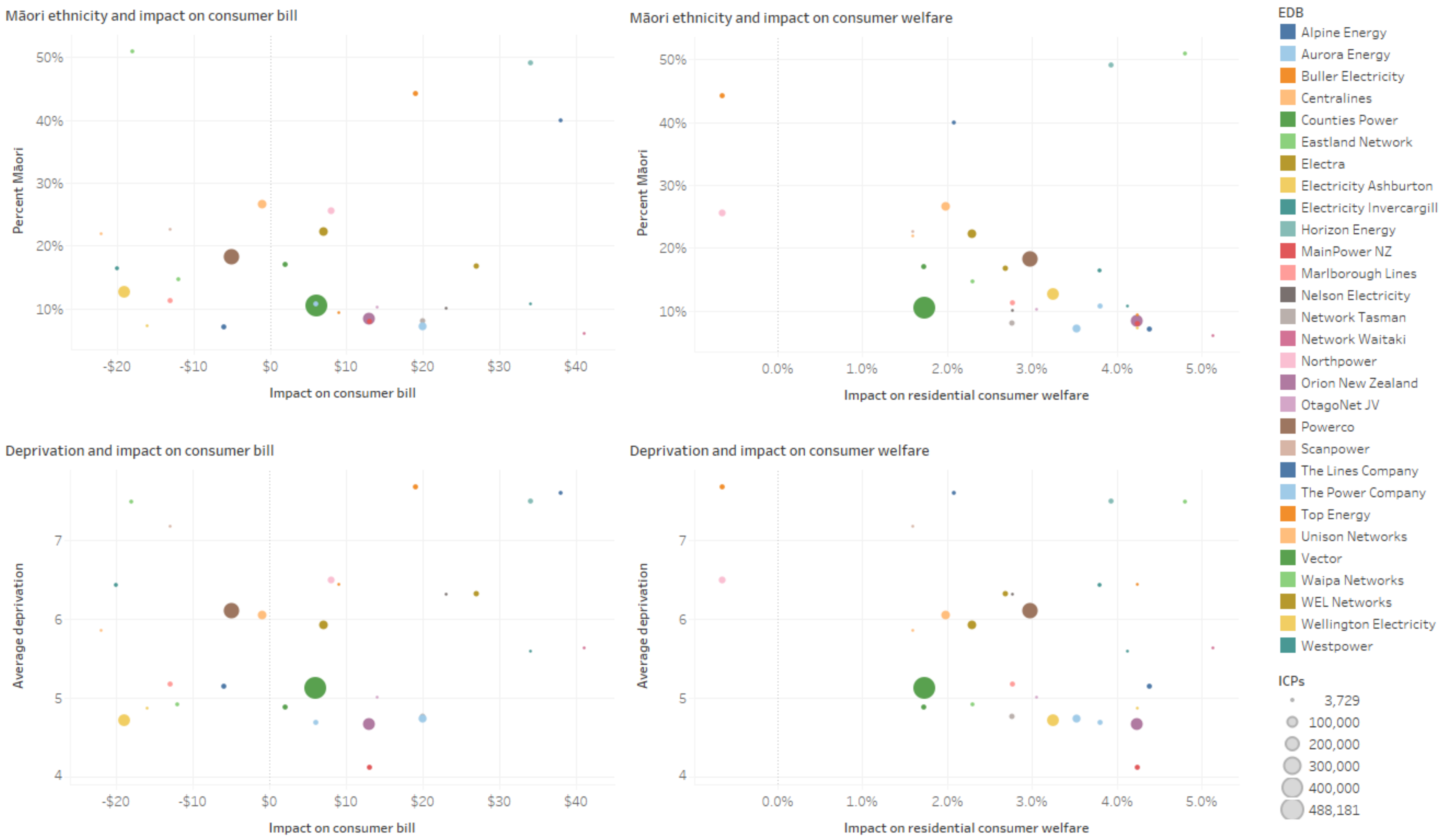
5.47 The patterns, if any, are very weak. It is not possible to draw strong conclusions in support of the proposition that areas with a greater proportion of poorer households or Māori are specifically affected negatively by the change. Overall, most consumers around the country will be better off in the long-run, as is discussed later.

5.48 The Authority is of course aware that the rebalancing of transmission charges toward Upper North Island customers (reflecting where the benefits of recent major transmission investment lie) may suggest Māori and more deprived segments of society might be more affected. But the rebalancing that will take place will also affect other parts of the country; that is, overall, communities with a higher than average deprivation are not especially affected positively or negatively. As explained in chapter 2, one of the problems with the current TPM - that the new TPM seeks to overcome - is that in some regions consumers (including households with lower incomes) have for a long time been paying for transmission investments that they do not benefit from.

5.49 It is difficult to draw simple conclusions. For this reason, the Authority considers it is appropriate that it will, as Transpower develops the TPM and the Authority considers Code amendments, watch for any potential negative impacts for specific regions or demographic groups. The Authority will ensure this information is available to the relevant economic and social government agencies who have the tools and resources to support communities.

5.50 Overall, the Authority considers its 2020 guidelines are not at odds with the government’s wellbeing objectives. The reforms will ensure that the right parties are paying for transmission investments. The reforms aim to avoid unnecessary transmission investments in the future and to stop rewarding those who are able to take action to avoid transmission costs and shift those costs onto others (who are more likely to be poorer consumers). The aim is a system that lowers costs overall for all New Zealand consumers, in a way that is principled.

Figure 5 Year one and long-term consumer impacts — Māori and communities with higher than average deprivation
Average deprivation and proportion of Māori population by distribution network



Note 1: ‘Impact on consumer bill’ is the indicative change in the average residential electricity bill for one year, with ACOT payments (see chapter 16)
Note 2: ‘Impact on residential consumer welfare’ has been estimated for a 30 year period (see chapter 15)
Note 3: The correlation coefficients (r-values) are: top-left: 0.05, top-right -0.34, bottom-left: 0.14, bottom-right -0.31 (i.e., weak correlations)
Sources: Proportion of Māori population: *NZ census, proportion of census respondents identifying as Māori*.
Otago University Department of Public Health, 2013, *New Zealand Deprivation Index*.

6 Guidelines: Authority's intent

Purpose

6.1 This section sets out the Authority's intent with respect to the substantive clauses of the guidelines as an aid to their interpretation.

6.2 This section is the same as that in the draft guidelines included in the 2019 Issues Paper (the "draft guidelines") apart from its new title, changes to be consistent with the substantive clauses of the guidelines and relatively minor drafting changes.

What we proposed

6.3 The draft guidelines included a 'Policy Objectives' section for two reasons:

(a) as explanatory notes to aid interpretation of the guidelines

(b) as a reference when the Authority is considering a review under a possible amended clause 12.86 of the Code of an approved transmission pricing methodology if the latter had become unworkable in its implementation or inconsistent with the Authority's objectives (see B.11 and F.42 to F.44 of the 2019 Issues Paper).

Submitters' views and our assessment

6.4 There was limited commentary on this section of the draft guidelines. For example, the Distribution Group noted (p 8) the draft guidelines included this section but did not comment further.

6.5 We assume that this limited commentary is because:

(a) this section summarises what the draft guidelines are intended to achieve, so that comments on the rest of the guidelines have natural implications for this section

(b) one of the reasons for this section is to provide context for the proposed workability Code amendment (see p 238 of the 2019 Issues Paper) and that Code amendment is not being progressed at this stage.

Authority's intent

6.6 Transpower submitted that (what was then) the 'Policy Objectives' section of the draft guidelines describes the charges rather than describing policy objectives, does not obviously add anything and should be deleted. We agree that the section describes what the Authority intends to achieve with the guidelines. Accordingly, we have changed its title to be the 'Authority's intent'. However, we disagree that it should be deleted as it will be a useful aid in interpreting the intent of the guidelines where there is doubt.

Detailed comments and relationship to the rest of the guidelines

6.7 Submitters made numerous detailed comments on the proposed guidelines that we have considered and adopted where we considered that to be appropriate.

6.8 Many of these are related to the detailed provisions in the remainder of the guidelines. For example, in its clause-by-clause review of the draft guidelines, Transpower makes numerous detailed comments on this section consistent with views it expressed on the substantive clauses of the guidelines. These various comments are discussed in the following chapters.

6.9 Others relate to the detailed wording of the provisions of the section itself. For example, PowerCo (p 4) submitted that the residual charge purpose statement set an unrealistically high standard and should be less definitive. We agree and have adjusted the wording accordingly. Similarly, Meridian (p 33) submitted that the 'Authority's intent' section should stand alone, rather than referencing clauses in the rest of the guidelines. We agree and have altered the section accordingly.

Use to deal with workability issues or issues of policy intent

6.10 Some submitters considered that the policy objectives section should not be used to deal with workability issues or issues of policy intent (for example, Transpower chapter 23 and Mercury p 14). Reasons included that workability issues can be dealt with by an operational review and that the proposed workability Code amendment would add to uncertainty. Trustpower (p 62) did not support the workability Code amendment because it thought the Authority's decision-making criteria lacked clarity.

6.11 We do not agree with these concerns. First, we think that the 'Authority's intent' section is likely to be a useful aid in interpreting the intent of the guidelines. Second, an operational review must be consistent with the guidelines and it is possible though unlikely that the guidelines might inadvertently prevent the intent of the guidelines being implemented. The proposed Code amendment, if progressed, would allow this to be dealt with. We think that this is likely to reduce, rather than increase, uncertainty, because it gives assurance that the TPM will give effect to the intent of the guidelines.

6.12 However, there is no need to take a firm view on the relevance to the proposed Code amendment at this stage. We will consider this issue and submitters' views on it further if we decide to progress the Code amendment.

7 Guidelines: general matters

Our decision

7.1 Clauses 1 to 9 of the 2020 TPM guidelines describe general matters that are relevant to Transpower's development of the proposed TPM as a whole.

7.2 This section is broadly the same as that proposed in the 2019 Issues Paper.

7.3 The section makes explicit that the Authority will consider any proposed TPM in light of its statutory objective. It also makes clear that, when Transpower is required to allocate charges in proportion to net private benefits, only an approximation to that allocation is required. This clarifies and generalises a provision in the benefit-based charge section of the draft Guidelines that Transpower may use a proxy in making the allocation.

7.4 The section also incorporates minor drafting changes to respond to submissions (for example, clause 6 has been made less stringent in response to Transpower's submission), to deal with minor technical changes and to clarify the wording.

What we proposed

7.5 This section provides for Transpower, in interpreting the rest of the guidelines and in developing the proposed TPM to:

(a) take into account practical considerations

(b) provide a proposed TPM which differs in its details from the proposed guidelines where doing so would, in Transpower's opinion, better meet the Authority's statutory objective

(c) set out consultation requirements.

7.6 The overall effect of these clauses is to:

(a) give Transpower wider discretion in interpreting and applying the guidelines while ensuring any proposed TPM remains consistent with our statutory objective and with the Government's expectations for good regulatory practice[62]

(b) simplify the wording of the rest of the proposed guidelines by removing the need to include provisions like those outlined in paragraph 7.5 throughout.

7.7 For more detail see the 2019 Issues Paper pages 108–110.

Submitters' views and our assessment

7.8 There were relatively few submissions on this section compared to other parts of the proposed guidelines the Authority consulted on. Submissions did address the appropriateness of the flexibility (when considered in the context of the rest of the draft guidelines) this section gives to Transpower in drafting the proposed TPM and the consultation procedures proposed, including those related to the provision of information about how the charges are calculated.

7.9 Some submitters raised issues that are in effect dealt with by this section of the guidelines. For example, Network Waitaki (Supplementary submission pages 2–3) suggested that the transactions cost of a prudent discount application could be problematic for a smaller customer. This section would allow Transpower to take this into account in designing the prudent discount policy.

62 See https://treasury.govt.nz/sites/default/files/2015-09/good-reg-practice.pdf

Flexibility

7.10 There was significant agreement that Transpower should have flexibility to develop the TPM, but disagreement on whether the draft guidelines provided an appropriate degree of flexibility. For example, some submitters (e.g. Buller Electricity p 3, Mercury p 9, The Lines Company) thought there was sufficient flexibility or that flexibility was desirable. Some (e.g. Orion p 12) noted that in addition to the flexibility provided in the 'general matters' section, specific provisions throughout the draft guidelines give Transpower flexibility in implementing the guidelines.

7.11 Other submitters disagreed:

- Transpower considered that the general matters section does not provide enough flexibility (chapter 6). Likewise, Mercury considered that the design should be left to Transpower (p 9). Trustpower (p 54) considered that the draft guidelines usurped Transpower's role in relation to the TPM.
- several submitters (e.g. Orion, Buller p 2) considered that the greater discretion now afforded Transpower increased uncertainty. Meridian submitted that the TPM should minimise Transpower's operational discretion and considered it wrong in principle for the TPM to allow Transpower to develop a TPM which differed in its detail from the guidelines (p 33).

7.12 We consider there is a balance to be struck in how much flexibility to give Transpower in implementing the guidelines. Too little flexibility risks creating unintended consequences. Too much flexibility is likely to increase the time and cost it takes to implement any new TPM and risks departures from the policy objectives the Authority is aiming for. We are comfortable the guidelines provide a reasonable trade-off between these competing ends.

7.13 This means for example, that although the guidelines require a benefit-based charge to be applied to all post-2019 investments, there may be scope for Transpower to:

- apply a rule of thumb to minor capital expenditure, such as allocating such investment at a GXP to the customer connected to the GXP
- apply a threshold, where the beneficiaries of minor expenditure are difficult to establish, even with a rule of thumb. However, we would expect that it would be relatively easy to develop a simple low-cost method of allocating very low-value investments, meaning that such a threshold is unlikely to be necessary.

7.14 Rio Tinto submitted that the detailed provisions of the draft guidelines undermined the flexibility provided for under the 'general matters' provision. We disagree, for the reasons outlined in the discussion in later chapters.

7.15 A few submitters (e.g. Orion p 12) considered that if two parties agree that the charges they face should be reallocated between them, in a way that does not impact on the charges other parties face, Transpower should have the flexibility to do so. The Authority does not agree there is a reason for such a provision in the guidelines. A TPM should provide a robust and transparent pricing methodology without the need to provide for potential bespoke charging. (This would not stop parties that wish to make alternative financial arrangements to do so, within any regulatory settings that may apply.)

Consultation

7.16 The guidelines include a requirement that Transpower consult on charges set under the proposed TPM with those who have a material financial interest in the benefit-based charge and the residual charge when it sets, allocates and adjusts them.

7.17 There was very little commentary on the proposal in the guidelines that Transpower consult when it sets the actual TPM charges.

7.18 PowerCo (p 4) submitted that Transpower should consult on whether there had been adequate previous consultation rather than making an ex ante assessment. Our view is it is unnecessary to add such an additional guideline as it is very likely Transpower will consult if it has any doubt about the adequacy of previous consultation.

7.19 In Appendix B of its submission, Transpower commented on the details of the consultation requirements but not on the requirement to consult itself. Several of its suggestions have been incorporated in the guidelines.

7.20 Relatedly, there have been a number of submissions over the course of consultation on the TPM guidelines calling for Transpower to identify how its charges are calculated. For example, in its submission on the 2019 Issues Paper, the Distribution Group (p 18) supported the proposal that Transpower should provide its customers with information about how a customer's charges have been calculated. Clause 6 of the guidelines provides for the provision of such information.

7.21 Given this and previous submissions on the need for transparency in setting charges, we are satisfied that the requirement in the guidelines that Transpower consult on setting the charges is appropriate.

8 Guidelines: connection charge

Our decision

8.1 The 2020 guidelines in respect of the connection charge (clauses 11 and 12) are essentially the same as the 2006 TPM guidelines and are the same as the draft guidelines, except for minor amendments to improve the clarity of the drafting.

What we proposed

8.2 In 2019 we proposed, apart from matters covered in the additional components A, B, C and F, the 2006 guidelines on charging for connection investments would be retained, as they were largely consistent with the principles of efficient transmission charging.[63]

8.3 We also considered whether any changes were required to connection charges in order to address 'first mover disadvantage'. This is a concern that the first customer to connect to new grid infrastructure may be subject to higher charges and risk, which could discourage, for example, investment in new renewable generation. We said our preference was not to make any changes to the TPM in order to address this issue. We noted that Transpower may be able to address the issue by contracting with connecting customers, as the terms of new investment contracts can be relatively flexible.[64]

Submitters' views and our assessment

8.4 Most parties submitting on the connection charge supported retaining the current guidelines for connection charges.[65] Contact Energy observed that the connection charge is consistent with the beneficiaries-pay approach and well understood by industry participants. We agree, although we consider these guidelines should be subject to any potential changes relating to additional components (discussed in chapter 14).

8.5 Some stakeholders supported addressing the first mover disadvantage through the guidelines.[66] Trustpower said a contract solution would not address the situation where other customers do not materialise. Transpower suggested a potential change to the TPM guidelines to address first mover disadvantage (a new charge for connecting parties to contribute to the costs of assets funded under an investment agreement). Others (such as Mercury) did not support addressing this issue through the guidelines.

8.6 We recognise inefficient grid use arrangements are a risk of the first mover issue. But in discussions with Transpower on this issue, it was recognised this issue can be dealt with under the 2020 guidelines without introducing a new charge, as the broad language of the guidelines allows discretion in the way connection charges are set.

8.7 The Authority therefore considers the first mover issue is better addressed by Transpower (either through the TPM or via commercial negotiation), rather than by introducing specific provisions to address it into the TPM guidelines (such as introducing a new charge), as Transpower has the incentive and ability to address the issue and has relevant operational experience.

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63 *2019 Issues Paper*, paragraphs B.23–B.26.

64 *2019 Issues Paper*, paragraphs B.28–B.35.

65 For example, The Distribution Group, Mercury, Meridian, Ngāti Tūwharetoa Electricity, Rio Tinto and Transpower.

66 For example, Fonterra, Genesis, Nova, Transpower and Trustpower.

9 Guidelines: benefit-based charge

Our decision

9.1 The 2020 guidelines for the benefit-based charge (clauses 13 to 26) are similar to the guidelines proposed in 2019, except for the following changes:

(a) setting the annual benefit-based charges based on the time profile the Commerce Commission uses to set Transpower's revenue, which is currently depreciated historical cost (DHC)[67]and removing the provision for an alternative method to be used

(b) removing the provision allowing Transpower to use a proxy for net private benefits, since this has now been shifted to the General Matters section in modified form, as noted in Chapter 7

(c) instead of requiring a simple method to 'broadly approximate the allocation that would have resulted if a standard method had been applied', the guidelines now require a simple method to result in an allocation that is broadly in proportion to major beneficiaries' expected positive net private benefits

(d) re-drafting the section on upgrading expenditure to clarify that upgrading expenditure does not alter the assessment of benefits from the investment being upgraded.

(e) shifting most of the provisions relating to adjustments to the benefit-based charge so the various adjustments are grouped in one place in the guidelines under the heading 'Adjustments to the benefit-based and the residual charges'

(f) making other minor clarifications, technical changes and drafting improvements.[68]

What we proposed

9.2 In 2019 we proposed a benefit-based charge to recover the costs of investments in the interconnected grid.[69] This was to promote more efficient investment by transmission customers and encourage them to reveal information about the benefits and costs of proposed grid investments. We proposed the benefit-based charge would:

(a) fully recover the costs[70] of each new investment in the interconnected grid and

(b) fully recover the remaining costs of seven recent major grid investments (according to an allocation set by the Authority) on the basis that this would make a new TPM more durable.[71]

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67 The guidelines specify that the annual benefit-based charge is to be set using the method of capital cost recovery specified in the IPP, which is currently DHC. This means that if the Commerce Commission changes the method of capital cost recovery in the IPP, the method of capital cost recovery for the annual benefit-based charge would change correspondingly. But there is no indication that the Commission has any intention of changing its method of cost recovery. So the Authority considers it is reasonable to note some advantages of aligning our method to the Commission's current method (e.g. DHC front-loads recovery).

68 For example, clause 16 now explicitly lists the circumstances in which the benefit-based charge for a benefit-based investment may recover less than the full covered cost of the investment. Likewise, clause 22(c) makes clear that any simple method is required to recover the covered cost of the investment. These are designed to clarify the circumstances in which the covered cost must be recovered and are not policy changes.

69 See *2019 Issues Paper*, from paragraph B.36.

70 *2019 Issues Paper*, paragraphs B.69–B.73.

71 *2019 Issues Paper*, paragraphs B.42–B.68.

(c) be allocated between load and generation customers in accordance with each customer's expected share of positive net private benefits from the investment using:[72]

(i) a standard method for new high-value investments meeting or exceeding the Commerce Commission cost threshold for the definition of major capex (currently $20 million)[73]

(ii) a simple benefit-based method, a standard method or a combination of both for new low-value investments worth less than this $20 million threshold

(d) be based on fixed allocator, apart from some specific provisions for revision.[74]

9.3 Initially we proposed annual benefit-based charges for post-2019 investments would be based on a flat recovery profile over the investment's life or an alternative method that better met the Authority's statutory objective.[75] In the 2020 Supplementary Consultation Paper we proposed instead that, for pre-2019 and post-2019 investments, annual benefit-based charges would be set according to the profile specified by the Commerce Commission for Transpower's individual price-quality path (currently DHC).

Submitters' views and our assessment

Overview

9.4 The Authority considers that a benefit-based charge is the best way to recover the costs of investments in the interconnected grid, for reasons set out in the 2019 Issues Paper. Our approach has been endorsed by leading expert Professor William W. Hogan.[76]

9.5 It is important to get the incentives right, particularly ahead of a potentially significant increase in transmission investment to accommodate the electrification of our economy in response to the decarbonisation challenge. The benefit-based charge will help ensure the right incentives are in place to promote the right investments at the right time. This will mean all New Zealanders continue to benefit from a reliable electricity supply at least cost.

9.6 By contrast, the current TPM creates a material risk of poorly targeted investment, meaning that consumers would pay higher electricity prices. The RCPD charge is volatile[77] and sends damaging signals. Particularly:

(a) it suppresses use of the grid to transport electricity, at times when New Zealanders most value it, even where there is plenty of capacity in the system and use of the grid is effectively costless.

(b) it encourages businesses to invest in distributed (including diesel) generation and batteries, purely to shift transmission costs to others.

9.7 Even critics of the Authority's proposal recognise removal of RCPD charging is timely.[78]

9.8 The current RCPD charge also spreads the costs of each grid investment across all load customers regardless of whether they receive benefit from it. The costs of transmission investments that address a local or regional supply or grid reliability issue are in effect

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72 *2019 Issues Paper*, paragraphs B.101–B.167

73 As with the use of DHC, discussed above, this means that if the Commerce Commission changes its threshold, that will automatically carry over to the TPM.

74 *2019 Issues Paper*, paragraphs B.133–B.137, B.168–B.175 and B.184–B.193.

75 *2019 Issues Paper*, paragraphs B.74–B.100.

76 See footnote 40.

77 See submission of EA Networks.

78 See, for example, Professor Derek Bunn (for Vector), *A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review*, pages 8–10.

subsidised by all other consumers. To a large extent, this means that those who benefit from an investment only pay a small share of its costs, with most of the costs instead spread among many who do not benefit from the investment. As a result, no stakeholder has the right incentives to give Transpower and the Commerce Commission the best possible information on the actual value of grid investments or of alternative solutions.

9.9 The current TPM also effectively taxes generation in the South Island via the HVDC charge. This discourages efficient generation investment at a time when New Zealand's generation needs are materially increasing.

9.10 The current TPM does not work and cannot be expected to do so. We consider that a new TPM based on benefit-based charges will address these problems.

9.11 The Authority understands, as submissions have pointed out, that benefit-based charging has many potential imperfections; for example that the assessment of customers' share of benefits from an investment at the time the investment is made cannot be a precise forecast and that the benefit-based charge could become increasingly misaligned with customer benefits over time.

9.12 In our final TPM guidelines we have sought to mitigate these issues. However, the assessment of benefits does not need to be perfect to achieve the intended outcomes for the benefit of consumers. We consider that no submitter has presented a better alternative than our proposal to address the problems with the current TPM.

9.13 Finally, on the contentious issue of whether to apply benefit-based charges to historical investments, the Authority has confirmed its 2019 proposal, that is, to apply these charges to seven major existing investments for which we were able to identify net positive benefits and identify beneficiaries, on the basis that:

(a) there is an increasing consensus that the charging methodology for existing HVDC assets must change to better reflect benefits

(b) we do not consider it would be appropriate to limit the benefit-based charge to recovering the costs of only the HVDC assets, as 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

(c) without making this decision, beneficiaries of new investments will pay for all the costs of those investments while also still paying for a portion of geographically remote investments they do not benefit from. No submitter was able to resolve this problem without applying benefit-based charges to historical investments.

9.14 We have reached the following conclusions on key contentious issues. The benefit-based charge will:

(a) apply to future grid investment, as this will promote more efficient grid investment and more efficient decisions by transmission customers

(b) apply to seven recent, major investments including the HVDC as that will lead to a more durable TPM and have material efficiency benefits and may (if the conditions for inclusion of Additional Component E are met) apply to other and potentially all pre-2019 investments in the interconnected grid

(c) be allocated via a standard method for high-value investments and, to reduce the administrative burden, via a simple method for low-value investments

(d) be largely fixed, to preserve customers' incentives for efficient behaviour and scrutiny of proposed investments — except that it can be re-opened in certain limited circumstances, to ensure the allocation of each customer's transmission charges is not too misaligned with the benefits it gets from the grid

(e) be recovered annually according to the Commerce Commission's front-loaded DHC method, for a better match between the allocation of charges and actual benefits, better customer incentives, reduced efficiency losses and lower administrative burden on Transpower.

9.15 We set out the key arguments on each of these issues below.

Benefit-based charge to apply to future investment in the grid

9.16 Some submitters endorsed the proposed introduction of a charge allocated based on a customer's expected benefits from an investment and the Authority's reasons.[79] Professor Bunn (for Vector) noted the increasing use of the beneficiary charging principle internationally, if only for future investments.[80] But others opposed the benefit-based charge on various grounds. Submitters' key concerns are discussed below.

9.17 Having considered the matters raised in submissions, the Authority's view remains that it would promote the efficient operation of the electricity industry for the benefit-based charge to be allocated between load and generation customers according to each customer's expected share of positive net private benefits from the investment.

Benefit-based charge will promote efficient grid investment decisions

9.18 Some participants (for example, Fonterra, Transpower) questioned whether greater scrutiny of grid investment would result in more efficient outcomes. Some argued that benefit-based charges would not promote efficiency in grid investment decisions because engagement would not increase and information provided by stakeholders would not be accurate or impartial as beneficiaries seek to avoid charges.[81] Trustpower submitted that "…potential beneficiaries have the incentive to understate the benefit they are likely to receive…".[82] Northpower submitted that scrutiny of investment proposals is the Commerce Commission's job, and that the TPM "cannot short-circuit that process."[83]

9.19 The Authority agrees that scrutiny of investment proposals is one of the Commerce Commission's roles. In our view, a TPM based on the 2020 guidelines will enhance that process by ensuring that grid users have good incentives to engage with Transpower and the Commerce Commission as part of the investment approval process and provide information that could otherwise be difficult for the Commerce Commission to obtain.[84]

9.20 The Authority considers that parties most affected (in terms of receiving benefits and paying transmission charges) by a new investment would have greater incentives to engage and reveal correct information.[85] Those who benefit from the investment would be encouraged to engage because they want the investment to be constructed. Those who would not benefit (but have been identified erroneously as beneficiaries) would be encouraged to provide evidence to show they will not benefit. Parties that would be disadvantaged by misleading information provided by others will have an incentive to expose it. We do not expect participation and the additional information it reveals to be perfect or unbiased, but that it will be a material improvement over the status quo. We

79 For example, Buller Electricity, Contact Energy, Distribution Group (see paragraphs 45–47), Federated Farmers and NERA (for Meridian).

80 See report of Professor Derek Bunn (for Vector), pages 2 and 10. Professor Bunn also raised concerns with aspects of the Authority's proposal (such as including historical investments) which are considered below.

81 Axiom and Northpower raised similar concerns. Also CEC, Flick Energy, Lantau Group, Mercury and Pioneer.

82 Trustpower, p 40–41, citing Professors Bushnell and Wolak, 2017.

83 Northpower, p 15.

84 For an example of scrutiny of a proposed investment due to beneficiaries-pay charging, see *2019 Issues Paper*, footnote 173 and literature relating to increased consumer participation in decision-making at page 42. See also the Authority's April 2020 Information paper, Revisions to CBA in the 2019 Issues paper, Chapter 7.

85 A stakeholder need not be disinterested to provide useful information. Stakeholders will be aware that their submissions are more likely to be accepted if they are relevant, sound, evidence-based and accurate.

consider that the 2020 guidelines will result in more efficient investment in (and promote competition between) the grid and non-grid alternatives.

9.21 Some stakeholders expressed the view that the benefit-based charge does not work in the case of an investment that does not provide immediate benefits but is expected to provide benefits in the future.

9.22 In our view, however, the benefit-based charge applies in a workable and efficient way to such investments.

9.23 For example, we considered an interconnection investment to facilitate committed future investment in renewable generation by identified parties that are not yet transmission customers. Such a grid investment would facilitate the transmission of electricity from the new generation to load centres and prevent a transmission constraint that would otherwise impede export of energy (if the new grid investment did not proceed). The new grid investment will not only benefit the new generators; it will also have future benefits for new and existing load customers (for example, lower future wholesale electricity prices). Existing load customers could be charged immediately on the basis of their expected future benefits from the grid investment (even if their immediate benefits may be zero). Once the new generators appear, they will be charged.[86]

9.24 This example raises issues similar to the 'first mover disadvantage' issue discussed in the context of the connection charge at paragraph 8.3. However, any such disadvantage is alleviated here because, while the first customer to benefit from a new interconnection investment may initially be subject to higher interconnection charges, customers appearing at a later date will still pay charges that reflect their share of benefits across the investment's whole life.[87]

9.25 Stakeholders were concerned that benefit-based allocation is difficult,[88] and highly sensitive to assumptions and the methodological approach adopted.[89] There was a concern this could lead to a potential increase in disputes over the allocation of investment costs and an increase in the cost of such disputes.[90] Transpower expressed the view that "The Authority's proposal would put timely, efficient grid investment at risk."

9.26 We acknowledge concerns about difficulty and sensitivity to assumptions and method, which mean the allocation may only approximately reflect benefits. However, our view is that even with a high degree of approximation, the benefit-based charge would provide better incentives for grid users than is possible under the 2006 guidelines.[91]

9.27 We also understand the argument that our decision will lead to disputes over the allocation of investment costs. However, in our view such disputes will be of limited duration and cost. If they do occur, it would be primarily at the outset as part of appropriate scrutiny when an investment is initially proposed. Further, we have looked to

86 In these circumstances clause 33 of the guidelines will ensure that the new generators do not unnecessarily benefit from their late entry. Likewise, the charges paid by the load customers who are charged the full costs of the new investment in the early years will reflect their share of benefits across the investment's life.

87 There would still be a risk that customers expected to arrive later do not appear. However, this risk is mitigated by (A) additional scrutiny of the proposed investment by existing customers (identified as future beneficiaries), which could provide high-quality evidence and identify forecasting problems that would otherwise have not been detected and (B) the Commerce Commission's review of investment proposals, which may be expected to dismiss objections that are not well-founded and approve proposals for efficient grid investment that are based on evidence (for example, evidence of commitment to future investment in new generation).

88 For example, Electricity Networks Association and Tilt Renewables.

89 For example, Transpower, Distribution Group, Orion, Unison and Centralines.

90 For example, Electric Kiwi, Electra, Electricity Networks Association, the Lantau Group (for the TPM Group), Transpower, Unison and Centralines.

91 *See 2019 Issues Paper*, pages 142–143, citing Hogan, W (2011), *Transmission Benefits and Cost Allocation*, at: http://www.hks.harvard.edu/hepg/Papers/2011/Hogan_Trans_Cost_053111.pdf .

mitigate the risk of dispute from increasing misalignment of benefit and cost over time via our decision to switch the recovery profile to DHC. We expect that this will lead to an enduring TPM that is likely to result in fewer disputes and fewer calls to fundamentally change the TPM because of various perceived or actual problems with benefit-based charge allocation.

9.28 Trustpower raised a concern that "…the benefit-based charge as currently described is not sufficiently scoped to provide a tractable solution…"[92] The Lantau Group for the TPM Group said that benefit-based charging would have a difficult and uncertain implementation. Transpower highlighted challenges it expected to face in seeking to apply the benefit-based charge. The Lantau Group noted various practical challenges and unresolved questions (including potential inconsistencies between the Commerce Commission's approvals process and the TPM regarding the treatment and calculation of benefits) and said detail was lacking in the TPM guidelines proposals, for example:

> "Crucially, the relevant approvals process, itself, must also be clear and comprehensive in relation to how all of the various types of benefits are to be treated, such as reliability, safety, competition, option value/development and other economic benefits, as each has different potential beneficiaries under different conditions and at different points in time."[93]

9.29 The Authority recognises there is still work to do before the benefit-based charge is fully developed. Transpower will need to work through various issues as it develops the proposed TPM. The case studies provided by Transpower in its submissions relating to a potential investment in Hawke's Bay are useful in this regard. We acknowledge the view of some submitters that Transpower's case studies are confined to a relatively simple situation relating to the expansion of a radial line (as opposed to more complex situations) and that the modelling does not deal with all issues or capture all the flow-on effects of a grid investment.[94] Nevertheless, the case studies provide a useful illustration of some of the considerations that will have to be taken into account and some of the judgements that will have to be made. We would also observe that the modelling of benefits does not need to precisely quantify all of the effects of an investment. The 2020 guidelines require only that the allocation of benefit-based charges is broadly in proportion to benefits.

9.30 The Authority has considered the practical challenges raised by The Lantau Group and is confident they can be resolved. For example, reliability benefits for a load customer in a given location can be quantified using estimates of value-of-lost-load (VOLL) and probability of outages. The 2020 guidelines provide for alignment with the Commission's cost benefit analysis approach.[95] The experience of system operators in the United States demonstrates the practical challenges of a benefit-based approach can be overcome.[96]

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92 Trustpower, p 41, citing The Lantau Group, p 21

93 The Lantau Group 2019, p 16. Professor Bunn also raised practical challenges (Vector, paragraph 17).

94 For example, Creative Energy Consulting (for Trustpower) – 23rd October 2019

95 The 'net private benefit' definition provides for consistency with 'electricity market benefit or cost elements'.

96 See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018 and *2019 Issues Paper*, pages 143–144. Transpower and CEC (for Trustpower) submitted that the Authority's proposal does not accord with international precedent and pointed out that in the United States the benefit-based approach has been implemented in ways that differ from the Authority's proposal, for example with respect to tariff structures and the level of granularity. We recognise that our approach differs in substantive ways from the approach adopted in the United States. However, the underlying principle is the same and the US experience demonstrates the beneficiary-pays principle can be successfully applied in practice.

Benefit-based charge will promote efficient customer investment decisions

9.31 Some submitters argued that benefit-based charges do not promote efficient investment decisions as forecasting future benefit-based charges will be too difficult for transmission customers, especially small participants and entrants.[97] For example, Trustpower said:

> "…in reality decision-making is unlikely to be significantly improved for the majority of customers under a benefits-based charging arrangement."[98]

9.32 The question of the quality of information available to participants is not black and white. The Authority's view on this issue has changed over time: in 2016 the Authority considered that distributors (amongst others) were unlikely to have the full information needed to determine what transmission investments might be required in future (as Axiom, for Transpower, has observed).[99] Axiom also submitted that "the implicit *ex-ante* 'shadow price' signals provided by [benefit-based] charges would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond."[100] This line of thinking leads to arguments for peak charges that reflect future costs.[101]

9.33 After further consideration, the Authority now takes a different position on these matters. In our view if users know they will pay their share of new grid investments, they will pay more attention to such costs when they make location and other investment decisions than they do now. Forecasts are inevitably imperfect. But even with this uncertainty, the guidelines would still be an improvement over the current pricing approach where load customers' charges are based on patterns of demand in the previous year, depend on how each customer's peak demand compared to that of other customers and do not send useful signals about transmission cost.

9.34 The Authority considers the solution to providing information for investment decisions is not found by setting additional transmission prices such as a peak charge.[102] Customers can assess their potential exposure to benefit-based charges using information that is already publicly available about transmission charges and future investments (e.g. Transpower's Transmission Planning Report). Grid users large enough to individually shift grid investment plans would have the capability and motivation to seek out the information they need, for example, by asking Transpower or distributors. That said, we acknowledge that there may be room for improvement regarding the quantity and quality of information provision. Such advances can and should be made over time.

9.35 Some participants questioned the proposed application of the charge to distributors (for example, Counties Power) or to generation customers (Mercury). Flick Energy and

97 For example, Creative Energy Consulting (for Trustpower) and NZ Steel.

98 Trustpower, citing HoustonKemp report (February 2017), p 13.

99 Axiom cited Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2–E.3. Northpower made a similar submission. The statement was made in the context of the ACOT arrangements in Part 6 of the Code. The Authority's thinking on this matter has evolved since 2016: its most recent consideration of the ACOT arrangements is set out in Appendix F of the *2019 Issues Paper*. See also: Electricity Authority, 2020, *Peak charges under proposed TPM guidelines: information paper and next steps*, available at www.ea.govt.nz

100 Axiom Economics 2019, page iv. Northpower expressed a similar view p 7.

101 The Authority has previously expressed such views. For example, in *TPM Review: LRMC charges Working paper*, 29 July 2014, the Authority expressed a view that long-run marginal cost (LRMC) charges could potentially promote more efficient investment.

