Transmission Pricing Methodology 2022

Decision paper

Executive summary

New Transmission Pricing Methodology

The Electricity Authority (the Authority) has decided to include a new Transmission Pricing Methodology (TPM) as a schedule to the Code. This new TPM is available on the Authority's website.[1]

This paper explains the Authority's decision to include the new TPM in the Code and responds to submissions on the October 2021 Proposed TPM consultation paper. It also outlines the next steps and timeframes as Transpower implements the new TPM, which will commence on 1 April 2023.

Consumers will benefit

As the regulator of the industry, the Authority's role is to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

With the demand for electricity forecast to increase by 50 percent by 2050, we want to lay solid foundations for consumers to reap the benefits of new and emerging technologies in the electricity sector. By enabling efficient innovation and investment, we can ensure that the settings we implement across the system are fit for the future.

Transmission costs pay for the national grid and make up approximately 10 per cent of the average consumer's total power bill, so getting it right is important.

The new TPM will encourage more efficient use of the grid, and more efficient investment in transmission and generation assets. It will:

- reduce the cost of electricity at peak times when New Zealanders want to use it most
- over time, lead to lower prices for delivered electricity.

The benefits of the new TPM are clear. The Authority's analysis suggests a central estimate of net benefit to New Zealanders of approximately $1.8 billion over the next 28 years.

Supporting the transition to a low emissions economy

New Zealand has a commitment to achieve net zero emissions by 2050, with the Government aiming for 100 percent renewable electricity generation by 2030.

Investment in new generation will be crucial to support the projected increase in consumer demand, including the electrification of transport and industrial processes, if New Zealand is to achieve these goals.

Completion of the Authority's transmission pricing review improves certainty for investment in new renewable generation. Better transmission pricing signals will support the right investments being made at the right time and in the right places, and result in New Zealanders being able to access new, cheaper renewable generation earlier. This will help to ensure the best use of existing and future infrastructure and better position New Zealand to transition to a low-emissions economy.

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1 The new TPM is published on the Authority's website: Transmission Pricing Methodology — Electricity Authority (ea.govt.nz)

The new TPM

The new TPM replaces a pricing methodology that is inefficient and no longer fit for purpose. The issues caused by the current methodology, reasons for them, and relative merits of different solutions have been canvassed in detail over the years. They are summarised in Chapter 2.

At the heart of the new TPM is a benefit-based approach. Those who benefit from transmission investments will pay for them, through fixed-like charges. These help to avoid incentivising participants to take inefficient actions to avoid transmission costs and shift them to others.

A residual charge will recover unallocated costs and the remaining costs of the historical transmission investments that are not recovered through benefit-based or connection charges.

At the start of the new TPM, residual charges will recover most of the costs. Benefit-based charges will become more significant over time.

Wholesale market electricity prices will work alongside the new charges as a more accurate, responsive and targeted real-time signal of the cost of using the grid and of congestion.

The methodology also includes connection charges, a prudent discount policy, and a transitional cap. While transmission charges are being rebalanced, the cap provides reassurance to consumers and businesses that their total electricity bill should not increase by more than 3.5 percent (plus inflation) from their 2019/20 energy costs as a direct result of the new TPM.

Summaries of the key features of the new TPM follow. We focus on the most notable changes to the methodology proposed in October 2021, which have been made as a result of having considered submissions.

Connection charge

As is currently the case, the TPM allocates costs of assets that connect customers to the grid to those customers. Key changes include:

- first mover disadvantages[2] are addressed by:
  - levelling the playing field between early investors (the first movers) and those who invest after, by charging second and subsequent movers a funded asset component which is rebated to the first mover
  - ensuring first movers do not pay for connection capacity that is built in anticipation of other future investments. Instead, the TPM allocates 50% of costs relating to anticipatory capacity to identified regional beneficiaries (through a benefit-based approach) while 50% are "pooled and shared" across all transmission customers (through an addition to the asset component of the connection charge).
- there is no injection overhead component (which under the current TPM is used to recover a share of overhead opex from generators), as it is no longer needed
- the new TPM provides Transpower with (limited) discretion to reclassify interconnection to connection assets.

2 These arise where the first customers to connect to the grid would bear a relatively greater share of connection charges than customers that connect later, and therefore are discouraged from or delay investing, either because they are put at a cost disadvantage to second movers, or they have to pay for extra capacity that they do not want.

Benefit-based charge

The new TPM allocates costs of new and certain historical grid investments to customers in proportion to their benefit. Benefits include giving consumers access to cheaper and more reliable electricity supply, and generators access to bigger markets.

Benefit-based charges (BBCs) recover capital and operating costs (including a share of overhead opex) attributable to a benefit-based investment. A standard method allocates costs of future grid investments valued over $20m, and a simple method applies to future investments under $20m.

The standard method consists of:

- a price-quantity method for investments that provide market, reliability, ancillary service, or "other" benefits
- a resiliency method for the subset of grid investments that mitigate high-impact, low-probability risks such as of a cascade failure.

The simple method allocates charges to regions identified based on historical power flows, as a proxy for benefits from Transpower's 'every day' asset investments (eg, tower painting), and to individual customers within regions in proportion to their share of a region's injection or offtake over a five-year period.

Costs under the simple method are to be split 62.5%:37.5% between load customers and generation customers – a change from the 50%:50% in the proposal. Having taken into account submissions, the Authority considers that on balance this somewhat higher weighting for load is more likely to reflect the relative benefits of simple method investments than the weighting proposed in October. A review of the weighting can occur through an operational review, but will not automatically occur every five years.

Residual charge

The residual charge recovers Transpower's remaining costs that are not recovered through other charges. This includes the remaining costs of all historical investments currently in place, except for the seven investments specifically allocated under BBCs per the 2020 TPM Guidelines decision.

The charge is to be paid by all transmission customers to the extent they are load customers. This includes grid-connected generators with embedded load. Initial allocations are updated over time, though with a significant lag to minimise distortions in grid use and investments.

This lag would also apply to residual charges for new entrants, so that the residual charge gradually ramps up. This avoids new entrants being placed at a competitive disadvantage compared to an existing customer that is expanding.

Batteries are allocated a residual charge based on their final consumption of energy (ie, losses) rather than their total intake of electricity while charging. This avoids double-counting the same electricity both when it charges a battery and again when it is ultimately consumed elsewhere.

The TPM allocates the residual charge using a non-coincident measure of maximum gross demand as a proxy for the customer's size and ability to pay. Where a customer has multiple points of connection at the same connection location, the TPM will measure the aggregated maximum gross demand as if there was only a single point of connection. This avoids double-counting of load, and so overstating a customer's size and ability to pay.

Adjustment to charges

Allocators that determine customers' transmission charges are intended to be largely fixed. But the TPM does provide for circumstances in which adjustments can be made, such as when a customer enters or exits, or there is a substantial and sustained change in grid use.

The adjustment provisions are largely the same as proposed in the 2021 Consultation paper. However, the standard 5 to 8-year lagged adjustment of the residual charge will now also apply where a transmission customer closes or de-rates a large plant but remains a customer. This ensures customers are treated the same whether they close a large plant (but remain a customer), de-rate a plant, or simply reduce output.

Prudent Discount Policy.

The prudent discount policy allows Transpower to discount a customer's transmission charges (including connection charges) to (a) avoid the customer investing in alternative projects to inefficiently bypass existing grid assets, or (b) ensure the customer's charges do not exceed the efficient standalone costs of the transmission services they receive.

As a transitional arrangement any prudent discount agreed by Transpower will be backdated to the start of the new TPM if Transpower receives an application within six months of publishing the relevant application requirements. This avoids customers seeking prudent discounts being disadvantaged by any delay in processing applications at the commencement of the new TPM.

No transitional congestion charge

The TPM does not include a transitional congestion charge (TCC) – the additional component that was provided in the Guidelines to give Transpower another tool to manage congestion if including such a charge would better meet the Authority's statutory objective.

Transpower found that any heightened short term congestion risk from removing the RCPD charge can be effectively and efficiently managed through the tools available to it as the system operator and grid owner. Following consultation, the Authority remains of the view that a TCC is not warranted, as wholesale electricity market nodal pricing provides an efficient market-based signal of the cost of using the grid. However, Transpower is able to propose a TCC later through an operational review, if it reconsiders its view about the tools it needs to manage congestion.

Impact on customers' charges

The new TPM will rebalance the allocation of costs of transmission services, and this means that some transmission customers will pay more and others less than they would if the current TPM had remained in place.

The TPM includes a 3.5% cap on the amount total electricity bills may increase for consumers and businesses relative to 2019/20 as a direct result of the new TPM being implemented (after allowing for inflation and volume growth).

In our 2021 Consultation paper we explained the impact of the new TPM on transmission customer bills and household consumers, including by providing indicative charges for 2021/22.

We have prepared a limited update of indicative charges, based on changes we have made since 2021 to three aspects of the TPM (the simple method weighting, the allocation of residual charges for customers with multiple GXPs at a single location and adjustments for disconnection of plant). Based on this indicative update, for the local networks that would pay more, on average annual household electricity bills would increase by $12 as a result of the TPM. In the local networks that would pay less in transmission charges, on average household electricity bills for the year would be around $18 lower.

The transitional cap limits the overall increase for some directly connected customers, providing them time to adjust to the implications of the new transmission charges.

We note that additional data on gross load of a small number of specific customers will result in some further rebalancing of charges.

With the TPM finalised, Transpower will calculate and consult on actual charges under the new TPM for 2023/24. Transpower intends to publish indicative charges for pricing year 2022/23 (ie, the pricing year commencing 1 April 2022) as soon as practicable before the end of April 2022.

Certainty under the new TPM

The Authority acknowledges that, like any change, the transition to the new TPM involves uncertainty; however, the uncertainty is not at a level that is out of step with other uncertainties typically considered in investment business cases. The Authority is confident the new TPM will not ultimately lead to uncertainty that would be a barrier to future electricity-related investments.

With the new TPM finalised, Transpower will over time work to establish what further information could be produced to help stakeholders better understand the implications of the new TPM. Transpower will also carry out its normal customer engagement, including consultation on inputs to transmission charges in the lead up to the first pricing year under the new TPM. Stakeholders will continue to invest time and resources in understanding the factors that matter to them, including engaging on investment proposals and scrutinising their costs and benefits.

Next steps

Both Transpower and the Authority will be carrying out various activities in advance of the new TPM coming into force on 1 April 2023.

Transpower will be calculating and publishing new transmission prices (and consulting with its customers along the way).

The Authority will be working on supporting Code amendments and on providing guidance on pass-through of transmission prices by distributors to their customers.

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1 Decision to incorporate a new TPM into the Code

1.1 The Electricity Authority has decided to include the new Transmission Pricing Methodology (TPM) as a new Schedule 12.4 of the Code, replacing the existing TPM. The new TPM is available on the Authority's website.[3]

1.2 The new TPM gives effect to the 2020 Transmission Pricing Methodology Guidelines (Guidelines) the Authority published on 10 June 2020.

1.3 In this Decision paper, the Authority sets out and explains the Authority's decision to adopt the new TPM into the Code and addresses submissions on the proposed TPM published for consultation on 8 October 2021.

1.4 This paper also outlines next steps and timeframes as Transpower implements the new TPM.

The Authority's statutory objective

1.5 As a Crown entity, the Authority must act consistently with its statutory objective, which is at s15 of the Electricity Industry Act 2010:

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.

1.6 The Authority considers the new TPM is consistent with its statutory objective, and the Guidelines (or consistent with the intent of the Guidelines, where the new TPM differs in its detail from the Guidelines, as permitted under clause 2).[4]

Process for the development of the TPM

1.7 The review of the TPM is governed by Part 12, subpart 4 of the Code. The legal framework around commencing a review and issuing TPM Guidelines was discussed in chapter 4 of the 2020 Decision paper.

1.8 The Authority may review an approved TPM if it considers there has been a material change in circumstances (clause 12.86).

1.9 The Authority considered that there had been a material change in circumstances since the current TPM came into force, meeting the clause 12.86 threshold. Its reasons for doing so are set out in para 4.25-4.35 of the 2020 Decision paper. These reasons have not changed.

1.10 In 2020, the Authority issued new TPM Guidelines following a decade-long review process.[5] This process included significant consideration of alternative options, benefits and costs. The Decision paper also set out the process for development and approval of the proposed TPM, in accordance with cl 12.81 to 12.83 of the Code.

1.11 In accordance with this process, Transpower developed the proposed TPM and received feedback from the Authority at various checkpoints. Transpower then

3 The new TPM is published on the Authority's website: [Transmission Pricing Methodology — Electricity Authority (ea.govt.nz)]

4 Clause 2 of the 2020 Guidelines allows the TPM to differ in detail from the particular requirements of the Guidelines, but not the Guidelines' intent, if doing so would better meet the Authority's statutory objective than complying with the Guidelines in their entirety.

5 See Figure 2, p11 of the Authority's [2020 Decision paper.] See also chapter 7 of the 2019 Issues Paper.

submitted the proposed TPM to the Authority on 30 June 2021, in accordance with cl 12.88 of the Code.

1.12 Throughout its development process for the proposed TPM, Transpower undertook various engagements with stakeholders. Transpower's Reasons paper discusses its proposal with reference to stakeholders' submissions and Authority feedback from its checkpoint process on different design topics.

1.13 The Authority considered Transpower's proposal against the 2020 Guidelines and the Authority's statutory objective, referring elements of the proposed TPM back to Transpower in accordance with cl 12.91(1)(b) of the Code. The Authority then finalised a proposed TPM that was to a large extent based on that provided by Transpower, with some minor amendments (under cl 12.91(2) of the Code).

1.14 In accordance with sections 38 and 39 of the Electricity Industry Act 2010, the Authority then, before amending the Code:

- published a draft of the proposed amendment
- prepared and published a regulatory statement, including referencing its earlier work on alternative options for reform
- consulted on the proposed amendment and regulatory statement.

1.15 The consultation period ran from 8 October 2021 to 23 December 2021, and the Authority received 33 submissions and 12 cross-submissions. These have been published on the Authority's website.

Addressing submissions

1.16 All submissions and cross-submissions in response to the 2021 Proposed TPM consultation paper have been reviewed and considered by the Authority in reaching its decision. All submissions have been made available to Board members, who have each conducted a review prior to reaching their decision.

1.17 A thematic discussion of submissions, reflecting the key points raised, is included in the chapters that follow. The discussion of submissions necessarily compresses the information provided. Submitters should be assured that, even where a submission or particular points made are not explicitly mentioned in this Decision paper, or not addressed in detail, they have been considered by the Authority's Board.