102 The Authority has published a detailed paper on the Authority's thinking on the role of peak and congestion charging and the submissions provided on that topic: Electricity Authority, 2020, *Peak charges under proposed TPM guidelines: information paper and next steps*, available at www.ea.govt.nz. The Authority's view remains the same as that expressed in the information paper.

Mercury did not agree transmission charges have a material impact on generation location decisions, as generation is sited at the location of the best fuel resources.[103]

9.36 We have considered the submissions questioning the proposed application of the charge to generation customers or distributors. However, our view is that the significant advantages for consumers flowing from a benefit-based approach can only be fully realised if all customers who benefit from transmission investments pay for them — regardless of whether they are generation or load customers. Both generation customers and distributors make significant investments of their own that are influenced by the grid charges they pay and may also have useful information on the efficient costs and benefits of a proposed grid investment. We acknowledge that generation location depends on fuel resources and other factors, but in our view transmission charges can be material on the margin, such as in the case of a decision between two otherwise similarly attractive locations that have different transmission costs. Our proposal promotes competition by providing a level playing field for generation to compete on the merits and eliminating subsidised transmission.[104]

9.37 Furthermore, the only alternative to requiring those who benefit from an investment to pay for it is to require those transmission customers who do not benefit from the investment to pay for it. That would create a range of efficiency concerns.

9.38 Creative Energy Consulting (for Trustpower) submitted benefit-based charges do not promote efficiency in user investment decisions as the price signal is too dilute: new entrants do not bear all of the extra transmission cost they cause by entering (as costs are shared by all beneficiaries).

9.39 Having studied this argument, we remain confident that our decision provides effective long-run price signals to support efficient operation and investment. Even to the extent that price signals are diluted, new entrants will still face more efficient incentives under the benefit-based charge than under the current TPM or other alternatives that have been considered. A new or expanding customer will pay a benefit-based amount for new infrastructure, but under the current TPM generators pay no interconnection costs and benefitting load customers pay a very low share of the interconnection costs associated with the investment. A new entrant will also pay charges for existing investments based on what a similar incumbent would pay.

9.40 Northpower submitted that the benefit-based charge would provide customers with “economically perverse price signals” and asked the question, if nodal prices provide customers with all the signals they need to make efficient decisions “then why would there be any need for the TPM to provide any further price signals?”.[105]

9.41 The Authority’s view is that nodal prices and benefit-based charges are complementary components in a two-part pricing structure.[106] Nodal prices provide customers efficient signals about the short-run cost of using the existing grid at a point in time and provide information about when a grid expansion is justified, whereas the benefit-based (and residual) charges pay for access to the grid. The expectation of benefit-based charges associated with transmission expansion would give forward-looking price information.

9.42 Consider a load customer faced with increasing demand at a given grid location. The customer can anticipate that, as the grid becomes more constrained over time, this will

[103] Similarly, Mercury disagreed that the existing TPM is an impediment to South Island renewable generation investment, citing as more important other factors including lower wholesale prices, the potential exit of the Tiwai Smelter and the difficulty of securing environmental consents.

[104] By contrast under the existing TPM generators do not pay for interconnection, effectively providing a subsidy to those generators that depend most heavily on transmission interconnection services.

[105] Northpower, p 7, citing Axiom Economics (for Transpower), who made a similar submission.

[106] See also Electricity Authority, 2020, *Peak charges under proposed TPM guidelines: information paper and next steps*, available at www.ea.govt.nz

result in a continued rise in nodal prices (which the customer will pay) to reflect the constraint. Alternatively, a grid investment (for which the customer will pay benefit-based charges) will relieve congestion and allow nodal prices to fall.[107] This is how transmission charges and prices set in the wholesale market will work together, facilitating the most efficient solution, for the long-term benefit of consumers.[108]

9.43 Northpower was concerned levying benefit-based charges on generators would increase their break-even point, resulting in higher wholesale prices over the long-term.[109] Others submitted benefit-based charges would discourage investment in renewable generation (for example, Ngāti Tūwharetoa, The Office of the Māori Climate Commission and Tauhara North No. 2 Trust) or electrification of load (for example, Fonterra).

9.44 We agree that the cost of the benefit-based charge will be built into generators' cost structures.[110] We see this as an advantage, not a flaw.[111] An investor in generation will need to consider the implications for grid-related costs when making its location decision.[112] We expect this to lead to generation investment under a TPM based on the 2020 guidelines that is more efficient overall — and lower wholesale prices over the long-term. We consider that our decision supports a transition to a low-emissions economy at least cost.[113]

Benefit-based charge applies to seven recent, major investments

9.45 Various stakeholders argued the benefit-based charge (if it applies at all) should not apply to historical investments.[114] Vector submitted that recovering historical costs from beneficiaries of the existing assets would not promote efficient decisions on new investments and could create inefficient location decisions.[115] Northpower also raised a concern about inefficient generation location decisions due to benefit-based charges.[116]

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107 The customer may benefit from a reduction in the congestion component of the nodal price and the loss element in the nodal price as a consequence of the new investment.

108 An outcome may be a rise in nodal prices and later an investment, or an investment in anticipation of rising nodal prices due to growing demand. This does not change the argument. More generally, the approach to pricing would give efficient, location-specific information on the trade-off between doing nothing (accepting higher nodal prices and a risk of unserved demand at times transmission is stressed), demand response, more local generation, or future transmission expansion.

109 Northpower, p 13.

110 There is no inconsistency with our reasoning for why generators should not pay the residual charge (discussed at paragraph 10.15 to 10.20). A key difference is that if the residual charge were paid by generators, it would be paid by all on the same basis — and so the cost increase would ultimately be paid by consumers. By contrast, the benefit-based charge is levied in different amounts on different generators, depending on the extent to which they benefit from various grid investments. Generators operate in a competitive market. As NZ Steel has observed (paragraph 24, footnote 5), in a competitive market there is little scope for a firm to pass on a cost increase that only affects that firm (rather than all firms in the industry).

111 It is no different in principle from a supermarket having to build into its product prices the rental cost of the land and building that it occupies. This gives the supermarket an incentive to consider these costs when choosing where to locate and how to structure its business and so results in the end in greater consumer benefits. If the supermarket was exempted from its rental costs because that added to product prices, that would lead the supermarket to make poor location decisions and after the cost of the rent subsidy is taken into account, to lower benefits for consumers.

112 This might delay the entry of a generator that would require a large new grid investment to transport its product to market but would not delay the entry of a generator in the same location as a large load centre.

113 See chapter 5 for a discussion of how our decision supports a transition to a low-emissions economy.

114 E.g. Contact, Eastland, Electricity Networks Association, Mercury, Tauhara North No. 2 Trust, TLC and Vector.

115 Vector, paragraph 13, citing Compass Lexecon's 2015 expert report for Vector. See also NZ Steel, pages 2 and 18, citing Covec and Professor Hogan.

116 Northpower, pages 13–14.

9.46 We agree that recovering historical costs from beneficiaries of the existing assets cannot change investment decisions that have already been made. Nevertheless, in our view there are strong reasons to recover some historical investment costs through the benefit-based charge (such as improving durability, discussed below). We recognise that the benefit-based charge in respect of pre-2019 grid investments could result in potential distortion to location decisions by load and generation. This potential cost has been taken into account in the cost-benefit analysis and is outweighed by the estimated benefits. Further, applying the charge only to future investments would create an uneven playing field for generation and so would not promote competition.

9.47 Vector (and Professor Bunn) said that reallocating the costs of historical investments "creates significant regulatory risk and uncertainty for investors which is likely to raise the cost of capital and undermine confidence in New Zealand's regulatory regime."[117]

9.48 However, Professor Littlechild (for Meridian) takes the opposite view.[118]

9.49 The Authority has previously set out a number of counterarguments to Vector's view that it considers to be strong.[119] The standard approach in New Zealand is that inefficient regulatory arrangements will not remain settled and changes to existing regulations are applied equally to both future investments and existing investments.[120] The Authority's view is that applying benefit-based charges to some historical investments will make a new TPM more durable and thus will reduce or eliminate ongoing uncertainty about the TPM. We would also observe that any substantial change to the allocation of the main transmission charges (even 'an incremental' change to the current TPM such as a weakened RCPD price signal) would have the effect of reallocating the costs of historical investments.

9.50 A number of submitters were concerned that applying the benefit-based charge to historical investments would mean a substantial wealth transfer away from consumers to generators and large industrials.[121]

9.51 Some submitters have quoted the Electricity Price Review which said that changes to transmission pricing should "reallocate the costs of past grid investments… only if the Electricity Authority can estimate with a high degree of confidence that such a reallocation will result in substantial, long-term benefits to consumers."[122] Vector says it is "extremely sceptical that the EPR Panel's proposed test can be met."

9.52 The Authority's test is whether such treatment of the cost of historical grid investment will promote its statutory objective. Experts for submitters present different views on that.

9.53 For example, Professor Bunn (for Vector) submitted that:

> "The apparent anomaly of including seven legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward."[123]

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117 Vector, paragraph 12. Refining NZ and Tilt Renewables raised similar concerns.

118 Professor Littlechild, 2019, p 2–3. Also see Unison and Centralines, p 2.

119 Electricity Authority, 2018, paper for Professor Hogan's review: *Should beneficiaries pay for existing grid assets?* pages19-20 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18138

120 For example, in the past, any change in the company tax rate has applied equally to both historic investments and future investments.

121 For example, Entrust and Vector.

122 Similarly, the Lantau Group (for the TPM Group) submitted that reallocation should be limited to instances where it "materially and unambiguously enhances efficiency".

123 Professor Bunn, 2019, p 29.

9.54 By contrast, Professor Littlechild (for Meridian) submitted that the Authority's approach seems sensible, improves the information available to customers, generators and transmission planners and would not undermine investor confidence.[124]

9.55 The Authority is, as outlined below, satisfied that the reallocation of the remaining costs of historical investments improves the durability of the 2020 guidelines and has material efficiency benefits.[125]

9.56 In particular, as discussed below, there is a strong case for reallocating HVDC costs. Further, having considered submissions that take the opposite view,[126] the Authority continues to consider its approach will lead to a more durable TPM. If benefit-based charges only applied to future investment, that means that some consumers would have to both pay for new investments made for their benefit and continue to pay for major investments they did not get significant benefit from. No submission that advocates a future-only application of the benefit-based charge has offered suggestions that solved this. The Authority agrees with the submission of Unison and Centralines that:

> "If benefit-based charges only applied on a forward-looking basis, then Unison and Centralines could face the jeopardy that future major investments to the East Coast of the North Island are funded through benefit-based charges and must subsidise historical major investments which we do not benefit from. This would be a manifestly unreasonable outcome."[127]

9.57 The Authority also does not agree with The Lantau Group (for the TPM Group) that the Authority's modelled cost allocation for some historic investments is spread broadly and evenly, so there is no durability argument to reallocate those investments:

> "…the beneficiaries of these investments, when considered in aggregate, are spread rather broadly and evenly across the country (covering both North and South Islands), with no clear case to suggest that the benefits are accruing disproportionately to a small group of customers in a given area…"

9.58 Instead, the reallocation of costs via the benefit-based charge would result in significant shifts in the incidence of the charges. For example, currently, Orion pays around 9% of the costs of all interconnection investments. Under the 2020 guidelines, Orion will pay approximately 5% of the HVDC, 18% of Bunnythorpe-Haywards and 1% of NIGU and the Wairakei Ring. These changes will bring charges in line with benefits, which in our view will promote more durable transmission pricing arrangements.

9.59 Having considered the matters raised in submissions, the Authority's view remains that it would be in consumers' long-term interests for the benefit-based charge to fully recover the remaining costs of seven recent, major investments, according to the allocation determined by the Authority (and the costs of each new interconnected grid investment).

9.60 The Authority's decision to include some historical investments is based on the qualitative considerations discussed in this paper and is also informed by the CBA discussed in chapter 15, which indicates that our decision delivers greater long-term net benefits for consumers, compared to for example a future-investments-only (or HVDC and future investments) version of the proposal. For all these reasons the Authority has a high degree of confidence that a reallocation of the costs of these historical investments will result in substantial, long-term benefits to consumers.

124 Professor Littlechild, 2019, pages 2–3.

125 Wealth transfers are not a relevant factor for the Authority's decision-making, except to the extent they result in effects on efficiency (e.g. via effects on durability), competition or reliability. Having considered potential costs of our decision in these respects, we are confident any such costs are outweighed by benefits.

126 For example, CEC (for Trustpower), Fonterra, Mercury, Northpower, Axiom, Transpower and The Lantau Group.

127 EA Networks made a similar submission. Nova also supported including historical investments.

There is a strong case for reallocating HVDC costs

9.61 Many submitters agreed the HVDC charge needs to change. For example, the NZ Wind Energy Association submitted that the current approach disadvantages new renewables development. Removing the disincentive to build wind farms in the South Island will achieve greater geographical dispersion and reduce the short-term variability of wind generation.

9.62 A handful of submissions (for example, Counties Power and the TPM Group) considered the HVDC to be a special case, for which it might be appropriate to reallocate costs, even though they opposed re-allocation for other historical investments. For example, The Lantau Group (for the TPM Group) argued for reallocating HVDC costs across North and South Island generators. The basis for this was that imposing the HVDC charge only on South Island generators is unfair and "likely distorts efficient generation investment decisions".

9.63 We agree there is a strong case for reallocating HVDC costs. The HVDC charge has to a significant extent operated as an additional tax on South Island generation. There is no need for a separate charge specifically for assets using DC technology: the Authority, guided by its statutory objective, is technology-neutral. Replacing the HVDC charge with benefit-based charges will promote competition by providing a level playing field between generation in the two islands, unlock investment in South Island renewable generation options and so deliver benefits to consumers.[128] However, our view is that other historical investment costs should also be reallocated (as discussed below).

9.64 We considered the submission from the Electric Power Optimisation Centre (EPOC) questioning the proposed application of the benefit-based charge to the HVDC, on the grounds of strategic behaviour by generators. We also considered Electric Kiwi's concern that reallocating HVDC costs could create retail competition problems due to windfall gains for incumbent generators.

9.65 Our view is that, even if there was a valid concern regarding South Island generators' trading conduct, it would not follow that such generators should continue paying the full costs of the HVDC. Similarly, there is no evidence that reallocating HVDC costs will create retail competition problems, or that such problems are avoided by retaining the HVDC charge. To the extent it is appropriate for the Authority to address concerns relating to retail competition and trading conduct, it will do so directly.

9.66 Northpower raised the possibility that the HVDC charge "could be an efficient locational signal", noting there is a differential between the cost of supplying transmission to North Island vs South Island generators and "at the moment, the HVDC charge is the only thing that signals that cost differential to prospective investors".[129]

9.67 Under the 2020 guidelines, however, there will continue to be a differential in transmission charges between North Island vs South Island generators. That differential will be based on the extent to which they benefit from the HVDC and other grid investments. South Island generators benefit significantly more from the HVDC than North Island generators (according to the Authority's calculations) and so they will pay a significantly higher benefit-based charge for that asset. The Authority is confident its decision to replace the HVDC charge with the (technology-neutral) benefit-based charge will lead to more efficient generation investment overall.

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128 The alternative option of reallocating HVDC costs across North Island and South Island generators (as opposed to a benefit-based allocation across generators and load) is discussed in Appendix B.

129 Northpower, p 14. Also see Mercury's point on factors relevant to investment in South Island renewable generation, discussed above.

For pragmatic reasons, not all historical investments are covered

9.68 A common submission, raised by MEUG and some South Island stakeholders, was that more, or all, historical investments should be recovered via a benefit-based charge.[130]

9.69 We have not included more historical investments as we are not certain that there is sufficient information available in respect of other investments, in order to limit implementation costs and to ensure that initial benefit-based charges do not exceed the benefits these investments are now expected to yield. However, we have provided for Transpower (via Additional Component E) to include more pre-2019 investments in the benefit-based charge if to do so would better meet our statutory objective.[131]

9.70 Some submissions endorsed the benefit-based charge covering the seven investments proposed in the 2019 Issues Paper. For example, Buller Electricity submitted that the seven pre-2019 investments may be the best outcome in terms of trading off durability objectives and the administrative burden of determining the benefit-based allocation (noting there is an argument for extending it to all pre-2019 investments).

9.71 The Authority's allocation of historical investment costs to transmission customers is set out at Schedule 1 of the 2020 guidelines. We considered MEUG's submission that this allocation should be on a GXP and GIP basis. However, in our view this would risk creating incentives for parties to attempt to avoid charges.[132] Nevertheless, for any customer that needs to identify and analyse how its benefit allocation breaks down on a GXP basis, there is publicly available information to enable this.[133]

9.72 Appendix A addresses submissions on selection and modelling of the historical assets.

Benefit-based charge to be allocated via a standard and a simple method

9.73 Some submitters largely endorsed this proposal and the Authority's reasons.[134]

9.74 However, some parties opposed the proposal. Trustpower questioned whether using a simple method would achieve the efficiencies that the Authority is hoping to achieve from benefit-based charging and raised a concern that the choice of threshold is an arbitrary one which could incentivise gaming and violate competitive neutrality (for example, between generators or between load customers).

9.75 We acknowledge Trustpower's concern. However, we note that a simple method can still result in allocation to the likely main beneficiaries with a reasonable degree of confidence (the main beneficiaries should be clearly identified in any well-prepared investment proposal). Our view is that, despite the limitations of a simple method, the improved incentives flowing from its use are likely to be superior to the incentives that would result from recovering these costs via the residual charge. Further, while using a simple method may forgo some of the (narrowly defined) efficiency benefits of the standard approach, there is a trade-off: a simpler method reduces administration and transaction costs. Consistent with our DME framework, we take these effects into account and consider that use of a simple method for low-value investments is likely to promote overall efficiency.

9.76 We do not agree that our decision on the threshold was arbitrary. A key reason for it was that $20 million is also the Commerce Commission's threshold for 'major capex', so our

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130 For example, Electricity Ashburton, Network Waitaki, Orion, Great South, Invercargill City Council, Southland District Council, Gore District Council and Environment Southland.

131 See *2019 Issues Paper*, paragraphs B.66–68.

132 For example, a load customer could move its load from one GXP to another. In our view using the overall offtake for a given load customer leads to a better reflection of benefit than using offtake at individual GXPs.

133 Supporting information and analysis is available on the Authority's EMI website: https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis

134 For example, The Distribution Group, NZ Steel and Transpower.

decision will allow Transpower to rely on information produced for the Commission's Investment Test and other cost benefit analyses in applying the standard method.[135]

9.77 We acknowledge that any threshold raises the risk of boundary effects and gaming. However, the boundary effects are likely to be much more problematic where the allocation methodologies are markedly different on each side of the boundary (as they would be if low-value investment costs were allocated via the residual charge). This is not the case under the 2020 guidelines. Low-value investment costs can be recovered by a simple method, which is low cost and results in an allocation of charges to major beneficiaries that is broadly in proportion to expected positive net private benefits, and so broadly approximates the allocation to major beneficiaries that would result from the standard method. In our view, this approach mitigates potential problems caused by introducing a boundary between low-value and high-value investments.

9.78 Having considered the matters raised in submissions, the Authority's view remains that it would be consistent with the statutory objective for the benefit-based charge to be allocated using a standard method for new high-value investments, with the option of a simple benefit-based method (or combination of methods) available for new low-value investments.

9.79 Transpower submitted if the guidelines include a requirement to apply the benefit-based charge to low-value investments, there should be discretion for Transpower to include a floor, as the administrative cost and effort of applying even a simple method to a very low-value investment is unlikely to be worth it. The costs of any investments below the floor would be recovered through the residual charge or an alternative charge.

9.80 As is discussed in chapter 7, clauses 1 and 2 of the 2020 guidelines give Transpower the scope to introduce such a threshold if it can be justified by administrative and compliance costs.

9.81 Some submissions advocated for the guidelines to stipulate that benefits be estimated on the basis of net load (for example, NZ Steel) or gross load (for example, Contact Energy and Powerco). However, our view is that a less prescriptive approach is best, allowing Transpower to take the most efficient approach to determining net private benefits in the circumstances.[136]

Benefit-based charge to be largely fixed

9.82 Submissions on this proposal were mixed. Some stakeholders endorsed the proposal and the Authority's reasoning.[137] However, many parties disagreed with our position.

9.83 Having considered the matters raised in submissions, the Authority's view remains that it would promote efficient investment and the efficient operation of the electricity industry for the benefit-based charge to generally have a fixed allocation, which could be revised in certain limited circumstances.

9.84 This decision strikes a balance between competing considerations. The benefit-based charge is intended to reveal information on efficient costs and benefits at the time a grid investment is proposed. To preserve the incentives for this and to discourage inefficient charge avoidance behaviour, it is critical that the guidelines limit the scope for revisiting the allocation of the benefit-based charge over time.[138] That said, we appreciate that submitters are concerned about the allocation becoming misaligned with benefits.

135 The threshold in the guidelines will automatically adjust if the Commerce Commission changes its threshold.

136 The Authority's less prescriptive approach is explained in the *2019 Issues Paper*, pages132–133.

137 For example, NERA (for Meridian).

138 The Authority agrees with the TPM Group (p 5) that some actions to avoid charges, such as investing in distributed generation to avoid the need for future transmission investment, may be efficient. This does require those actions to be informed by efficient price signals.

9.85 We agree that there may be circumstances where the charges get so far out of line with the initially expected benefits that the durability of the regime may be affected. We have included a 'substantial and sustained change in grid use' provision in the guidelines to deal with these rare circumstances. Also, we have looked to mitigate longer-term problems by adopting the DHC recovery profile. But beyond that and having considered the submissions received, the Authority remains of the view that it should retain the core principle that benefit-based charges should largely be fixed 'up front'.

9.86 A number of submitters raised the concern that in practice (depending on how distributors respond) transmission charges might not be passed through into distribution pricing in the form of a non-distortionary fixed charge.[139] Trustpower said "The Authority assumes complete pass-through of signals from its regime."[140]

9.87 This is not an accurate characterisation of the Authority's assumptions. We recognise that some, but not all, consumers are directly exposed to transmission price signals (and wholesale price signals). We also recognise that distribution pricing is subject to constraints including the LFC regulations.[141] Nevertheless, despite the LFC regulations, our expectation (and observation) is that distribution pricing will become increasingly cost-reflective over time.[142] The removal of a strong RCPD charge may assist distributors to design distribution pricing that more clearly reflects their own costs and network issues. We also consider it is reasonable to assume that mass-market load (or their agents) will increasingly respond to both transmission and wholesale price signals in the coming years.[143] And we consider that a largely fixed benefit-based charge will lead to more efficient outcomes than charges customers can easily avoid by changing grid use.

9.88 Some submitters argued it is unlikely that a fixed benefit-based charge will reflect benefits, because the future will turn out differently from what was assumed when charges are set.[144] As Transpower put it: "The Authority's proposal would not ensure those who benefit pay for transmission investment in the longer term." This would cause lobbying and so the regime would not be durable. A number of submitters argued that the allocation of all benefit-based charges should be updated regularly, so that the allocation continues to reflect customers' benefits as they shift over time.[145] We understand the logic of these arguments. However, on both efficiency and practicality grounds we decided against regular revisions.

9.89 Our view is that charges should reflect *expected* benefits *at the time the investment is made*. The investment decision takes account of and so the charges should reflect, the range of possible outcomes when the investment is made and their likely probability, adjusted for risk. Inevitably, the actual outcome will turn out to be different from what is forecast. Some parties may get significantly fewer benefits than were expected when the investment was made and some parties may get significantly more.[146] In both cases,

139 For example, Unison and Centralines and Vector.

140 Trustpower, p 41.

141 This constraint was also noted by the Electricity Networks Association, Powerco, Unison and Centralines.

142 See the Authority's decision on distribution pricing principles at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/.

143 See *2019 Issues Paper*, p 28.

144 For example, Northpower, Tilt Renewables and Transpower. Professor Bunn also raised "dynamic fairness" issues (Vector, paragraph 18). Oji Fibre suggested that benefits should be calculated on an ex-post basis.

145 For example, Meridian, Orion and Powerco.

146 Trustpower provides case studies at p 49ff that illustrate this point. We have considered Trustpower's case studies carefully and in our view, the main points to be taken from them (in addition to this point) are that the choice of counterfactual is critical in determining the benefits from an investment and where they fall; and the re-opener provisions (even more so than the initial allocation) are likely to require considerable judgement to apply. We acknowledge these points. We remain confident that the benefit-based charge is workable and efficient, for the reasons discussed in this paper.

however, the charges reflect the benefit they were *expected* to get and so an amount that they would have been prepared to pay for the investment, despite the uncertainty, at the time the investment was made.

9.90 The Authority does not consider that this difference between forecasts and out-turns will significantly affect the durability of the 2020 guidelines. Forecast errors are an accepted, familiar and inevitable feature of commercial investment decision-making under uncertainty. Our position (not updating charges) is consistent with the analogous case of investments in generation, where if actual conditions differ from the generation owner's forecast, there is no reallocation of generation investment costs to other parties. The same holds for investments in other major assets.

9.91 Furthermore, the charges for individual investments matter much less once the investment is made and incorporated into the grid. Once this happens, the only decision the customer has to make is whether and how extensively to use the grid. This is affected by the marginal cost and their total transmission charges — the charges for an individual investment are no longer relevant to their decision making with respect to that investment. So the only significant concern is whether a customer's total transmission charges get substantially out of line with the benefits they receive from connecting to the grid. This concern is addressed by the substantial and sustained change in grid use provision and the prudent discount policy.

9.92 In addition, regularly updating the allocation of the benefit-based charge would distort customers' incentives to scrutinise proposed grid investments and customers' grid use and investment incentives. In the case of transmission, it is Transpower's customers, rather than Transpower or its shareholders, who get the benefits or suffer the costs when outcomes turn out to be different from forecasts. In our view, it is efficient for customers to bear this risk, as it means they have 'skin in the game', which encourages appropriate scrutiny of grid investment proposals.

9.93 Another factor against a regular review is that it would be practically challenging and likely controversial. The Authority prepared the allocation for the seven historical investments in order to reduce such issues later in the process. Estimating the benefits from an existing investment is much more difficult to carry out than setting the allocation once at the outset of an investment, principally because subsequent investments affect the estimation of benefits. (Also, a programme of regular reviews could eventually become costly and burdensome, given the size of the transmission asset base.)

9.94 Nevertheless, the Authority accepts that if the misalignment became too large, it could undermine the perceived integrity of the benefit-based charge. Consequently, the 2020 guidelines adopt four measures to mitigate this risk:

(a) a DHC recovery profile, which ensures that most of the benefit-based charge for an investment is recovered during the early years of its life when there is likely to be a better alignment between the allocation of charges and actual benefits

(b) a revision to the allocation in the event of a substantial and sustained change in grid use

(c) a reassignment of part of the benefit-based charge to the residual charge if the investment turns out to be a 'white elephant'

(d) the PDP provides a safeguard against inefficiencies resulting from fixed charges, as allocations can be modified to avoid uneconomic bypass of the grid.

9.95 In the last two of these, the part of the cost of the investment no longer recovered by the benefit-based charge is spread across all load customers via the residual charge.

Annual cost recovery for benefit-based charge aligned to Commission's

9.96 In response to submissions received in 2019,[147] we consulted in the 2020 Supplementary Consultation Paper on a proposal to align annual recovery of the benefit-based charge to the time profile specified by the Commerce Commission for Transpower's individual price-quality path (currently DHC). We received submissions in 2020 both for and against this proposal. A number of parties (for example, MEUG) endorsed the Authority's position. The IEGA said that application of DHC to both pre-2019 and post-2019 investments is pragmatic. Transpower submitted that while its pricing efficiency concern remains, it considered that DHC is likely to be more straightforward than using IHC.

9.97 Others disagreed with our change in approach. Some key concerns are set out below. Having considered submissions, the Authority's view is that setting annual benefit-based charges according to the DHC method would be consistent with its statutory objective.[148]

9.98 Some stakeholders observed that the proposed approach raises the possibility of price shocks when fully depreciated existing assets are replaced.[149] Some submissions said the proposed approach creates an inconsistency with beneficiaries-pay, as customers would pay the most for an investment when its benefits are lowest and pay the least when its benefits are highest (e.g. Entrust and Trustpower). Northpower submitted that a flat recovery profile (IHC) should be used for both pre-2019 and post-2019 investments.

9.99 We agree with Network Waitaki that under DHC benefit-based charges would rise significantly when fully depreciated existing assets are replaced (a sawtooth pattern of charges). We recognise this creates inconsistency with the beneficiaries-pay principle. In making our decision we have weighed up the possibility of inefficiencies arising from this source. We recognise the risk that — while we consider this unlikely — a DHC approach could inefficiently discourage replacement investment. However, this effect would be mitigated because the net present value of the charges would be the same and, for an efficient investment, would be less than the benefits provided by the investment. Furthermore, the variability of each customer's total transmission charges is likely to be moderated because the total charges will average relatively high charges for relatively new investments with relatively low charges for older investments.

9.100 In addition, the prospect of a significant rise in benefit-based charges is likely to raise the likelihood that a customer will carefully scrutinise a grid proposal and actively investigate the possibility of grid alternatives. Such investigations could be an important source of improvements in the efficiency of investment. Further, while distributors might see a sawtooth pattern of charges, there are offsetting effects for end-consumers. Wholesale energy prices in a previously constrained location could be expected to fall after an investment and reliability of transmission services could be expected to improve.

9.101 In our view submitters' concerns around the sawtooth pattern of charges and inconsistency with the beneficiaries-pay principle are outweighed by the significant advantages of a DHC approach, which include:

(a) more costs are recovered earlier in the life of an asset, when it is more likely there would be a better match between the allocation of charges and actual benefits

(b) charges later in an asset's life are lower, reducing customers' incentives both to dispute allocations and to (inefficiently) alter grid use to reduce future charges (as it means the potential gains from altering grid use in anticipation of a re-opener will be lower as time goes by)

[147] Meridian, NERA (for Meridian) and Rio Tinto. The Distribution Group supported the approach we proposed in 2019 (indexed historic cost unless it materially impacted the residual charge).

[148] Our approach means there is no prospect of over-recovery of the benefit-based charge, so there is no need to treat revaluations as income within the TPM (as proposed by Contact Energy).

[149] For example, Electricity Networks Association and Network Waitaki.

(c) efficiency losses that could be caused by a higher residual charge early in the life of the investment are avoided

(d) the Authority's approach is consistent with the cost recovery profile used by the Commerce Commission in its decisions on Transpower's Input Methodologies, which could promote certainty for investment and reduce administration costs.

9.102 For the above reasons we have also decided against using the IHC method for both pre- and post-2019 investments.

9.103 Vector argued that the proposed approach risks Transpower 'sweating' old assets, which may have implications for reliability and security.

9.104 We agree with Vector that the proposed approach could increase customers' incentives to find ways for Transpower to extract more value from its existing assets as opposed to replacing them. However, we do not agree with the conclusions that Vector draws. In our view, this is a feature of our proposal that could lead to a more efficient use of existing assets. Transpower has strong incentives to maintain reliability and security, so we expect that any increased use of existing assets that results from our approach would not be allowed to compromise the reliability and security of the grid.

9.105 Northpower submitted that the DHC approach proposed by the Authority (that is, the profile specified by the Commerce Commission for Transpower) bears no resemblance whatsoever to the way services are priced in most workably competitive markets.

9.106 However, that is not the view of the Commerce Commission's expert advisors, Yarrow, Cave, Pollitt and Small, who concluded the Commission's approach was comparable to the outcome that would occur in certain workably competitive markets. For example, the authors concluded that there is: "a distinct similarity (of this type of regulation) with a key feature of a workably competitive market in which long-term contracts are a major form of supply relationship."[150] As a submitter has observed, in such a market "high charges are paid earlier in the life of an asset than in the later years, reflecting the higher risks to the asset owner on obtaining a return in the later years (because demand might change, or assets become obsolete or by-passed)."[151] This is consistent with Orion's observation in submissions that a front-loaded recovery profile helps address stranding risk.

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150 Yarrow, Cave, Pollitt and Small (May 2010), *Asset Valuation in Workably Competitive Markets: A Report to the New Zealand Commerce Commission* p 29

151 Pacific Aluminium, 2017, *Transmission Pricing Methodology: Second Issues Paper: Supplementary Consultation: Cross-Submission on Valuation Method*, p 4, paragraph 17a

10 Guidelines: residual charge

Our decision

10.1 The 2020 guidelines on the residual charge (clauses 27 to 30) are similar to those proposed in 2019, except that they now:

(a) provide explicitly that the initial allocation will be based on peak energy use in the four-year period between 1 July 2014 and 30 June 2018

(b) clarify that for the initial allocation to customers with multiple connection points, historical AMD is to be calculated by taking the highest AMD separately for each of a customer's connection points, then summing (a non-coincident peak approach, as was proposed in the 2019 Issues Paper and reflected in indicative charges), as opposed to summing demand across all a customer's connection points in a single trading period (a coincident peak approach)

(c) are more high-level with respect to the definition of gross load, referring to generation behind the point of connection, rather than to distributed generation and behind-the-meter generation

(d) provide for the allocation to be updated regularly based on changes in usage

(e) no longer explicitly provide for Transpower to propose an alternative allocator.

10.2 The annual updates to the allocation will be as proposed in the 2020 Supplementary Consultation Paper, except that the lag on changes in energy usage will be reduced, so that the updated allocation will begin to apply in the 2023–24 pricing year, when 2018–19 energy usage enters the rolling average, rather than the 2025–26 pricing year.

10.3 Minor clarifications and drafting amendments have also been made. For example, the word 'largely' has been included in the provision that initial residual charge allocations should be adjusted where a customer has experienced a substantial change to demand due to factors largely beyond the customer's control.

What we proposed

10.4 In 2019 we proposed a residual charge paid by load customers that would recover Transpower's remaining costs in a non-distorting way.[152] We proposed:

(a) a single residual charge to recover all remaining costs that are not recovered through other transmission charges

(b) the residual charge would apply only to load customers

(c) a default allocation based on historical gross AMD.

10.5 We also proposed a principle that in initially 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.

10.6 While we proposed in 2019 that the allocation of the residual charge would remain fixed, in the 2020 Supplementary Consultation Paper (chapter 5) in response to submitters' feedback we proposed instead that the allocator be updated regularly. In particular, we proposed the initial allocator (which was based on historical gross AMD) be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, with a lag such that 2018–19 energy usage would enter the rolling average (and the allocator would first be adjusted) in the 2025–26 pricing year.

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152 *2019 Issues Paper*, paragraphs B.194–B.231.

Submitters' views and our assessment

10.7 Below we separately address feedback on the following aspects of the residual charge:

(a) a single residual charge to recover remaining costs, as the guidelines allow for transparency to be promoted without the need for multiple residual charges

(b) load customers pay the residual charge, because if generators paid the residual charge, consumers would ultimately pay higher wholesale prices

(c) initial allocation of the residual charge based on historical gross AMD, as in our view this will recover remaining revenues in the least distorting manner

(d) regular updates of the residual charge allocation based on lagged changes in usage, to balance two objectives: keeping charges aligned with customers' size and ability to pay and the need to avoid distorting customers' decision-making.

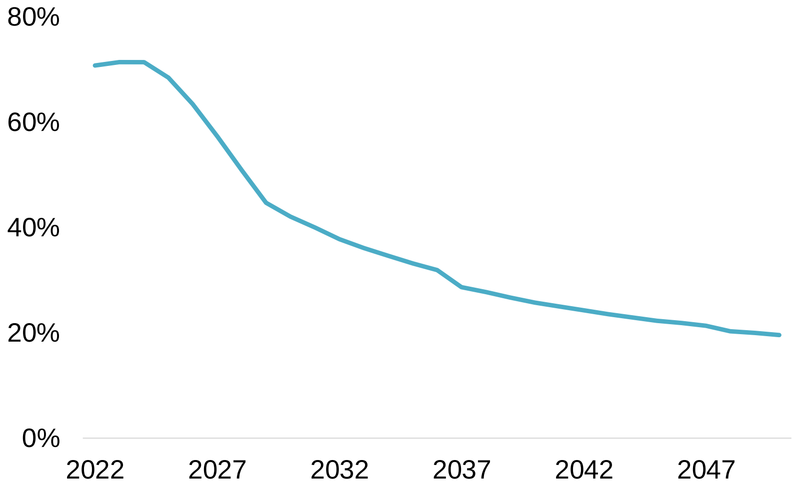
A single residual charge to recover remaining costs

10.8 Having considered the matters raised in submissions, the Authority remains of the view that allowing Transpower to recover its remaining costs through a single residual charge is appropriate and would be consistent with the long-term benefit of consumers.

10.9 Several parties submitted that the residual charge is too large (recovers too much revenue).[153] Some of these said the proposal does not provide full relief to customers who have been subsidising other customers by paying high transmission charges for some time.[154] Other stakeholders were concerned that under the proposed TPM guidelines, Transpower will be charging unallocated residual capital charges and other unallocated costs, including overhead expenses, to parties that receive no net benefit.[155]

10.10 We would observe that the share of total grid costs recovered through the residual charge will reduce materially over time as older investments depreciate and as new investments are recovered via the benefit-based charge (see the indicative modelling in Figure 6 below).

Figure 6 Residual charge will decline as share of benefit-based + residual charges



10.11 Even so, we acknowledge that a substantial proportion of the costs of grid investments would be recovered through the residual charge initially and for some time after commencement of a new TPM. This reflects our decision to not require allocation of all

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153 For example, Eastland, Great South, Invercargill City Council, Southland District Council, Gore District Council and Environment Southland, Network Waitaki, NZ Steel and Pan Pac.

154 For example, A.D. Wilson and Rio Tinto.

155 For example, MEUG, Oji Fibre and Pan Pac.

historical investment costs on the basis of benefits. This was because of a lack of information, to limit implementation costs and to ensure initial benefit-based charges do not exceed the benefits the investments are expected to yield.

10.12 In our view we have struck the right balance in our selection of the seven pre-2019 investments to which the benefit-based charge applies.[156] That said, we have provided for Transpower (via Additional Component E) to subject more pre-2019 investments to the benefit-based charge if to do so would promote the Authority's statutory objective.

10.13 MEUG and others recommended that Transpower publish sub-components of the aggregate total annual residual charge, as, with this information, customers would be able to make Transpower accountable, by challenging why any increases in (for example) unallocated other costs have not been allocated to benefit-based charges.

10.14 The Authority agrees with MEUG that transparency as to the components of the residual charge would be desirable. In our view transparency is promoted by clause 6 of the guidelines, which requires Transpower to provide transmission customers with information, including the extent to which the residual charge comprises unallocated opex, the cost of prudent discounts and costs reallocated as a result of the reassignment of benefit-based investments.

Load customers pay the residual charge

10.15 We received submissions both for and against the proposal that the residual charge should apply to load customers only. Some generation customers supported the Authority's position that load customers should pay the residual charge.[157] Some load customers argued the residual charge should be allocated to generation as well as load customers.[158] For example, Vector (citing Compass Lexecon and Professor Bunn) argues that requiring generators to pay the residual charge would not raise energy prices:

> "Compass Lexecon's 2015 expert report for Vector explains clearly why this view is incorrect. Specifically, the residual charge would be a fixed cost for generators that would not be affected by dispatching decisions, which in a competitive market are determined by marginal costs. It is therefore not the case that generators would be able to simply pass through fixed transmission charges to load customers, *at least in the short-run*."[159] [emphasis added]

10.16 Professor Bunn submitted that fixed costs would not be simply passed through:

> "…as the transmission charges would be fixed, not short-run marginal, costs, one would not expect those to go through a simple pass through into the energy market. Rather, they would be part of all the annual fixed costs that have to be covered by wholesale market profit contributions…"[160]

10.17 We agree with these statements by Compass Lexecon and Professor Bunn. In a competitive market, if generators paid residual charges they would not take the residual charge into account in short-run dispatching decisions; rather, they would be part of annual fixed costs that have to be covered by wholesale market profit contributions. However, it is not our contention that there would be a simple pass-through into the energy market via generators increasing their wholesale market offers. Rather, we expect investors in new generation would respond to the requirement to cover a larger annual

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156 The application of the benefit-based charge to historical investments and our decision on the scope of its coverage is discussed in chapter 9 of this decision paper, at paragraphs 9.45 to 9.72.

157 For example, Contact, Mercury, Meridian, NERA (for Meridian), Nova and Trustpower.

158 For example, Buller Electricity Ltd, The Distribution Group, Electra, the ENA, ETNZ, Fonterra, Rio Tinto and Vector.

159 Vector, paragraph 26, citing Compass Lexecon, 2015.

160 Prof. Derek Bunn for Vector, section 5.

fixed cost by not entering or by delaying their entry until energy prices were expected to cover the additional cost of the residual charge.[161,162]

10.18 Rio Tinto accepted that *new* generation should not pay the residual charge — for the reasons set out in the preceding paragraph. However, Rio Tinto argued that the residual charge for existing transmission infrastructure should be paid by *existing* generators (as well as load customers). As new generators would be exempt from the charge, they would then not factor the charge into their entry considerations, so in that case any residual charge on generators would not result in higher energy prices.

10.19 We understand this line of argument. However, we consider that making the distinction between future and existing generation as suggested by Rio Tinto would be problematic. Allocating a residual charge to existing generation only would, in effect, subsidise new generation, so would distort competition in the generation market (e.g. it would cause existing generation to be less profitable and therefore risk premature exit). It would most likely be seen as regulatory opportunism, heightening uncertainty and so indirectly increasing energy prices.

10.20 Having considered the matters raised in submissions, the Authority remains of the view that it would be consistent with its statutory objective for the residual charge to apply to load customers, but not to generation customers (except to the extent they have load).

Initial allocation of the residual charge based on historical gross AMD

10.21 We received a variety of submissions on the allocation of the residual charge. Some parties were comfortable with the Authority's design of the charge.[163] However, many stakeholders opposed the proposed approach to residual allocation on various grounds.

10.22 A number of stakeholders were concerned about the impact of an increase in their total transmission charge bill as a result of the allocation of the residual charge.[164]

10.23 The Authority acknowledges that while some customers will pay less, others will initially pay more than they would under the current TPM. For those that pay more, the initial increase is limited by the transitional cap. Over time, we expect the share of total grid costs recovered through the residual charge to reduce materially (see the indicative modelling in Figure 6 above). We are satisfied that the allocation of the residual charge according to gross historical AMD will have material efficiency benefits.[165]

10.24 Having considered the matters raised in submissions, the Authority's view remains that it would be consistent with the long-term benefit of consumers for the initial allocation of the residual charge to be based on historical gross AMD. Below we respond to key themes in submissions on allocation of the residual charge.

The Authority has determined an effective and efficient residual allocation method

10.25 Transpower and some other submitters argued that the Authority should not set a default residual allocator, but should instead set principles for the allocation of the residual charge (for example, it should be unavoidable and incentive-free) and otherwise leave it to Transpower to propose an appropriate residual allocator. Similarly, Waitaki Power Trust

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161 NERA (for Meridian) and CEC (for Trustpower) supported the Authority's position in cross-submissions.

162 Vector also said benefit-based charges would have a similar effect on generation entry. In our view this is not the case, for the reasons set out at paragraph 9.44.

163 For example, Meridian.

164 For example, Lower Waitaki Irrigation Company, Network Waitaki, NZ Steel, Norske Skog, Waitaki Irrigators Collective and Waitaki Power Trust.

165 Wealth transfers are not a relevant factor for the Authority's decision-making, except to the extent they result in effects on efficiency (e.g. via effects on durability), competition or reliability. Having considered potential costs of our decision in these respects, we are confident any such costs are outweighed by benefits.

proposed an additional component that would allow Transpower to amend the allocation of the residual charge as and when appropriate.

10.26 Our view is that the approach suggested in these submissions should not be followed. There are important policy objectives that depend on selection of the appropriate allocator, particularly the need to avoid creating inefficient incentives for the avoidance of residual charges. This objective goes to the core of the design of the 2020 guidelines. In our view, the allocator we have decided on is consistent with the long-term benefit of consumers and so there is limited value in requiring Transpower to repeat the task. So, the guidelines do not provide for Transpower to do this.

An initial allocation based on historical demand is consistent with efficient grid use

10.27 Some parties agreed that residual allocation should be based on pre-2019 figures.[166] Others took issue with our approach. Creative Energy Consulting (for Trustpower) submitted that an allocation based on historical demand is retrospective.

10.28 The Authority rejects this argument. Our approach is clearly not retrospective. Our decision applies only to future transmission charges and to grid costs that remain to be recovered by Transpower. It does not retrospectively reallocate charges that have already been paid or grid costs that have already been recovered. Historical demand is used as a basis for allocation of those future charges. Its chief advantage is that — being historical — it cannot be avoided and so consumers will not be encouraged to inefficiently shift charges onto other customers. If instead we chose future demand as the allocator, it would create strong incentives for customers to undertake investment and other actions in order to shift their charges to other customers. This is clearly inefficient.

10.29 Trustpower submitted that charging by distributors (and retailers) would not be based on their customers' contribution to historical AMD. A number of submitters noted the constraint imposed by the LFC regulations on charging by distributors and retailers.[167]

10.30 To be clear, the Authority does not expect charging by distributors or retailers to be based on their customers' contribution to historical AMD.

10.31 Further, we recognise that distribution (and retail) pricing is subject to constraints including the LFC regulations. Nevertheless, as discussed in paragraph 9.87 above, our view is that distribution pricing will become increasingly cost-reflective over time.

10.32 Orion submitted that an allocation based on historical demand risks locking in circumstances from too long ago. We have addressed this concern by providing for the initial allocation to be updated (see below).

Gross demand, rather than net demand, is the better basis for allocating the residual

10.33 A number of stakeholders[168] advocated for residual allocation based on a net measure of demand.[169] Many of these submitted that a net load approach to residual allocation was efficient as net load best reflects the burden that a customer places on the transmission network. Similarly, NZ Steel said gross AMD contradicts the beneficiaries-pay philosophy. The IEGA submitted that it is difficult to understand why allocation of the benefit-based charge is on a net basis and for the residual is on a gross basis.[170]

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166 For example, Buller Electricity Ltd and Meridian.

167 For example, the ENA, Network Waitaki and Vector.

168 For example, Distribution Group, Eastland, Fonterra, IEGA, Mercury, Network Waitaki, NZ Steel, Norske Skog, Ngāti Tūwharetoa Electricity, The Lines Company and Trustpower.

169 Under a net approach, load customers with embedded generation would receive a lower allocation.

170 Trustpower also submitted that this differential treatment could create unintended consequences.

10.34 We acknowledge the residual charge is set on a different basis to the benefit-based charge. This is because these two charges have different purposes which in turn have prompted different rules on allocating and updating them (to align with desired incentives):

(a) the benefit-based charge reflects the benefit a customer gains from an investment. If a load customer has generation behind its point of connection, it is likely to receive a lower benefit from new grid investment and this is reflected in a net measure

(b) the residual charge is not intended to reflect a customer's benefit from or burden on the transmission network. Rather, it is to recover remaining revenues in the least distorting manner. In the long-term, it will recover unallocated overheads and costs, for example, Transpower's Human Resources system costs: these costs are not related to grid use and not related to the benefits customers receive from particular grid investments. Residual charges are allocated on a proxy for customers' size and so their ability to pay (much like the way the tax system works). This is not reduced by the presence of generation behind the point of connection

(c) allocation of the residual charge based on net demand would risk creating an artificial incentive for investment in distributed generation, in advance of the residual allocator being updated (and the shorter the lag with which updating occurs, the worse this inefficient incentive would be). This risk does not present itself in relation to the (largely fixed) benefit-based charge — parties face the cost and benefits of either the grid investment or of their decisions to avoid or minimise grid investment.[171]

10.35 Some stakeholders submitted that a gross demand measure for the residual charge does not recognise the benefits of distributed generation (for example, NZ Steel and NZ Wind Energy Association) or that it shields the transmission grid from any competition by creating an environment that disadvantages transmission alternatives (Pioneer).

10.36 The Authority acknowledges that distributed generation has many benefits for consumers and plays a crucial role in energy markets, including as an alternative to transmission. Distributed generation can be rewarded in various ways (for example, through prices realised in the energy market or from entering a grid support contract with Transpower). In our view, however, it is generally appropriate for generation behind the customer's point of connection to reduce a load customer's liability for the benefit-based charge for future investments, but not for the residual charge (for the reasons explained above). We would observe that over time, we expect the share of total grid costs recovered through the benefit-based charge to materially increase as the share of the residual charge reduces (see Figure 6 above).

10.37 Some submitters argued for allocation based on net AMD on the basis that consumers with embedded co-generation and associated load never expose the grid to their full gross demand.[172] One potential option would be to treat co-generation as a special case (that is, net off co-generation, but not other embedded generation). The Authority's view is that gross AMD is a proxy for customers' size and ability to pay. It is a better measure of size and ability to pay than net demand. In principle, the fact that some customers manage their use of the grid using embedded co-generation should not have the effect of reducing their allocation of the residual charge.

10.38 Transpower has expressed concern about the availability of data to calculate gross load, especially with respect to behind-the-meter generation. In response, to enable Transpower to deal with practical considerations, such as data availability, we have made the guidelines more high-level, providing Transpower with greater flexibility on this point.

171 The net approach may however create efficient incentives resulting from reducing future investment requirements — see paragraph 10.53 below.

172 See for example Fonterra, NZ Steel, Norske Skog and Nova.

10.39 Creative Energy Consulting (for Trustpower) argued the residual charge should be allocated using the accepted best practice of Ramsey pricing.[173]

10.40 The Authority does not consider that Ramsey pricing in its pure form is a realistic or practical option for the TPM.[174] While Ramsey pricing is often suggested in theoretical work, we know of no situation when Ramsey pricing has been fully implemented in the real world.[175] Further, as Professor Hogan (see footnote 40) notes aspects of the Authority's guidelines (such as the prudent discount policy) are designed as a practical way to achieve similar outcomes to Ramsey pricing, (such as discouraging inefficient disconnection by the most price-responsive customers).

Residual charge should not aim to influence grid use

10.41 Several parties submitted that allocation of the residual charge based on coincident peak demand would send more efficient signals for grid usage and managing peak demand.[176]

10.42 However, the residual charge is specifically not intended to actively influence grid use and investment. It does not need to, because this is done by other elements of the TPM guidelines and existing arrangements, in particular, nodal pricing.[177] The Authority has published a detailed paper on the Authority's thinking on the role of peak and congestion charging and the submissions provided on that topic.[178] The Authority's view remains the same as that expressed in the information paper.

A historical AMD allocator is consistent with the efficient operation of the industry

10.43 Some parties agreed with this proposal. For example, Powerco said a historical AMD allocation is intuitive given it is a driver of transmission investment and is a likely/natural metric used by distributors to allocate the cost to customer groups in their networks.

10.44 Some participants advocated an initial allocation based on usage (MWh);[179] while others preferred a mix of allocators.[180] Some argued against an initial allocation based on AMD, submitting that it:

(a) favours large load customers who have flatter demand profiles, compared to distributors who have peaky retail type loads[181]

(b) tends to overstate the share of distributors with multiple GXPs[182]

(c) does not provide a useful measure of relative size (if non-coincident AMD is used)[183]

(d) penalises customers whose demands on the grid are proportionately lower over system peaks.[184]

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173 Ramsey pricing entails charging a customer at a rate inversely proportional to its price elasticity of demand.

174 Ramsey pricing is discussed in the *2019 Issues Paper* in the section on the PDP in Appendix B and also at Appendix G. In the *2016 Second Issues Paper* we discussed using Ramsey pricing 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, the Authority concluded that this was impractical. This remains our view.

175 For example, New Zealand's GST, which in theory could, but in practice does not, follow Ramsey pricing, is regarded as a model of sound tax policy.

176 For example, Contact Energy, Network Waitaki, Norske Skog, NZ Steel and NZIER (for MEUG).

177 See *2019 Issues Paper*, paragraphs B.196–B.199 and appendices D and E.

178 Electricity Authority, 2020, *Peak charges under proposed TPM guidelines: information paper and next steps*, available at www.ea.govt.nz

179 For example, Electra and Oji Fibre.

180 For example, Nova.

181 For example, Marlborough Lines.

182 For example, Orion.

183 For example, Distribution Group.

184 For example, Lower Waitaki Irrigation, NZ Steel and Waitaki Irrigators Collective.

10.45 Network Waitaki submitted that an AMD allocation does not acknowledge the drivers of investment in the core grid:

> "An average gross AMD charge does not acknowledge that core grid investments, to meet either capacity or security constraints, are typically driven by winter peak demand not summer and middle of the night demand. Summer usage of the transmission network provides diversity in usage patterns and improves the overall load factor of the transmission network."[185]

10.46 We acknowledge the residual charge is not based on the drivers of grid investment. This is intentional. As noted above at paragraph 10.34, the residual charge has a different purpose and so is allocated based on a proxy for customers' size.

10.47 For customers with multiple points of connection, AMD is measured via a non-coincident approach (measured separately for each point of connection, then summed). This does not allow customers to take full advantage of a customer base with demand peaks at different times (which reduces the demands a customer places on the grid). A customer placing a lower demand on the grid will typically have lower future benefit-based charges. However, the residual charge has a different purpose: to recover remaining costs in the least distortionary manner possible and to allocate cost on customers' size and ability to pay. The Authority considers that a non-coincident approach better achieves this aim. As noted above, we expect the share of total grid costs recovered through the residual charge to materially reduce over time (see Figure 6 above).

10.48 The Authority recognises that there is no perfect allocator: load customers have differing characteristics and any metric will inevitably be preferred by some parties and not others. Having considered the above submissions, the Authority considers that its reasons for using AMD to set the initial residual allocation still hold: AMD is a good proxy for a customer's size and ability to pay and would reduce the likelihood of inefficient disconnection of some industrial loads that would be adversely impacted if the initial allocation was based on energy consumption (MWh).[186]

Regular updates of residual allocation based on lagged changes in usage

10.49 Most submitters agreed with the idea that the guidelines should provide for regular updates to the allocation of the residual charge. Following submissions on the 2019 Issues Paper,[187] the Authority proposed regular updating of the residual allocator in the 2020 Supplementary Consultation Paper. Some parties supported this revised updating method. However, others had a different view.

10.50 Having considered further the matters raised in submissions, the Authority's view is that it would be consistent with the long-term benefit of consumers for the initial allocation of the residual charge (which is based on historical gross AMD) to be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, with a lag. In response to submissions, we have decided to reduce the length of the lag, such that 2018–19 energy usage would enter the rolling average (and the allocator would first be adjusted) in the 2023–24 pricing year (rather than the 2025–26 pricing year).

10.51 Below we respond to key themes in submissions on the updating method.

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185 Network Waitaki, p 4.

186 Submissions on AMD measured at the GXP vs ICP level and on the effects on direct-connect vs embedded consumers are discussed in Appendix A under Approaches to measuring gross AMD for residual allocation.

187 Some submitters (including Buller Electricity, Contact Energy, Winstone Pulp, Unison and Centralines) argued the residual charge allocation should be revised on a regular basis. Trustpower said the residual charge must be capable of evolving with changing circumstances rather than only in extreme circumstances.

Gross total energy usage to update the allocation

10.52 Some submitters advocated use of AMD, rather than energy usage, for updating the allocation (see NZIER, for MEUG, 2020). Vector (2020) questioned our rationale for using total energy usage rather than AMD as the basis for future reallocations. We had stated that businesses would have a stronger incentive to change their behaviour to reduce their future share of residual charges if AMD was used to update the allocation.[188] In response, Vector submitted that:

> "It is not clear that this would be a bad outcome, given that reducing AMD can serve to reduce future investment requirements."

10.53 We take a different view. The Authority considers that a business should benefit by its actions to the extent these serve to efficiently reduce:

(a) the demand for future grid investment requirements, meaning lower future benefit-based charges for it and all customers that would benefit from the investment

(b) the customer's benefit from a future grid investment relative to the benefits to other customers, reducing its share of future benefit-based charges

(c) the customer's own energy costs (including associated carbon costs).

10.54 As explained above, the residual charge has a different purpose from the benefit-based charge: to recover remaining costs in the least distortionary manner possible. In our view, it would be a bad outcome if a business changes its behaviour just to avoid paying its share of the costs of a grid investment that has already been constructed. Its behaviour cannot reduce those costs: they have already been incurred. The business would just be shifting those costs onto another customer. But the change to behaviour could be costly. We aim to reduce this inefficient distortion to behaviour, by making the residual charge difficult to avoid. Using gross total energy usage to update the allocation is consistent with this aim. As noted above, we expect the share of total grid costs recovered through the residual charge to materially reduce over time (see Figure 6 above).

Lagged measure to mitigate inefficient behaviour

10.55 Some stakeholders objected to our proposed use of total energy usage as the basis for future reallocations on the basis that it could create inefficient incentives for customers to invest in options to reduce their energy consumption.[189]

10.56 We agree this is a potential concern — while noting that in our view using AMD or RCPD to update the allocation would create worse incentives than using total energy usage.[190] It was to address this remaining concern about potential distortion from the total energy usage allocator that we proposed a lag such that 2018–19 energy usage enters the rolling average in the 2025–26 pricing year.

10.57 However, many submitters argued that the duration of the lag period should be reduced, if not eliminated.[191] MEUG submitted analysis by NZIER suggesting that our proposed adjustment is likely to deliver only a very slow change in the residual allocation over time. Network Tasman and Network Waitaki (supplementary submission p 2) noted the guidelines do not allow Transpower to adjust the residual charge in circumstances where a customer experiences a large change to its demand.

188 Our view was based on a submission from Creative Energy Consulting (for Trustpower).

189 See also, for example, Orion's submission, p 3 and the ENA's submission, pages 1–2.

190 The reasons for this view are set out in paragraph 5.10 of the *2020 Supplementary Consultation Paper*.

191 For example, Oji Fibre.

10.58 We consider that these submissions make valid points. So, we have decided to reduce the length of the lag period, so that 2018–19 energy usage enters the rolling average — and the updates will begin to be made — in the 2023–24 pricing year (rather than the 2025–26 pricing year). The Authority considers this strikes the best balance between:

(a) the speed at which charges align to changes in customers' ability to pay and

(b) the increase in inefficient incentives to reduce consumption.

Principle that initial allocation can be adjusted for changes due to factors beyond control

10.59 A number of stakeholders endorsed this principle.[192]

10.60 The Distribution Group supported adjusting the residual allocation where a customer has faced a substantial change in demand due to factors beyond their control, noting this is particularly relevant to small distributors.

10.61 Network Tasman submitted that the guidelines should provide for an adjustment to the residual charge where a customer has experienced a large one-off change to its demand due to factors beyond its control on an ongoing basis, not just initially.

10.62 We acknowledge Network Tasman's concern. We recognise that there are valid arguments in favour of such an adjustment and we considered whether to provide Transpower with the ability to make such adjustments on an ongoing basis.

10.63 For example, if a very large distribution-connected customer disconnects, this would increase charges for the distributor's other customers. This could create inefficiencies if it takes those charges above stand-alone costs (which also would be inconsistent with the distribution pricing principles). We considered creating a threshold of 10% of the distributor's total load, above which adjustments could be made.

10.64 However, we have decided not to allow adjustment on an ongoing basis. If distributors were able to reduce their liability for residual charges immediately, this risks making the distributor indifferent to the customer's departure. By contrast, if there is a lag before adjustment takes place, the distributor has an incentive to keep the customer for as long as this is efficient (for example, by offering a discount, as reflected in the distribution pricing principles). Also, immediate adjustment could be costly as it risks triggering a large number of applications (even if this could be mitigated to an extent by a threshold).

10.65 In any case, the 2020 guidelines provide for the residual allocation to be updated regularly, as discussed above. So even a large, one-off change to demand will in time flow through to charges. In addition:

(a) as noted above, the Authority has decided to reduce the length of the lag period for the adjustment — in response to Network Tasman's submission, amongst others

(b) as shown in Figure 6 above, the residual charge is expected to decline relatively quickly over time, making the issue less material

(c) distributors losing a large customer may get relief due to a reduction in the benefit-based charge, via the reassignment provision.

10.66 Transpower submitted that for the residual adjustment principle, the words "due to factors beyond their control or influence" should be deleted, on practicability grounds.

10.67 To assist with practicability, we have adjusted the wording so that the clause now applies where the change is "…in Transpower's reasonable opinion…due to factors that are largely beyond the customer's control or influence".

[192] For example, Buller Electricity Ltd, The Distribution Group and Mercury.

11 Guidelines: adjustments to charges

Our decision

11.1 The guidelines have been reordered to bring provisions related to adjustments to charges together (clauses 31–44) and to clarify the relationship between them. The principal change is to shift to this section the provisions that were in the benefit-based charge section of the draft guidelines. These are the provisions relating to: adjusting an annual benefit-based charge to take account of changes to parameters (such as the WACC); damage to an investment, reassignment; and a substantial and sustained change in grid use.

11.2 The provisions for adjustments have also been revised to better reflect the policy intent set out in the 2019 Issues Paper and the 2020 Supplementary Consultation Paper. Some of the changes include:

(a) clarifying that damage to a benefit-based investment should result in its being written down only if the damage was outside the control of relevant participants

(b) clarifying the drafting of the new customer and related provisions by separating out the charge adjustments relating to designated transmission customers from those for parties indirectly connected to the interconnected grid through designated transmission customers and specifying that changes in transmission charges in respect of these other parties' load and generation are to be treated in a manner that parallels that of the treatment of designated transmission customers

(c) making clear that for a new entrant and for a large customer that substantially increases its capacity:

(i) its benefit-based charge for each relevant investment should if possible reflect its share of the benefits over the whole life of the investment from the date the benefit-based charge was first applied to the investment

(ii) its residual charge should be equivalent to what would have been imposed if the party had been fully operational from 1 July 2014

(d) adding a provision that if a customer closes one of its plants, its subsequent liability for associated benefit-based charges would cease ten years from the commissioning dates of the relevant grid investments

(e) allowing for benefit-based and residual charges to be reallocated after a party ceases to be a transmission customer

(f) amending the reassignment provisions, including:

(i) making clear that Transpower must undertake necessary investigations where (but only where) it is presented with evidence that suggest to Transpower reassignment is justified

(ii) making the $5m threshold for reassignment the current (rather than initial) book value of the investment, partly as a consequence of the decision to adopt DHC

(iii) making clear that the adjustments to charges under this provision take account of any adjustments as a result of the adjustment provisions earlier in the guidelines.

(g) amending the substantial and sustained change in grid use provisions:

(i) to ensure they take into account the other adjustments referred to earlier in the guidelines

(ii) to make clear that they should only be invoked rarely and if some circumstances or event causes a widespread, substantial change in the pattern of grid use

(iii) to make the provisions with respect to a pre-2019 investment workable

(h) allowing a further adjustment if it is necessary to ensure allocators total 100% where, as a result of an adjustment or otherwise, allocators have ceased to do so

(i) limiting the provisions relating to scaling back charges to circumstances in which Transpower wishes to recover less than its maximum revenue (since over-recovery will generally be addressed by the residual charge provisions)

(j) other minor changes for clarification or drafting improvements.[193]

What we proposed

11.3 In the 2019 Issues Paper, we proposed provisions in this section:

(a) to allow adjustments to be made to the benefit-based and residual charges where there has been one of a limited number of changes, including:

(i) entry of a new large consumer or generator

(ii) substantial increase in an existing large consumer's or generator's grid use

(iii) potential shifts of connection point by a large consumer or generator

(iv) partial sale of a business[194]

(b) to allow charges to be scaled back if necessary.

11.4 We also included in the benefit-based charge section of the draft guidelines, various provisions relating to re-opening the setting of the benefit-based charge and its allocation.

11.5 In the 2020 Supplementary Consultation Paper (chapter 4), in response to submissions,[195] we proposed that if a customer closes one of its plants, its liability for associated benefit-based charges would cease ten years after the commissioning date of the relevant grid investment (instead of continuing indefinitely, as was proposed in the 2019 Issues Paper).

Submitters' views and our assessment

11.6 Some stakeholders endorsed the Authority's 2019 Issues Paper regarding adjustments.[196]

11.7 Others called for changes to the provisions on adjustments. For example, Meridian submitted that the guidelines proposed in 2019 do not address the situation where a business shrinks rather than expands or is purchased.

11.8 We decided not to make changes in response to this submission, because allowing for adjustments when a business shrinks could inefficiently encourage a customer to take some action in order to reduce its allocation of transmission charges.

11.9 Transpower submitted that the provision for the TPM to avoid creating incentives for large consumers or generators to shift their connection point should be deleted and this issue should be dealt with through the prudent discount policy.

11.10 We acknowledge that the prudent discount policy is one potential tool for addressing these inefficient incentives. However, our intention is that it is the tool of 'last resort' in this

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193 The treatment of upgraded investment is unchanged and charges for the upgrading expenditure are allocated according to the private benefits it provides. Pages 146–147 of the *2019 Issues Paper* discuss how these provisions might be applied in practice.

194 *2019 Issues Paper*, paragraphs B.232–B.247.

195 For example, Contact Energy.

196 For example, Mercury and Trustpower.

instance; we note that providing a discount to one customer also affects other customers' charges. For this reason, we consider this provision should remain, in order to require Transpower to design the other elements of the proposed TPM to avoid creating inefficient incentives for customers to shift their point of connection. The 2019 Issues Paper discussed on page 160 one possible method Transpower might use to do this.

Liability for benefit-based charges after plant closure ceases after a period

11.11 Most parties submitting on this aspect of the 2019 proposal agreed with the direction of the change that we proposed in the Supplementary Consultation Paper (that is, providing for charges to cease sometime after plant closure), even if they disagreed with the proposed length of the period before charges cease. Some parties (such as MEUG) endorsed the Authority's reasons for the proposed ten-year period after commissioning of a grid investment before charges cease. However, many parties disagreed.

11.12 Having considered the matters raised in submissions, the Authority's view remains that if a customer closes one of its plants, it would promote the efficient operation of the electricity industry if its liability for associated benefit-based charges ceases after ten years from the commissioning date of the relevant grid investment. Below we discuss our views of some submissions reflective of key concerns raised.

11.13 Rio Tinto criticised the Authority's proposal on the grounds that it imposes obligations equating to a long-term contract only on customers; it does not propose to balance the 'take or pay' provisions it would impose on customers with reciprocal obligations on Transpower as a supplier.

11.14 We acknowledge that, unlike in a workably competitive market, Transpower as a supplier does not bear the risk if demand for the services supplied by a grid investment is lower than expected. This is a function of the regulatory regime that is outside the Authority's remit: we do not have the power to stipulate that Transpower will recover a proportion of the cost of an investment that is lower than 100%.

11.15 Nevertheless, we do not agree with Rio Tinto that the 'take or pay' provisions that we proposed would impose a one-sided obligation. We consider our position balances the obligations on an individual customer with the obligations on transmission customers collectively. At one extreme, charges could cease immediately upon closure of a plant. This is the preference of Rio Tinto (and other submitters). While this would minimise payment obligations on the customer shutting down a plant, as noted by Orion it would instead transfer those payment obligations to other transmission customers, such as distributors, due to the regulatory requirement to fully recover Transpower's costs of the investment. At the other extreme, under which charges continue, there is no impact on other transmission customers, but payment obligations on the customer shutting down a plant are maximised. The decision is a balance between these two extremes.

11.16 Several stakeholders preferred a shorter period before payments cease. Contact Energy submitted that — while it would prefer there to be no ongoing charges — it would prefer the option of a five-year period over the proposed ten-year period. Oji Fibre submitted that payments should cease from the following pricing year, noting plants may close due to factors beyond a customer's control.

11.17 The Authority's view is that these shorter periods would not provide customers with sufficient incentive to reveal key information during the investment approval process.

11.18 Trustpower was concerned that the proposal that benefit-based charges for an investment would continue for ten years after commissioning (even if a plant closes) could deter new investment in low-emissions technologies.

11.19 We acknowledge that any continuation of charges following plant closure might have the effect Trustpower is concerned about. For example, a customer might be discouraged from closing one of its fossil-fuel generators and investing in low-emissions generation.

On the other hand, Trustpower's preferred solution (that the obligation to pay charges should cease at plant closure) could also deter new investment in low-emissions technologies. If charges ceased immediately, a potential investor in a new wind farm (for example) might be concerned about the risk that it has to shoulder a much larger share of a new grid investment's costs, if a neighbouring transmission customer closes one of its plants. This risk could deter investment in new generation (which is more likely to be renewable). Further, Trustpower's preferred solution could result in the construction of grid infrastructure that turns out not to be needed.[197] This would result in higher electricity prices (which could discourage load from switching from fossil fuel to electricity).

11.20 In our view the Authority's guidelines balance these competing concerns. Our view overall is that the 2020 guidelines support the transition to low emissions at least cost across emitting sectors.[198] More generally, we consider that this provision of the guidelines appropriately balances the competing objectives of allowing customers flexibility with respect to adjusting their portfolio and providing customers with an incentive to reveal relevant information during the investment approval process. In our view this balanced position is consistent with the long-term benefit of consumers.[199]

11.21 Rio Tinto submitted that the Authority's concern that a business holds private information on the likelihood that its plant will close is "commercially unrealistic".

11.22 We disagree. Businesses are required to act in the interests of their shareholders, subject to legal and regulatory requirements. In some circumstances these factors will encourage the business to make information public or divulge it to a regulator; in other cases, it will be in shareholders' commercial interests for the business to keep some information private. The Authority's guidelines are designed to align the business' incentives with the public interest and provide an increased incentive to reveal relevant information during the investment approval process.

11.23 Northpower questioned the proposal's durability, noting a trade-off between, on one hand, inefficiency due to regularly revisiting charges and on the other hand — if charges were locked-in and seldom revisited — ongoing lobbying for allocations to be adjusted.

11.24 We acknowledge the existence of trade-offs in designing a TPM regime. No design can eliminate all inefficient incentives. No solution will satisfy all stakeholders. That said, we consider that the solution we have decided on with respect to liability for benefit-based charges after closure of a plant is likely to prove both efficient (as liability for the costs of a grid investment do not cease immediately after its commissioning) and durable (as we have struck a careful balance between competing considerations — as discussed above).

11.25 Transpower has advised there is a risk that transmission customers may attempt to avoid continuing liability for a charge after plant closure, by changing their corporate structure. In our view, Transpower is able to take steps to avoid incentivising or to counter such attempts at avoidance (for example by 'looking through' such corporate arrangements and treating all entities with common beneficial ownership as a single transmission customer).

11.26 Specifically, clause 1(c) of the guidelines requires Transpower to, as far as reasonably practical, develop the TPM in a way that avoids creating incentives for existing and potential designated transmission customers to avoid transmission charges in ways that cause economic inefficiency.

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197 This could occur if a customer withholds information concerning a shut-down of one of its plants that it privately expects to occur soon after a new grid investment is commissioned — see paragraph 4.14 of the *2020 Supplementary Consultation Paper*.

198 For detail on how the 2020 guidelines support the transition to a low-emissions economy, see chapter 5.

199 We've also considered whether the requirement for benefit-based charges for a grid investment to continue for ten years after commissioning risks causing the inefficient exit of a transmission customer. In our view it does not. The risks of inefficient exit are appropriately managed through the prudent discount policy.

Benefit-based charge can be re-opened in certain circumstances

11.27 This section of the guidelines now contains the provisions that allows the allocation of the benefit-based charge to be re-opened in certain circumstances. These provisions were previously incorporated in the benefit-based charge section of the guidelines.

11.28 Some stakeholders endorsed the proposed re-opener provisions.[200] Other parties criticised these provisions. For example, Transpower was critical of the reassignment provisions on the grounds that the potential efficiencies do not justify the administrative burden.[201] Transpower suggested these provisions be replaced by a provision that benefit-based charges be limited to aggregate, positive, net benefit.

11.29 The Authority does not agree that a provision that benefit-based charges be limited to aggregate, positive, net benefit would be appropriate for post-2019 investments. Such a rule would not promote efficient grid investment, as it could reduce customers' incentive to scrutinise proposed grid investments. We consider reassignment will be an important — albeit rarely used — safety valve and we do not consider that the administrative burden of the reassignment provisions would outweigh the potential efficiencies. In our view the provisions are clear and the method adopted for reassignment need not be overly complex and burdensome, particularly given that the guidelines allow Transpower to allocate benefit-based charges between customers in a way that is broadly in proportion to their expected positive net private benefits.

11.30 Some parties were also critical of the substantial and sustained change in grid use provisions. For example:

(a) Transpower criticised the substantial and sustained change in grid use provision on the grounds that it only applies to high-value investments, which risks significant benefits-to-allocation misalignment over time for low-value investments

(b) Trustpower advocated that the wording "substantial and sustained changes in grid use" should be broadened to encompass situations where the forecast benefits are substantially different from the actual benefits; otherwise the methodology will not be durable — however Trustpower acknowledged these re-openers would have implications for the efficiency of the charges.

11.31 We do not agree with these submissions, for the reasons set out in the benefit-based charge chapter above. That is, in general (other than the limited exceptions provided by re-openers), we have decided against regular revisions of the benefit-based charge to re-align benefits to charges over time, as:

(a) we do not consider that out-turn results that diverge from forecasts will significantly affect the durability of the 2020 guidelines

(b) regularly updating the allocation of the benefit-based charge would distort customers' incentives to scrutinise proposed grid investments and customers' grid use and investment incentives

(c) a regular review would be practically challenging and likely controversial.