1.18 After considering submissions, the Authority has made a number of changes to the proposed TPM. A list of the changes the Authority has made is at Appendix A.

Supporting information

1.19 As is outlined above, the contents of this Decision paper represent the end of a long process, which included the Authority's decision to issue new Guidelines in June 2020, Transpower's proposed TPM development and engagement process that ran for approximately a year to 30 June 2021, and the Authority's consultation on a proposed TPM between 8 October and 23 December 2021.

1.20 This Decision paper thus builds on prior materials. This paper sets out the key features of the new TPM and summarises the Authority's analysis and the reasons for its decision, with a focus on the key choices set out in the 2021 Consultation paper and other relevant aspects raised in submissions and cross-submissions. That is, the focus is on the key issues which remained for discussion at this latter stage of the TPM process, without necessarily repeating analysis of issues addressed in earlier papers.

1.21 Accordingly, this Decision paper should be read with reference to the 2021 Consultation paper, Transpower's Reasons paper, and the Authority's 2020 Decision paper, the 2020 Guidelines and associated papers. Taken together, these papers explain the intent, approach and detailed provisions of the new TPM and the reasons for them.

1.22 This Decision paper also does not replicate the cost-benefit analysis (CBA) or indicative charges contained in the 2021 Consultation paper. Following consideration of submissions on the CBA the Authority is satisfied that the assumptions and methods it has used in the CBA are appropriate and reasonable and that the CBA produces reliable results.[6] The limited scope of the amendments to the proposed TPM in light of submissions also mean that CBA assumptions or methods do not require amendment; however, for completeness the Authority did re-run the CBA's central scenario changing the assumed simple method weighting to 62.5%:37.5%, but without making any other changes. Those results are reported in this paper (although as previously noted the CBA results are only one factor in the Authority's decision).

1.23 The Authority has prepared a limited update of indicative charges, based on changes we have made since 2021 to three aspects of the TPM (the simple method weighting, the allocation of residual charges for customers with multiple GXPs at a single location and adjustments for disconnection of plant). The results of this indicative update are set out in Chapter 12. With the TPM finalised, Transpower will calculate and consult on actual charges under the new TPM for pricing year 2023/24. Transpower also intends to publish indicative charges for pricing year 2022/23 (ie, the pricing year commencing 1 April 2022) as soon as practicable before the end of April 2022.

1.24 Table 1 on the following page provides links to key reference information.

Next steps

1.25 Both Transpower and the Authority will be carrying out various activities in advance of the new TPM coming into force on 1 April 2023.

1.26 Transpower will be implementing the new TPM in its systems, allocating transmission costs, and calculating and publishing new transmission prices (and consulting with its customers along the way).

1.27 The Authority will be working on supporting Code amendments on such topics as data availability, existing prudent discount agreements and notional embedding contracts, the settlement residual allocation methodology, the avoided costs of transmission rules, and future reviews of the TPM. We will also be providing guidance on pass-through of transmission prices by distributors to their customers.

1.28 Next steps are discussed further, with expected timings, in chapter 15.

[6] The Authority's consideration of submissions on its CBA is discussed in Chapter 14 and Appendix C.

Table 1 Key sources of information

Item	Reference
2021 Proposed TPM consultation paper	https://www.ea.govt.nz/assets/dms-assets/29/Proposed-Transmission-Pricing-Methodology-Consultation-paper-v2.pdf
Transpower's Reasons paper	TPM Proposal Reasons Paper 30 June 2021.pdf (transpower.co.nz)
Transpower TPM development	https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm
2020 Guidelines	https://www.ea.govt.nz/assets/dms-assets/26/26850TPM-2020-guidelines-10-June-2020.pdf
2020 TPM Guidelines Decision paper	https://www.ea.govt.nz/assets/dms-assets/26/26851TPM-Decision-paper-10-June-2020.pdf
Peak charges under proposed TPM Guidelines information paper	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published
2020 Supplementary consultation paper	https://www.ea.govt.nz/assets/dms-assets/26/26354TPM-supplementary-consultation-Feb-2020.pdf
2019 Issues paper	https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf

1.29 Further relevant background related to the decision is available on the Authority's transmission pricing review webpage at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

2 A new TPM to give effect to the 2020 Guidelines

Addressing issues with the existing TPM

2.1 Transpower provides the infrastructure that transports electricity from where it is generated to local lines companies and large industrial users.

2.2 The Transmission Pricing Methodology (TPM) sets out how Transpower will recover its maximum allowable revenue from its transmission customers. The Commerce Commission determined this at an average of $809 million per year between 2020 and 2025.[7]

2.3 In 2020, the Authority issued new Guidelines for development of a proposed new TPM following a decade-long review process.[8]

2.4 This review identified evidence that the current approach to transmission pricing is causing inefficient behaviours and outcomes which do not promote the Authority's statutory objective. Some issues had been present since the review of the TPM started in 2009, while rapidly changing technology (including reducing technology costs) and the implications of New Zealand's transition to a low-emissions economy meant the need for change was becoming increasingly pressing over time.

Existing issues

2.5 The 2020 Decision paper provides a comprehensive problem definition with respect to the existing TPM. In brief, the Authority found evidence of inefficient behaviours and outcomes caused by the current TPM, the key issues being that:

- the RCPD charge distorts the cost of using transmission. Consumers unnecessarily reduce their demand at peak times, even when there is no congestion of the grid, meaning consumption is inefficiently reduced. The charge promotes unnecessary investments in distributed generation, processes and technologies to avoid and shift transmission charges on to others. The RCPD charge is likely to get more volatile over time as customers get increasingly good at managing their peaks, further encouraging these behaviours
- the HVDC charge distorts the cost of South Island generation. It raises the cost of generation in the South Island, and tilts the playing field towards otherwise more expensive generation in the North Island which does not face equivalent charges
- smearing charges across the country (postage stamping) results in poor incentives to scrutinise grid investments. Those who would benefit from a grid investment know that most of the costs will be paid for by the rest of the country, so may favour this over alternative solutions (eg, local generation, demand response).

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7 Commerce Commission, *Transpower's individual price-quality path from 1 April 2020. Companion paper to final RCP3 IPP determination and information gathering notices*, Nov 2019. https://comcom.govt.nz/__data/assets/pdf_file/0035/188783/Transpower-Individual-Price-Quality-Path-from-1-April-2010-Companion-paper-to-final-RCP3-IPP-determination-and-information-gathering-notices-14-November-2019.PDF .

8 See Figure 2, p11 of the 2020 Decision paper.

2.6 As a result of these issues, the Authority considers that the current TPM is not durable.

2.7 The Authority also identified that long-standing debates over many of these issues would get worse given the projected growth in transmission use and investment as part of the transition to a low-emissions economy.

Other strategic considerations

2.8 The new transmission pricing methodology supports New Zealand's transition to a low carbon future at the least cost to consumers by providing more certainty for investment in new renewable generation and electrification of industrial processes.[9]

2.9 Better transmission pricing signals will result in New Zealanders being able to access new cheaper renewable generation earlier. Improved pricing will support the right investments being made at the right time and in the right places and help ensure the best use of existing and future infrastructure.

2.10 The new TPM addresses potential barriers to investments that will be required in the transition to a low-emissions future, which is premised on the connection of new renewable generation and the electrification of process heat.

2.11 For example, the TPM has provisions that smooth the path for investment in new renewable generation and electrification by addressing the 'first mover disadvantage.' Under the new TPM the party who first funds the capital cost of a connection asset (first mover) only pays for what they need but:

- not disproportionately more than a second mover who connects later (subsequent movers rebate a share of connection costs to the first mover)
- not for any extra capacity that Transpower considers it is prudent to build in anticipation of (uncertain) future requirements (which is instead funded by a wider group of customers until subsequent movers connect).

2.12 The Authority has also considered consistency with the Government's wellbeing and living standards objectives.[10] The TPM provides for a transitional cap on transmission charges to protect household and most business consumers, ensuring that the new TPM does not directly result in an increase to their total electricity bills of more than 3.5% (plus inflation) relative to 2019/20. Transmission revenue 'lost' due to customers' charges being capped is recovered by a surcharge on other customers' charges.

The 2020 Guidelines provide for new charges to address these issues

2.13 The TPM is expected to address the issues with the current TPM through a set of new charges for transmission, which involve:

- relying on wholesale electricity market nodal prices to signal the immediate cost of using the grid (with the Guidelines also enabling Transpower to implement a targeted transitional congestion charge via an operational review in the future, if needed to assist it to efficiently manage ongoing congestion in specific circuits),

[9] See 2021 TPM Consultation paper Chapter 14, para 14.22 on, and the 2020 Decision paper Chapter 5.

[10] See 2021 TPM Consultation paper, Chapter 14, para 14.30 on.

thus addressing any risks of congestion as needed, while otherwise avoiding distortionary over-signalling

- charging the costs of grid investments to those who benefit from them in the form of a fixed-like benefit-based charge or connection charge, thus sending efficient signals as to the cost of connecting to, and using, the grid
- using a fixed-like residual charge to recover any revenue not gathered through other transmission charges
- allowing for transmission charges to be discounted if otherwise they would exceed a customer's standalone costs or make it viable for that customer to inefficiently bypass the grid
- providing for a transitional cap to limit the exposure of load customers to increased total electricity bills as a result of introducing the new TPM.

Submitters' views and Authority comment

2.14 While the problems of the TPM were comprehensively submitted on and analysed during earlier phases of the TPM review, some submitters, like Contact Energy or Meridian Energy reiterated their support for the need for change in general and provided feedback on particular aspects of the proposed TPM. Such feedback is considered alongside other submissions on relevant topics.

2.15 Other submissions disagreed with the Authority's previously identified problem definition (Oji Fibre), questioned the issues (Orion), considered it had not been properly assessed for materiality (Trustpower), were critical of the solutions as expressed in the Guidelines (eg, Network Waitaki), or expressed a general concern that the proposed TPM would slow decarbonisation and electrification (eg, Hiringa Energy, Oji Fibre, Fonterra). For example:

- Oji Fibre disagreed that the RCPD charge distorts the cost of using transmission or promotes cost shifting
- Orion thought the problem definition does not acknowledge that long term price signals are needed to encourage a response in an inelastic electricity market
- Trustpower submitted that the propositions had not been properly assessed for materiality, counterbalancing factors, or tested against actual evidence[11]
- Network Waitaki disagreed the proposed TPM was the most efficient model given for example the disproportionately large residual charge
- some submissions expressed concern that the new TPM would slow decarbonisation and electrification because:
  - removing the RCPD charge would reduce incentives to invest in demand response solutions (Hiringa Energy)

[11] The Authority disagrees with Trustpower's statement and related examples. For example, Trustpower suggests that the Authority assumes transmission customers will just accept allocations or adjustments as reasonable and not dispute them. However, the Authority expects additional scrutiny of proposed allocations and in the CBA made specific allowances for the cost of additional disputes.

- allocating residual charges on gross demand would reduce incentives to invest in Central North Island bioenergy infrastructure (Oji Fibre) or electrification (Fonterra).[12]

2.16 These submissions tended to focus on matters that relate to decisions on the Guidelines and thus which had been consulted on and responded to previously. For example:

- the 2019 Issues paper (pp 9-10) provided specific descriptions of how the RCPD charge is a poor signal of the cost of using the grid and of cost-shifting
- the 2020 information paper, Peak charges under proposed TPM Guidelines (p6), notes that benefit-based charges associated with potential new grid investments give forward-looking price information
- the 2020 Decision paper documented both qualitative and quantitative assessments of the status quo vs a considerable number of options (with the CBA providing a quantitative assessment of the materiality of different concerns, such as the impact of transmission charges on demand and locational decisions)
- the 2020 Decision paper explained how the 2020 Guidelines for transmission pricing promoted the Authority's statutory objective, with a pricing structure which, as Professor Hogan put it "adheres to first principles and can accommodate workable implementation"[13]
- the Guidelines allowed for Additional component E which could have been used to reduce the residual charge, but Transpower did not propose it, and the Authority agreed that this was the right choice.[14] Further, the prudent discount policy is available in the event that a disproportionately large residual charge may cause a customer to disconnect from the grid or have inefficiently high charges
- the 2020 Decision paper (and the consultation paper) showed how the proposed TPM would lead to reduced electricity prices and increased volumes (consistent with the Climate Change Commission's demonstration path).

2.17 Such submissions are nonetheless considered in the context of the specific topics that are part of the new TPM.

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12 Though Mataura Valley Milk supported a TPM with a residual charge with lagged adjustment.

13 Hogan W, 2020, Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal, Microsoft Word - Hogan_EA_Report_020120

14 It could potentially be proposed later via an operational review.

3 Grid asset classification

3.1 Grid assets are classified as either connection or interconnection assets. This classification determines the charges that apply to recover the costs of those assets.

3.2 Grid asset classification under the new TPM is largely similar to that under the existing TPM. That is, in general, interconnection assets are configured in a loop of continuous nodes and links (the interconnected grid) and connection assets form a link between a transmission customer's plant and the interconnected grid.

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
General: Clause 11, 12, 69	Clauses 17-23
Add. components A & B: Clause viii, 54, 55	Clauses 17(1), 19(3), 20(4)
Discretion to classify and reclassify: Clause vii(b)	Clause 23

Additional component A: Classification of grid assets during staged commissioning

Our decision

3.3 The new TPM adopts the approach to the classification of grid assets during staged commissioning that was proposed in the 2021 Proposed TPM consultation paper.[15] The submissions on this topic are noted below.

What we proposed

3.4 Reflecting the Guidelines, the proposed TPM provided for connection assets to be treated as interconnection assets for a limited time if the assets would ultimately be interconnection assets when fully commissioned.[16]

Submitters' views and our assessment

3.5 Several stakeholders commented on this proposal in their submissions.[17] All those that submitted on it were supportive. For example, Contact Energy submitted:

"We support treating connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned. This will avoid circumstances where staged commissioning would be efficient but be opposed by customers reluctant to pay connection charges in the short term."

3.6 The Authority agrees with Contact's submission and considers that its decision on this issue is consistent with the Guidelines and will promote the statutory objective for the reasons noted by Contact.

15 See chapter 3 of the Proposed TPM consultation paper 2021.

16 See Chapter 4: Part B - Grid Asset Classification of Transpower's Reasons paper.

17 Submissions on this topic were received from Contact Energy, Fonterra, Orion and Trustpower.

Additional component B: Effect of other parties connecting to grid assets

Our decision

3.7 The new TPM adopts largely the same approach to this issue as was proposed in the 2021 Consultation paper.[18] However, in response to a submission, the Authority has decided on a minor change to the relevant TPM provision to clarify that it applies only to the effects of other parties connecting to grid assets *in future*; it will not result in a change to the status of existing grid assets.