11.32 Some submissions appeared to be based on the assumption that the substantial and sustained change in grid use provision might be a relatively frequent occurrence. For example, in its discussion of case studies on how the charge might apply to an upgrade of a transmission line between Wairakei and Hawke's Bay, Transpower observed that consideration would need to be given to whether the proposed TPM guidelines re-opener triggers had been met. It is not our intention that the substantial and sustained change in grid use provision would be available in the sorts of scenarios that Transpower has

200 For example, The Distribution Group.

201 Rio Tinto and Contact Energy also made arguments against providing for reassignment. Meridian submitted on a lack of clarity in the reassignment provisions.

considered in its case studies. As noted in the 2019 Issues Paper, we expect that the sort of event that could trigger a substantial and sustained change in grid use would be rare.[202]

11.33 In response to this concern, we have clarified the requirements for a substantial and sustained change in grid use to occur. In particular, we have included in the guidelines the conditions outlined in the 2019 Issues Paper, namely that other provisions for adjusting charges must be considered first, that a reallocation of charges must be rarely triggered and must only be invoked if some event leads to a widespread, substantial change in the pattern of grid use.

11.34 We have also modified the condition that must be met before a substantial and sustained change in grid use is considered to have occurred from that proposed in the 2019 Issues Paper. For post-2019 investments, this is consistent with the policy outlined in the 2019 Issues Paper — that if the allocation of the benefit-based charge for the investment took account of the change of circumstances (for example, by considering possible future scenarios), then a substantial and sustained change in circumstances has not occurred.

11.35 For a pre-2019 investment, this approach is not feasible, since the default allocation of charges for these investments is now determined by Schedule 1 and the methodology used to calculate Schedule 1 did not explicitly quantify a range of scenarios. Instead, the guidelines for these investments adopt the policy position set out in pages 144–145 of the 2019 Issues Paper that the change in grid use must be substantial and sustained. This is intended to recognise that a major change in use, such as the permanent closure of NZAS's smelter at Tiwai Point, may have been anticipated, but may nevertheless result in a substantial and sustained change to grid use.

11.36 These changes are intended to ensure that the use of the substantial and sustained change in grid use provision will be rare (such as a one-in-20-year occurrence). The change in grid use that would trigger such a provision would need to be truly substantial and an exceptional event, not a frequent occurrence.

Other changes

11.37 The Authority has made a number of minor changes to the adjustment provisions of the guidelines in response to submissions and for technical reasons, including:

(a) grouping the various adjustment provisions under one heading and clarifying the relationship between the various provisions

(b) clarifying that in the provision relating to damage to a benefit-based investment, the investment should only be written down if the damage was outside the control of relevant participants. This is because the provision could otherwise be used to scale back charges where the damage is caused deliberately by one of the parties; for example, as part of decommissioning of the investment. As the discussion on p 128 of the 2019 Issues Paper makes clear, that was never the intention

(c) clarifying that the 'new customer' provision allows adjustments in the case of any new transmission customer and in the case of distributors' charges where a large consumer or generator connects to a distribution network

(d) clarifying that the allocation of benefit-based charges to a new entrant should, if possible, reflect its share of the net private benefits over the life of the investment. This change is in part a consequence of shifting to the DHC method for cost recovery over time and so gives effect to the policy set out in the 2020 Supplementary Consultation Paper. Adopting the DHC approach creates the possibility that the present value of the new entrant's share of the charges could be substantially less than the present value of its share of the benefits. Our proposed approach promotes effective competition by taking a whole-of-life approach to the

202 *2019 Issues Paper*, paragraph B.168.

benefits from investments, which ensures that new entrants do not unnecessarily benefit from their late entry

(e) clarifying that the residual charge faced by a new entrant should be the same as if it had been fully operational at the time the residual charge was initially allocated

(f) allowing for benefit-based and residual charges to be reallocated after a party ceases to be a transmission customer — in response to a submission by Transpower

(g) changing the threshold for reassignment from the original value of the investment to the depreciated value, in part because of the adoption of a DHC annual cost recovery method and in part because it is the latter that determines future charges for the investment

(h) allowing adjustment to ensure that allocators total 100% — in response to a submission by Transpower

(i) removing the provisions relating to scaling back charges to avoid a possible over-recovery by Transpower — as the move to a DHC annual cost recovery method makes this provision unnecessary.

12 Guidelines: prudent discount policy

Our decision

12.1 The 2020 guidelines for the PDP (clauses 45–48) are essentially the same as those in the 2019 Issues Paper, except that they now:

(a) no longer include provision for the discount to be available for the remaining life of the relevant investment

(b) allow a customer to apply for a prudent discount if its transmission charges would exceed the efficient stand-alone cost of the transmission services it receives

(c) explicitly carry over from the 2006 guidelines the provision related to facilitating transparency about prudent discounts.

What we proposed

12.2 The existing TPM includes a prudent discount policy (PDP) that allows Transpower to discount the transmission charges of a customer who otherwise would find it privately beneficial to bypass the grid, resulting in an inefficient outcome.

12.3 In the 2019 Issues Paper,[203] we proposed that:

(a) prudent discounts would be made available to a load customer that might inefficiently disconnect from the grid in favour of alternative supply — on the basis that this would avoid economic inefficiencies arising from such disconnections

(b) the discount would be available for the remaining life of the relevant investment — to provide greater certainty and promote efficient investment.

12.4 In the 2020 Supplementary Consultation Paper, in response to submissions,[204] we proposed a further expansion to allow a customer to apply for a prudent discount if its transmission charges would exceed the efficient stand-alone cost of the transmission services it receives — to prevent inefficient overcharging and address the risk of inefficient exit. This new proposal was met with some speculation regarding whether it was targeted at Rio Tinto. We respond to that speculation below.

Submitters' views and our assessment

Prudent discount to avoid disconnection in favour of alternative supply

12.5 A number of submissions supported this proposal,[205] but there were also some opposed. For example, Mercury submitted that a PDP should not be included in the guidelines in any form, due to concerns about gaming, administrative cost and a risk that Transpower and the Authority may be required to make judgements outside their areas of expertise.

12.6 However, prudent discounts can avoid large inefficiencies and avoid other transmission customers paying higher transmission charges. We consider that the prospect of avoiding large inefficiencies outweighs the concerns raised by Mercury. In our view the option of bypassing the grid is likely to be a real possibility for some customers.[206]

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203 *2019 Issues Paper*, paragraphs B.249–B.258.

204 For example, Contact Energy and Rio Tinto.

205 For example, Meridian, NERA (for Meridian), Network Waitaki, Jock Webster, N. Otago Irrigation Company Ltd and Waitaki Irrigators Collective Ltd.

206 See Network Waitaki's submission, p 16 and Norske Skog's submission, p 3.

12.7 In response to submissions on the need for transparency in setting transmission charges,[207] the provision about transparency of prudent discounts in the 2006 guidelines also appears in the 2020 guidelines.

Life of the investment

12.8 Submitters expressed varying views on this proposal. Some parties agreed with it.[208] For example, Rio Tinto submitted that to achieve the intended efficiency benefits, the prudent discount should apply for the life of the relevant asset, because the bypass option may exist for the life of the relevant asset.

12.9 Other parties (for example, Contact) opposed the proposal. Transpower raised a concern that customers would be able to force inappropriately long discounts. Some parties noted that the conditions that applied when the prudent discount was agreed may not be enduring. Trustpower observed that a discount may be provided on the basis that the customer is able to use an alternative energy source (such as gas) but the price of that alternative may later increase, suggesting that the discount should be revised.

12.10 We consider that Transpower and Trustpower have raised valid concerns relating to the proposal to make the discount available for the remaining life of the relevant investment. Accordingly, we have decided instead to adopt the alternative option set out in the 2019 Issues Paper: to leave the duration of a prudent discount unspecified, so that it is to be agreed via commercial negotiation between Transpower and its customer.

12.11 We note that the current TPM makes provision for a customer to seek review by an independent expert of Transpower's decision on a prudent discount. In our view, a review of this nature would be a useful way to resolve any disagreement between Transpower and its customer on the length of the prudent discount.

A prudent discount if charges would exceed efficient stand-alone cost

12.12 A number of submitters supported the Authority's proposal.[209] Transpower observed that extending the PDP to cap charges at stand-alone cost appears workable, subject to the detail. A range of parties submitted against this proposal, for reasons considered below.

12.13 Having considered the matters raised in submissions, the Authority remains of the view that a prudent discount to cap charges at stand-alone cost will be a useful tool to address the risk that a customer's charges are set at an inefficiently high level. We consider that it would be consistent with the long-term benefit of consumers for this to be a component of the TPM. Below we discuss our views of some submissions representative of key concerns raised.

12.14 Some stakeholders objected that this amendment was designed for the benefit of Rio Tinto, at the expense of other grid-connected customers.[210] Some media commentators have made the same assumption.

12.15 The Authority rejects these claims. This new limb of the prudent discount policy is neither targeted at nor restricted to use by only one stakeholder and will be consistent with the long-term benefit of consumers. It will lead to a more efficient outcome and may prevent the inefficient exit of price-sensitive customers and so lead to charges for other customers that are lower than they would otherwise be. It will not enable any unjustified wealth transfers. The calculated level of stand-alone cost must reflect an appropriate level of service and cost in order to meet the Authority's statutory objective.

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207 For example, the Distribution Group.

208 For example, Meridian, Rio Tinto and Nova.

209 For example, Contact Energy, Meridian, Network Waitaki, Waitaki Power Trust, Rio Tinto and Hamish Walker, MP for Clutha-Southland.

210 For example, Northpower, Oji Fibre, the TPM group and Vector.

12.16 The development of the stand-alone cost methodology by Transpower will involve a number of important judgements, on which it will likely seek sector input. Bearing this in mind we would caution any stakeholders or commentators about drawing any conclusion regarding the likely stand-alone cost for Rio Tinto's aluminium smelter at Tiwai Point. While Rio Tinto would be able to apply for a prudent discount under this new test like any other transmission customer, it is not possible to form a robust view on the likely success of that application at this point.

A cap at stand-alone cost will lead to a more efficient outcome

12.17 It is an accepted principle of economic regulation that common costs should be allocated such that each party's share is below stand-alone cost and above incremental cost.[211] Such an allocation is one that could be expected to emerge voluntarily in a workably competitive market because no party or subgroup subsidises any other. It follows that an allocation that satisfies these conditions will not only promote efficiency, it will also be a more durable arrangement than one that does not.

12.18 The argument for maintaining this position after the investment is made is to avoid regulatory opportunism. If the party involved had known that it would in future be charged above stand-alone cost for its use of the grid, it would have had an incentive to make the grid investment itself. If a higher transmission charge is imposed after the investment is made, the risk is that other parties will undertake potentially inefficient investments in future so as to avoid the risk of being charged above stand-alone cost.

12.19 In cases where the transmission customer can build a stand-alone facility, this limb of the prudent discount policy will help to prevent such an inefficient outcome. In other cases limiting charges to efficient stand-alone cost could mean that an industrial facility remains located in New Zealand instead of exiting as a result of inefficiently high prices, which could prevent substantial damage to the national (and regional) economy. In both cases the Authority's decision could keep other consumers' charges lower than they would otherwise be.

12.20 Some stakeholders argued that, as stand-alone cost is a hypothetical measure that has no relevance to exit decisions, any discount will be either too high (more than is needed to prevent a company from exiting) or too low (not enough).[212] Further, some submitters observed that the Authority does not have the requisite expertise to calculate the correct discount in such a case.

12.21 We agree with the above points but draw a different conclusion. Neither the Authority nor Transpower has the expertise to calculate a discount at exactly the level that would prevent a firm from exiting, but we do not envisage that the discount would be set in this way. Instead, our approach is intended to prevent transmission charges from being set at an inefficiently high level and thus detract from long-term benefits to consumers. This objective sits within the Authority's jurisdiction and within Transpower's expertise. We acknowledge that any calculation of stand-alone cost will necessarily be imperfect. However, in our view even an imperfect application of this rule would be preferable to forcing a customer to pay an inefficiently high charge with no opportunity for relief.

12.22 The Authority recognises that a prudent discount might be more than is actually required to prevent an inefficient exit. Nevertheless, we consider that the potential cost of paying too high a discount in some cases is likely outweighed by the efficiency benefits discussed above.

12.23 As submitters have observed, in some cases a discount based on stand-alone cost would not be enough to prevent a company from exiting. However, preventing an exit that is

211 H.P. Young (1994).

212 For example, Northpower, Trustpower and Vector.

caused by factors other than inefficiently high transmission charges would go well beyond the Authority's role and is outside the purpose of the prudent discount policy.

A cap at stand-alone cost will not result in unjustified wealth transfers

12.24 Some submitters were concerned that granting a discount would result in wealth transfers from other customers, which could have unintended consequences.[213]

12.25 The Authority recognises that granting a discount impacts on other customers' charges. However, we are satisfied that the stand-alone cost provision will not enable any unjustified wealth transfers, as discounts are only provided where charges would otherwise be inefficiently high. In any case, the size of a discount's impact on any other individual customer will be limited, as funding for the discount is spread across a large pool of customers. Furthermore, not providing for a discount could result in an exit by a price-sensitive customer, which could have an even greater impact on other customers' charges and raises the ongoing efficiency concerns discussed above. On balance, we are satisfied that any resulting costs are likely to be outweighed by the benefits.

Transpower will develop an appropriate method for calculating stand-alone cost

12.26 NZIER (on behalf of MEUG) was concerned that the Authority's proposal did not specify how a discount based on stand-alone cost would be calculated.

12.27 As is discussed in the 2020 Supplementary Consultation Paper, we describe in the guidelines how stand-alone cost should be calculated. This includes that the calculation must be for transmission services of equivalent value. This means for example that the hypothetical stand-alone investment must provide energy of the same reliability and quality, or that the calculation must estimate and take into account the differences in value to the customer of the different quality and reliability.

12.28 All of the costs involved in constructing such a hypothetical stand-alone investment would need to be taken into account, including the reasonable cost of obtaining a resource consent for the stand-alone development. (In the Supplementary Consultation Paper we described the calculation as 'greenfields', with the intention of ensuring such costs be taken into account. However, we have removed this word in response to Transpower's view that it is unnecessary and would require an unnecessarily burdensome methodology.)

12.29 We are comfortable that this provides sufficient guidance to Transpower on how the calculation is to be undertaken, without unduly constraining it. The calculation method will be set out in the proposed TPM, which Transpower will develop, before submitting to the Authority for approval.

12.30 Some parties submitted that calculating stand-alone cost might be impossible to implement in practice or require making subjective and contentious assumptions.[214]

12.31 However, the Authority is confident that such challenges can be overcome. Calculation of stand-alone cost will require assumptions to be made on key parameters. These will no doubt be subject to debate, however, that does not mean the calculation cannot be completed. There are precedents both in New Zealand and overseas for the calculation of concepts similar to stand-alone cost in regulatory proceedings.[215]

12.32 Trustpower submitted that applicants would be encouraged to obfuscate their current position, leading to a waste of resources. Similarly, others were concerned that the

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213 For example, ENA, Entrust, Northpower, Oji Fibre, Orion and the TPM group.

214 For example, Northpower and the TPM Group.

215 See discussion in *Supplementary Consultation Paper*, pages 18–19.

hypothetical nature of the proposal allows too much latitude for manipulation.[216] Other submitters raised concerns about administrative costs.[217]

12.33 We acknowledge that in order to ensure its decisions are for consumers' long-term benefit, Transpower will need to carefully scrutinise applications for a prudent discount, including an application under the stand-alone cost limb. This scrutiny will require some administration costs to be incurred. In our view, the level of administration costs can be kept to a reasonable level and the development of a transparent, well-understood method will assist with that. We consider that the administration costs are likely to be outweighed by the benefits of the stand-alone cost limb of the prudent discount policy.[218]

12.34 Some stakeholders emphasised the various benefits of being part of the interconnected grid system. Trustpower noted that previous owners of the smelter placed a high value on "a safe and secure energy supply". Counties Power observed that:

> "… the issue lies in the definition of the stand-alone cost of supply because all customers connected to Transpower benefit from being connected to the large electricity market and transmission network."

12.35 We agree that there are important benefits from being connected to a wider transmission network. These benefits would be taken into account (at least implicitly) in any real-world decision on whether to disconnect from the grid. As is noted above, we would similarly expect them to be taken into account in calculating the value a party obtains from a stand-alone investment.

12.36 This does not mean calculating the stand-alone cost of the bare minimum service (for example, a single line to the nearest dam). Rather, in defining the transmission services received by the customer, the calculation method should take into account all relevant dimensions of service including grid reliability, energy security and price considerations. The calculated level of stand-alone cost must reflect an appropriate level of service and cost in order to meet the Authority's statutory objective. A customer's stand-alone cost of supply will be higher to the extent that it benefits from its connection to the wider transmission grid. These are key questions of design that will need to be addressed by Transpower when it develops the method for calculating stand-alone cost.

12.37 Rio Tinto submitted that Transpower is conflicted in specifying a method for determining the stand-alone cost and so the Authority should specify guidelines for such a method. By contrast, Northpower submitted that the Authority is not the appropriate body to make determinations of this nature.

12.38 We consider that it is appropriate for the Authority to specify guidelines on this matter and for Transpower to develop a method for determining the stand-alone cost, consistent with its role in developing a proposed TPM and submitting it to the Authority for review and approval. The method will need to be developed in a transparent manner so that the basis for making judgements on the level of the prudent discount can be clearly understood. However, the Authority will remain the ultimate decision-maker with respect to approving any TPM proposed by Transpower. Further, the Authority intends to engage formally and informally with Transpower during the TPM development process.

216 For example, ENA, Orion and Powerco.

217 For example, Network Waitaki.

218 The Authority expects the administrative costs relating to a stand-alone cost application would be in the order of $100,000 per assessment, whereas the economic benefits of making available a discount where charges are above stand-alone cost are expected to be in the order of millions of dollars (depending on the size of customer), even after taking into account the uncertainty around whether or not the customer would exit.

Transpower will consider applications based on stand-alone cost

12.39 Transpower said that, given the significant wealth transfer effects involved, the Authority, not Transpower, should decide whether to approve an application for a stand-alone cost prudent discount. Transpower's role should be to make a recommendation.

12.40 The Authority does not agree that it should take an active role in deciding on prudent discount applications and considers that Transpower is better suited to making such a decision, given its operational role and expertise. We understand Transpower's reluctance to be the sole arbiter of a matter that involves wealth transfers. However, this need not be the case: the current TPM makes provision for a customer to seek review by an independent expert of Transpower's decision on a prudent discount. The independent expert's findings are binding on Transpower and the customer. The Authority may have a role in appointing the independent expert, in the event Transpower and its customer cannot agree. Transpower could look to make provision for a similar process in its proposed TPM, should it wish to do so.

Stand-alone cost is part of the PDP, a core component of the guidelines

12.41 Trustpower submitted that, if it was included, the stand-alone cost limb of the PDP should be an additional component, as it considered the proposal had not been sufficiently justified to be included as a mandatory component of the guidelines.

12.42 We acknowledge that the method for determining stand-alone cost has not yet been determined and neither have a number of other practical elements of the policy (see, for example, those raised by the IEGA, p 5). However, in our view the prudent discount policy — including the stand-alone cost limb — is an important safeguard in the regime, so should be a core component.[219]

12.43 Rio Tinto submitted that the specification of guidelines for determining stand-alone cost should be split off from other elements of the proposed TPM and advanced to approval and implementation without delay.

12.44 The Authority does not agree with the proposed course of action. We have considered this submission together with other submissions on the process for TPM development. We are conscious of the value of a timely implementation of any new TPM, including the PDP. Splitting off the PDP and addressing it early would risk delaying development of the proposed TPM as a whole, which would materially delay significant consumer benefits. Our decision on the TPM development process is set out in chapter 17.

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[219] Professor Hogan has recognised the role of the prudent discount policy as a safety valve to avoid efficiency problems. See Electricity Authority Board Teleconference with Professor William (Bill) Hogan, 17 May 2018. https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/

13 Guidelines: a cap on transmission charge increases

Our decision

13.1 The 2020 guidelines on the cap on transmission charges are at clauses 49-53.

13.2 The 2020 guidelines include such a cap to limit the increase in total electricity bills that would otherwise be caused by implementing a new TPM consistent with the 2020 guidelines.

13.3 The cap expires at the end of the 2038/39 pricing year.

13.4 The provisions are otherwise the same as proposed in 2019, except for minor technical and drafting improvements. These include clarifying that the cap only applies to existing transmission customers, and, as proposed by Transpower, amending clause 49 to focus on charges covered by the cap, rather than those not covered (including removing from the definition of capped charges any adjustments due to application of the provisions of the guidelines relating to adjusting charges).

What we proposed

13.5 The Authority (2019 Issues Paper pages 164–169) proposed a price cap to limit any electricity bill shock as a result of a new TPM. This would give households and businesses greater certainty about the impact of a new TPM and give industrial customers time to adjust, mitigating the risk of inefficient business exits.

13.6 The cap would limit the increase in customers' total electricity bill since 2019/20 due to any increases in transmission charges from the new guidelines to 3.5% (plus inflation):

- for a distributor the cap would be calculated based on the estimated total electricity bill of consumers in its network
- for direct-connect load customers the cap would be calculated based on each customer's estimated total electricity bill. The 3.5% cap would be in place for five years from 2019/20 and then would ramp up by 2 percentage points each year (to 5.5%, 7.5%, etc)
- the cap would phase out due to inflation and as charges reduce due to depreciation, expiring in the first year the customer's charges fall below the capped level
- charges for new assets allocated by the benefit-based charge are outside the cap.

13.7 As Transpower had previously requested, the guidelines prescribe the calculations that Transpower must make. For data availability reasons, the calculations leave out retail margins and industry levies. As a result, the cap will in practice be a bit less than 3.5%.

13.8 The 2019 Issues Paper estimated that the cap would protect three distributors and five direct-connect customers. The cap's cost was proposed to be spread among all other customers in proportion to their total transmission charges subject to the cap.

Submitters' views and our assessment

13.9 There continue to be mixed views on the price cap. Submissions tended to support having some price cap,[220] while raising concerns about aspects such as the impact, method, scope or transition.[221] Some were concerned the cap provides no meaningful protection.[222]

220 For example, Buller p 6, Unison and Centralines p 7.

221 For example, Contact, Mercury p 12, Pan Pac, Powerco, Transpower, Trustpower, Vocus Group, Waitaki Power Trust and Waitaki Irrigators Collective.

222 For example, NZ Steel, Norkse Skog, Northland Councils, Northpower and Northpower Electric Power Trust.

13.10 A few submissions did not think a price cap is needed at all because: the cap would only slightly protect consumers in three networks (Meridian); it would slow the introduction of efficient charges (Meridian); or the time between decision and implementation already gives customers sufficient notice (Orion and Meridian).

Sharing the cost of the cap

13.11 Concerns raised about how the cap was proposed to be paid for included that:

- the cap would be paid for in part by customers who faced increased transmission charges[223]
- residential consumers would end up paying to support large industrials[224]
- the cap should be paid for by those getting reductions in transmission charges[225]
- the cap would be paid by consumers who already had been paying for grid investments that benefitted others over the past decade.[226]

13.12 The Authority acknowledges these concerns. However, it considers the chosen cap best promotes the Authority's statutory objective. For example, alternative approaches to manage any price increases (such as a gradual transition or phase-in period)[227] would delay the benefits to consumers from more efficient pricing and capping charges also for industrial direct-connect customers for a transitional period is to avoid inefficient exit (which would increase charges paid by residential consumers).

13.13 While we understand the objection by Entrust and others that the cap would be paid for (in part) by those also facing increased transmissions charges, there are equally strong views from those who perceive they have overpaid for years and consider they should not continue to do so by carrying the costs of the cap.

Applying the cap

13.14 Transpower considered the cap would not limit price increases to 3.5% as intended because the cap does not apply to all transmission charges (see also ENA p 9, Northpower p 24) and there are no controls on how distributors pass on the charges.[228] Relatedly, Northpower (p 27) pointed out the cap provides no protection against non-transmission components such as electricity and distribution bills that may also be affected.[229]

13.15 We consider that the cap appropriately targets changes in transmission charges resulting from the new guidelines. Any consequent changes in demand and costs to serve that demand reflect voluntary market-based decisions, given new price signals and so do not need to be capped. The Authority accepts the guidelines do not control how distributors

[223] For example, Entrust, Northpower p 26, Refining NZ p 4, Transpower pages 22–25 and Vocus.

[224] Energy Trusts of New Zealand p 7, Distribution Group p 15, ENA p 5, Lower Waitaki Irrigation Company, Waitaki Irrigators Collective and Waitaki Power Trust p 23.

[225] For example, Northpower p 26, Orion p 13 and Refining NZ p 4.

[226] For example, Otago Southland Employers' Association, Rio Tinto p 3 , Southland Chamber of Commerce, South Port, Faulkner, van Eeden, EIS, Group and others.

[227] As suggested by ENA p 10, Trustpower p 59, or Transpower p 10.

[228] Transpower p 10 and Axiom Economics for Transpower, p 167. Transpower also notes (e.g. chapter 15) that the cap is inconsistent with the Commerce Commission's to managing regulated price increases. The Authority notes its cap manages a different issue, i.e. a reallocation, not actual prices or revenues of regulated entities.

[229] Northpower p 24 and ENA p 9, note the cap does not apply to charges 'if Transpower decided to reallocate more than just the seven existing investments earmarked for [benefit-based] charges' under Additional Component E. As the *2019 Issues Paper* explains at B339–340, that component provides for a transition for the same reason as the cap but leaving its design open to best respond to circumstances at the time and (at B338) the benefit-based charge would be capped at estimated present value of positive net private benefits.

pass through the transmission charges. However, we note distributors are working to make their pricing more cost-reflective and are accountable to their customers and communities if they do put any bills up by more than 3.5% as a result of a new TPM consistent with the 2020 guidelines.

13.16 Northpower (p 25) also argues it makes no sense that the price cap does not apply to the charges for new transmission investments. The Authority considers its approach does make sense: Decisions on future investments are clearly not part of a transition from one pricing methodology to another. Further, the guidelines provide that benefit-based charges are to be allocated to transmission customers who are expected to benefit from an investment in proportion to the expected net private benefits. That is, for an efficient investment, benefits will equal or exceed changes in charges for each customer, so no customer is adversely affected by charges for new transmission investments.[230]

13.17 Fonterra and Refining NZ suggested the price cap does not protect industrial customers that are connected via distributors in the same way as it protects direct-connected industrials. The Authority considers large customers connected via distributors may be advantaged in that a distributor's transmission charges will be based on the coincident demand of all its customers and because the cap for direct-connect customers starts phasing out after five years. However, the boundary issue appears minor relative to the disadvantages of other approaches the Authority considered.

Guidelines specify the cap in terms of total electricity charges

13.18 Some submitters suggested the cap was very complex[231], not efficient or transparent[232], or of no help.[233] Some considered the cap should be set in terms of transmission charges.[234] This would be simpler, as it avoids the need to estimate consumers' electricity bills. It may also be able to better target customers with the greatest rises in transmission charges[235] (some by 50%–100%, or much more where customers have previously paid no or very low transmission charges).

13.19 The Authority agrees that this approach could in principle achieve the same outcome — through a higher percentage cap on what is a smaller portion of a consumer's total bill. However, the Authority does not favour that approach as it considers the total electricity bill is more salient to most consumers. Also, it would lead to less consistent electricity bill outcomes across customers (unless different percentage caps are to be applied to different customers). This is because transmission charges make up a different proportion of each transmission customer's total electricity bill.

13.20 Northpower (p 27) pointed out that the reduction in Transpower's maximum allowable revenues (MAR) from 2020 and elevated spot prices at the end of 2019 mean the amount that charges can increase would now be higher before the cap provides support (compared to the 2019 Issues Paper). This is true, but importantly the cap still gives the same assurance to consumers and businesses about the impact of transmission charges on their total electricity bill. Further, as Table 8 illustrates, our estimates of indicative charges indicate the reduction in Transpower's MAR lowers the impact and thus the total cap amount to be funded.

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230 Trustpower p 59 called the potential for price shocks from new transmission investments "one of the most undesirable features of the proposed benefit-based charge." Powerco p 7 notes the cap should be retained with the level to be able to be changed as part of an operational review.

231 Energy Trusts of New Zealand and MEUG.

232 Genesis p 3.

233 Golden Bay Cement.

234 For example, Contact p 7, Genesis p 2 and Transpower p 10.

235 This effect was highlighted by Energy Trusts of New Zealand p 6, Northpower p 24, Transpower pages 9, 22–26 and Trustpower p 59.

Guidelines do not extend the cap to generators

13.21 Contact and Nova support the price cap being limited to load customers. Conversely, some submissions thought the price cap should also apply to generators, either as a matter of principle, or because it would ease the transition for smaller North Island generation that currently pay no interconnection charges (e.g. Ngā Awa Purua, Tuaropaki Power and Whareroa Cogen).[236]

13.22 The Authority decided not to adopt this approach because generators already are exempt from residual charges (except to the extent they have load). Their charges are thus linked to benefits from transmission services, suggesting the risks are thus not to the same extent as those set out in paragraph 13.5.

Alternative transitions have been considered

13.23 As noted above, some submitters suggested a simpler approach to manage any bill shock would be to phase in new charges over just a few years, starting from charges in the final year of the current TPM.[237] This would avoid the situation where customers facing an increase in charges must also contribute to the cap.

13.24 The Authority considered alternative transition paths, such as those advanced by submitters. However, it considered their benefits were not outweighed by their disadvantages, being that: they would further delay the benefits of more efficient pricing, customers (such as various South Island load customers) would continue to be charged in excess of benefits for even longer and charges would rise more rapidly for industrial direct-connect customers (e.g. Norske Skog and NZ Steel) risking inefficient exit.

Sunset clause

13.25 Meridian suggested an expiry date on the cap. An expiry date on the cap would be consistent with the aim of protecting households and businesses during a transition.

13.26 In the case of those few capped distributors, the amount of support provided is minor and will phase out automatically in a matter of a few years. In the case of direct-connect industrial consumers, the amount of support is more substantial. In practice, as specified, cap support will reduce substantially over 10 years and is likely to be largely extinguished by 2035, though this is sensitive to assumptions. To provide certainty, the guidelines provide that the cap expires at the end of the 2038/39 pricing year.

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236 Genesis p 4, Office of the Māori Climate Commission, Ngāti Tūwharetoa Electricity Group p 3 and Trustpower p 59.

237 For example, Contact p 6, ENA p 10, Pan Pac p 6, Transpower p 10 and chapter 16 and Trustpower p 59.

14 Guidelines: additional components

14.1 The 2020 guidelines include seven additional components, which Transpower must include in the TPM if doing so would better meet the Authority's statutory objective.

14.2 Transpower submitted that the inclusion of the additional components should be at its discretion, even if the statutory objective test is arguably satisfied (‘must’ should be ‘may’), as making inclusion mandatory would invite challenge from stakeholders who prefer that any omitted additional components were included. In our view, however, where there are long-term net benefits for consumers, ‘must’ is appropriate.

14.3 Meridian submitted that some of the additional components risk unnecessarily delaying TPM reform and proposed deferring consideration of several of the additional components (particularly A, B, C, F and G) in order to expedite development of the TPM.

14.4 We agree that the additional components in general are lower priority than other elements of the TPM, particularly the benefit-based charge. However, they need not delay implementation of more important elements of any TPM. The 2020 guidelines provide that the implementation of additional components, other than a transitional congestion charge, must be deferred if necessary in order to expedite the implementation of the benefit-based charge for high-value benefit-based investments (clause 67). Also, Transpower need not propose an additional component if the costs of doing so would outweigh the benefits. We have therefore decided to retain the additional components.

Additional component A: Adjustments to charges for staged commissioning

14.5 The 2020 guidelines in respect of this component, clause 55, have been revised following a submission by Transpower which in our view will better achieve our objective.

14.6 The new wording clarifies that Transpower can adjust charges, change asset classification and/or use a hybrid asset classification in order to ensure the charges do not unreasonably deter partial commissioning of assets where staged commissioning of grid investments creates connection assets that will ultimately be interconnection assets, until the assets meet the definition of interconnection assets.

14.7 In the 2019 Issues Paper, we proposed that where an investment is commissioned in stages, Transpower can adjust the time profile and allocation of charges, to address any inefficient incentives for a customer to seek to avoid staged commissioning.[238]

14.8 Transpower provided suggested alternative drafting for this additional component, which we used to revise the guidelines. The intention is to ensure that the way the charges are set better reflects the net private benefits from the asset during different phases of commissioning.

238 *2019 Issues Paper*, paragraphs B.289–B.293.

Additional component B: Charges for assets principally providing connection services

14.9 This component is in clause 56 of the 2020 guidelines. The intent of this component is unchanged, but the wording has been revised.

14.10 The new wording states that connection assets cannot be changed into interconnection assets by a person other than Transpower investing in other assets to create an interconnection loop.

14.11 Under this component, interconnection assets that principally provide connection services would be charged for as if they were connection assets, even if they do not meet the technical definition of a connection asset. The aim was to address inefficient incentives for a customer to seek to have assets classified as interconnection assets.[239]

14.12 Transpower submitted that it agrees with the intent of this additional component, though not the execution and has provided alternative drafting, which we have adopted.

Additional component C: Charges for connection investments to use a method substantially the same as for benefit-based charges

14.13 The 2020 guidelines in respect of Additional component C, clause 57, are the same as the guidelines included with the 2019 Issues Paper, save for one minor amendment to accommodate changes in defined terms.

14.14 Under this additional component, connection charges would be allocated in substantially the same way as benefit-based charges. This was proposed to address inefficient incentives for a customer to seek to have assets configured as either connection assets or interconnection assets, depending on whether the method for calculation of the connection charge or benefit-based charge was more advantageous to them.[240]

14.15 Transpower submitted that this additional component should be deleted, as the connection charge is already a beneficiaries-pay charge and is not controversial and any efficiencies that might be gained from treating connection assets as benefit-based assets are very unlikely to justify the transaction cost of the change.

14.16 The Authority does not consider that this additional component should be deleted. Providing for it in the guidelines means it will be available to include in the TPM if needed to address potential boundary issues that may be caused by having two distinct classes of grid investments, for which charges are determined using two different methods. Providing for this potential issue to be addressed is consistent with the long-term benefit of consumers. If significant boundary issues do not arise, such that the efficiencies that could be gained from including this additional component in the TPM do not justify its costs, then it would not be introduced into the TPM.

239 *2019 Issues Paper*, paragraphs B.294–B.301.

240 *2019 Issues Paper*, paragraphs B.302–B.305.

Additional component D: Transitional congestion charge

14.17 This additional component has been renamed 'transitional congestion charge' to better reflects its purpose. Clauses 58–61 of the 2020 TPM guidelines are otherwise the same as proposed in 2019, except for minor edits to better align the wording to the policy intent.

14.18 The Authority has published a detailed paper on the Authority's thinking on the role of peak and congestion charging and the submissions provided on that topic.[241] The Authority's view remains the same as that expressed in the information paper.

14.19 In that paper, the Authority noted most submissions on the 2019 Issues Paper expressed concerns about what could happen in the absence of a peak transmission charge.[242] Many considered a permanent peak transmission charge is needed.[243] For example, Transpower said "A peak price signal is needed for an efficient TPM."

14.20 A key concern was that without a peak transmission charge there would be a sudden increase in demand at peak times and that this would create operational issues and inefficiently bring forward transmission and distribution investments. A related concern was that nodal prices do not signal the cost of potential future grid investments.

14.21 The Authority acknowledges the uncertainty about whether all the appropriate settings are in place or implemented as expected (e.g. scarcity pricing) and about how market participants might react. This uncertainty is greater at the start of a new TPM.

14.22 The Authority has decided the transitional congestion charge is the most effective way to respond to this uncertainty. It provides Transpower an option for a targeted congestion charge in addition to nodal pricing and other available tools.

14.23 We do consider that nodal prices (including forward prices and enhanced by implementation of real time pricing) are likely to provide efficient, location-specific information on the cost of using the available transmission capacity. Users can compare this to the costs of alternatives, including demand response or grid investment. The expectation of benefit-based charges associated with transmission expansion will also give forward-looking price information.

14.24 As discussed in the 2019 Issues Paper and the 2020 Peak Charges Information Paper, this technology-neutral approach would ensure all the appropriate signals would be in place to guide both short- and long-term use and investment decisions by grid users and Transpower, including in transmission alternatives.[244]

14.25 We note concerns raised by Nova about the SPD modelling of line losses were addressed when the modelling of all transmission lines was updated in 2015. [245] Further, we expect real time pricing to further mitigate remaining concerns.[246]

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241 Electricity Authority, 2020, *Peak Charges under proposed TPM guidelines: information paper and next steps and* its companion papers, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/

242 The Authority's 2020 *Peak Charges* Information Paper considers submissions thematically.

243 Including e.g. Entrust, ENA, IEGA, NZ Steel, Norske Skog, Transpower, Vector and the TPM Group p 5.

244 The Authority therefore disagrees with submissions that a permanent peak charge is required, with NZ Steel (paragraph 48) when it states "TPM proposals continue past thinking of one-way energy flows", and with Vector (pages 9–14) when it suggests we have not appropriately addressed the balance of charges between generation and load.

245 See Nova's answer to question 55 in the *2019 Issues Paper*. (Nova does not agree a peak charge is needed.)

246 For example, concerns about oscillating prices should be mitigated by the inclusion of the two dispatch notification products in the RTP arrangements.

Additional component E: Including additional pre-2019 investments in the benefit-based charge

14.26 The 2020 guidelines in respect of this component, clauses 62–63, are the same as the guidelines included with the 2019 Issues Paper except for some minor amendments to improve the clarity of the drafting and to allow use of a standard method or combination of standard and simple methods if Transpower wishes.