What we proposed

3.8 Reflecting the Guidelines, the proposed TPM included provisions to ensure that connection assets cannot be changed into interconnection assets simply by a person other than Transpower investing in other assets to create an interconnection loop.[19]

Submitters' views and our assessment

3.9 We received largely positive feedback from submitters on these proposed provisions.[20] For example, Orion's submission was largely supportive but also made some other points suggesting that changes may be in order:

"we agree with the limitation on a third party's ability to convert connection assets into interconnection assets via their own investment to close a loop. However, when exercising its discretion, Transpower should have regard for existing situations (and prior investments) where assets have been categorised as interconnection assets in this way eg, the possible future reconsideration of the connection status of a GXP that becomes a net injector from renewable generation or where the lines to a GXP are considered a spur and the GXP a connection asset."

3.10 In response to Orion's submission, the Authority has decided on a minor change to this TPM provision to clarify that it will not result in a change to the status of existing grid assets; it applies only to the effects of parties connecting to grid assets *in future*. Transpower's Reasons paper and the 2021 Consultation paper are clear that this provision was only intended to apply to future connections and so the Authority has looked to clarify this in the TPM itself. The Authority considers that its decision on this issue is consistent with the Guidelines and will promote its statutory objective, because it will remove inefficient incentives for customers to – *in future* – construct assets in order to avoid paying connection charges. By contrast, applying this provision to existing assets would not change incentives, as the relevant assets have already been constructed. Further, if any assets have been inappropriately classified as interconnection, Transpower has the discretion to correct the situation (as discussed in the next section).[21]

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18 See chapter 3 of the Proposed TPM consultation paper 2021.

19 See chapter 4 of Transpower's Reasons paper.

20 Submissions on this proposal were received from Orion and Trustpower.

21 The Authority does not consider that any other changes suggested by Orion's submission (noted in the quotation above) would be appropriate. We note that whether a grid point of connection is mostly a grid exit point or mostly a grid injection point does not have any impact on the connection/interconnection status of the grid assets at or connecting to the relevant connection location.

Discretion to classify and reclassify as connection

Our decision

3.11 The TPM includes a discretionary power for Transpower to reclassify interconnection assets as connection assets in certain circumstances. The TPM requires Transpower to consult affected customers, and Transpower's decision may be referred to an independent expert whose decision will be binding.

What we proposed

3.12 The proposed TPM included Transpower's proposal that it be afforded a discretionary power to reclassify interconnection assets as connection assets if the grid asset directly or indirectly connects one or more customers to the rest of the interconnected grid, the grid asset does not provide material transmission services to any other customers, and Transpower considers it is fair and reasonable in all the circumstances to do so. There was no explicit requirement on Transpower to consult on the use of its discretion, or a right of review.

Submitters' views and our assessment

3.13 Buller submitted (pp1-5) that providing Transpower with discretion to reclassify interconnection assets as connection assets was not ideal, preferring that the Authority improve the definition of connection assets to remove the need for such a power. Fonterra's submission (p 2) also did not support the proposal (because it considers it is not Transpower's role to determine who is or who is not an interconnection customer) and that if the TPM provides for this discretion further conditions should be in place to mitigate potential bias or conflicts that could arise.[22]

3.14 The Authority considers that the definitions of connection asset and interconnection asset have proven to be fit-for-purpose, and generally produced appropriate classifications. We are currently only aware of a single instance where a reclassification was thought to potentially be appropriate, and as such do not consider there is a case for a general review of definitions.

3.15 The Authority considers that careful definitions likely would not eliminate the potential need for judgement entirely. The discretionary power in this case is to cater for the rare instances where reclassification may be appropriate. The Authority does, however, consider that a discretionary reclassification power should be no broader than necessary, thus promoting certainty of the asset classification rules.

3.16 We have made drafting changes to clarify the situations in which the clause applies and to focus on the reasonableness of Transpower's approach. These changes have been made to provide more certainty as to when reclassification might occur.

3.17 The criteria Transpower must assess when deciding whether to classify or reclassify an interconnection asset as a connection asset have been slightly changed from the version consulted on to provide this may occur where Transpower determines:

(a) the grid asset provides or will provide transmission services to one or more customers of a type and nature typically provided by connection assets; and

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22 Fonterra suggested the following conditions: consultation with stakeholders; approval by the Commerce Commission or the Authority; and definitions of initiation points that allow Transpower to make such changes.

(b) the grid asset does not provide or will not provide any material transmission services of a type and nature typically provided by interconnection assets; and

(c) it is reasonable in all the circumstances to classify or reclassify the grid asset as a connection asset.

3.18 We do not agree with Buller's submission that a "material impact" test should be applied when exercising the discretion, which would in effect establish a threshold for when different distributional outcomes may be appropriate. We consider that the assessment should be based just on the technical criteria above, not also on materiality / distributional outcomes, as this would reduce certainty for stakeholders (due to greater complexity and scope for controversy).

3.19 Given the potentially significant financial impact on customers of the use of the reclassification power,[23] the TPM requires Transpower to consult affected customers before finalising its decision, and if these customers are not satisfied with the decision, they may refer the matter to an independent expert for a binding decision.[24]

3.20 The TPM does not provide discretion for Transpower to reclassify assets from connection to interconnection assets. Refining NZ submitted in favour of allowing reclassification from connection assets to interconnection assets (if the asset in substance principally provides interconnection services). Refining NZ considers that the Bream Bay connection assets are oversized (for historical reasons) and provide additional electricity security benefits to northern consumers other than itself. As such it suggests they could be considered to be interconnection assets.[25]

3.21 The Authority considers that there is not a strong case for Transpower to have the discretion to reclassify connection assets as interconnection assets. Where connection assets are funded through commercial contracts, a discretion to reclassify may interfere with efficient investment incentives as it shares the risk of overinvestment across other transmission customers. If a discretion to reclassify connection assets as interconnection assets is required at some future date, Transpower can propose it via operational review.

3.22 The Authority has considered a number of options that might potentially be available to address the issue raised by Refining NZ around oversized connection assets.[26] A prudent discount might be available to deal with situations such as this. However, we have been unable to identify any other appropriate solutions within the TPM.[27]

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23 As an example, Buller's connection charges in 2021/22 under the current TPM were $1.7k. Buller's indicative connection charges for that year under the proposed TPM (ie, with certain interconnection assets reclassified as connection assets) were $459k.

24 This replicates review rights for decisions on applications for reassignment and prudent discounts under the TPM.

25 Transpower has advised that the Bream Bay transmission assets are connection assets as they meet the existing (and proposed) definition of connection assets, which is based on physical configuration.

26 Refining NZ also discusses other solutions to deal with Bream Bay, including applying for a prudent discount and extend de-rating under clause 34 to embedded customers' assets.

27 For example, extending de-rating under clause 34 to embedded customers' assets only addresses the problem of oversized connection assets if the connection is shared between two or more customers.

4 Connection charge

4.1 The connection charge recovers the costs of connection investments that connect a transmission customer's assets to the interconnected grid.

4.2 Transpower's modelling of indicative prices estimates that approximately 15% of its maximum allowable revenue (that is, its regulated revenue) would relate to connection charges ($121m in 21/22).

Relevant sections in the Guidelines and the new TPM

Guidelines	TPM
Clause iii, 11, 12 connection charge	Part C: Clauses 24-34
Clause viii, 54, 57, 64 Additional component C, F	

General provisions

Our decision

4.3 The new TPM retains many of the connection charge provisions in the current TPM.

4.4 With respect to particular changes to the connection charge provisions discussed in the 2021 Proposed TPM consultation paper, the Authority has decided that the connection charge provisions in the TPM should:

- not include an injection overhead component
- provide for the regular updating of replacement costs
- add a cable line type for maintenance cost calculation.

The decision to retain, with the above modifications, the existing provisions for the connection charge is consistent with the Guidelines, as discussed in chapter 4 of the 2021 Consultation paper.

In addition, the TPM contains provisions that seek to address first mover disadvantage with respect to investing in connection assets. These are discussed in separate sections below.

What we proposed

4.5 The Authority proposed not to include an injection overhead component as found in the current TPM in the new TPM provisions for connection charges. As Transpower identified, certain overhead operating costs would be included in the benefit-based charges that also apply to generators and such a component is therefore not needed.[28]

4.6 The proposed TPM also provided for replacement costs of connection assets to be updated at least every five years (subject to appropriate consultation). This helps to keep customers' connection charges broadly cost-reflective.[29]

28 See Authority's 2021 proposed TPM Consultation paper, para 4.6-4.8.

29 See Authority's 2021 proposed TPM Consultation paper, para 4.9-4.15.

4.7 A cable line type was proposed to be added to the three line-types that are listed in the current TPM. This is to support a more cost-reflective calculation of the maintenance cost component of connection charges.[30]

Submitters' views and our assessment

4.8 Only a few submissions commented on the general aspects of the connection charge or the three modifications summarised above.

Injection overhead component

4.9 Transpower had proposed there was no longer a need for the overhead injection component.[31] [32] This was because it instead proposed a reasonably attributable amount of overhead opex would be recovered through benefit-based charges (with the remainder recovered through residual charges).[33]

4.10 Contact did not support removal of the injection overhead component, because it disagreed with the proposal to recover overhead opex through benefit-based charges. Instead, it preferred recovering overhead opex through the residual charge, as the Authority had suggested was the intent previously, and retaining the overhead injection component as there was general satisfaction with the way connection charges currently work.

4.11 Given the Authority's decision on the treatment of overhead opex discussed in more detail at Chapter 6 below, the Authority has decided there is no need for an injection overhead component.

Regular updating of replacement costs

4.12 Replacement costs of connection assets are used to determine the share of connection asset costs allocated to each connection asset. When replacement costs get out of date, connection charges may no longer sufficiently reflect costs.

4.13 Contact, Nova and Trustpower agreed with the Authority's rationale for regular updating of replacement costs (para 4.6 above). Orion submitted it was not clear such updating would change allocations much and was concerned, as was Refining NZ, that updating replacement costs may not align with the depreciated historic cost approach in the Input Methodologies under part 4 of the Commerce Act.

4.14 Regular updating of replacement costs is consistent with the Guidelines as it would help set charges in a way that reflect the costs of connection assets. The updating clause provides connection customers with certainty that their charges will be regularly updated in line with the (relative) replacement cost of the connection assets.

4.15 Because replacement costs are used for cost allocation, it is the relativities between replacement costs that are important in calculating connection charges. The actual

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30 See Authority's 2021 proposed TPM Consultation paper, para 4.16-4.18. Orion agreed with the proposal.

31 See 2021 proposed TPM Consultation paper p12, and Transpower's Reasons paper, Chapter 5: Part C -Connection Charges, Page 5.7.

32 In addition, the Guidelines do not provide for different treatment of generators and load in the setting of connection charges.

33 See Chapter 6. Non-network overhead expenses would be recovered through the residual charge.

costs to be allocated reflect historical costs, consistent with part 4 of the Commerce Act.

Type 1 First Mover Disadvantage: free-riding

4.16 As set out in the 2021 Consultation paper, there are two types of first mover disadvantage (FMD) relevant to the connection charge. The Type 1 first mover disadvantage occurs when a customer (the first mover) continues to bear the full cost of the connection investment even if second and subsequent movers later connect to the asset. Further explanation can be found in the 2021 Consultation paper.[34]

Our decision

4.17 The TPM (clauses 28 and 29) adopts the "funded asset component" (FAC) mechanism unchanged from the proposal consulted on. This involves adding a component to the second and subsequent movers' connection charges to collect a financial contribution from them towards the capital cost of the connection investment, which would then be rebated to the first mover.

What we proposed

4.18 The FAC is essentially a reallocation of connection charges for a connection investment so as to charge the first mover less and the second and subsequent movers more, once those second and subsequent movers later connect. The Authority considered this proposal was comparable to a commercial outcome the first mover and subsequent customers might reasonably have agreed.[35]

Submitters' views and our assessment

4.19 All submissions we received on this matter were supportive of the proposed approach.[36]

4.20 We consider that the proposed FAC is consistent with the Guidelines and will promote efficiency and competition as further explained in the 2021 Consultation Paper.[37]

4.21 We also sought submissions on whether this FAC mechanism may cause competition issues in the market for generation development.[38] However, no submissions raised concerns on this issue and we consider the issue is not likely to be significant in practice and therefore no modification to the proposed FAC mechanism is needed.

Type 2 First Mover Disadvantage: inefficient sizing

4.22 The Type 2 FMD occurs when a connection asset is built with more capacity than the first mover requires (ie, anticipatory capacity for anticipated future connections) and the first mover bears the cost of the anticipatory capacity until the second and

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34 2021 proposed TPM Consultation paper, paragraphs 4.23 to 4.26.

35 See 2021 proposed TPM Consultation paper, footnote 28 and 29.

36 Contact, IEGA, Mercury, Northpower, Orion, Refining New Zealand, and Trustpower. Vector also suggested that Transpower should consider the impact of its New Investment Contract practices on connection customers.

37 2021 Proposed TPM Consultation paper, paragraph 4.25 and footnote 29.

38 Paragraph 4.26 of the 2021 proposed TPM Consultation paper.

subsequent movers connect, as well as the risk that no future customers connect.[39] This may deter the first mover from connecting in the first place, or deter the building of the anticipatory capacity even if that were efficient.[40] Further explanation can be found in the 2021 Consultation paper.[41]

Our decision

4.23 The new TPM will address the Type 2 first mover disadvantage (FMD) issue by:

(a) allocating 50% of the capital cost of anticipatory capacity to identified regional beneficiaries under a benefit-based approach (using the simple method regional allocation tables)

(b) allocating the remaining 50% of the capital cost of anticipatory capacity to all transmission customers under a “pool-and-share” approach, through an addition to the asset component of the connection charge.[42]

What we proposed

4.24 The 2021 Consultation paper proposed that the Type 2 FMD would be addressed by only allocating to the first mover costs relating to the capacity it requires (not costs relating to any anticipatory capacity).

4.25 We proposed several approaches to allocating the costs relating to anticipatory capacity (noting that when second and subsequent movers connect, anticipatory capacity assets are reclassified as connection assets and the amount of anticipatory capacity reduces, eventually to zero):

(a) The primary proposal was a benefit-based approach. Anticipatory capacity assets would be treated as benefit-based investments and capital costs relating to these assets would be allocated to customers in regions that would benefit from accessing the expected lower or higher wholesale electricity prices that result from subsequent connections.[43] If anticipatory capacity is being built for expected generation, local and downstream consumers would be expected to benefit from lower prices, and if it is being built for expected new load, local and upstream generation customers would be expected to benefit from higher prices. This allocation would be made using the regional allocation tables used by Transpower under the BBC simple method.