14.27 In the 2019 Issues Paper, we proposed an additional component under which the benefit-based charge would extend to pre-2019 benefit-based investments other than the seven major investments specified in the Issues Paper.[247]

14.28 Submissions on this proposal were mixed. Some parties opposed it as part of a general stance that the benefit-based charge should not apply to any historical investments.[248] We do not agree with this view for the reasons discussed in chapter 9.

14.29 Some stakeholders favoured extending the benefit-based charge to all existing assets.[249] We acknowledge that extending the benefit-based charge to all grid investments has the potential to promote the efficient operation of the industry. However, we decided not to make this extension part of the core components in the guidelines. This is because we are not certain that there is sufficient information available in respect of all investments, in order to limit implementation costs and to ensure that initial benefit-based charges do not exceed the benefits these investments are now expected to yield. In our view we have struck an appropriate balance in our selection of the seven pre-2019 investments to which the benefit-based charge applies.[250]

14.30 Meridian opposed the introduction of this additional component on this basis, noting that it supported the Authority's criteria for identifying the seven major investments specified in the 2019 Issues Paper as subject to the benefit-based charge. Buller Electricity submitted that the guidelines should not make applying a benefit-based charge to additional pre-2019 investment a core component of the guidelines, noting that a fully informed decision on this issue would require information as to the scale, impact and materiality of the issue.

14.31 The Authority considers that it is appropriate that we make provision for Transpower, via Additional Component E, to subject more pre-2019 investments to the benefit-based charge. We agree with Buller that more information would be needed prior to any decision on extending the benefit-based charge to other historical investments. Transpower is well placed to determine whether there is sufficient information available and whether implementation costs are likely to be excessive and on this basis can form a view as to whether extending the benefit-based charge to other grid investments would promote our statutory objective.

14.32 Rio Tinto submitted that the TPM needs to define specific triggers to require Transpower to review relevant assets and criteria to apply in determining whether a benefit-based charge should apply.

14.33 We do not agree. Specific triggers are not required, as Transpower must consider whether, in its reasonable opinion, including an additional component better meets the Authority's statutory objective than not including it, when it develops and submits a proposed TPM. Separate criteria are not required, as the Authority's statutory objective is the criterion. We have indicated that availability of information and implementation costs are relevant considerations, but we do not consider that it would be appropriate to limit the consideration by specifying criteria.

247 *2019 Issues Paper*, paragraphs B.327–B.340.

248 For example, Trustpower.

249 For example, Rio Tinto.

250 See chapter 9.

Additional component F: Allocation of opex

14.34 The 2020 guidelines in respect of Additional component F, clause 64, are largely the same as the guidelines included with the 2019 Issues Paper (with only a minor amendment to the heading to improve clarity).

14.35 In the 2019 Issues Paper, we proposed an additional component that would attribute opex to the asset it was spent on (without reliance on broad allocation rules), on the basis that this would result in charges that better reflect actual costs and so promote efficiency.[251]

14.36 Trustpower submitted that the way in which the additional opex component is framed does not seem unreasonable.

Additional component G: kvar charge

14.37 The 2020 guidelines in respect of the kvar charge, clause 65, are the same as the 2019 proposal.

14.38 In the 2019 Issues Paper, we proposed, as an additional component, a kvar charge, which would be levied on those that cause a deterioration in the power factor to reflect the cost that deterioration imposes on other grid users. We did not see an immediate need for such a charge, but we proposed to provide for its introduction in the guidelines in case there were net benefits from having it in the future.[252]

14.39 Trustpower supported the introduction of a kvar charge, noting the application of such a charge to grid-connected load would improve competitive neutrality and improve efficiency through incentives for customers with poor load factors. We agree that there may be benefits to the introduction of a kvar charge and have therefore retained it as an additional component.

251 *2019 Issues Paper*, paragraphs B.341–B.351

252 *2019 Issues Paper*, paragraphs B.352–B.358

15 Cost benefit analysis

Material net benefits

15.1 The Authority considers that a TPM based on the 2020 guidelines would result in material net benefits and is superior to alternative options considered. This supports the Authority's assessment that the guidelines would promote its statutory objective and be for the long-term benefit of consumers.

15.2 The Authority has previously released its response to feedback on the 2019 cost benefit analysis and remains of the views outlined in that paper. That paper included a detailed consideration of submissions on that cost benefit analysis and of revisions we made having taken into account submissions received.[253] The scrutiny has helped improve the estimates.

15.3 The Authority estimates the net benefits have a median present value of +$1.3 billion with a range of $0.3b–$2.3b, or a weighted mean value of +$1.2 billion over 30 years.

Cost benefit analysis is an aid to decision-making

15.4 A CBA is only an aid to support deliberation and decision-making, alongside a much broader range of factors the Authority has to consider. A quantitative CBA gives a sense of the order of magnitude of benefits or costs that are involved, alongside likely effects that cannot reasonably be quantified. The modelling also improves the understanding of the economic model of the electricity system and how different parts influence each other.

15.5 In addition to the quantified effects, specific examples of probably the most important impacts that have not been able to be quantified, but which are relevant and need to be weighed alongside these results, are:

- the benefits from removing incentives for mass-market consumers to invest in technologies to help them avoid transmission charges (which would add costs overall)
- the cost of a less durable approach, which the Authority considers could be considerable. The approach would be less durable if, for example:
  - some customers would have to continue to pay for the relatively recent major investments from which they do not benefit, while also paying the full costs of future investments from which they do benefit
  - a substantial share of the costs of future grid investments would continue to be spread across all New Zealanders, so that beneficiaries of investments favour more expensive solutions than they otherwise might (the 2019 Issues Paper provided the example of undergrounding transmission lines)
  - the allocation of the HVDC charges were not addressed, retaining the uneven playing field between generation investment options.

15.6 Overall, a CBA cannot be a precise exercise and there will always be different views about assumptions and approaches that could have been taken and opportunities to refine the analysis.

15.7 The Authority is satisfied and confident that the quantitative CBA is a robust and useful input to inform its decision-making.

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[253] Electricity Authority April 2020, *Response to feedback on the 2019 cost benefit analysis*, information paper, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/revisions-to-cba-in-response-to-feedback/ The *2019 Issues Paper* (chapter 4) provides an overview of the approach underpinning the CBA which remains a useful reference. An updated technical paper with detail on the methodology is published with this decision paper.

Consumer welfare changes

15.8 The Authority's statutory objective is to promote competition in, reliable supply by and the efficient operation of the electricity industry for the long-term benefit of consumers. As such our approach is to consider consumer surplus as an appropriate economic measurement of consumer benefits from more efficient grid use.

15.9 Consistent with looking at what is for the long-term benefit of consumers, the Authority does not take into account pure wealth transfers when measuring consumer benefits.[254] Therefore, in quantifying the estimated costs and benefits from more efficient grid use of the TPM proposal, we use a measure of consumer surplus that is adjusted to remove pure wealth transfers.

15.10 It would not be for the long-term benefit of consumers if regulatory settings were to cause electricity prices to fall in a way that undermined producer profitability and incentives to invest. The latter can lead to under-investment, reduced competition, higher prices or reduced quality over the long-term. Paragraphs 4.18 and 4.19 above summarise how a TPM based on the 2020 guidelines would promote competition in, reliable supply by and the efficient operation of the electricity industry for the long-term benefit of consumers.

15.11 To test the guidelines would not undermine efficient market dynamics, the Authority therefore also examined total market surplus (the sum of changes in consumer and producer surplus), alongside the reported consumer surplus measures. See Figure 10 and assessment below.

15.12 The total surplus measure confirms that the estimated net benefit is not unduly influenced by the timing of generation investment cycles. There is a dynamic where electricity prices rise (generating producer surplus), until there is new generation investment, after which prices may stabilise or fall (generating consumer surplus). We wanted to ensure that the estimated net benefit of the proposal does not rely on the timing of these movements.

Results and sources of quantified benefits

15.13 Table 2 below presents results for a TPM consistent with the 2020 guidelines and three alternative options in terms of:

- the median
- an average
- a probability-weighted average drawn from 113 simulations of the grid use model.[255]

15.14 The median estimates report typical modelling results to be consistent with, and so assist comparisons of, the results reported in the 2019 Issues Paper. For example, the input assumption value for short-run generation costs is treated as being just as likely as some other value for short-run generation costs.

15.15 The sensitivity analysis we have undertaken (as explained in the CBA Revisions Information Paper) enables us to weight the net benefit/cost estimates based on the relatively likelihood, or probability, of key input assumption values. The results for the median and weighted mean are similar.

254 Wealth transfers are not a relevant factor for the Authority's decision-making, except to the extent they result in effects on efficiency (e.g. via effects on durability), competition or reliability. Having considered potential costs of our decision resulting from wealth transfers, we are confident any such costs are outweighed by benefits.

255 Results of multiple sensitivities are weighted by their relative likelihood of occurring. For more information see the *2020 CBA Revisions Information Paper* and the *2020 CBA Technical Paper*.

Table 2 Summary of cost benefit analysis results

$ million in present values

More efficient grid use	Guidelines	Alternative	Future-only	HVDC-only
Weighted mean	965	-896	921	396
Mean	973	-808	869	839
Median	**1,131**	**-1,057**	**626**	**900**

At the median	Guidelines	Alternative	Future-only	HVDC-only
Net change in consumer welfare	1,131	-1,057	626	900
Less inefficient battery investment	51	49	51	51
More efficient investment	40	-	40	40
Increased scrutiny	49	-	49	49
Increased investor certainty	31	-	31	31
Transmission benefits	95	127	107	109
Transmission costs	-35	-36	-43	-35
Other costs*	-27	-9	-27	-27
Net benefit	**1,335**	**-927**	**834**	**1,117**

At weighted mean	Guidelines	Alternative	Future-only	HVDC-only
Net change in consumer welfare	965	-896	921	377
Less inefficient battery investment	49	47	48	49
More efficient investment	40	-	40	40
Increased scrutiny	49	-	49	49
Increased investor certainty	31	-	31	31
Transmission benefits	93	135	109	112
Transmission costs	-32	-36	-42	-37
Other costs*	-27	-9	-27	-27
Net benefit	**1,169**	**-760**	**1,130**	**594**

Ranges	**344–2,236**	**(2,019)–19**	**(85)–2,098**	**(170)–2,123**

Note: Ranges based on interquartile results from sensitivity analysis of the grid use model.
Note: Other costs are primarily estimates of TPM development, implementation and operational costs, as previously submitted by Transpower and < $2m for the efficiency cost of the price cap and distortion of load location (see *2019 Issues Paper*).

15.16 Most of the quantified benefits from a TPM based on the 2020 guidelines would be due to:

- increased electricity use during peak demand periods (a 1% increase in demand in the near term), when consumers value electricity the most
- lower wholesale electricity prices when compared to the baseline.

15.17 For each component of the CBA estimated using the grid use model, the probability-weighted average estimate takes account of the distribution over outcomes for the component. The total net benefit/cost of the components of the CBA estimated using the grid use model is the sum of these probability-weighted average estimates.

15.18 The increase in electricity use during peak demand periods is the result of removing the RCPD charge.[256] That charge, it is generally agreed, is overly high and encourages actions and costs to avoid using the grid, even when there is plenty of grid capacity. Its removal makes it cheaper to consume electricity during peak demand periods.

15.19 Higher demand at peak lifts wholesale energy prices. This, with lower transmission costs on South Island generators from removing the HVDC charge, would bring forward generation investment. Subsequently average wholesale electricity prices inclusive of transmission charges would fall compared to the baseline. (Wholesale electricity prices still rise in the model, in line with projections of the cost of thermal fuels and carbon emissions.)

15.20 The removal of the RCPD charge also removes incentives to invest in utility-scale batteries to avoid transmission charges and shift transmission costs to other grid users. The benefit to consumers is $51m (at the median). Investment in batteries and other distributed energy resources is of course likely to continue.

15.21 An increase in peak demand would bring forward transmission investment relative to the baseline. The cost of this transmission investment brought forward ($35m) is offset by reduced losses and constraints ($95m at the median), which lowers wholesale prices.

15.22 A TPM consistent with the new guidelines would also result in a net benefit from generators or consumers in a region facing transmission-related costs of their investment and consumption decisions. A net benefit of $40m arises because, unlike under the current TPM, generation and load would pay for grid upgrades in proportion to their benefits from those upgrades. As such, benefit-based transmission charges would incentivise an efficient reduction in demand growth in areas likely to require transmission investment.

15.23 Another net benefit of the guidelines ($49m) comes from improved incentives on beneficiaries of transmission investments to more closely scrutinise proposed transmission investments and provide information so Transpower and the Commerce Commission can make better investment choices, including on transmission alternatives. The literature and empirical basis for these estimates are discussed in the 2019 Issues Paper (pages 41-42) and the April 2020 CBA revisions paper. The range of $9–98m around this estimate indicates there is a benefit but acknowledges the limitations in the available evidence.

15.24 The 2020 guidelines would increase certainty for investors ($31m). Increased certainty reduces the risk premium or cost of investment in generation, in industrial plant and transmission. The 2019 Issues Paper describes the literature we drew on to estimate this effect. As acknowledged in that paper and the CBA revisions paper, there is uncertainty about the quantum of this benefit, but the lower end of the range of $11m–$59m is clearly positive.

15.25 The majority of the remaining costs associated with the guidelines pertain to the estimated cost of development implementation and operation of a new TPM. To estimate these costs, the Authority drew on cost information Transpower provided to the Authority in its submission on the 2016 Issues Paper (available on the Authority's website).

15.26 Figure 7 illustrates the changes in wholesale electricity prices (inclusive of interconnection charges) and demand.

[256] NZ Steel's submission questioned the accuracy of the modelled increase, given NZ Steel alone could add 25-30MW on an average day and more than 75MW 'subject to a very high spot price or other strong signal' (such as the RCPD charge). We note the modelling results present annual averages, rather than day- or trading-period level results.

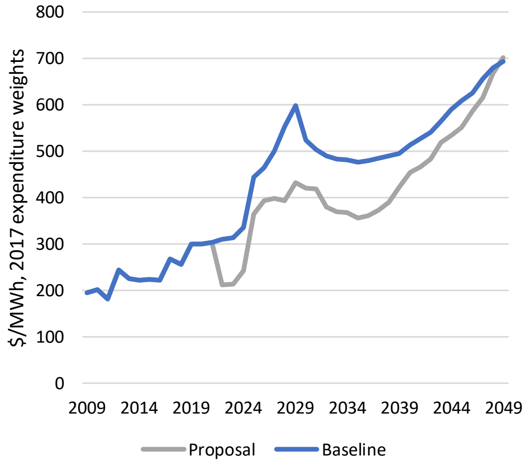
Figure 7 Summary of changes in prices and demand

Removing the RCPD charge reduces wholesale electricity prices inclusive of interconnection charges at peak. Demand at peak increases, by around 1% in the initial period.

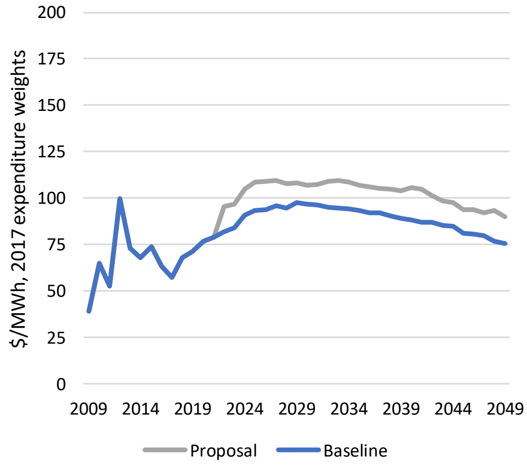
Charges under the guidelines are modelled as a per MWh charge. Hence off-peak prices inclusive of interconnection charges rise. This and lower demand for charging of utility-scale batteries, result in electricity consumption outside peak periods that is, on average 0.7% lower compared to the baseline.

Additional demand at peak increases wholesale electricity prices during peak periods and brings forward generation investment. This dynamic suppresses the growth in average wholesale electricity prices inclusive of interconnection charges.

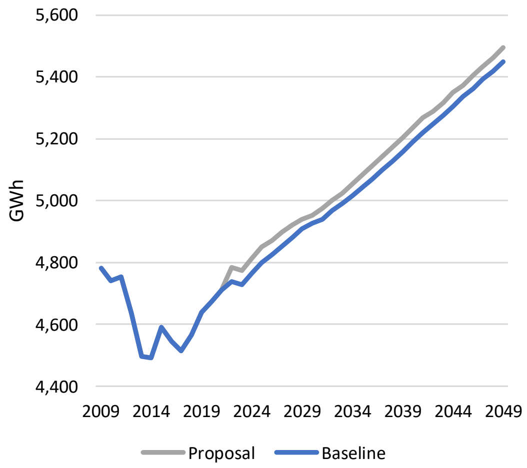
Price at peak (incl interconnection charge)



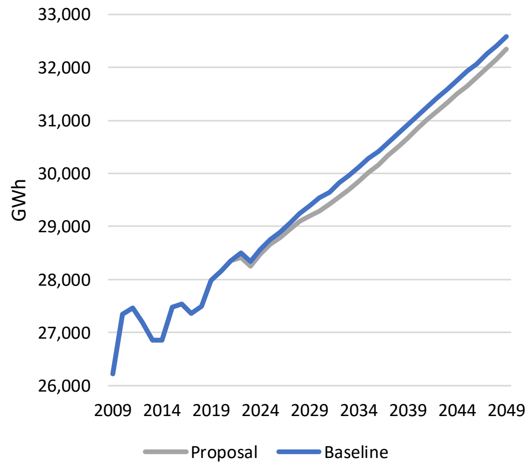
Off-peak price (incl interconnection charge)



Demand at peak



Off-peak demand



Note: Charts show the arithmetic average of model simulations.

Options modelled in the CBA

15.27 We also provide the quantified results for three other options that have been assessed in the CBA alongside the guidelines. Appendix B contains a qualitative assessment of other options considered.

An alternative option: weakening the RCPD price signal

15.28 We considered an alternative option that assumed that the only change to the current TPM would be that the RCPD charge is replaced with a per-MWh charge over all trading periods. Some submitters have argued for de-powering the RCPD charge. This is a version of such an approach.[257]

15.29 This design increases electricity use during peak demand periods. But generation investment is not brought forward as it would be under the guidelines. This is because, without the re-allocation of the HVDC charge, higher wholesale electricity prices are needed to cause investment in South Island generation to satisfy increased electricity demand. As such, wholesale electricity prices would rise by more than under the guidelines, which negatively impacts consumer welfare.

Guidelines 'future-only' option

15.30 The Authority also considered a future-only version of the guidelines. This would recover only future grid investment costs through the benefit-based charge. The costs of all historical grid investments would be recovered through the residual charge.

15.31 In this future-only scenario a greater share of transmission charges would be recovered from consumers and less from generators. This would suppress demand and prices in the initial years compared to what is modelled under the guidelines.

15.32 While this option might be the easier route to take, this option does not address other issues, such as the re-allocation of the remainder of the costs of the HVDC charges, for which submitters expressed more general support.

Guidelines 'HVDC-only' option

15.33 Another option considered was to recover the cost of future grid investments and the remaining costs of historical HVDC investments through benefit-based charges. The costs of all other historical grid investments would be recovered through the residual charge.

15.34 This HVDC-only version of the guidelines sits in between the guidelines and the future-only option in design and also in impact. The re-allocation of the HVDC charge reduces the threshold for investment in South Island generation, with associated efficiency benefits.

15.35 The quantitative analysis supports the Authority's decision that a TPM consistent with the 2020 guidelines would provide higher quantified net benefits than the other policy options.

Modelling approach

15.36 The 2019 Issues Paper and the 2020 CBA Technical Paper provide further detail regarding the modelling approach used in the CBA.

15.37 In summary, the modelling considers the interdependent effects of transmission charges on generation cost, consumer demand and wholesale electricity prices at different geographical locations on the grid and generation investment. These are the key components needed to understand the effects of changing the approach to transmission pricing.

257 The Authority could, as an alternative, have introduced revised guidelines that retained an RCPD charge but required RCPD to be calculated using all trading periods.

15.38 The model is a necessarily simplified but tractable representation of reality. It cannot aim to be perfect but does provide sufficient detail and realism to give the Authority confidence that it has a reasonable estimate of the likely impact and materiality of the net benefits of different options and that the CBA's estimates are robust to a range of reasonable input assumptions.

15.39 The model is based on a robust empirical approach to estimating key relationships or linkages between transmission charges, wholesale energy prices and wholesale demand for electricity in New Zealand by time-of-use and in different geographical areas.

15.40 The model uses a representation of the transmission grid consisting of 14 separate geographical areas (backbone nodes). Figure 8 shows the location of these backbone nodes and illustrative transmission line connections between them.

Figure 8 Simplified transmission grid with 14 backbone nodes

Demand

15.41 Demand, costs and prices are projected for the baseline and for each option for the period 2018 to 2049 (and assumes a new TPM consistent with the new guidelines comes into effect in 2022).

15.42 The modelling of the new guidelines' costs and benefits is based on an updated version of the Mixed Renewables scenario in MBIE's 2016 Electricity Demand and Generation Scenarios (EDGS). We updated MBIE's scenario to reflect actual and forecast changes in the electricity industry and the New Zealand economy since the EDGS were finalised.

15.43 Demand grows on average at 0.5% per year under the baseline. This draws on assumptions of underlying growth rates in gross national income and population and the response of electricity demand to changes in electricity prices and income.

15.44 The Authority notes the future rate of demand growth is uncertain. For example, the high grid demand scenarios in Transpower's Te Mauri Hiko publications imply the sector could experience double the rate of growth than we assumed in our modelling of the guidelines' costs and benefits.[258] But another scenario could be that electricity demand growth stagnates. The sensitivity analysis (see below) covers a range of demand growth scenarios large enough to encompass such structural changes.

15.45 The modelling of the new guidelines also includes analysis of the response of investment in utility-scale batteries to changes in interconnection charges and the effect of utility-scale batteries on the level of peak and off-peak demand.

Supply

15.46 Changes in wholesale energy prices are an important driver of benefits under the new guidelines. Prices in the CBA grid use modelling (by time-of-use and by region) are derived from the intersection of demand with typical annual generation offer curves. The offer curves shift up or down in the modelling as short-run marginal costs change over time. Prices capture trends in the cost of thermal fuels and greenhouse gas emissions.

15.47 The CBA models new generation investment is modelled as occurring when wholesale energy prices are expected to rise. New investment occurs if the price that generators expect to receive exceeds their long-run marginal cost, once their capacity and offers are added to the market. Multiple investments could occur in a single year as long as all these investments are profitable after accounting for the collective effect of these investments on suppressing wholesale electricity prices.

15.48 Modelled investment in transmission is based on the estimated amount of transmission needed to meet incremental demand per year in each of the four transmission pricing regions. The cost is based on estimates of the long-run incremental cost of transmission. The benefit of transmission investment is a reduction in the cost of losses and constraints.

15.49 This modelling, while drawing on a sound framework and empirical relationships, is inevitably a simplification. But such simplification exists in the analysis of both the options and the baseline. This equality of treatment means the modelling focuses on the key effects of changes in transmission pricing methodologies. The sensitivity analysis provides a check on the robustness of results to different input assumptions.

Transmission charges

15.50 Under the baseline, the grid use modelling allocates interconnection costs to consumers based on shares of peak demand (as a proxy for the RCPD charge). HVDC charges are allocated to South Island generators based on estimates of South Island Mean Injection.

15.51 When model the guidelines, the Authority assumed that, over the longer-term transmission investments would be driven as much by economic as reliability considerations. Therefore, in the CBA modelling the costs of new grid investment is allocated 50/50 between:

- economic investments, with charges allocated to grid users in proportion to each user’s share of the loss and constraint excess
- reliability investments, with transmission charges for these investments allocated:
  - between consumers and generators in proportion to the value of reliability to consumers ($20,000/MWh) and generators ($200/MWh)
  - among distributors and grid-connected consumers in proportion to each party’s shares of peak demand
  - among grid connected generators in proportion to each generator’s share of peak generation.

258 https://www.transpower.co.nz/about-us/transmission-tomorrow/whakamana-i-te-mauri-hiko-empowering-our-energy-future

15.52 Benefit-based charges are conservatively modelled as a per-MWh price at the GXP (that is, they are not modelled as a pure fixed charge). As a result the CBA modelling overstates the repressive effect of benefit-based charges on demand. Further, in the CBA's grid use modelling these charges are not offset by reduced losses and constraints following a grid investment. In other words, the CBA's grid use benefits are understated because the grid use modelling understates electricity demand growth under the guidelines.

Distribution of consumer benefits

15.53 The CBA indicates that residential and large industrial consumers in almost all regions would be better off as a result of the new guidelines (Table 3).

Table 3 Net benefits for consumers by backbone node

Backbone node	Large industrial	Non-residential	Residential	Total
Marsden	--	-3.7%	-0.9%	-2.5%
Ōtāhuhu	-1.6%	-1.9%	1.5%	-0.5%
Huntly	1.5%	-0.6%	2.1%	0.7%
Tarukenga	2.3%	0.9%	3.8%	2.2%
Whakamaru	--	-15.2%	-15.3%	-15.3%
Stratford	1.3%	0.3%	3.2%	1.5%
Redclyffe	2.2%	1.5%	4.7%	2.7%
Bunnythorpe	1.4%	-1.1%	1.5%	0.2%
Haywards	--	-0.3%	3.1%	1.2%
Kikiwa	--	-0.3%	2.6%	0.9%
Islington	3.3%	1.1%	4.1%	2.4%
Benmore	--	2.2%	5.1%	3.3%
Roxburgh	--	-0.4%	2.6%	0.9%
Tiwai	3.3%	1.1%	3.8%	3.1%
Total	**2.2%**	**-0.6%**	**2.4%**	**0.9%**

Note 1: Net benefits as % of baseline expenditure (PV). These are not net of transfers.
Note 2: Baseline expenditure as wholesale electricity costs plus interconnection charges (PV).
Note 3: Baseline shares of expenditure (PV): large industrial 16.4%, non-residential 48.2% and residential 34.4% (does not add to 100% due to rounding).

15.54 In a small number of areas the estimated grid use efficiency benefits will not be sufficient to offset the modelled increase in fixed-like transmission charges for residential consumers. This mainly happens in regions with significant distributed generation. These areas currently pay very small amounts of interconnection charges.

15.55 For example, transmission charges at Whakamaru would initially increase significantly from a very small base. This is because of local geothermal generation around Taupō — under the current TPM distributed generation significantly reduces the local network's transmission charges, as the RCPD charge is based on a net measure of peak demand. Residual charges would be based on a gross measure.

15.56 The impact of more efficient transmission pricing would be more ambivalent for non-residential consumers. This is because, compared to domestic consumers, they consume relatively little at peak and so do not benefit as much from lower prices at peak. Lower prices at peak may not be enough to offset increased costs of consuming off-peak.[259]

[259] This increase in off-peak prices reflects our approach to modelling fixed benefit-based and residual charges as a per MWh charge, as discussed elsewhere in this chapter.

Sensitivities

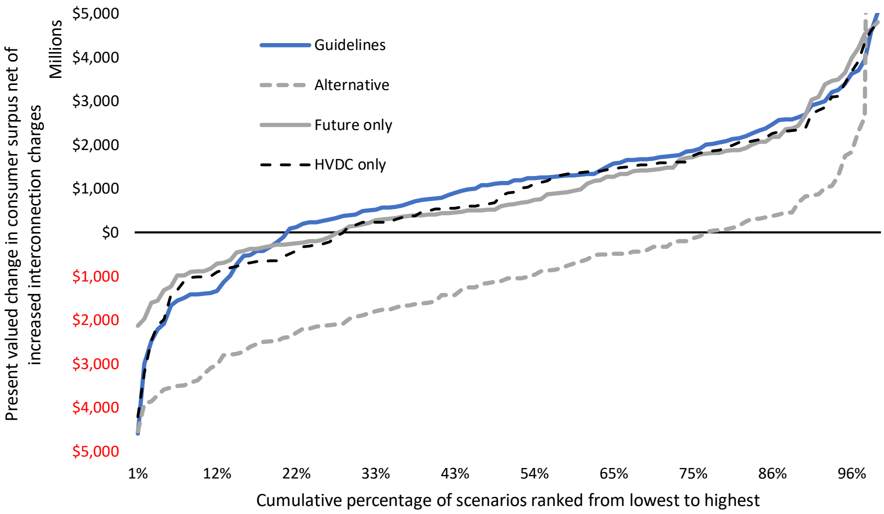
15.57 In addition to considering alternatives to the proposal, the Authority also tested the sensitivity of results to different assumptions for short-run generation costs, long-run generation cost, underlying electricity demand growth and utility-scale battery investment costs. Detail on these assumptions and the approach to sensitivity analysis is set out in the 2020 CBA Revisions Information Paper.

15.58 The sensitivity analysis covers a sufficient range of possible circumstances to test the potential effects of changes in a range of assumptions (including for example the Commerce Commission's reset of Transpower's regulated maximum allowable revenue).

15.59 Figure 9 illustrates that the results are highly sensitive to changes in the values for the above input assumptions. It shows that:

- around 80% of simulations of the guidelines option (i.e. our decision) show an increase in net consumer surplus, with a median of $+1.13b and a weighted mean of +$0.97b
- a TPM consistent with the 2020 guidelines typically has higher benefits that the other options, although the future-only option is better at the high and low end of these distributions.

Figure 9 Sensitivity of grid use benefits (consumer surplus)

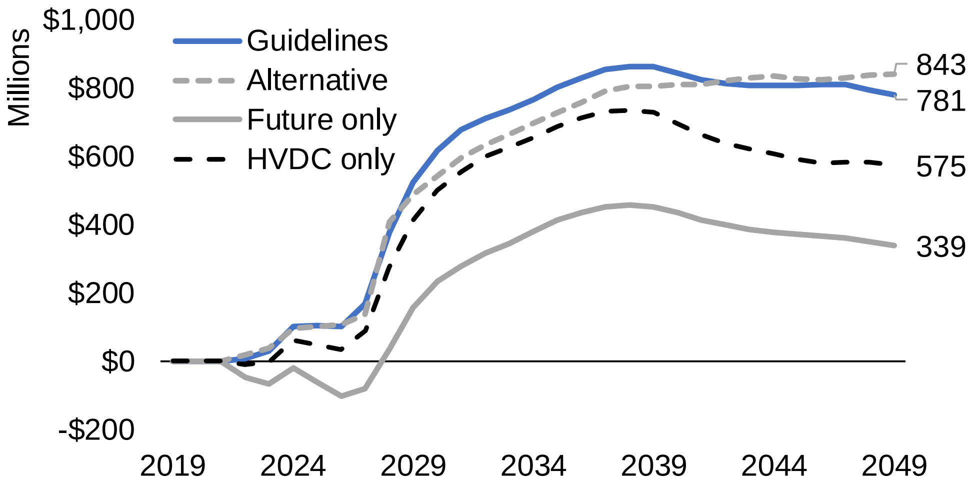


Note: Top of y-axis is shortened to exclude two extreme values under the Alternative.

15.60 Figure 10 presents the assessment of total surplus changes for the different options, to test for sensitivity of the CBA results to timing issues. Total surplus is the total of changes in consumer surplus and producer surplus (i.e. earnings or revenue above costs). This measure confirms that the estimated net benefit is not unduly influenced by the timing of generation investment cycles.

15.61 The guidelines show a superior result, not just in consumer surplus but also in total surplus terms to the future-only and HVDC-only options. It tracks the 'alternative' closely, except for the effect of two large outliers; notably, as Figure 9 shows, in terms of consumer surplus changes, 75% of the sensitivities are negative under the alternative.

Figure 10 Present value cumulative change in (mean) total surplus $m



Areas of uncertainty not quantified in the CBA

15.62 The CBA models a range of demand scenarios that cover significant shifts in demand over a long period of time, including significantly higher and lower demand growth.

15.63 The simulations do not cover material changes in demand and costs caused by external factors, such as the impact of COVID-19 on the New Zealand and global economies, or the demand shock caused should the Tiwai Point Aluminium Smelter close. In the case of the current risks from COVID-19, it is simply too early to make a reasoned assessment of the likely effects over a timeframe relevant to this CBA.

15.64 While the immediate demand impact of COVID-19 on the electricity market could be significant and sustained, we have no reason to believe it will be deeper in the long-run than the demand sensitivities that have been modelled.

15.65 There is no strong reason to believe a significant negative demand shock would change the qualitative conclusions reached in the CBA. Indeed, a substantial negative demand shock would exacerbate the negative effects on consumers of current transmission pricing. This is because interconnection charges might have to be recovered over a smaller quantity of peak electricity demand, leading to higher RCPD charges per kWh, further dampening peak demand and even higher RCPD charges per kWh (a price spiral effect).

15.66 The Authority appreciates the extent of the current uncertainty and the likely prospect of a recession but is confident that there is no good reason to delay the TPM for another year.

15.67 We have not examined the potential impacts of other specific significant external events, as that is outside the scope of a CBA that is intended to examine the likely balance of effects of a TPM consistent with the guidelines on consumers.[260] We note however, the range of demand sensitivities modelled cover significant shifts in demand over a long period of time.

[260] Assessing a substantial demand shock requires consideration of both supply-side and demand-side responses. Such analysis must be more detailed on the specifics of the demand shock and ramifications than is required of the analysis in a CBA of this type. If the Tiwai Point Aluminium Smelter was to close, a more detailed analysis of the impact on transmission would be needed to give a complete picture, as some transmission investment plans might be deferred, but others might be brought forward if, e.g. the reduction in load reveals generation export constraints. In May Transpower proposed to progress Clutha Upper Waitaki Lines Project to provide capacity to deal with a Tiwai closure scenario or a significant increase in generation in the region.

16 Indicative impact on transmission charges

16.1 Implementation of the 2020 guidelines would rebalance the transmission charges between transmission customers. Some customers will be charged more and some less, than they would under the current TPM.[261]

16.2 This chapter presents estimates of transmission charges should a new TPM consistent with the 2020 guidelines be implemented in 2022. Charges are indicative only as they are subject to various factors, including the precise formulation of a final TPM that is consistent with the 2020 guidelines.

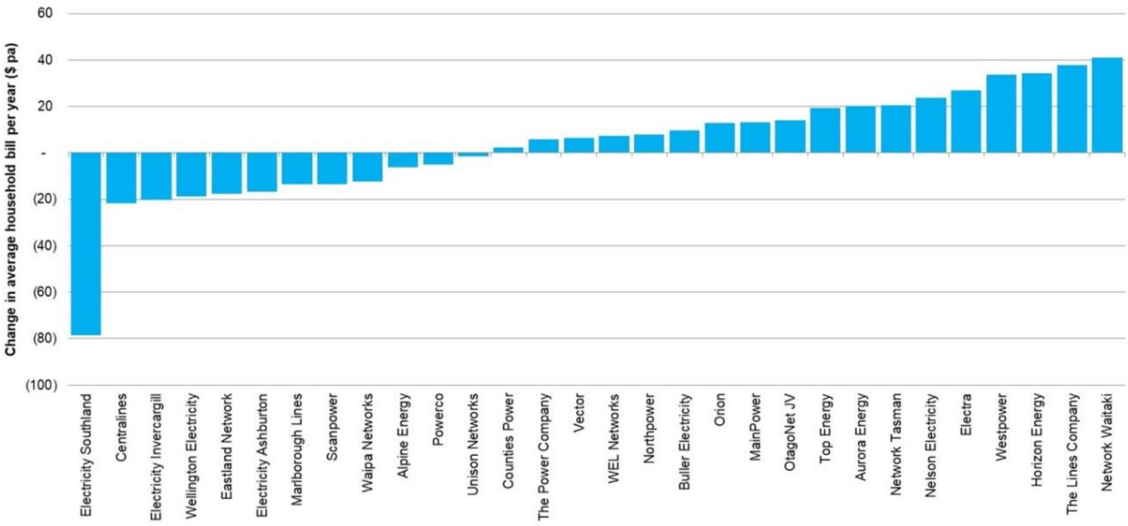
16.3 Transmission charges are included in residential consumers' bills from their electricity retailer. For residential consumers the effect of this rebalancing is modest on average:

- in networks where charges would rise, the increase in the average household electricity bill is estimated to be $19 in 2022. Households in Network Waitaki would experience the largest average increase of $41 in 2022 (79 cents a week)[262]
- in the 12 networks where charges would fall, savings on the average household electricity bill would average $19 a year (or $13, excluding Electricity Southland).[263]

16.4 To put these initial price effects into perspective, 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.[264]

16.5 To reassure households and businesses they would not face large cost increases and to avoid inefficient exit by industrial firms, there is a cap on the amount a designated transmission customer's total electricity bill may rise due to implementing the 2020 guidelines. This cap provides significant transitional support to some direct-connect industrial customers who currently pay little, if any, transmission charges, as under the current TPM they are currently able to minimise their exposure to RCPD charges.

Figure 11 Impact on the average annual residential electricity bill in 2022



261 The guidelines do not change the total amount that Transpower may recover, as this is set by the Commerce Commission. Estimates are inclusive of the reduction in Transpower's maximum allowable revenue.

262 From 2020/21 line charges for regulated distributors are set to reduce consumer bills by similar amounts per month. For example, bills for consumers in Network Tasman would reduce $21 a year, $181 a year for The Lines Company, and $348 a year for Top Energy. Consumer Bills Impact model – EDB DPP3 final determination 27 November 2019 available at comcom.govt.nz

263 Averages in this paragraph refer to simple, unweighted averages.

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

16.6 A TPM consistent with the Authority's 2020 guidelines may also reduce Avoided Cost of Transmission (ACOT) payments. These potential reductions in distributors' cost would in turn help to reduce consumers' electricity bills.

16.7 Under the current TPM, distributors pay owners of distributed generation when the latter reduce a distributor's RCPD charges by producing power at transmission peak periods.

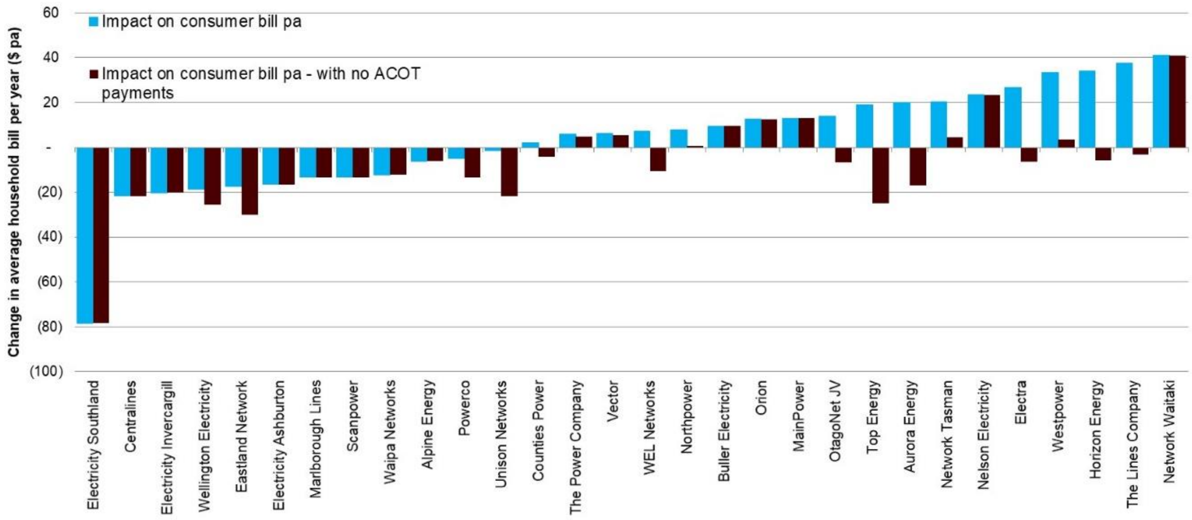
16.8 In December 2016 the Authority decided to amend the Code so that distributed generation that did not efficiently defer or reduce grid costs would no longer receive ACOT payments under the regulated terms in Schedule 6.4. The amendment was made because there had been rapid growth in ACOT payments and consumers were paying for distributed generation that did not in effect reduce costs for them.[265]

16.9 The Authority's 2020 guidelines remove the RCPD charge and replace it with fixed-like benefit-based and residual charges that cannot easily be avoided. As such, no ACOT payments would be made for this reason. (See also F34–F38 of the 2019 Issues Paper).

16.10 This could reduce residential electricity bills, as up to approximately $40 million in ACOT payments are made per year. [266]

16.11 Figure 12 shows the potential impact. For consumers served by Aurora Energy, Electra Energy, Horizon Energy, OtagoNet, The Lines Company, Top Energy and WEL Networks this could mean a modest reduction in their annual electricity bill (rather than a modest increase).

Figure 12 Estimated impact of proposal on bills, with and without ACOT



16.12 However, these effects represent an upper limit.

16.13 For example, some ACOT payments are subject to commercial contract and may endure.[267] And if a transitional congestion charge or kvar charge was included in a new TPM, distributed generation could act to avoid those charges which are aimed at efficiently avoiding or deferring grid investments. In those cases, ACOT payments would be in the interests of consumers and would continue.

265 Part 6 of the Code states distributed generation are eligible to qualify for ACOT payments under regulated terms provided that the distributed generation was installed before 6 December 2016 and the distributed generation appears on a list published by the Authority under clause 2C (1) of Schedule 6.4.

266 Sourced from Distributors' Information Disclosures to the Commerce Commission and Authority analysis of ACOT payments following implementation of the 2016 Code change.

267 See footnote 54 on this point.

Impact by designated transmission customer

16.14 Table 4 sets out indicative charges by designated transmission customer. It includes the Commerce Commission's reduction of Transpower's maximum allowable revenue (MAR) in Regulatory Control Period 3. Table 8 in Appendix A shows these data before the adjustment in MAR.

Table 4 Estimated 2022 charges $m, by customer, inclusive of reduced MAR

$ million	Status quo[268]	Benefit-based	Residual	Pre-cap Total	Cap impact	Capped Total	Total Change
Distributors							
Alpine Energy	10.6	1.3	8.4	9.7	0.2	9.9	-0.6
Aurora Energy	17.6	2.2	18.6	20.7	0.5	21.2	3.6
Buller Electricity	0.5	0.1	0.6	0.7	0.0	0.7	0.1
Centralines	1.7	0.2	1.1	1.3	0.0	1.4	-0.4
Counties Power	9.7	2.8	6.8	9.6	0.2	9.9	0.2
Eastland Network	4.6	0.4	3.2	3.6	0.1	3.7	-0.9
Electra	5.2	1.1	5.9	7.0	0.2	7.2	1.9
Electricity Ashburton	12.1	0.8	9.8	10.6	0.2	10.8	-1.3
Electricity Invercargill	7.5	0.8	5.4	6.3	0.1	6.4	-1.1
Electricity Southland[269]	0.5	0.0	0.3	0.3	0.0	0.3	-0.2
Horizon Energy	2.6	0.3	5.6	5.9	(0.4)	5.5	2.9
MainPower	8.9	1.3	8.4	9.6	0.2	9.9	1.0
Marlborough Lines	5.5	0.7	3.9	4.6	0.1	4.7	-0.8
Nelson Electricity	0.7	0.1	0.7	0.8	0.0	0.9	0.2
Network Tasman	7.2	1.1	8.2	9.3	0.2	9.5	2.3
Network Waitaki	2.8	0.6	3.7	4.2	0.1	4.3	1.6
Northpower	13.3	5.1	9.3	14.4	0.3	14.7	1.4
Orion	43.9	7.0	40.8	47.8	1.1	48.9	5.0
OtagoNet JV	3.8	0.6	3.9	4.6	0.1	4.7	0.9
Powerco	69.4	7.9	55.8	63.7	1.5	65.2	-4.2
Scanpower	1.2	0.2	0.8	1.0	0.0	1.0	-0.2
The Lines Company	3.1	0.5	4.1	4.6	0.1	4.7	1.6
The Power Company	6.6	0.7	6.1	6.9	0.2	7.0	0.4
Top Energy	3.6	0.9	3.7	4.7	0.1	4.8	1.2
Unison Networks	21.7	1.5	19.3	20.8	0.5	21.3	-0.3
Vector	151.8	44.9	111.2	156.2	3.7	159.8	8.0
Waipa Networks	5.7	0.9	4.0	4.9	0.1	5.0	-0.7
WEL Networks	16.7	2.1	15.6	17.7	0.4	18.1	1.4
Wellington Electricity	43.7	5.5	30.7	36.1	0.8	37.0	-6.8
Westpower	1.6	0.1	2.9	3.0	0.1	3.1	1.5
Total	**483.8**	**91.9**	**398.8**	**490.6**	**11.0**	**501.6**	**17.8**

268 Indicative, based on 2019/20 and scaled to expected revenues: see paragraph A.4 and footnote 289. Under the current TPM, charges may also vary considerably from year to year, depending on the timing of and contributions to, regional coincident peak demand in the measurement year.

269 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).

$ Million	Status quo	Benefit-based	Residual	Pre-cap Total	Cap impact	Capped Total	Total change
Generators							
Contact Energy	19.9	17.9	1.6	19.6	0.5	20.0	0.1
Genesis Power	5.3	6.0	1.0	7.0	0.2	7.1	1.9
KCE (Mangahao)	0.0	0.1	0.0	0.1	0.0	0.1	0.1
Mercury	0.0	4.7	1.3	6.1	0.1	6.2	6.2
Meridian	65.4	36.1	1.6	37.6	0.9	38.5	-26.9
Nga Awa Purua JV	0.0	1.3	0.3	1.6	0.0	1.6	1.6
Ngatamariki Geothermal	0.0	0.8	0.1	0.8	0.0	0.9	0.9
Nova	0.0	0.0	0.1	0.2	0.0	0.2	0.2
Southdown Generation	0.0	0.0	0.1	0.1	0.0	0.1	0.1
Southern Generation	0.0	0.0	0.0	0.0	-	0.0	0.0
Tilt Renewables	0.0	0.1	0.1	0.2	0.0	0.2	0.2
Todd Gen. Taranaki	0.0	0.3	0.0	0.3	0.0	0.3	0.3
TrustPower	1.7	0.8	0.1	0.8	0.0	0.9	-0.8
Tuaropaki (Mercury)	0.0	0.5	0.7	1.2	0.0	1.2	1.2
Whareroa Cogen. Ltd	0.0	0.04	0.4	0.4	0.0	0.4	0.4
Total	**92.3**	**68.7**	**7.4**	**76.0**	**1.8**	**77.8**	**-14.5**

$ Million	Status quo	Benefit-based	Residual	Pre-cap Total	Cap impact	Capped Total	Total change
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	0.6	0.0	0.6	0.0
Methanex	0.4	0.1	0.5	0.6	0.0	0.6	0.1
New Zealand Rail	1.0	0.2	2.3	2.5	(1.2)	1.3	0.4
Norske Skog	0.0	0.3	6.1	6.4	(5.1)	1.4	1.3
NZ Steel	2.2	2.2	9.1	11.3	(5.6)	5.7	3.4
NZAS	52.2	9.9	31.2	41.1	1.0	42.0	-10.2
Pan Pacific	1.1	0.6	4.2	4.7	(2.0)	2.8	1.6
Port Taranaki	0.010	0.002	0.013	0.015	0.000	0.015	0.005
Resolution Dev	0.004	0.002	0.015	0.017	(0.012)	0.005	0.002
Southpark Utilities	0.006	0.000	0.009	0.009	0.000	0.009	0.003
Winstone Pulp Int	2.2	0.3	1.9	2.3	0.1	2.3	0.1
Total	**60.6**	**13.8**	**56.2**	**70.1**	**-12.8**	**57.3**	**-3.3**

Aggregate total	**636.8**	**174.4**	**462.4**	**636.8**	**0**	**636.8**	**0**

Assumptions

16.15 The overall approach to modelling and key assumptions are explained in Appendix H of the 2019 Issues Paper.

16.16 For modelling purposes, the 2021/22 pricing year was chosen in 2018 as no implementation date had been decided then. This assumption has limited impact.[270]

16.17 Appendix A of this paper discusses the Authority's response to submissions on the modelling of charges and various adjustments to data and calculations made as a result.

16.18 The indicative charges for 2022 differ from those set out in the 2019 Issues Paper due to:

(a) minor tidy-up adjustments to data and calculations made in response to submissions, discussed in Appendix A

(b) the Commerce Commission's determination of Transpower's maximum allowable revenue (MAR) in the Regulatory Control Period 3.[271]

16.19 Transmission charges modelled (net of the loss rental rebate) cover only revenue currently recovered through the RCPD charge (an estimated $544m in 2021/22) and the HVDC charge ($93 million). Connection charges are not expected to change materially as a result of the 2020 guidelines and are thus not discussed any further.

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

16.21 We also assumed that Transpower makes no new major investments between 2019 and implementation. Where this assumption proves wrong and depending on the approach to implementation, benefit-based charges would rise for identified beneficiaries of the new investments and residual charges would adjust accordingly so that Transpower does not recover more than its maximum allowable revenue.

270 This assumption has limited impact as:

(a) Transpower's maximum allowable revenue is smoothed [SMAR increases from $798.8m in 2021/22 to $809m (+1.28%) for 2022/23 and $819m for 2023/24 (+1.24%)].

(b) rising revenues will alter both the status quo and proposed charges, so the choice of year only has a marginal impact linked to the rebalancing of charges.

For designated transmission customers whose charges would increase, the average impact of going from 21/22 to 22/23 MAR is less than $25,000, well within acceptable margins of error of estimates, given the indicative nature of the charges.

271 Commerce Commission 2019, *Transpower Individual Price-Quality Path from 1 April 2020*, companion paper to final RCP3 IPP determination and information gathering notices, available at www.comcom.govt.nz. This reduces the benefit-based and residual charges to be recovered from an estimated $679.1m to $636.8m in 2012/22 (net of an estimate of the loss and constraint excess rebate).

Impact by transmission customer group

16.22 Table 5 sets out the key reasons for changes in charges above by broad customer group.

Table 5 Summary analysis of changes in charges by broad customer group

Customer group[272]	Explanation
North Island generation	The share of transmission charges **rises** from around 1% to 3%. Benefit-based charges are assigned in line with North Island generators' share of benefits from grid investments. Currently, North Island generation pays no interconnection charge (except as consumers).
South Island generation	The share of transmission charges **falls** from around 13% to 9%. HVDC costs, currently paid 100% by South Island generators, would be shared with other beneficiaries — e.g. North Island customers benefit from access to South Island generation; North Island generators benefit from the HVDC link during dry periods, as do South Island distributors and the smelter. South Island generators' benefit-based charges would include an increase to account for 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** from around 28% to 30%. The increase in transmission charges would reflect the significant benefits to this region from the seven major pre-2019 investments. Their moderate 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** from around 28% to 27%. This group of distributors attracts just 12% of charges related to the seven major pre-2019 investments. But this group would attract a relatively high share of residual charges, reflecting their high share of electricity consumption compared to other regions. Residual charges (based on gross demand) increase charges for networks with distributed generation, as the RCPD charge is currently based on net demand.
South Island distributors	The share of transmission charges **rises** from around 20% to 22%. South Island distributors' transmission charges would rise because in general they are peaky users compared to other groups. Residual charges (based on gross demand) increases charges for the networks with distributed generation such as Waitaki, Westpower and Tasman.
Major industrials	The share of transmission charges **falls** from around 10% to 9%. Charges reduce for the Tiwai Smelter. Transmission charges rise for North Island based firms such as NZ Steel, Norske Skog and Pan Pacific. Significant support is provided by the price cap to protect against price shock and inefficient exit by firms. The cap will progressively lift for this group of customers.

272 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.

Effect of the transitional cap on transmission charges in 2022

16.23 To reassure household and businesses that they will not experience electricity bill shocks, the 2020 guidelines provide for a cap on transmission charges so total electricity bills do not rise need to rise by more than 3.5% as a result of a new TPM consistent with the proposed guidelines.

16.24 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. Chapter 13 discusses the Authority's decision on the cap and its response to submissions on the cap.

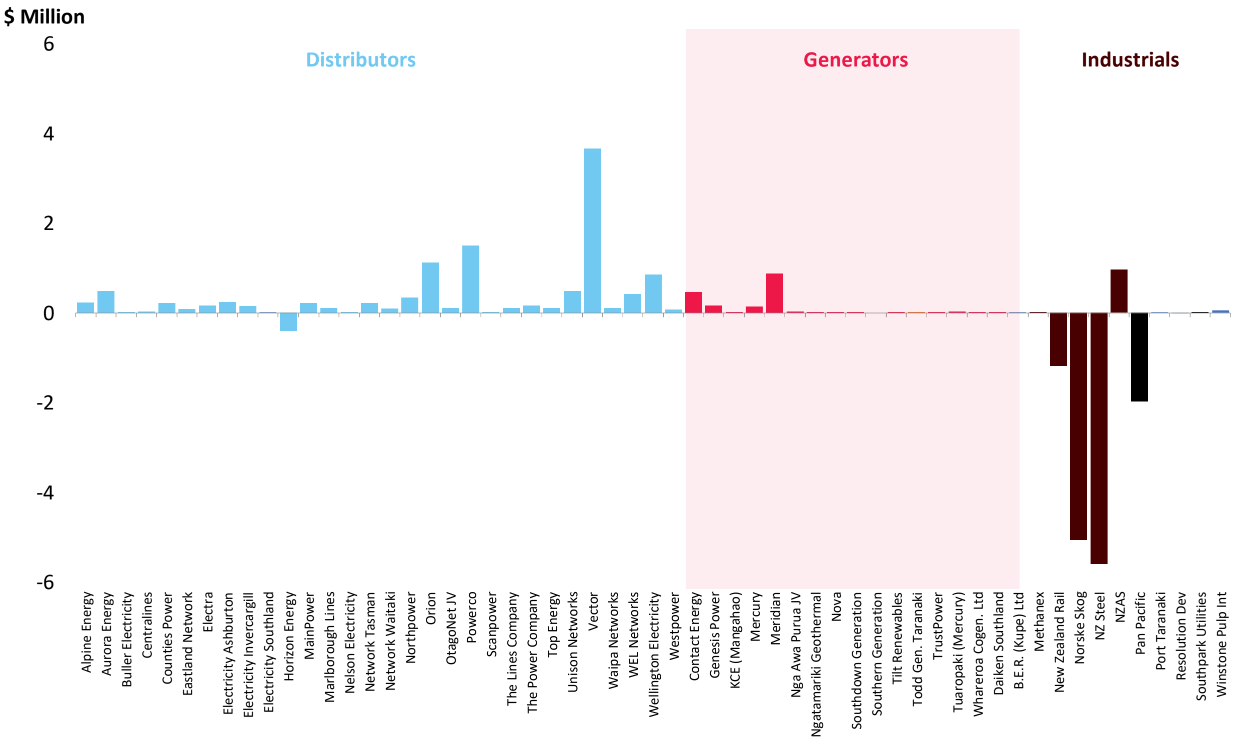
16.25 The cost of this cap is $14.2 million, or 2.2% of total charges of $636.8 million. It would be spread among other distributors, generators and direct-connect customers, with the share determined on the basis of their total charges.

16.26 Before the Commerce Commission determined to reduce Transpower's maximum allowable revenue, the Authority had estimated the cap would be in effect to support consumers of Buller Electricity, Westpower and Horizon Energy. This limited need for protection from price shocks reflects the modest impact of the Authority's approach.

16.27 Following the reduction in Transpower's MAR the price cap is likely to apply to just one distributor — Horizon. Given the extent of local generation, Horizon currently pays low transmission charges relative to other networks. Their indicative charges under a new TPM would come up to be similar to other networks on a $/MWh basis, but the increase is such that the cap applies even after the reduction in MAR.

16.28 Five direct-connect industrial customers would receive significant support from the cap. These customers currently pay little, if any, transmission charges, as they have responded to current incentives. Their charges would rise materially under the 2020 guidelines as shown in Table 4. The cap provides for a transition and will progressively lift after five years for this group of customers so that they would pay full charges in future.

Figure 13 Indicative contributions to, or support from, the cap in 2022



16.29 We discussed the impact on residential electricity consumers at paragraph 16.3.

Benefit-based charge allocation in 2022

16.30 The benefit-based charge would initially cover the depreciated value of the seven recent, major investments listed in Schedule 1 of the 2020 guidelines. In 2022 the combined amount charged for these investments is estimated to be $174.4 million.

16.31 Figure 14 illustrates these Schedule 1 allocations. The coloured circles give a sense of the spread or concentration of benefits by designated transmission customer.

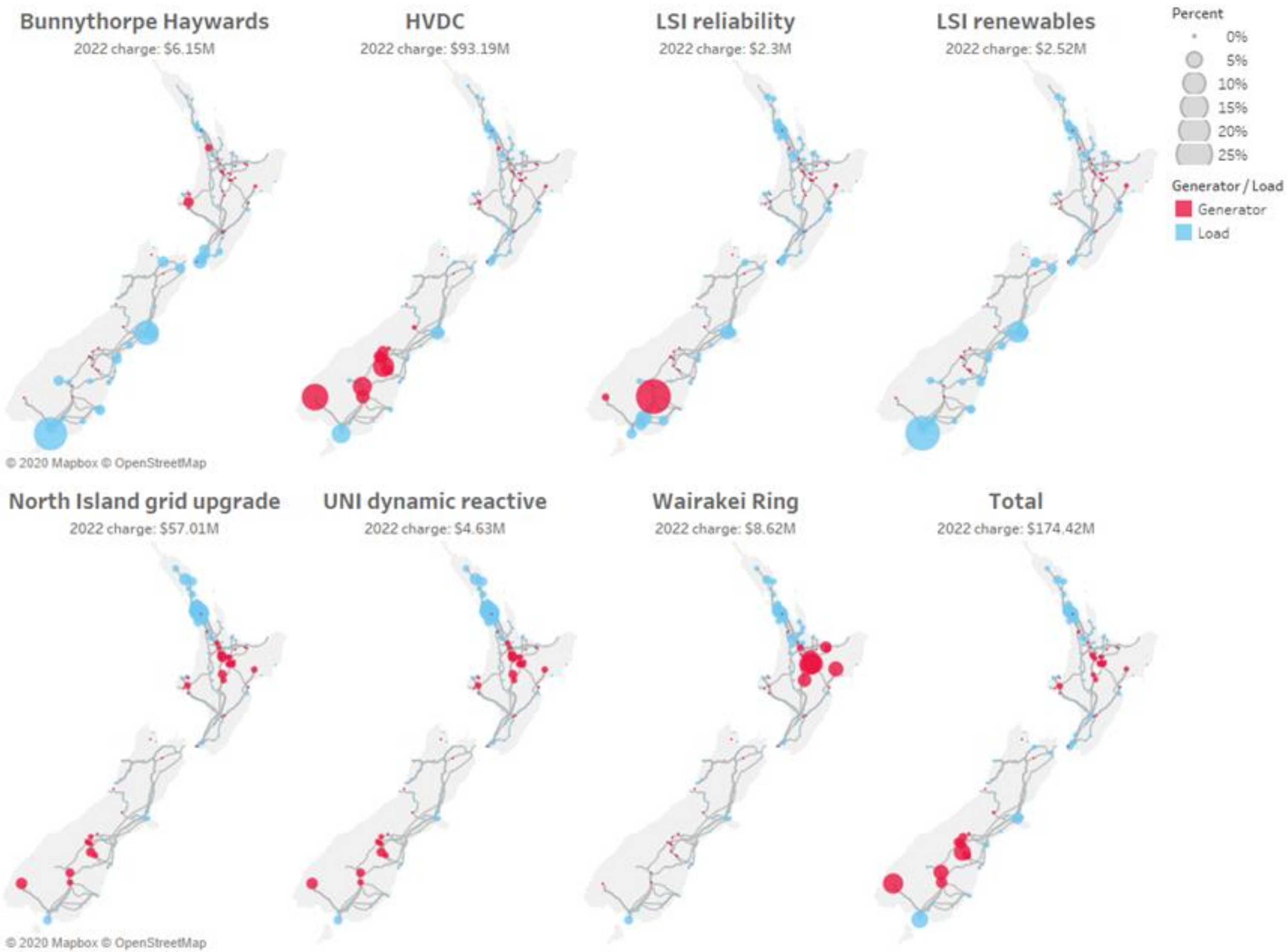
16.32 Table 6 summarises the current estimate of what the annual total charge would be for each of these seven investments in 2022 and the general rationale for each allocation. (The modelling methods and assumptions are explained in Appendix H of the 2019 Issues Paper.)

16.33 Over time, an increasing share of transmission charges will be allocated via the benefit-based charge as historical grid assets depreciate and new transmission investments are made or assets are replaced or refurbished (offset by depreciation).

Table 6 Allocation of benefit-based charges for seven historical investments

Investment	Comment
North Island Grid Upgrade (Charge is $57m in 2022)	Assessed benefits of $84m per year to distributors in Upper North Island through lower electricity prices and improved reliability. North and South Island generators are also assessed as benefitting ($36m per year) from access to Upper North Island markets.
HVDC (Charge is $93m in 2022)	Assessed benefits of $901m per year. Approximately 50% of benefits are to South Island generators through access to higher prices in the North Island. The balance of benefits is spread across North and South Island consumers. South Island consumers benefit from the HVDC when South Island lake levels are low.
UNI dynamic reactive support (Charge is $4.6m in 2022)	Beneficiaries deemed to be the same as the North Island Grid Upgrade beneficiaries.
Wairakei ring (Charge is $8.6m in 2022)	Benefits assessed as $220m per year, mainly to Central North Island generators and Upper North Island consumers, because the investment improves access to the Upper North Island market.
LSI renewables (Charge is $2.5m in 2022)	Benefits assessed as $20m per year, mainly to Lower South Island consumers due to better access to generation than without the investment.
Bunnythorpe-Haywards (Charge is $6.2m in 2022)	Benefits assessed as $31m per year. South Island consumers are the major beneficiaries of Bunnythorpe-Haywards because the investment facilitates delivery of electricity southward when South Island lake levels are low. Accordingly, their share of charges for this investment would be 67%.
LSI reliability (Charge is $2.3m in 2022)	Benefits assessed as $8m per year. South Island generation and consumers in general are the main beneficiaries of LSI reliability.

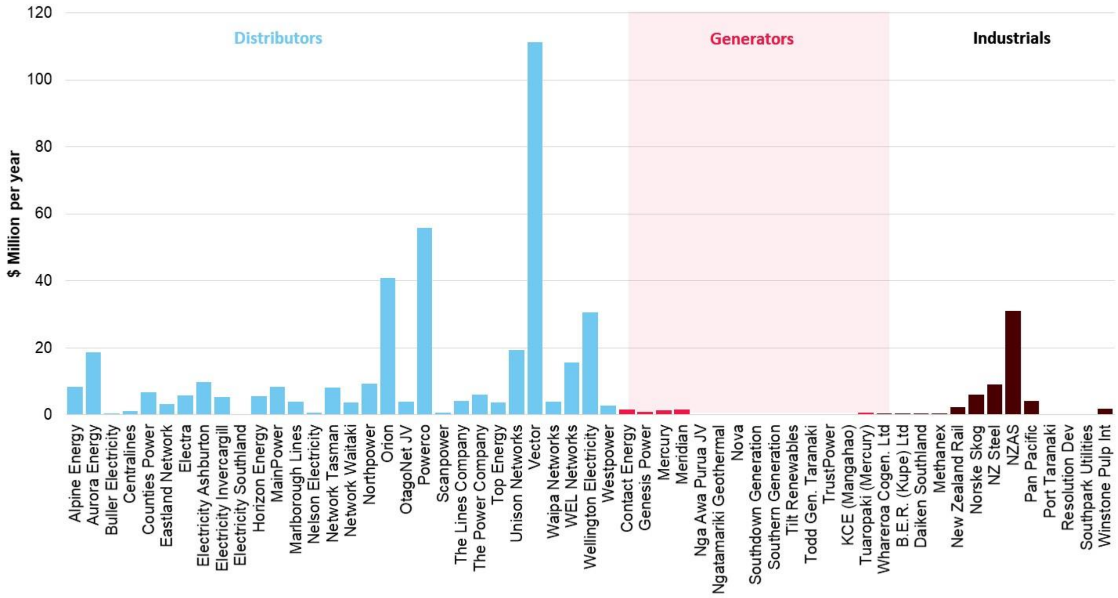
Figure 14 Schedule 1 allocation of benefits (percentage of total benefit-based charge) for seven recent major transmission investments



Residual charge allocation in 2022

16.34 Figure 15 illustrates the allocation of the indicative residual charge. The allocation reflects customers' average anytime maximum demand over the four years to 2017/18.

Figure 15 Indicative residual charge per transmission customer ($m for 2022)

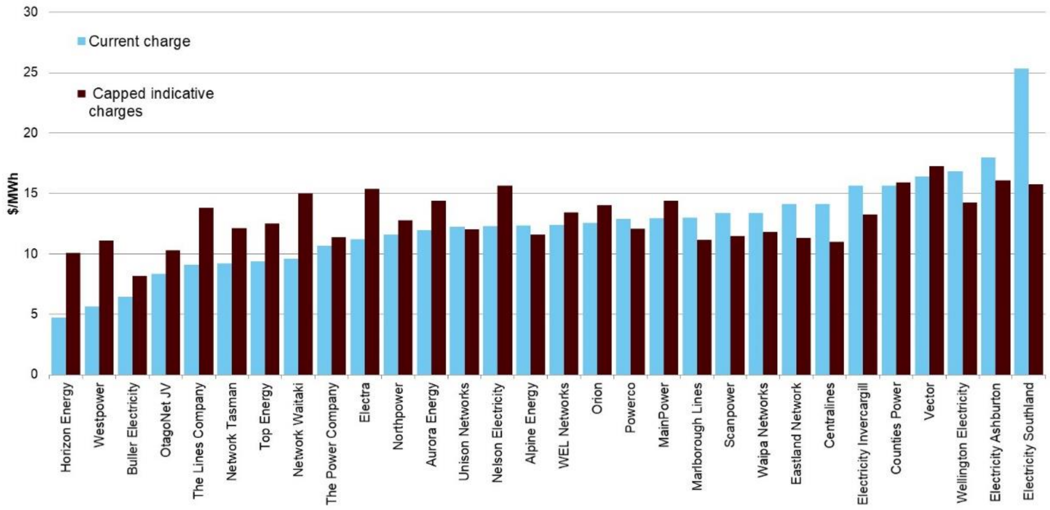


16.35 The difference in charges shown reflect differences in demand by transmission customer. For example, when charges are expressed on a $ per total MWh of demand basis, these differences are much reduced, for distribution networks.[273]

(a) some distributors' charges (such as Westpower's or Horizon Energy's) are currently relatively low as local generation helps to reduce their RCPD charges

(b) Electricity Southland sees a relatively large reduction in its charges on a $/MWh basis, because a doubling in its electricity consumption (e.g. due to factors such as winter tourism) over recent years increased its interconnection charges.

Figure 16 Transmission costs in $/MWh for residential consumers, 2022



273 This measure is much more variable for generators and large industrials. For example, residual charges are low for generators that can experience very high peaks compared to annual use and thus their $/MWh can be very high compared to distribution networks. The same is the case for industrial customers such as NZ Rail.

17 Next step: developing a proposed new TPM

17.1 The Authority must set the process for the development of a proposed new TPM.[274]

17.2 This chapter contains the Authority's decision on that process. The Authority confirms 30 June 2021 as the date by which Transpower must submit a proposed new TPM to the Authority for review. Box 1 sets out this decision.

17.3 The Authority will, in early June 2020, issue a request for Transpower to submit a proposed new TPM within this timeframe.[275] An earlier submission will be welcomed.

17.4 The reasons for this decision on the process, including a thematic summary of submitters' views, follow. For completeness, the steps following Transpower's development stage are also described. The Authority anticipates a 12-month development timeframe (if development starts on 1 July 2020) will mean new transmission prices consistent with a new TPM will apply from 1 April 2023.

17.5 Transpower will then develop a proposed new TPM in accordance with the process and timeframe the Authority has published. 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

(c) the published guidelines.

Box 1: The Authority's decision on process and timeframe for the development of a proposed new TPM consistent with the 2020 guidelines

The process

Transpower's development of the proposed new TPM must include the following steps:

- identify options for a method for setting each required new charge
- assess which of the additional components better meet the Authority's statutory objective and should therefore be included in the proposed TPM
- identify options for a method for any additional components that will be included
- select and develop a preferred option for each charge proposed to be introduced
- calculate indicative prices to show the impact of the proposed TPM on transmission customers
- show how the proposed TPM meets the requirements in Clause 12.89(1)
- confirm the proposed TPM is workable, and scope the implementation, ongoing operational costs, and timeline for implementation.

The proposed TPM must include indicative prices to allow its impacts to be understood.

Transpower must share its up-to-date project timeline (an overview of planned project steps and timings) for the development of a proposed TPM with the Authority before or on 1 August 2020 and at the commencement of each of the two checkpoints. The Authority may provide feedback on Transpower's project timeline.

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274 Electricity Industry Participation Code 2010 Clauses 12.81(1)(a) and 12.83(a).

275 Code Clause 12.88.

Box 1 *(Continued)*

Checkpoints

There will be two checkpoints with requirements for both Transpower and the Authority. Some flexibility is allowed on the timing of each checkpoint to enable Transpower to follow its own preferred internal processes. The checkpoints are:

Checkpoint 1: initial analysis for benefit-based charge and any transitional congestion charge

Between 1 September and 1 October 2020, so two to three months after 1 July 2020 and at least 7 weeks before releasing any written paper on options to stakeholders, Transpower must provide the Authority with a written summary describing its initial analysis towards a proposed TPM, focussing on key design choices (under consideration and currently preferred) for allocation methods for the benefit-based charge and any transitional congestion charge.

- By three weeks later, the Authority will provide any feedback on Transpower's summary and may advise whether it is likely to approve a proposed TPM based on the currently preferred options, if these are submitted within a proposed new TPM, or whether it would be likely to seek any revisions.
- If requested by the Authority, by six weeks later, Transpower would provide a revised written summary, incorporating the Authority's comments.
- If a revised summary is provided, the Authority may, by three weeks later, provide feedback on whether it supports the revised proposed approach.

Once Transpower has made any consequent changes to take into account the Authority's feedback, it will be able to proceed with any stakeholder engagement it is planning.

Checkpoint 2: a preliminary draft of a proposed new TPM

Between 1 February and 1 March 2021, so seven to eight months after 1 July 2020 and at least 6 weeks prior to any second stakeholder engagement on a proposed new TPM Transpower plans to undertake, 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 any transitional congestion charge.

- By three weeks later, the Authority may provide feedback on Transpower's preliminary draft.
- If requested by the Authority, by six weeks later, Transpower would provide a revised draft, incorporating the Authority's comments.
- If a revised draft is provided, the Authority may, by three weeks later, provide feedback on whether it supports the revised draft or whether it seeks any further revisions.

Once Transpower has made any consequent changes in response to feedback from the Authority, it will be able to proceed with any further stakeholder engagement it wishes to undertake.

Stakeholder engagement

Transpower is not to engage with stakeholders on policy matters that have already been covered in the Authority's consultation on its proposed guidelines; rather, its engagement should concern detailed matters of TPM development within the guidelines set by the Authority.

Transpower must design the scope and duration of any engagement with stakeholders to ensure that the deadline for submission of a proposed TPM is achievable.

The timeframe

The date by which Transpower must submit its proposed TPM to the Authority is 30 June 2021. An earlier submission will be welcomed.

What we proposed, submitters' views and our assessment

17.6 This section contains the reasons for the Authority's decision on process, checkpoints and timeframe, including a summary of submitters' views.

The process

17.7 Some submitters stated that, given the urgency of reform, the Authority should publish a prescriptive process for Transpower to follow in developing a new TPM. Others said the timeframe for Transpower to implement the guidelines needed more flexibility to allow for insights and problems that arise.

17.8 The Authority's decision on process is consistent with the proposed process set out in chapter 6 of the 2019 Issues Paper.

Checkpoints during TPM development

17.9 The 2019 Issues Paper proposed checkpoints during the development process[276]: for Transpower to first present the Authority with its emerging analysis, and then a preliminary proposed TPM for the Authority to consider. If, in the Authority's view, the TPM proposal is not developing in a manner consistent with the 2020 guidelines and other requirements of clause 12.89(1), the Authority can then ask Transpower to amend its developing TPM to be consistent with Authority comments.

17.10 Ngāti Tūwharetoa Electricity suggested Transpower should come back to the Authority with a final design at least three months prior to proposed design confirmation. Rio Tinto thought checkpoints during the development of the TPM should "ensure that Transpower makes timely progress in the development of the TPM and eliminate the risk that Transpower develops a TPM proposal that would not be approved by the Authority. This reduction in risk should flow through to significantly reduced approval and implementation time periods."[277]

17.11 Entrust submitted the proposed checkpoints — at which Transpower would formally engage with the Authority — would be more appropriate as requirements for Transpower's engagement with customers and stakeholders.

17.12 The Authority's decision on checkpoints is similar to its proposal in the 2019 Issues Paper:

(a) the nature of each checkpoint remains the same

(b) the timing of checkpoints has been altered to fit a 12-month timeframe and made flexible to ensure the formal Transpower–Authority engagement can occur at appropriately timed stages.

17.13 This engagement will ensure Transpower's proposal is well-aligned with the 2020 guidelines and so is more likely to elicit the Authority's approval.

Engagement with stakeholders during TPM development

17.14 The 2019 Issues Paper noted that "The Authority envisages that Transpower would also engage with industry stakeholders at various points in the development of its proposed TPM."

17.15 With respect to formally consulting on the proposed TPM itself, only the Authority is required by Clause 12.92 of the Code to publish and consult on the proposed TPM. Nevertheless, submitters commented on, and generally supported, the desirability of Transpower also engaging as it is developing the proposed TPM.

17.16 Transpower expressed that consultation on the guidelines does not equate to engagement on design choices to be made when developing the TPM (p 6, 291-3).

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276 *2019 Issues Paper* chapter 6, 6.13–6.16.