(b) The 2021 Consultation paper also referred to Transpower’s proposed pool-and-share approach. Capital costs relating to anticipatory capacity would be

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39 For greenfield projects, Transpower could elect to carry this cost and risk itself, but it is not required to do so.

40 Although the first mover does stand to benefit via FAC payments from sharing its connection costs in the longer term.

41 2021 Proposed TPM Consultation paper, paragraphs 4.27 to 4.32.

42 Only capital expenditure relating to anticipatory capacity assets is being allocated in this way. Maintenance and operating expenditure in relation to the connection asset (including the anticipatory capacity) will be borne by the first mover through the maintenance and operating components of the connection charge (although these components are likely to make up a relatively small proportion of the total connection charge for the asset).

43 As explained in the 2021 Proposed TPM Consultation paper, “anticipatory capacity assets” may be separable assets or just a shared part of assets that are sized larger than the capacity needed for the first mover. For these purposes, the costs relating to the anticipatory capacity will need to be separated out from the costs relating to the capacity required by the first mover.

socialised across all transmission customers in proportion to the replacement cost of their connection assets.[44]

4.26 The 2021 Consultation paper also discussed a complementary alternative to the benefit-based approach where the amount allocated to identified regional beneficiaries would be limited in some way. The purpose of this limit would be to limit cost impacts where there are only a small number of identified beneficiaries who would therefore each bear a larger proportion of the benefit-based investment cost.[45]

4.27 Alternative approaches ("temporary socialisation" and "brownfield-only" approaches) were also presented. These options were not proposed or preferred by the Authority and they did not receive much attention in the submissions.[46]

Submitters' views and our assessment

4.28 Submissions largely agreed that building anticipatory capacity into certain connection assets makes sense, but that the cost of that anticipatory capacity should not be borne by the first mover.[47,48]

4.29 However, submissions disagreed on who should pay for the anticipatory capacity. Some submitters agreed with the proposed benefit-based approach.[49] Others argued that the cost of anticipatory capacity should be met by the Crown or by Transpower (although such a solution is outside the scope of the TPM)[50] or through

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44 These costs would be socialised across the entire transmission customer connection asset pool, including assets funded under investment agreements.

45 Suggested limits included limiting a customer's transmission charges increase by a set percentage or limiting the size of the anticipatory capacity relative to the first mover's capacity.

46 Transpower noted that the temporary socialisation approach only reduces and defers the Type 2 FMD, but does not remove it. Both Contact and Transpower referred to the "brownfield-only" option in their submissions, but did not support it. MEUG argued that for greenfield investments (or brownfield investments where the existing connection customers have decision rights), whether to invest in anticipatory capacity should be determined by the New Investment Contract (or by the existing connection customer).

47 We note that Mercury didn't think that any anticipatory capacity should be built at all. Transpower disagreed in their cross submission and stressed that "it will sometimes be necessary, prudent and efficient to invest in anticipatory capacity".

48 Trustpower's submission included a report by Creative Energy Consulting which argued that the proposal did nothing to address the Type 2 FMD as first movers would be "required to pay the lion's share" of costs for anticipatory capacity until subsequent movers connect. The report argues these costs should be allocated to load customers through the residual charge instead. This misunderstands the proposal, which was to allocate the cost of anticipatory capacity to identified regional beneficiaries.

49 For example, Orion.

50 Contact, MEUG, Northpower, Refining NZ and Vector.

contractual arrangements.[51] A number of parties preferred Transpower's pool-and-share approach, based on the following reasons:

(a) The pool-and-share approach avoids highly concentrated cost impacts in certain regions (eg, Northland) that may occur where there is a low number of identified beneficiaries under the benefit-based approach.[52]

(b) It is a simple approach that would be workable and easy to implement.[53] By contrast, some submitters considered that customers would likely not engage on a benefit-based approach.[54]

(c) The pool-and-share approach would be a more cost-reflective allocation than the proposed benefit-based approach. Transpower argued that the benefit-based approach does not adequately identify beneficiaries of anticipatory capacity, as anticipatory investment could lead to a change in grid flows (once in use). Network Waitaki argued that any cross subsidies resulting from the pool and share approach would reduce over time.

(d) Because the pool-and-share approach spreads capital costs across a large group, it provides less incentive for cost-bearers to lobby against anticipatory capacity to reduce their charges (such lobbying could lead to the grid being undersized).[55]

4.30 The Authority remains concerned that a complete pool-and-share approach would result in inefficient overbuild, as capital costs would be socialised beyond the area benefitting from the investment (one of the main concerns that the TPM is seeking to fix for interconnection investments). Transpower argued that this concern is overstated as investments will be subject to scrutiny by Transpower and the Commerce Commission.

4.31 Our concern remains that pool-and-share would provide little incentive for customers to engage meaningfully with the investment approval process (for example, by submitting useful information). While the Authority supports efficient investment in anticipatory capacity, the risk of overbuild (even in an environment of increased electrification) remains real and is not cost-free. We consider that it is important, in terms of ultimately protecting consumers from bearing unnecessary costs, to incentivise some level of countervailing scrutiny.

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51 Transpower has also opened consultation on a plan for Renewable Energy Zones (REZs). The potential approach would require all parties who want to connect to the connection assets in the REZ to contractually commit before the asset is built. This would mean that no extra capacity would necessarily be required as all second and subsequent movers would be already identified and could be charged for their share, so the Type 2 FMD would not arise in these cases (unless further anticipatory capacity was added beyond the needs of the initially committed parties). Without commenting on the merit of Transpower's proposal, we note that it would necessarily be targeted at specific areas where a high concentration of new renewable generation or electrification is likely, and is therefore unlikely to solve all the FMD type 2 issues that will arise on Transpower's network.

52 Northpower, Transpower and Trustpower. Trustpower also argued that this issue is "exacerbated by the Guideline requirements that connection charges cannot be backloaded."

53 Contact, Fonterra, Transpower.

54 Contact submitted that the benefit-based approach would be "unlikely to elicit the stakeholder interrogation of anticipatory investments that the Authority assumes".

55 Transpower agreed with the Authority's analysis that the pool-and-share approach would "remove … incentives to undersize the connection asset".

4.32 We acknowledge that cost concentration may well be an issue under the benefit-based approach. The 2021 Consultation paper considered the issue for some specific regions (eg, Northland and Hawkes Bay),[56] but the issue also arises in other regions. We considered addressing this through a limit mechanism as discussed in the 2021 Consultation paper.[57] However, we accept Transpower's submission that such a mechanism would be complex,[58] especially in comparison to the pool-and-share approach, which would also address the issue of cost concentration.

4.33 We do not consider the benefit-based approach itself to be unduly complex. Both it and the pool-and-share approach allocate investment costs based on a specific allocator, with the key difference being the type of allocator (ie, regional allocation tables for the benefit-based approach or replacement cost of connection assets for the pool-and-share approach).