277 Rio Tinto p 27.

Transpower saw constructive and highly engaged stakeholder participation key to a successful development and implementation of any new TPM: "strong engagement with our stakeholders would save time and work in the end." Transpower prefer to retain flexibility over how they will consult: "We do not consider the Authority should set requirements for how and when Transpower engages with its customers and other stakeholders (other than the Authority checkpoints)."

17.17 Other submitters agreed Transpower should consult (Buller p 2 and Mercury p 9). Some considered there should be full consultation throughout the development of the proposed TPM (Entrust p 5 and NZAS p 30). Contact submitted that establishing an industry working group would be appropriate (Contact p 1). In contrast, Meridian suggested that whatever length of time is given for Transpower to develop the TPM, additional informal engagement by Transpower with stakeholders is not likely to be useful (Meridian p 43).

17.18 Given the requirement for the Authority to consult on the proposed TPM prior to amending the Code, we do not see a need to mandate additional consultation during the development of the TPM. We note also that there is nothing in the guidelines to prevent Transpower undertaking such additional engagement with stakeholders as it sees fit, provided it meets the timeframe the Authority has determined for TPM development.

17.19 The Authority's preferred approach is consistent with Transpower's February 2017 submission: that it expects its engagement with stakeholders during development of 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."[278]

Timeframe for TPM development

17.20 The time period in the Code for Transpower to produce a proposed TPM is 90 days, or such other time as the Authority allows.[279]

17.21 The 2019 Issues Paper indicated that the process should require Transpower to submit its draft TPM to the Authority by a set date, which, indicatively, would be somewhere between 12 and 18 months after the date the guidelines are published.

17.22 Following submissions, a wide range of options have been considered. Retaining the 90-day timeframe was considered, alongside options for submission dates that allow a proposed development duration of six months, 12 months, 18 months or longer. Staged development or dual track options (developing different components of the TPM to different submission dates) were also considered.

17.23 In arriving at a decision on timeframe, the Authority has considered how best to balance a number of potential trade-offs. These include the expected timing of consumer benefits, ensuring Transpower has sufficient time for its own analysis and internal processes, creating regulatory certainty for stakeholders (which will be affected by perceived risk to the development timeframe as this affects the expected commencement date) and the likely acceptability of a process and timeframe to stakeholders.

17.24 A key consideration mentioned in many submissions on the 2019 Issues Paper's discussion on development timeframe is that Transpower should have adequate time to engage with stakeholders as it develops the TPM. Powerco thought the timeframe for Transpower needed enough flexibility to allow for insights or problems that arise during the process. Other submitters have told us the 2019 indicative timeframe for Transpower to develop pricing is ambitious or should be longer.[280] For example, Nova has suggested a

[278] Transpower's submission to the *second Issues paper*, *Supplementary Consultation February 2017*, section 5.3.2.

[279] Code Clause.12.88(1).

[280] Buller, ENA, Entrust, IEGA, Mercury, Pioneer. KCE and the TPM Group stated more time could be taken because there were no material net benefits for almost a decade.

minimum of two and a maximum of three years. Transpower submitted that 18 months would be ambitious and very challenging, and that they would be more comfortable with 24 months (p 10), and in its cross-submission stated 12 months was not practicable.

17.25 Meridian and Rio Tinto stated a shorter timeframe to develop a new TPM would be beneficial — to reduce the current regulatory uncertainty. Given the time that has already elapsed on TPM reform, Rio Tinto proposed cutting two years from the indicative timetable that we published in 2019.

17.26 Ngāti Tūwharetoa Electricity also suggested that approximately 12 months should be allowed for Transpower to complete its development and finalisation as “this is sufficient time to design in consultation with customers and stakeholders but short enough to have to get on with it”, with a further 12 months’ notice given to customers and stakeholders before a new TPM takes effect.

17.27 The Authority anticipates that Transpower would require longer than 90 days to complete the above process. Whilst the Authority’s strong preference is to achieve commencement in 2022 and believes a six-month development of the TPM should be feasible, upon consideration of stakeholder feedback, 30 June 2021 has been adopted as the latest permissible submission date. The Authority anticipates this will allow new prices to take effect on 1 April 2023. An earlier submission will be welcomed.

17.28 Reasons for this decision include that a 30 June 2021 submission date:

(a) will be feasible for Transpower and allows for engagement by Transpower during development

(b) allows sufficient buffer (so remaining on track for a 1 April 2023 commencement date) to facilitate the 20-working day period should the Authority, at its review stage, choose to refer the proposed TPM back to Transpower.

17.29 The benefits of the new TPM would begin immediately in relation to how users engage with Transpower on costs and investment decisions and strengthen over the year beginning 1 July 2021.

17.30 Compared to shorter options for a development timeframe (aiming for 2022 commencement), this option also:

(a) supports more coherent grid users’ responses to changes in grid usage incentives, as users would have a good indication of the basis for charges by winter 2022. This timing will also allow consultation on an exposure draft of the new TPM ahead of winter 2022. Benefits related to decisions on grid use can be expected to begin to flow during 2022, in the year preceding the commencement of the new TPM

(b) will be feasible for Transpower to achieve (also allowing for stakeholder engagement) and so offers more regulatory certainty regarding the commencement date. Once stakeholders know the TPM is coming, their behaviour can be expected to change, including:

(i) increased scrutiny of new capex proposals by expected beneficiaries

(ii) reduced investments by load customers for the purpose of shifting RCPD charges

(iii) improved investments by load and generation (e.g. whether to reinvest in ripple-control, how to size diesel back up, whether to embed).

The expected commencement date is 1 April 2023

17.31 A firm commencement date (for new TPM prices) cannot yet be stated, as this will be confirmed at the same time as the Code is amended to incorporate the new TPM. However, the Authority expects a 12-month development timeframe will lead to rebalanced transmission prices commencing on 1 April 2023.

17.32 Figure 17 illustrates the expected process stages, following publication of the 2020 TPM guidelines. After a proposed TPM is submitted and the Authority's subsequent review, Transpower must calculate, implement and publish new transmission prices. These new prices will take effect from 1 April (the start of the pricing year) following publication. The project timeline shown is assumed: Transpower will set its own project schedule.

Figure 17 Post guidelines, a possible timeline towards commencement of a new TPM

JUL 2020	JULY 2021 *	APR 2022	SEP 2022 **	LATE NOV 2022	APR 2023
TRANSPOWER **Develop proposed TPM**	AUTHORITY **Code Review including consultation**	TRANSPOWER **Calculation and implementation**	TRANSPOWER **Assurance and audit**	TRANSPOWER **Publish prices**	**New prices start**

Notes:

* The Code Review stage includes a contingency month in case the Authority refers the proposed TPM back to Transpower, in which case Transpower would need to resubmit.

** The timeline assumes (but does not show) some overlap in stages (for example, assurance could start prior to the completion of the calculation and implementation stage.

17.33 For completeness, this section describes the stages following Transpower's development of a proposed TPM:

(a) Once Transpower has submitted the proposal, the Authority may:

(i) decline to consider the proposed TPM if, in its view, Transpower has not provided sufficient information for the Authority to assess the matters required by the Code and inform Transpower of the further information required and specify a date by which the revised TPM must be submitted [281]

or

(ii) consider the proposed TPM, after which the Authority may:[282]

1. approve the proposed TPM where the Authority considers that it is consistent with the requirements set out at paragraph 17.5 above or

2. refer the proposed TPM back to Transpower if, in the Authority's view, it does not adequately conform with the requirements set out in paragraph 17.5 above, in which case Transpower will have 20 business days to consider and resubmit the proposed TPM. If the resubmitted TPM still does not conform with those requirements, the Authority is then able to make any amendments it considers necessary to make the proposed TPM conform.

(b) Once the Authority is satisfied the proposed TPM conforms with the requirements of clause 12.89(1), it must publish and consult on it.[283]

281 Clause 12.90.

282 Clause 12.91.

283 Clause 12.92.

(c) After consideration of submissions, the Authority will then consider whether to incorporate the TPM into the Code (which may entail some amendments as a result of the Authority's consideration of submissions on the proposed TPM).[284] Where the Authority determines to include the TPM in the Code, it must also determine, after consultation with Transpower, the date on which the TPM must take effect.[285]

(d) After an Authority decision to incorporate a new TPM into the Code, Transpower alters its processes to calculate new transmission prices and implement the new TPM.

(e) After carrying out its own internal assurance processes Transpower must then publish transmission prices consistent with the TPM.[286]

(f) The system goes into operation (commences) at the start of the next pricing year. Transpower may only charge for transmission services in accordance with the approved TPM.[287]

Deferral of implementation of certain aspects of the TPM

17.34 Clauses 66 to 68 of the 2020 guidelines provide for implementation of certain aspects of the TPM (additional components and the benefit-based charge for low-value investments) to be deferred in order to expedite implementation of the more important parts. These clauses are essentially the same as proposed in 2019.

17.35 Some submitters (e.g. Winstone Pulp International) argued against deferring the implementation of the charges for low-value post-2019 investments, as – with the Authority's proposal for a simplified methodology – a delay is not needed. Other submitters (e.g. Nova) submitted that that deferral should be allowed only to the extent to which priority needs to be given to applying the benefit charge on the large investments.

17.36 The Authority considers the likelihood of a delay being required is reduced, given that the 2020 guidelines allow for a simple approach in the case of low-value investments. However, the guidelines allow deferral only if it is necessary (consistent with Nova's submission above). In our view, this position is consistent with the long-term benefit of consumers as it may facilitate faster implementation of the benefit-based charge for new high-value investments. That should achieve the related efficiency gains more quickly. Any deferral would not be excessively long, as the guidelines state that these charges must be implemented within five years of the commencement of the TPM.

Note: Potential Code amendments

17.37 The 2019 Issues Paper discussed (in Appendix F) some potential Code amendments on related matters including allocation of loss and constraint excess (LCE), the avoided cost of transmission (ACOT) provisions in Part 6 of the Code and an amendment to ensure workability of the TPM.

17.38 The Authority is not yet proposing to make these Code amendments and they are not considered further in this paper. Subject to consideration of submissions received on these topics, we expect to consult on whether to adopt the Code changes (if the Authority considers them necessary) alongside the proposed TPM to be developed by Transpower.

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284 Clause 12.93.

285 Clauses 12.93 and 12.94.

286 Clause 12.96.

287 Clause 12.95. This provision exempts input connection contracts, new investment agreement contracts and notional embedding contracts from this requirement.

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

Appendix A Modelling of indicative transmission charges

Our decision

A.1 Schedule 1 of the 2020 guidelines specifies the share that each customer pays for the seven historical investments that are initially included in the benefit-based charge.

A.2 These shares and the basis for the indicative charges are largely unchanged from what was proposed in 2019, apart from some minor tidy-up adjustments in response to submissions on data and calculations. [288]

What we proposed

A.3 The 2019 Issues Paper contained an estimate of transmission charges and their incidence under the Authority's 2019 proposal.

A.4 It compared charges under a TPM consistent with the proposed guidelines with the status quo for the 2021/22 pricing year. The year was selected noting no decisions had been made about the implementation date. The impact of a later implementation on the charges would not materially impact the indicative charges.[289]

A.5 The charges are also indicative as they are subject to Transpower's proposal for a TPM that is consistent with the 2020 guidelines. One exception to this is the modelling of the allocators for the remaining costs of seven historical investments. Each customer's share of the annual benefit-based charge for each of these investments is specified in Schedule 1 of the 2020 TPM guidelines.[290]

A.6 The 2019 Issues Paper proposed the following approach to determining the benefit-based shares in Schedule 1 and the indicative impacts on charges by customer:

(a) use of the vectorised Scheduling, Pricing and Dispatch (vSPD) tool and associated assumptions about virtual price offers and annual sensitivities to estimate benefits for the benefit-based charge

(b) use of Reconciliation Data and detailed methodology to calculate the residual based on gross Anytime Maximum Demand (AMD)

(c) a detailed methodology and selection of data sources for calculating the cap.

A.7 The methodology is documented in Appendix H of the 2019 Issues Paper.

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288 The vSPD modelling underpinning the Schedule 1 allocators is available at: https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper

The modelling of indicative charges and the adjustments discussed later in this section is available at: https://github.com/ElectricityAuthority/tpm-impacts-model

289 This is because Transpower's maximum allowable revenue is smoothed. The SMAR increases from $798.8m in 2021/22 to $809m (+1.28%) for 2022/23 and $819m for 2023/24 (+1.24%). Increasing revenue will alter both the status quo and proposed charges, so the choice of year only has a marginal impact from the effect of rebalancing. For customers whose charges are rising, the average impact is less than $25,000. Base year data 2019/20 was the most recent available year, sourced from Transpower Information Disclosure Schedules F1-6, G1-8, SO1, Disclosure Year, 30/6/2018, sheet F6 titled revenues, 'Current Year+2' (forecast year), being the pricing year to March 2020. Charges were scaled to maximum allowable revenues.

290 Charges will change when Transpower includes new investments in the benefit-based charge.

Submitters' views and our assessment

A.8 The Authority received submissions related to points of modelling methodology and specifically on:

(a) the use of the vSPD model for identifying beneficiaries and calculating the initial benefit-based charge, in particular;

(i) whether vSPD is an appropriate tool for identifying beneficiaries

(ii) inputs and assumptions used, specifically the virtual price offer (VPO) assumptions, the timeframe for analysis and the treatment of disbenefits

(iii) a concern that results are volatile

(iv) a concern that results are not intuitive

(v) the need to account for reliability and resilience

(b) the suitability of calculating gross AMD by point of connection and customer, compared to other options

(c) adjustments to allocators and charges, given data and calculation issues.

Use of vSPD model to calculate benefit-based allocators

A.9 The Authority used the vSPD tool to approximate customers' benefits from seven historical transmission investments. It used generation, demand and price data, from July 2014 to June 2018, reasoning that the distribution of benefits over a recent historical period is a reasonable proxy for future benefits and their distribution.

Use of vSPD is appropriate

A.10 Fonterra submitted that vSPD disincentivises renewables because vSPD generator benefits are measured as the difference between the offer price and the settlement price (times volume), so renewable generators that offer in at a low SRMC would typically benefit more than other generators. We disagree with this view:

(a) there is an important distinction between renewables and intermittent generators. Non-intermittent renewable generators typically have traditional offer tranches

(b) most intermittent generators are classified as distributed generation and therefore do not attract benefit-based charges. Their generation is netted off against load in their network, reducing that networks benefit-based charge

(c) there are a small number of intermittent generators that are grid-connected (e.g. Trustpower's Tararua Stage 3 windfarm and Meridian's West Wind). These generators offer in at low rates compared to baseload generators, although their generation is less likely to occur during peak times when most of the benefits occur (because without the investment in place the grid is more likely to be constrained)

(d) a low offer generator may attract greater benefits, but these benefits will occur in both the factual and counterfactual cases (with and without the investment). Testing showed benefits typically cancel out and for these generators are instead among some of the lowest per unit of generation.

A.11 Genesis, Trustpower and Mercury submitted that vSPD does not consider market behaviour as generator offers in the model do not change in response to changed market conditions, such as constraints caused by removing an investment from the network. Genesis submitted the Authority should consider adopting a dynamic model.

A.12 While the Authority can see the advantages of a dynamic model, it would be considerably more complex than vSPD as such a model would need to predict changing generator offer behaviour in response to transmission constraints every half hour across some 250 nodes. The Authority considers that:

- the cost of such additional complexity is not justified by the additional insights for determining allocators for historical investments these need to be approximately and not necessarily precisely, right to achieve their efficiency benefits
- modelling scenarios and sensitivities provide reassurance that the allocators are reasonable.

A.13 The methodology the Authority used with respect to seven historical investments does not preclude Transpower from developing alternative approaches in identifying the beneficiaries of future investments.

A.14 Entrust submitted that the vSPD tool overstates consumer surplus and understates producer surplus. Norske Skog submitted that vSPD is not configured to incorporate dispatchable demand.

A.15 The Authority recognises the model does not account for demand response when in the model a transmission investment is not in place, causing constraints. This will overstate consumer surplus and understate generator benefits. We addressed the absence of demand response through our Virtual Price Offer (VPO) assumptions (see below) and through capping infeasibilities at $10,000/MWh.

vSPD modelling inputs and assumptions — timeframe for identifying benefits

A.16 Some submissions questioned the Authority's use of four single year scenarios (2014–2018) to approximate future benefits:

(a) Trustpower submitted the timeframe was not sufficient and that benefits should be based on expected future benefits over the life of investments

(b) Mercury submitted the Authority should include a fifth year, being 2018/19, to see if that led to material differences

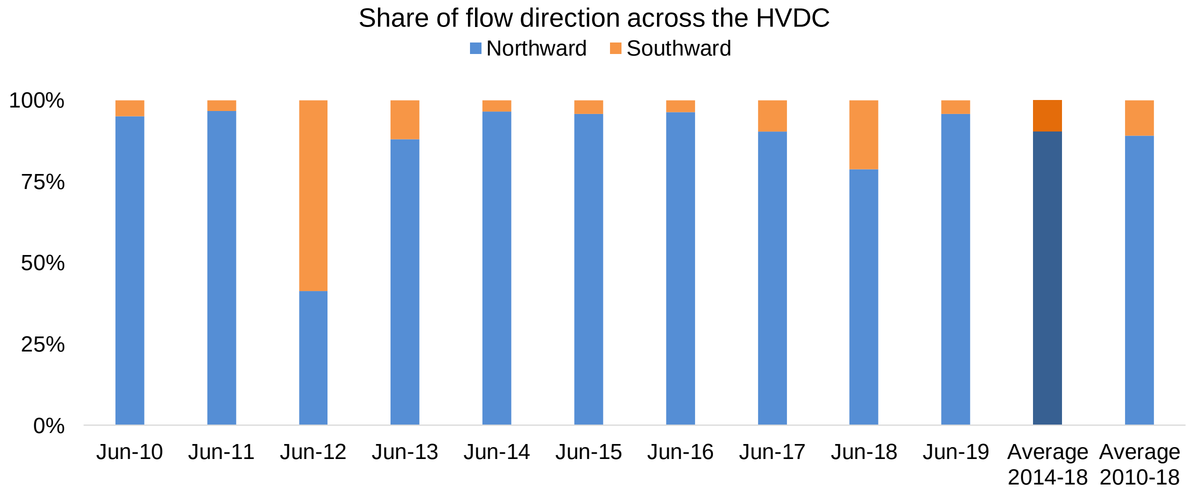
(c) Network Waitaki submitted that the four-year timeframe was not representative of the typical range of benefits over the long-term

(d) Rio Tinto suggested the Authority should calculate benefits over ten years, or use one dry year and four (instead of three) wet years, instead of the years it chose.

A.17 We consider our selection of data points is appropriate. It uses the four most recent years available at the time and for these years the mix of northward versus southward volumes is similar to that observed over the past 10 years.

A.18 Customer benefits from transmission investments are highly correlated to the net HVDC flow direction. For example, when flows are northward over the HVDC, Upper North Island load and South Island generation benefits from the HVDC, whereas when flows are southward, South Island load and North Island generation benefits from the HVDC (see Figure 18).

Figure 18 Net flow direction across the HVDC over 10 years



Treatment of disbenefits

A.19 The Authority's approach to estimating benefits was to take the most recent year of data available; if the year showed a disbenefit overall to a customer, the allocation was set to zero (as by design customers should not get a rebate). This was repeated for three other recent years that reflected different but typical market conditions. A simple average of these scenarios was taken to calculate representative benefit allocators. That is, each year has a 25% weighting in the calculation of the benefit-based charge allocator.

A.20 NZAS and Network Waitaki suggested the benefits and disbenefits should be assessed and netted over the four years (or more) of data combined. This way disbenefits in any year would fully offset benefits in others, rather than be set to zero. This reduces net benefits. As benefits are highly correlated to HVDC flow direction and quantity, the effect of adopting that approach would be a significant reduction in the initial benefit-based charge for South Island distributors and the aluminium smelter, offset by increases for North Island load.

A.21 The approach is one of perspective — taking a recent year as reference and adjusting it for likely market conditions or taking an average of (say) four recent years. The Authority considers there are no strong methodological reasons to prefer one approach over the other and no compelling reason to change the approach taken in the 2019 Issues Paper.

A.22 Its approach has evolved in response to submissions on the modelling undertaken in 2012 and 2016, which did benefit assessments using more limited data. The 2014 beneficiaries-pay working paper canvassed options on netting disbenefits. The Authority was of the view then that annual netting as used in 2019 was reasonable, compared to either the gross benefits approach proposed in 2012, or taking net benefits over a transmission investment's economic life (requiring construction of long-term projections with and without historic investments). We remain of that view.

Virtual price offer (VPO)

A.23 In calculating the benefit-based charge allocators, we compared wholesale electricity prices with and without a grid investment. The assumption is that, without the grid investment, generation would be built as a response to potential unserved energy or high prices that could otherwise occur.[291]

291 The Authority introduced this concept of a virtual generator making virtual price offers in its 2016 proposal, in response to submissions on the 2012 proposal.

A.24 The 2019 proposal assumed such virtual generation was in Auckland — putting back generation that was recently decommissioned in an area close to the main load in New Zealand. We assumed that such generation would make virtual price offers at 1.2 times the price observed with the investment in place — the variable VPO. We also used the alternative assumption of a fixed VPO at $500/MWh (a virtual diesel generator).

A.25 Few submitters specifically commented on these assumptions. Pan Pacific and Nova preferred the variable VPO. Mercury preferred a fixed VPO on the basis that it would match wholesale prices at beneficiary nodes prior to an investment going in. Trustpower submitted that the variable VPO seemed more realistic but noted that the modelling outputs were sensitive to the VPO assumption. Network Waitaki and Rio Tinto objected to the assumed absence of a virtual generator in the South Island: without the HVDC, the South Island cannot be served by Auckland's virtual generator lifting prices in dry periods, increasing benefits of the HVDC (and other grid investments) to South Island consumers.

A.26 The modelling did not show unserved energy in the South Island in the scenario without the HVDC, but it did show prices over $1,000 were reached. Network Waitaki submitted that, at the least, a virtual diesel generator should be made available to address high price situations (which would reduce their assessed benefits).

A.27 The Authority considers the VPO assumptions to be appropriate and decided not to change the approach adopted for the 2019 Issues Paper. If the HVDC had never been built, the generation mix in New Zealand would have been quite different to what it is today. It is unlikely the same level of hydro generation would have been built in the South Island, for example, as there would not likely have been a business case for such investment. Alternatively, there would need to be significant generation surplus to meet demand during dry periods. Such intermittent demand would unlikely be sufficient to finance the excess generation investment. Either way, this indicates South Island load benefits considerably from the HVDC.

vSPD results are intuitive

A.28 Some submissions (e.g. Entrust cross-submission, Trustpower, Transpower, Network Waitaki and Rio Tinto) submitted the resulting benefit-based charges were not intuitive. They cited examples of unexpected charge outcomes for investments such as HVDC, Wairakei Ring, LSI renewables and Bunnythorpe-Haywards. For example:

- Rio Tinto and Network Waitaki submitted Upper North Island load was more likely to be the principal beneficiary of the HVDC and Bunnythorpe-Haywards investments and that South Island load paid too much for these investments
- Vector submitted in previous consultations that the modelling undertaken led to charges to Upper North Island load that were too high, while generator charges were too low.

A.29 The Authority considers the results to be consistent with what are reasonable and credible assumptions. In particular, the HVDC, LSI renewables and Bunnythorpe-Haywards results are explained by our VPO assumption whereby high prices are reached during southward flows across the HVDC in the absence of those investments.

A.30 The quantum of benefits North Island load receives during normal (Northward) flows across the HVDC is not symmetrical with South Island load benefits during the more uncommon southward flows across the HVDC when lake levels are low (as explained by the VPO assumption). This answers Network Waitaki's concern that the flow over the HVDC was southward only 15% of the time while South Island load's share of the remaining cost of the HVDC would be 30%.

Volatility in results explained by evolving assumptions and passage of time

A.31 Some submitters noted that estimated charges were volatile with large differences in outcome every time the modelling is redone. Volatility would create disputes, undermining durability.[292]

A.32 Trustpower submitted that the benefits were spread more evenly compared to the 2016 modelling, proof that no change to the TPM was required. It also noted (p 68) that the vSPD approach is sensitive to input assumptions and not suitable to lock-in transmission charges for the seven historical investments. Transpower submitted that compared to the 2019 proposal modelling the 2012 modelling was a comparatively settled methodology.

A.33 Changes in the benefit-based charges for historic investments reflect the evolution in our vSPD input assumptions over successive consultations, in response to submissions, as well as a reduction in recoverable revenues associated with the historical investments.

A.34 The estimated amount of revenue associated with the historic assets to be recovered on a benefit-basis has reduced by 50%, from $374m in 2012 to $185m in the 2019 Issues Paper and now an estimated $174m following the Commerce Commission's decision on Transpower's revenue for Regulatory Control Period 3. Changes in 2019 and 2020 are due mostly to depreciation, a reduction in the weighted average cost of capital and the exclusion of three investments for which the modelling did not identify significant benefits.

Table 7 Estimates of year 1 benefit-based charges have reduced over time

$M revenues. Estimates prepared in:	2012	2016	2019	2020
North Island Grid Upgrade	117	85	61	57
HVDC (Pole 2 and 3)	171	118	99	93
Wairakei Ring	20	15	9	9
North Auckland and Northland Grid Upgrade	59	39		
Lower South Island Renewables		4	3	3
Upper North Island Dynamic Reactive Support		6	5	5
Bunnythorpe-Haywards Reconductoring		6	7	6
Lower South Island Reliability		2	2	2
Otahuhu GIS		12		
Upper South Island Reactive Support		3		
Islington-Kikiwa 2	4			
WDC MST	2			
Total revenue	**374**	**290**	**185**	**174**

292 For example, see ENA, Orion, Fonterra, Mercury, Transpower and Trustpower.

Approach to accounting for reliability and resilience benefits

Seven historical investments

A.35 Some submitters[293] critiqued the treatment of reliability benefits in the calculation of the benefit-based charge allocators.

A.36 For example, Nova submitted the Authority should measure increased security of supply for the North Auckland and Northland (NAaN) grid upgrade and Ōtāhuhu GIS — two investments included in the benefit-based charge in 2016 but removed in 2019 due to the lack of 'reduced constraint' related benefits.

A.37 The Authority did not explicitly measure the reliability benefits for the initial investments in the benefit-based charge. Instead, we assumed the (price) benefit calculation with and without the assets is a reasonable proxy also for reliability benefits from those investments. The Authority's reason is that the cost of outages (and thus value of reliability) is likely to be correlated with those estimated price benefits.

A.38 This approach (which does not specifically value the cost of outages at for example the Value of Lost Load [VoLL]) does mean the benefits to consumers may be understated. However, this bias is offset by other modelling features that may overstate benefits to consumers. For example, generator offers were not revised, nor did we incorporate a demand response to higher prices, in the scenario without the grid investment.

A.39 We explicitly modelled reliability for the Ōtāhuhu GIS investment. The modelling assumed a low probability, high impact event, with the duration of the outage valued at VoLL. The reliability benefits accounted for less than 20% of the investment's cost at 2021.

A.40 Given this finding, no such analysis was carried out for the other two investments (NAaN and USI reactive support), which the modelling had found were not required to meet demand for the period analysed (July 2014 to June 2018).[294] This does not preclude potential constraint reducing benefits in the future if demand rises.

A.41 Because our approach did not identify positive net benefits for these investments, the Authority decided to exclude them from allocation via the benefit-based charge.

Future resilience investments

A.42 A different methodology will likely be applied for assessing and allocating the reliability benefits of future investments. The guidelines do not specify the methodology.

A.43 Conceptually, the assessment of benefits of investments that improve reliability or resilience (in case of a major earthquake, say) can be approached in a similar way to the Ōtāhuhu substation example. That is, an assessment of the probability of a future event and its expected impacts will define the benefits and beneficiaries of mitigation. The costs of mitigation — a resilience project — could be allocated accordingly.

A.44 This does not imply cost socialisation for reliability or resilience investments: these should be allocated according to benefit shares, like other investments. If reliability or resilience benefits are local, then the charges would be local. If the benefits are wide-spread, then the charges would likewise be wide-spread.

A.45 The Authority acknowledges assessments of the benefits of reliability and resilience investments can be very difficult, for example because of a lack of robust data to help form a reasonable view on probabilities of very low probability, high impact events and

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293 ENA, Nova, Orion, Rio Tinto, Transpower and Trustpower.

294 Mercury submitted the modelling in 2016 identifying benefits in relation to NAaN, but not in 2019. This was because allocation in 2016 assumed certain Upper North Island loads benefited from NAaN and allocated charges to those loads based on gross AMD.

other technical questions. Even so, the intent is that these aspects are transparently and thoroughly tested.

A.46 The 2020 guidelines provide that, in assessing the allocation, Transpower must consider net private benefits consistent with electricity market benefit or cost elements (as defined in the Transpower Capital Expenditure Input Methodology Determination 2012). The guidelines also provide Transpower discretion to include other benefits and costs.

Approaches to measuring gross AMD for residual allocation

Gross AMD will be calculated at the level of the grid exit point

A.47 The 2020 guidelines provide that the allocation of the residual charge is based on transmission customers' gross anytime maximum demand (AMD), calculated at the level of each of a customer's grid exit points (that is, points of connection). This involves aggregating a measurement at the GXP with an estimate of concurrent generation behind the GXP.

A.48 NZ Steel (p 1) highlights that this methodology treats direct-connect consumers differently than consumers connected through distribution networks who can benefit from a 'diversified AMD' measure.[295] We accept that this means that the residual charge can be higher for a directly connected industrial than the same industrial customer connected through a distribution network.

A.49 Pan Pacific (paragraph 20) suggests the allocation should be at the consumer level for large commercial and industrial consumers connected within networks. MEUG considers that AMD should apply to each consumer at the interconnection point (ICP).

A.50 Waitaki Irrigators Collective and Network Waitaki note the gross AMD measure does not recognise the value that peak use in summer provides in diversifying demand and improving the load factor of the transmission network.

A.51 The Authority consulted on an ICP-based residual charge for mass-market load in our Options Working Paper published in 2015. Theoretically, an ICP-based residual has merit by being a more granular indicator of size and ability to pay and treating otherwise similar customers equally. However, an ICP-based charge is difficult to estimate because half hourly data is not yet available at every ICP. For the options working paper, we estimated capacity at each ICP based on meter type. After considering submissions on that paper we agreed that capacity was likely to overestimate AMD, which would result in higher charges for distributors as compared to industrials.

A.52 Calculation of AMD at the level of a point of connection does not have those disadvantages. As discussed below, calculation of AMD at point of connection should recognise that some customers switch load between points of connection. Otherwise customers are allocated AMD at the different points of connection, which would inflate their allocation. The section below describes adjustments we made in estimating indicative charges to address such 'double-counting'.

Distributors determine how to pass-through transmission charges

A.53 Pioneer submitted that the Authority should confirm that distributed generators will not be required to pay the residual on account of their distributed generation.

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295 Consumers do not all have their peak demand at the same time. This diversity means that coincident peak demand in a network is lower than if consumers in a network do have their peak demand all at the same time. Large commercial and industrial consumers within a network may contribute little to AMD if their peak demand is not at a network's residential peak demand (e.g. a cold winter night).

A.54 Pass-through of transmission charges by distributors is a matter for distributors. In 2019 the Authority updated distribution pricing principles to guide the pricing methodologies.

A.55 Residual charges are allocated on the basis of gross AMD (that is, electricity use), not generation. Generation, co-generation, or generation within a distributor's network does not add to gross AMD (except to the extent that generation uses electricity).

Revisions to the input assumptions required

A.56 The Authority requested that parties identify adjustments to input data or charge calculations should they be warranted, by providing relevant information to assist the Authority's decision making.

A.57 Some submitters proposed adjustments to the impacts modelling inputs and/or the calculations.[296] These are set out below.[297]

A.58 The resulting adjustments are of a minor 'tidy-up' nature and did not affect the nature of the Authority's decision. The adjustments reduce charges for a small group of customers, while increasing indicative charges by 1% for other customers. This would translate to about +$1 on the average annual household electricity bill.

Ownership changes

A.59 A submission by KCE, a generator, identified its change in ownership was not captured in reconciliation data. This affects the benefit-based charge allocator and transfers $120k from Nova to KCE (majority-owned by Trustpower).

Reclassify as distributed generation

A.60 Southern Generation submitted it is partially embedded in Horizon's network and thus should be classified as distributed generation. As a result, its $751k indicative charges are reset to zero and as its generation is netted off Horizon's load, Horizon's benefit-based charge is reduced.

A.61 The submission also noted that a significant volume of load assigned to Southern Generation is attributable to the Horizon network. Having made enquiries with Horizon, load linked to Aniwhenua was re-allocated, reducing Southern generation's charges and increasing Horizon's charges.

Material changes in demand and asset sales

A.62 Submissions identified material changes in demand, changes in ownership during a year, or load alternating between two supply points, which caused double-counting of Anytime Maximum Demand (identifying AMD for both former and new owners, rather than apportioning AMD between them). This has led to the following changes:

- Buller and Westpower — adjustment for permanent demand change and double-counting; reducing benefit-based and residual charges by $714k (50%) and $306k (9%) respectively
- Eastland and Northpower — adjustment for asset sales that caused double-counting, reducing residual charges by $95k (2.1%) and $747k (4.6%) respectively

296 For example, KCE, Horizon, Southern generation, Buller, Westpower, Eastland networks, Northpower, Trustpower, Contact Energy and Orion.

297 Network Waitaki p 6, submitted that the proposal overstates the residual charge for Network Waitaki because it does not recognise the contractual arrangements regarding the North Otago Irrigation Company. The latter made a similar point. The indicative residual charge is based on gross load for the reasons discussed in chapter 10. The Authority is aware of the notionally embedding agreement involving Transpower, Meridian and Network Waitaki which expires 31 March 2026. The guidelines do not look through to contractual arrangements and the Authority notes the 2020 guidelines provide for prudent discounts.

- Trustpower — adjustment for an asset sale which turned Cobb generation into distributed generation; netting off load reduces its benefit-based charges by $101k (9.7%)
- Orion — adjustment for asset sales during assessment period, reducing its residual charges by 2.3m (4.3%).

A.63 These adjustments of $4.3m are recovered instead from all other customers.

Loss and Constraint Excess (LCE) adjustment

A.64 Contact identified that the Authority erroneously compared transmission charges in 2019 before adjusting for LCE to charges in 2022 after adjusting for LCE. This understated the impact on customers' total electricity bills and so affects the cap.

A.65 The impact of the correction is minor. It reduces capped charges for some direct-connects and a 0.1% increase to parties that fund the cap.

RCP3 reduction in Transpower's maximum allowable revenue

A.66 We note that Transpower's maximum allowable revenue for 2022 reduces 5.8% from $848m to $799m. This will further reduce the charges across all transmission customers. Including the above changes, the net reduction compared to the indicative charges in the 2019 Issues Paper averages -5.5% for 44 of 57 transmission customers.

Table 8 Indicative charges: 2019 proposal, adjustments and final estimates

$ M (indicative)	2019 Issues paper			Adjustments made after consultation			Adjusted for new Transpower MAR			Status quo (adjusted)
	Charges	Cap	Total	Charges	Cap	Total	Charges	Cap	Total	Total
Alpine Energy	10.3	0.25	10.5	10.4	0.26	10.6	9.7	0.23	9.9	10.6
Aurora Energy	21.9	0.53	22.5	22.1	0.56	22.7	20.7	0.49	21.2	17.6
Buller Electricity	1.4	-0.29	1.1	0.7	0.02	0.7	0.7	0.02	0.7	0.5
Centralines	1.4	0.03	1.4	1.4	0.04	1.5	1.3	0.03	1.4	1.7
Counties Power	10.2	0.24	10.4	10.3	0.26	10.5	9.6	0.23	9.9	9.7
Eastland Network	4.6	0.11	4.7	3.8	0.10	3.9	3.6	0.08	3.7	4.6
Electra	7.4	0.18	7.6	7.5	0.19	7.7	7.0	0.16	7.2	5.2
Electricity Ashburton	11.2	0.27	11.5	11.3	0.29	11.6	10.6	0.25	10.8	12.1
Electricity Invercargill	6.6	0.16	6.8	6.7	0.17	6.8	6.3	0.15	6.4	7.5
Electricity Southland	0.3	0.01	0.3	0.3	0.01	0.3	0.3	0.01	0.3	0.5
Horizon Energy	5.7	-0.05	5.7	6.3	-0.77	5.5	5.9	-0.37	5.5	2.6
MainPower	10.2	0.24	10.4	10.3	0.26	10.5	9.6	0.23	9.9	8.9
Marlborough Lines	4.9	0.12	5.0	4.9	0.13	5.0	4.6	0.11	4.7	5.5
Nelson Electricity	0.9	0.02	0.9	0.9	0.02	0.9	0.8	0.02	0.9	0.7
Network Tasman	9.9	0.24	10.1	9.9	0.25	10.2	9.3	0.22	9.5	7.2
Network Waitaki	4.5	0.11	4.6	4.5	-0.04	4.5	4.2	0.10	4.3	2.8
Northpower	16.1	0.39	16.5	15.3	0.39	15.7	14.4	0.34	14.7	13.3
Orion	53.3	1.28	54.5	51.0	1.30	52.3	47.8	1.12	48.9	43.9
OtagoNet JV	4.8	0.12	5.0	4.9	0.12	5.0	4.6	0.11	4.7	3.8
Powerco	67.3	1.62	68.9	68.0	1.73	69.7	63.7	1.49	65.2	69.4
Scanpower	1.0	0.02	1.1	1.1	0.03	1.1	1.0	0.02	1.0	1.2
The Lines Company	4.9	0.12	5.0	4.9	0.13	5.1	4.6	0.11	4.7	3.1
The Power Company	7.2	0.17	7.4	7.3	0.19	7.5	6.9	0.16	7.0	6.6
Top Energy	4.9	0.12	5.0	5.0	0.13	5.1	4.7	0.11	4.8	3.6
Unison Networks	22.0	0.53	22.5	22.2	0.56	22.8	20.8	0.49	21.3	21.7
Vector	165.2	3.96	169.1	166.6	4.23	170.8	156.2	3.66	159.8	151.8
Waipa Networks	5.1	0.12	5.3	5.2	0.13	5.3	4.9	0.11	5.0	5.7
WEL Networks	18.7	0.45	19.2	18.9	0.48	19.4	17.7	0.41	18.1	16.7
Wellington Electricity	38.2	0.92	39.1	38.5	0.98	39.5	36.1	0.85	37.0	43.7
Westpower	3.5	-0.16	3.4	3.2	0.02	3.2	3.0	0.07	3.1	1.6
Contact Energy	20.7	0.50	21.2	20.8	0.53	21.3	19.6	0.46	20.0	19.9
Genesis Power	7.4	0.18	7.6	7.4	0.19	7.6	7.0	0.16	7.1	5.3
Mercury	6.4	0.15	6.6	6.4	0.16	6.6	6.1	0.14	6.2	0.0
Meridian	39.9	0.96	40.8	40.0	1.01	41.0	37.6	0.88	38.5	65.4
Nga Awa Purua JV	1.7	0.04	1.7	1.7	0.04	1.7	1.6	0.04	1.6	0.0
Ngatamariki Geothermal	0.9	0.02	0.9	0.9	0.02	0.9	0.8	0.02	0.9	0.0
Nova	0.3	0.01	0.3	0.2	0.00	0.2	0.2	0.00	0.2	0.0
Southdown Generation	0.1	0.00	0.1	0.1	0.00	0.1	0.1	0.00	0.1	0.0
Southern Generation	0.8	0.02	0.8	0.0	0.00	0.0	0.0	0.00	0.0	0.0
Tilt Renewables	0.2	0.00	0.2	0.2	0.00	0.2	0.2	0.00	0.2	0.0
Todd Gen. Taranaki	0.3	0.01	0.3	0.3	0.01	0.3	0.3	0.01	0.3	0.0
TrustPower	1.0	0.03	1.1	0.9	0.02	1.0	0.9	0.02	0.9	1.7
Tuaropaki (Mercury)	1.3	0.03	1.3	1.3	0.03	1.3	1.2	0.03	1.2	
Whareroa Cogen. Ltd	0.5	0.01	0.5	0.5	0.01	0.5	0.4	0.01	0.4	0.0
KCE (Mangahao)			0.0	0.1	0.00	0.1	0.1	0.00	0.1	
B.E.R. (Kupe) Ltd	0.6	0.01	0.6	0.6	0.02	0.6	0.6	0.01	0.6	0.8
Daiken Southland	0.7	0.02	0.7	0.7	0.02	0.7	0.6	0.01	0.6	0.7
Methanex	0.6	0.01	0.6	0.6	0.02	0.6	0.6	0.01	0.6	0.4
New Zealand Rail	2.7	-1.24	1.4	2.7	-1.35	1.3	2.5	-1.18	1.3	1.0
Norske Skog	6.8	-5.42	1.4	6.8	-5.49	1.4	6.4	-5.06	1.4	0.0
NZ Steel	11.9	-6.06	5.8	12.0	-6.34	5.7	11.3	-5.60	5.7	2.2
NZAS	43.4	1.04	44.4	43.8	1.11	44.9	41.1	0.96	42.0	52.2
Pan Pacific	5.0	-2.16	2.9	5.1	-2.30	2.8	4.7	-1.98	2.8	1.1
Port Taranaki	0.0	0.00	0.0	0.0	0.00	0.0	0.0	0.00	0.0	0.0
Resolution Dev	0.0	-0.01	0.0	0.0	-0.01	0.0	0.0	-0.01	0.0	0.0
Southpark Utilities	0.0	0.00	0.0	0.0	0.00	0.0	0.0	0.00	0.0	0.0
Winstone Pulp Int	2.4	0.06	2.5	2.4	0.06	2.5	2.3	0.05	2.3	2.2
Indicative cost of cap		15.4			16.2			14.2		

Note: Highlighted cells show support from cap. Adjusted status quo (last column) represents an estimate of charges after accounting for for Transpower's MAR for RPC3, and in the absence of implementation of guidelines.

Appendix B Alternatives put forward in submissions

B.1 The Authority has, over the course of the TPM review, considered both high-level alternatives to and variations on, the benefit-based approach that has been adopted.

B.2 This Appendix sets out the Authority's views on the main alternatives proposed as a means of achieving the objectives of its review of the TPM and that have been supported by submitters in response to the 2019 Issues Paper. The Authority considers that it is helpful to stakeholders to summarise in this document this aspect of our analysis. In this Appendix we also signpost where more detailed analysis can be found.

B.3 For the higher-level alternative approaches that the Authority has considered over the duration of this TPM review see Appendix E of the 2019 Issues Paper, chapter 9 of the 2016 Issues Paper and chapter 6 of the 2012 Issues Paper. The 2019 Issues Paper explained, at Appendix B, alternatives considered that were variations to the then proposed guidelines.

B.4 The remaining sections in this chapter summarise the analysis of the following alternatives that have been supported in submissions since July 2019:

(a) an RCPD charge with a weakened price signal

(b) a tilted postage stamp charge

(c) a deeper connection charge

(d) a regional approach

(e) Transpower's options for incremental TPM reform

(f) Trustpower's most practicable options.

B.5 In quantifying the costs and benefits of its proposal, the Authority also considered particular variations on its proposal, including 'future investments only' and 'HVDC and future investments only' options.

B.6 The Authority considers that the 2020 guidelines meet its statutory objective better than all these alternatives.

An RCPD charge with a weakened price signal

B.7 One option identified for the Authority's review of the guidelines would be to retain the RCPD charge but reduce the associated price signal. Transpower did have the ability under the 2006 guidelines to weaken the RCPD price signal, although the 2006 guidelines did not require this approach. As an alternative option, the Authority could introduce revised guidelines that retained an RCPD charge but required Transpower to weaken the RCPD price signal (for example by requiring RCPD to be calculated using a greater number of trading periods than 100).

Our conclusion

B.8 The Authority's view is that a TPM that includes an RCPD charge with a weakened price signal is likely to be less effective than a TPM based on the 2020 guidelines at addressing the problems identified with the current TPM and meeting the Authority's statutory objective.

Authority's position in the 2019 Issues Paper

B.9 In 2019 we considered, as an option, addressing RCPD charge problems in a manner consistent with the 2006 guidelines. We modelled the effects of flattening out the RCPD price signal completely, with RCPD required to be calculated using all trading periods so that the RCPD charge becomes a MWh charge. We concluded that this option would be materially less effective than the Authority's 2019 proposal at addressing problems with the TPM and noted that this was consistent with the results of the CBA.[298]

Submitters' views and our assessment

B.10 A number of stakeholders submitted that the Authority should consider a weakened RCPD charge as an alternative to its proposal (for example, calculating RCPD over an increased number of trading periods).[299]

B.11 Vector and WEL recommended we consider alternatives to full removal of the RCPD charge.[300] Network Waitaki recommended allocating residual costs using coincident maximum demand measured in peak and shoulder periods.[301] Unison and Centralines submitted we should consider whether "Permanent retention of a small, but sufficiently material, RCPD-based charge would be effective at achieving a better balance of encouraging shifting low-value discretionary loads (such as hot-water heating) away from peak." Marlborough Lines and the Distribution Group made similar submissions.[302]

B.12 The Authority considered if an RCPD charge calculated using more periods than 100, but fewer than all trading periods, would be an effective option. Our view is that it would not.

B.13 While weakening the price signal would reduce the economic harm caused by the RCPD charge to some extent, even a weakened RCPD charge would still create inefficiency. It would still send an inefficient signal (over and above the efficient price signal provided by nodal prices) which would create perverse incentives for customers to reduce their load at particular times to avoid the charge, even when there is no benefit from doing so (such as when there is plenty of unused grid capacity). It would still risk encouraging businesses to make investments mainly to shift transmission costs to others. Since a weakened RCPD price imposes economic costs (including the cost of foregone demand) when using the additional grid capacity is essentially costless, it reduces the efficiency of grid use.[303] And a weakened RCPD charge would still mean volatility (that is unrelated to the cost of transmission) for some customers' charges.

B.14 Further, if the weakened RCPD charge applied instead of a benefit-based charge, then the beneficiaries of a new investment would not face their share of the cost of the investment. As a result, grid users would have an inefficient incentive to ignore the impact of their own decisions on the need for grid investment and would not be encouraged to scrutinise proposed grid investments and give Transpower and the Commerce Commission the best information on the actual value of grid investments or of alternative solutions. This could result in investment inefficiency that could be substantial,[304] particularly given the expected significant increase in transmission investment for electrification and renewables, discussed in Transpower's Te Mauri Hiko documents.

B.15 The CBA considered an alternative option that assumed that the only change to the current TPM would be that the RCPD charge is replaced with a per-MWh charge over all trading periods. This is one version of an RCPD charge with a weakened price signal. The revised CBA results reported in chapter 15 confirm that the 2020 guidelines produce substantially greater long-term benefits for consumers than this alternative option.

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298 *2019 Issues Paper* paragraphs E.96–E.103.

299 Including Contact Energy p 6, Horizon p 1, the IEGA p 9, Northpower pages 28–29, Oji Fibre paragraph 27, Pioneer p 3, The Lantau Group (for the TPM Group) pages 13–14, Transpower Appendix 1 of its submission to the *2019 Issues Paper* and Trustpower p 43.

300 Vector p 18 and WEL p 1.

301 Network Waitaki p 19.

302 Marlborough Lines p 2 and The Distribution Group paragraphs 74–76.

303 See Appendix E of the *2019 Issues paper.*

304 The CBA estimates investment efficiencies arising from the benefit-based charge. These efficiencies would not be achieved with a TPM based on a weakened RCPD charge instead of the benefit-based charge.

B.16 The Authority also considered whether it is plausible, from a CBA perspective, that a TPM with an intermediate-range RCPD charge (calculated over a number of trading periods somewhere between 100 and all trading periods), that is otherwise similar to the current TPM (including the HVDC charge), might have higher net benefits than the Authority's proposal. Based on the CBA, the Authority considers that this is not a plausible result. Solely modifying the number of RCPD periods would not capture other material benefits from changes to the TPM, such as improvements to the efficiency of long-term supply through modifications to methods that determine generators' transmission charges.

B.17 The problems and deficiencies of the current TPM, including the RCPD charge, are well documented, including in the 2019 Issues paper and in this decision paper. In considering this alternative option, the Authority is faced with a choice between reducing the problems (a weakened RCPD charge) and a more complete solution to the problems (the 2020 guidelines).

B.18 If the Authority had formed the view that removing the RCPD charge completely had material negative side-effects or unintended consequences then retaining a peak charge (such as a weakened RCPD charge) might be the better choice. However, that is not the Authority's view. Rather, the Authority has decided that a permanent peak charge is unnecessary, for reasons set out in the March 2020 'Peak charges under proposed TPM guidelines' information paper.[305] Our best assessment is that any remaining potential negative effects of removing the RCPD charge are not sufficiently material to shift our position away from choosing the least distortionary option: fixing the underlying problems with the RCPD charge by removing it completely.

Tilted postage stamp charge

Our conclusion

B.19 The Authority's view is that a TPM based on a tilted postage stamp charge is likely to be less effective than a TPM based on the 2020 guidelines at addressing the problems identified with the current TPM and meeting the Authority's statutory objective.

Authority's position in the 2019 Issues Paper

B.20 The 2019 Issues Paper stated that a TPM based on a tilted postage stamp charge would be more efficient than the status quo, but less effective than the proposal at addressing the problems identified with the current TPM.[306]

B.21 The main reason was that it does not align users' transmission charges for new investments with the costs or the benefits of those investments. As a result, grid users would have an inefficient incentive to ignore the impact of their own decisions (for example, investment in generation in various locations) on the need for grid investment and would not be encouraged to scrutinise proposed grid investments and give Transpower and the Commerce Commission the best information on the actual value of grid investments or of alternative solutions. The CBA indicates the cost (or benefit foregone) if the estimated efficiency gains from the benefit-based charge are not realised.

Submitters' views and our assessment

B.22 Creative Energy Consulting (CEC) (for Trustpower) suggested that a tilted postage stamp (using a heuristic approach to derive the pattern of transmission flows and usage in the market) would improve dynamic efficiency much more effectively than the Authority's proposal. By a heuristic approach, CEC meant a simpler method that, empirically, is expected to give similar pricing outcomes to long-run nodal prices (prices that tilt upward

305 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published/

306 *2019 Issues Paper*, paragraphs E.125–E.130.

from south to north).[307] CEC submitted that the Authority should draw on the implications of its "nodal prices are efficient" principle, arguing that efficient transmission prices should have similar characteristics and the tilted postage stamp is an example of this approach.[308] CEC's proposed tilted postage stamp prices would also have the general characteristics of applying to peak load or output; and applying equally and oppositely to load and generation in the same location.

B.23 CEC explained that its proposed tilted postage stamp charge — which would be proportionate to energy use and (largely) independent of individual new investment — would be different to the version of a tilted postage stamp charge that the Authority considered in the 2019 Issues Paper (a charge that 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).[309]

B.24 Citing CEC's advice, Trustpower submitted that tilted postage stamp was one of the most practicable options and its ability to address the problems with the current TPM should be evaluated.[310] Transpower listed tilted postage stamp as an incremental reform option available to address problems with the interconnection charge (in particular, the problem of spreading the costs of regional transmission investment too widely).[311]

B.25 The Authority does not agree with CEC that efficient transmission prices should have similar characteristics to nodal prices, because in our view transmission charges and nodal prices generally have different functions. Nodal prices provide an efficient signal of the marginal cost of using the grid at specific times and locations. This enables the effective and targeted management of congestion on the grid. By contrast:

(a) the benefit-based charge is intended to bring implications for grid-related costs into proper consideration when businesses make location and other investment decisions and encourage customers to participate in the scrutiny of investment proposals and reveal information about the benefits and costs of those proposals

(b) the residual charge is intended to recover transmission costs that are not recovered through other charges in a way that is designed to limit inefficient impacts on grid use and investment decisions.

B.26 The tilted postage stamp approach proposed by CEC is not required to provide efficient signals for grid use. This is because nodal prices already provide this — adding a tilted postage stamp on top of nodal prices would inefficiently 'over-signal'. Further, it would not achieve the objectives of benefit-based charges and residual charges. For example, under the tilted postage stamp approach proposed by CEC:

(a) a transmission customer would not be encouraged to scrutinise a proposed transmission investment that would benefit it to determine whether the benefits outweigh the costs. This is because the customer would not be paying those costs in proportion to the benefits it receives (as a tilted postage stamp charge would spread the costs widely across the country, albeit with charges differentiated by way of the tilt)

(b) instead, transmission customers could be encouraged to favour a grid upgrade over local solutions — even if the local solution is an efficient investment. Further, businesses would make location and other investment decisions without bringing implications for grid-related costs into proper consideration, thereby increasing the

307 CEC, p 18.

308 CEC, p ii.

309 CEC, pages 19–20.

310 Trustpower, p 24.

311 Transpower's submission in response to the *2019 Issues Paper*, Appendix 1.

overall cost of consuming electricity and failing to support the transition to a low-emissions economy at the lowest overall cost

(c) a transmission customer could be encouraged to make inefficient investments for the main purpose of reducing its peak demand and so avoiding the tilted postage stamp charge, even if the grid had plenty of spare capacity at peak (so increasing the overall cost of consuming electricity and shifting costs onto other consumers)

(d) electricity consumption would be inefficiently suppressed at peak times.

B.27 In the Authority's view an approach based on a tilted postage stamp charge cannot address all of the problems with the current TPM and would lead to less efficient outcomes than an approach based on the 2020 guidelines.

B.28 Transpower submitted that a tilted postage stamp charge could be a pragmatic alternative for recovering the costs of pre-2019 investments and low-value investments.

B.29 The Authority considered applying a tilted postage stamp charge to recover the costs of pre-2019 investments while recovering the costs of new investments via the benefit-based charge. However, if benefit-based charges only applied to future investment, that means that consumers in the Eastland and Horizon network areas, for example, would have to pay both for new investments made for their benefit and also pay an outsize share of the costs of major investments they did not get significant benefit from, such as the North Island Grid Upgrade (NIGU).[312] In our view a tilted postage stamp charge is not a durable solution for recovering the costs of pre-2019 investments.

B.30 The Authority also considered applying a tilted postage stamp charge to recover the costs of low-value investments while recovering the costs of high-value investments via the benefit-based charge. However, under that approach a customer would not be encouraged to scrutinise low-value transmission investments that would benefit it to determine whether the benefits outweigh the costs. Also, it could 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 into smaller tranches.

B.31 By contrast, the approach in the 2020 guidelines (under which a simple benefit-based method may be applied to low-value investments):

(a) encourages customers to scrutinise low-value investments[313]

(b) mitigates the potential problem caused by introducing a boundary between low-value and high-value investments.

Deeper connection charge

Our conclusion

B.32 The Authority's view is that a TPM based on a deeper connection charge (or a deep connection charge) is likely to be less effective than a TPM based on a benefit-based charge at addressing the problems identified with the current TPM and meeting the Authority's statutory objective.

[312] Eastland and Horizon would pay an outsize share of NIGU's costs: this follows from the idea that a tilted postage stamp charge would tilt upward from south to north and the fact that, on a North-South axis, Eastland and Horizon are located in the mid-North Island: that is, in the northern part of the country. The Authority has estimated that these customers receive virtually none (0.04% to 0.05%) of NIGU's benefits.

[313] For low-value 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.

Authority's position in the 2019 Issues Paper

B.33 In 2019 the Authority considered the option of the guidelines requiring a TPM based on a deeper connection charge, which would apply to those grid assets used only by a few customers and allocate costs between them based on customers' share of the energy flow over the relevant grid assets. We recognised that a deeper connection charge would be more efficient than the status quo, but decided against it on the basis of a number of identified disadvantages, set out at paragraph E.123 of the 2019 Issues Paper, including that it would be poor at promoting efficient investment in new large assets and could create incentives which encourage grid users to inefficiently alter their grid use.[314]

Submitters' views and our assessment

B.34 Network Waitaki recommended that the Authority "Consider the use of a simple load flow-based approach such as the Intra-Utility MW-Mile methodology."

B.35 The Authority considers that simple load flow-based approaches suffer from similar disadvantages to the deeper connection charge option discussed above. Axiom (for Transpower) described the deeper connection charge option that the Authority had previously considered as deeply flawed.[315]

B.36 Creative Energy Consulting (CEC) (for Trustpower) proposed a deep connection charge that differed in some important ways from the deeper connection charge considered by the Authority in 2019. Like the Authority's deeper connection charge, CEC's deep connection charge would apply to those grid assets used only by a few customers and allocate costs between them. Unlike the Authority's version, CEC's deep connection charge is a one-off charge that is applied when a new user connects and is shared between users in proportion to attributable benefits (like a beneficiaries-pay charge).[316] CEC envisaged that its deep connection charge could be used in combination with a tilted postage stamp regime. The deep connection charge would apply to grid investment closer to the transmission customer's point of connection, while the tilted postage stamp charge would apply to investments deeper in the grid (further from points of connection).

B.37 The Lantau Group (TLG) (for The TPM Group) proposed an approach with some similarities to CEC's deep connection charge: TLG submitted that if a decision was made to proceed with a benefit-based charge, it should be applied only where there is unambiguous localisation of benefits, otherwise cost recovery should default to a broad-based framework.[317]

B.38 Similarly, Oji Fibre submitted that the benefit-based charge should apply only to specific assets for which benefits are demonstrably obtained by a small number of participants.[318]

B.39 Trustpower submitted that the deeper connection charge as described in the CEC 2019 Report and TLG 2019 Report was one of the most practicable options and its ability to address the problems with the current TPM should be evaluated.[319]

B.40 While it would depend on the detail (noting the Authority's assessment of deeper connection charging in the 2019 Issues Paper), this part of CEC's proposal has similarities to the Authority's proposal, in that the costs of the 'deep connection assets' would be shared in proportion to attributable benefits. However, this does not deal with investments made deeper in the grid.

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314 *2019 Issues Paper*, paragraphs E.120—E.124.

315 Axiom Economics p 12.

316 CEC p 19.

317 TLG p 8.

318 Oji Fibre paragraph 27.

319 Trustpower p 24.

B.41 Under CEC's scheme, the costs of such investments would be recovered through a tilted postage stamp charge or similar. In our view this would not be consistent with the Authority's statutory objective for the reasons set out in the earlier discussion on the tilted postage stamp charge. Similarly, under the broad-based cost recovery framework that TLG recommends for investments without unambiguous localisation of benefits, a customer would not be encouraged to scrutinise a proposed transmission investment, as it would not be paying those costs in proportion to the benefits it receives (as the costs would be spread widely across the country). And businesses would make location and other investment decisions without bringing implications for grid-related costs into proper consideration, so increasing the overall cost of consuming electricity.

B.42 As such, the Authority considers that CEC's proposed deep connection charge would not promote the Authority's statutory objective as well as our 2020 guidelines would.

Regional approach

Our conclusion

B.43 The Authority's view is that the benefit-based charge set out in the 2020 guidelines would be more effective at addressing the problems identified with the current TPM and meeting the Authority's statutory objective than a benefit-based charge that was specified according to a regional approach.

Authority's position in the 2019 Issues Paper

B.44 The Authority has previously considered regional approaches. For example, it considered a beneficiaries-pay approach that would apply on a zonal basis as one of the options in the beneficiaries-pay working paper (2014).[320] In that paper, the Authority observed that under a zonal approach, the costs of a new investment would be spread across a broader base and as a result, the price signal will not be as clear so the incentives on beneficiaries would be dulled somewhat relative to the other options.[321] This option was not strongly supported in submissions.

B.45 In the 2016 second Issues Paper, the Authority considered a broad-based, low-rate charge for each island or four transmission pricing regions combined with a broadly levied HVDC charge and concluded it would be less efficient overall than the Authority's proposal, noting that it would involve more spreading of the costs of transmission services.[322]

B.46 In 2019 we noted that the Authority had previously considered a number of options (including the above two) and said that, for a variety of reasons, we did not prefer any of those options relative to the current proposal.[323]

Submitters' views and our assessment

B.47 Some stakeholders, including Contact Energy,[324] supported a zonal or regional approach. For example, Pioneer recommended a regionally based assessment of benefits for new transmission investments.[325] NZWEA suggested a simpler regional volume-based benefits

320 *The beneficiaries pay working paper*: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c7492.

321 An offsetting advantage of the zonal option was that it applied a form of beneficiaries-pay across all assets, rather than recovering some investment costs through the residual charge.

322 The *Second Issues Paper*: https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15999.

323 *2019 Issues Paper*, paragraphs E.131—E.132.

324 Contact Energy p 3.

325 Pioneer p 4.

allocation.[326] Transpower noted with approval that in the United States, charges are fixed ahead of time to large beneficiary zones and then on-charged to individual parties.[327] Transpower included the following two variations of a regional approach on its list of incremental reform options available to address the problem of the interconnection charge spreading the costs of regional transmission investment too widely:[328]

(a) Regional postage stamp (using location as a proxy for benefit)

(b) Regional postage stamp with net importing regions (and/or generators) picking up a proportion of the cost of net exporting regions.

B.48 The Authority would observe that the 2020 guidelines allow Transpower to allocate benefit-based charges between customers in a way that is broadly in proportion to their expected positive net private benefits. Transpower has suggested using location as a proxy for benefit. It has not yet explained in detail what this would involve. We are unable to provide a view now on whether this would be acceptable, noting this would depend on the detail. If Transpower does propose a TPM that uses location as a proxy for benefit, the Authority would of course need to consider such a proposal. In particular, we would need to consider such a proposal to ensure that (as required by the guidelines) any proposed allocation method would result in an allocation between customers that is broadly in proportion to their expected positive net private benefits.

B.49 We note that a key risk with a regional approach (and with using location as a proxy for benefit) is that it may not effectively address the problem of spreading the costs of transmission investment too widely. A regional approach is also likely to suffer from boundary issues, whereby a customer will be deemed to benefit from an investment because it is located in a zone that benefits.

B.50 Under some variants of a regional approach, the costs of an investment would be spread in a postage stamp fashion across all customers in a given region. However, those customers might not benefit equally from the investment. Some customers could be charged more than their level of benefit from an investment, which could encourage them to oppose an efficient investment. In another situation, a customer could be charged less than its level of benefit from an investment, which could encourage them to lobby for an investment (even if it was inefficient). Similarly, a regional approach could lead to distortions with respect to a customer's incentives to pursue its own investments.

B.51 By contrast, a charge that reflects the expected net private benefits of each customer would reflect more accurately the cost of providing transmission customers with the transmission services that they receive and so would promote efficient investment. For this reason, we consider that the benefit-based charge set out in the 2020 guidelines would be more effective at addressing the problems identified with the current TPM and therefore better meet the Authority's statutory objective than a benefit-based charge that was specified according to a regional approach.

B.52 However, the Authority does not rule out the use of location as a proxy for benefit in circumstances where that approach would result in an allocation between customers that is broadly in proportion to their expected positive net private benefits. If this is possible, we envisage that it would require the zones or locations involved to be relatively small.

326 NZWEA p 11.

327 Transpower's submission in response to the *2019 Issues Paper*, page 8.

328 Transpower's submission in response to the *2019 Issues Paper*, Appendix 1.

Transpower's options for incremental TPM reform

Our conclusion

B.53 The Authority's view is that a TPM based on the 2020 guidelines is likely to be more effective than any of Transpower's incremental reform solutions at addressing the problems identified with the current TPM and meeting the Authority's statutory objective.

Submitters' views and our assessment

B.54 Transpower submitted that "The concerns with the TPM may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology." Transpower listed a number of high-level examples of incremental reform options in Appendix 1 of its submission in response to the 2019 Issues Paper.

B.55 Some of these options have been discussed already in this Appendix; in this section we consider each of the remaining options (and some similar options proposed by other submitters). The Authority's assessment of each option listed by Transpower is set out in the right-hand column of each of the following tables.

Table 9 Incremental reform solutions to problems with the interconnection charge

Transpower's listed solution	Authority's assessment
Mean offtake as an allocator (in whole or part). (Mercury also suggested a reform option that included assessing moving towards a MWh charge for interconnection[329]).	Allocating using offtake would not promote efficient grid use, grid investment or efficient customer investment. This is because as an avoidable charge it would distort grid use decisions; nor does it link charges to benefits, distorting investment decisions. For example, see from paragraphs 9.18 and 9.31 above. We assessed a per-MWh charge as an alternative option in the CBA, finding it inferior to the Authority's solution. We considered a net measure of demand (i.e. offtake at GXP) to allocate the residual charge but decided against it for reasons set out from paragraph 10.33 above. The Authority also considered MWh usage for the initial allocation of the residual charge but decided against it, for reasons set out from paragraph 10.43 above. We decided on lagged gross MWh usage to update residual allocation. See from paragraph 10.49 above.
Two-part tariffs (fixed/volume/mean + peak usage). Variant: ability to dial up the peak usage part as constraints are foreseen in short-to-medium term grid planning).	The Authority's approach is an efficient two-part tariff (fixed charges plus nodal prices). As Prof Hogan noted, "Adding a peak usage charge on top of [nodal prices] would create perverse incentives…. to avoid such charges." [330] The 'fixed/volume/mean' part suggested would not be related to benefit and so would not promote efficient grid investment or efficient customer investment, as noted in the row above.

329 Mercury p 6.

330 See also Hogan p 6 (footnote 40).

Transpower's listed solution	Authority's assessment
	We considered a (permanent) charge based on peak usage but decided against it for the reasons set out in the 'Peak charges under proposed TPM guidelines' information paper, published in March 2020.[331] The proposal provides for a transitional congestion charge, which may complement nodal prices under certain conditions (see from paragraph 14.17 above).
Multi-year averaging for capacity measurement [for RCPD]. (Tilt Renewables made a similar suggestion[332]).	The RCPD method does not promote efficient investment and encourages inefficient avoidance (discussion from paragraph 2.6 of this paper). Multi-year averaging for capacity measurement would not fix these problems — but could address year-to-year volatility.

Table 10 Incremental reform solutions to problems with the HVDC charge

Transpower's listed solution	Authority's view
Bi-directional HVDC charge on generation in the sending island, calculated half-hourly.	May partly address one concern with the current HVDC charge (by also charging North Island generators). Not charging on the basis of benefits risks inefficient grid investment choices. It would not promote durability of TPM regime as charges would not reflect the benefits received from the HVDC link. The HVDC link provides widely spread benefits such as through its role in the provision of ancillary services, to North and South Island load and generation customers. (See B.56–B.58 below.) Compared to a fixed-like charge, charging for the HVDC investment on some measure of injection risks distorting generation customers' operational and investment decisions by providing an inefficient incentive to avoid the charge.

331 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published/

332 Tilt Renewables p 5.

Transpower’s listed solution	Authority’s view
Exemption for Upper South Island generators, or more general recognition of intra-South Island zonal import/export characteristics.	Would not address disincentive to invest in generation in the Lower South Island (or more generally, exporting zones in the South Island) due to the HVDC charge, or deliver the benefits of benefit-based allocation (as mentioned in the row above). An exemption would not be robust to changing circumstances over time and would thus not be durable in the long-term. (For example, the import/export balance may change as the exemption would distort intra-South Island generation location choices).
Generation plant with a capacity above a threshold is deemed grid connected.	May address the inefficient embedding issue, but risks inefficiently distorting investment in generation due to boundary providing an incentive to invest in generation with capacity below threshold to avoid the charge.

B.56 Other stakeholders have also suggested alternative approaches to charging for the HVDC. The TPM Group and The Lantau Group recommended all North and South Island generators pay a simple $/MWh charge. The Distribution Group made a similar suggestion.[333] Oji Fibre made a similar proposal for Pole 3 of the HVDC.[334] Northpower suggested reallocating the incidence of the HVDC charge incrementally to reduce the proportion paid by South Island generators.[335]

B.57 The Authority’s view is that the best way to reallocate the HVDC charge is to charge the beneficiaries of the HVDC link in proportion to their level of benefit from this investment. A decision not to charge on the basis of benefits means that charges would have to be levied on those who do not benefit from the investment or at least disproportionately on those who benefit relatively less from the investment. Such charges are not likely to be durable, since those who pay the charges without getting any, or without getting commensurate benefits, are likely to object to such charges.

B.58 Furthermore, with respect to future investments in the HVDC link, a decision not to charge on the basis of benefits is likely to lead to inefficient investments, as:

(a) parties who would benefit from a proposed investment but would not pay proportionately for it may have an incentive to exaggerate the investment’s benefits, even if the investment is inefficient

(b) parties who would benefit relatively little from a proposed investment but who would pay disproportionately for it may have an incentive to discredit evidence of the investment’s benefits to reduce the investment’s size, or to delay or stop it, even if the investment is efficient.

333 The Distribution Group paragraph 43.

334 Oji Fibre paragraph 27.

335 Northpower pages 29–30.

Table 11 Incremental reform solutions to problems with generation and transmission charges

Transpower's listed solution	Authority's view
Bi-directional HVDC charge on generation in the sending island, calculated half-hourly.	Considered above.
Generators pay part of the current interconnection charge.	Risks inefficiently distorting generation customers' operational decisions by providing an incentive to change generation levels at particular times to avoid the charge. Likely to lead to greater distortion as costs are ultimately passed on to load customers, unless the charge is related to the benefit generators receive from the investment — see our discussion of the reasons generators should not pay part of the residual charge (paragraphs 10.15–10.20 of this paper). Retaining RCPD would not promote efficient investment and would encourage inefficient avoidance measures.
Use bilateral investment contracts to partially or fully fund transmission investment to release generation capacity.	The Authority is not opposed to the use of bilateral investment contracts to privately fund efficient transmission investment to release generation capacity. However, the TPM applies to transmission investments that are not funded through private contracts but instead are funded through Transpower's regulated revenue. The Authority considers that the 2020 guidelines are the best solution for the latter investments.

Trustpower's most practicable options

Our conclusion

B.59 The Authority's view is that a TPM based on the 2020 guidelines is likely to be more effective at addressing the problems identified with the current TPM and meeting the Authority's statutory objective than any of the options identified by Trustpower.

Submitters' views and our assessment

B.60 Trustpower critiqued the Authority's options analysis and submitted that the most practicable options to address problems with the current TPM are:[336]

(a) the status quo

(b) the status quo with modifications to facilitate the further management of the strength of the RCPD and to enable a wider allocation of the HVDC charge

(c) the Authority's proposal (ideally with the modifications described in chapter 13 of Trustpower's submission)

(d) tilted postage stamp as described in the CEC 2019 Report and

(e) deeper connection charges as described in the CEC 2019 Report and TLG 2019 Report.

B.61 In chapter 13 of its submission in response to the 2019 Issues Paper, Trustpower said that if the Authority decides to proceed with the reform it would recommend the following changes:[337]

(a) a revised and weakened peak charge that reduces over time and may, for example, transition to a LRMC charge. This should be applied to net load, with the specification, measurement and application to be determined by Transpower (including whether a national or regional approach is adopted)

(b) a residual charge applied to net load, with the specific details to be determined by Transpower, subject to the dual criteria of being durable while minimising distortions

(c) incorporation of the HVDC charges into the residual, with a five-year transition

(d) a broader transition path to avoid price shocks, which is achieved by the proportion of charges recovered through the peak charge declining to a lower permanent level and

(e) the benefit-based charges would not apply to existing assets but would be confined to new investments where the beneficiaries can be clearly identified, with the details of the methodology to be determined by Transpower.

B.62 The status quo, tilted postage stamp and deeper connection charges have already been considered. In this section the Authority considers each of the remaining options (including each of the changes recommended in chapter 13 of Trustpower's submission). The Authority's assessment of each option (including amendments) listed by Trustpower is set out in the right-hand column of the following table.

336 Trustpower submission to the *2019 Issues Paper*, p 24.

337 Trustpower submission to the *2019 Issues Paper*, p 43.

Trustpower's listed option	Authority's assessment
Status quo with modifications to manage the strength of the RCPD and to enable a wider allocation of the HVDC charge.	Modifications to manage the strength of the RCPD were considered earlier in this chapter (under the heading 'An RCPD charge with a weakened price signal'). Some incremental reform solutions for a wider allocation of the HVDC charge were considered above.
The Authority's proposal, with the following modifications: • Revised and weakened peak charge that reduces over time and may, e.g. transition to a LRMC charge. Applied to net load, with the specification, measurement and application to be determined by Transpower (including whether a national or regional approach is adopted) • A residual charge applied to net load, with details to be determined by Transpower, subject to being durable while minimising distortions • Incorporation of the HVDC charges into the residual, with a five-year transition • A broader transition path to avoid price shocks, which is achieved by the proportion of charges recovered through the peak charge declining to a lower permanent level and • The benefit-based charges would not apply to existing assets but would be confined to new investments where the beneficiaries can be clearly identified, with the details of the methodology to be determined by Transpower.	A revised and weakened peak charge was considered above (see 'An RCPD charge with a weakened price signal'). See also 'Peak charges under proposed TPM guidelines' information paper.[338] Confining the benefit-based charge to a subset of investments close to the beneficiaries was considered earlier in this chapter (see 'deeper connection charge'). Using net load to allocate the residual charge was considered and rejected for reasons set out from paragraph 10.33 of this paper. The Authority considers that Trustpower's recommended amendments would not lead to a durable TPM, as load customers that get relatively little benefit from the HVDC (such as Buller, Scanpower or Horizon) would be required to pay its costs (and those of other existing investments) and also the costs of future investments that they do benefit from. Cost-benefit analysis (CBA) discussed in chapter 15 indicates that our decision delivers greater long-term net benefits for consumers, compared to the status quo or a future-investments-only version of the proposal that would recover HVDC costs through the residual. A transition path that only slowly and gradually reduces the peak charge over time would not be consistent with the long-term interests of consumers, as the inefficiencies caused by the peak charge would remain for a longer period of time. These inefficiencies are significant and have been evaluated in the CBA. The CBA shows that consumers will receive significant benefits from a TPM consistent with the new guidelines early on,[339] so delay would be costly to consumers. Guidelines provide for a transitional congestion charge. The price cap and congestion charge, if required, ensure transition is consistent with consumers' long-term benefit.

338 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published/

339 See the *April 2020 CBA Information paper*, https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/revisions-to-cba-in-response-to-feedback/, Figure 2.