4.34 The Authority is also satisfied that the benefit-based approach broadly allocates costs to parties that would significantly benefit from the new generation or load enabled by the anticipatory capacity (noting that costs cannot be allocated to the primary beneficiary of the anticipatory capacity, ie, the second mover, until it commits to connection). Even if grid flows change, the initially identified regional beneficiaries will likely benefit significantly due to price changes.[59]

4.35 By not socialising the entire capital cost of anticipatory capacity, there will be an incentive on identified beneficiaries to critically evaluate the merits of anticipatory capacity,[60] and therefore submit information into Transpower and the Commerce Commission processes, contributing to the correct decision to "right-size" the grid. We consider that concerns around undue lobbying are overstated as Transpower and the Commerce Commission are used to receiving submissions from competing parties and we are confident that they will be able to focus on the useful information submitters provide.[61]

4.36 The Authority expects that Transpower will facilitate this process of customer scrutiny of proposed anticipatory capacity by making relevant information available to stakeholders – particularly regional benefiting customers – in advance of making the investment. This information would likely include the nature of anticipated future

56 2021 TPM Consultation paper para 4.42

57 There was a mixed response to the limit mechanism idea. MEUG and Trustpower supported the limit mechanism (but expressed preferences for Transpower bearing the costs or the pool-and-share approach respectively). Transpower considered the limit mechanisms would add complexity and cost and should not be required if the Authority's proposal led to benefit-reflective charges (which Transpower did not consider to be the case).

58 For example, Transpower would need to keep track of multiple limits across multiple regions.

59 For example, even if there is substantial generation investment in Northland that shifts the region from being a net importer to a net exporter of electricity, local load customers would still receive major benefits due to reductions in average wholesale prices locally, driven by the connection of more local generation.

60 We strongly disagree with Contact's submission that the economic incentives of potentially higher connection charges will not motivate parties to submit on the relevant investment proposals or otherwise reveal relevant information.

61 The Authority disagrees with CEC when it suggests (as on page 26 of their report attached to Trustpower's submission) that stakeholders would distort the truth in the engagement process, or that Transpower would "second-guess or discount their submissions".

connecting parties, the size and cost of the anticipatory capacity and impact on customers' charges from the additional capacity.

4.37 Following the above feedback and our analysis, the Authority has decided on a hybrid approach where 50% of anticipatory capacity capital costs are allocated using the benefit-based approach and the other 50% are socialised as per Transpower's pool-and-share method. We consider this would be a pragmatic way to address the above concerns. This approach:

(a) will reduce the cost-concentration issue significantly by halving the costs that would fall only on regional benefiting customers

(b) is administratively simple (eg, is less complex than a limit mechanism)

(c) is consistent with changes in grid flows spreading benefits more widely than identified regional beneficiaries (half of the costs are spread more widely under the hybrid approach)

(d) will incentivise scrutiny of anticipatory capacity investment (eg, parties will be encouraged to provide valuable information to Transpower and the Commission), as only half of the costs would be socialised, so there are still parties with "skin in the game".

4.38 The new TPM's contribution to New Zealand's transition to a low carbon future is limited to working within current regulatory settings to promote the Authority's statutory objective. Initiatives to address wider government objectives would ultimately be the responsibility for the relevant lead government agency. For example, if local or central government was seeking to promote a specific renewable energy zone for generators, the Authority considers that, at least in some cases, it may be more efficient that additional capacity is funded outside of the TPM, by the party best placed to manage the risks and get the returns when subsequent movers turn up.

5 Benefit-based charge: allocation

5.1 Benefit-based charges recover the costs of post-2019 grid investments, and seven historical investments.

5.2 This section focuses on the methods for allocating those costs to transmission customers expected to benefit from grid investments, in proportion to customers' positive net private benefits from those investments as expected at the time of setting the charge.

5.3 Benefits include giving consumers access to cheaper and more reliable electricity supply, and generators access to bigger markets.

5.4 For a full description of the proposal and reasoning in respect of benefit-based charge allocations see Chapter 5 of the Authority's 2021 Proposed TPM consultation paper.

Relevant sections in the Guidelines and the new TPM

Guidelines	TPM
Clause iv, 8, 13-26	Part D: Clauses 35-67

Our decision

5.5 The new TPM largely adopts the approach to allocating benefit-based charges proposed in the 2021 Consultation paper, except for the following key changes:

(a) The allocation of costs under the simple method will be 62.5% to load customers and 37.5% to generation customers.

(b) This allocation will not be subject to a scheduled five-yearly review. As with other aspects of the TPM, a different weighting between load and generation may be proposed through an operational review.[62]

5.6 The submissions on these topics and the Authority's reasoning for its decisions are discussed in more detail below. The sections below also discuss the Authority's reasons for adopting the 2021 proposal in response to other points raised in submissions, specifically around the Authority's decisions that:

(a) provisions for determining the counter-factual scenario in the BBC standard method for market benefits are generally appropriate

(b) the assumptions book that would include the benefit-based charge allocations will not be binding

(c) confirming how grid-connected batteries would be treated in the allocation of benefit-based charges.

Standard methods for allocation

5.7 The Authority has decided to adopt the standard methods as proposed in the 2021 Consultation paper, that is, covering the approaches illustrated in Figure 1.

62 Transpower can propose these at any time, provided a year has passed since the TPM was last approved. The Authority is also considering whether further TPM re-openers should be allowed, and is likely to consult on this point later in 2022.

What we proposed

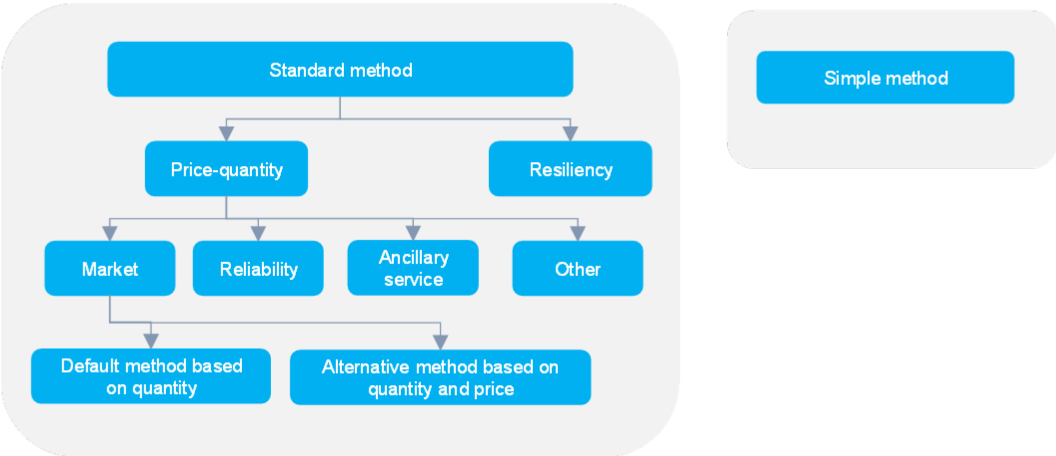
5.8 Reflecting the Guidelines, the proposed TPM provided for standard methods for allocating the cost of grid investments valued over $20m, and a simple method for investments valued at under $20m.

5.9 The proposed standard methods were:

(a) a price-quantity method for investments that provide market, reliability, ancillary service, or “other” benefits

(b) a resiliency method for the subset of grid investments that mitigate high-impact, low probability risks such as of a cascading outage that could result in an island-wide black-out.

Figure 1 Schematic of methods for benefit-based allocations



5.10 The price-quantity method quantifies benefits using price-quantity modelling aligned with that required by the Capex IM.[63] Figure 1 illustrates that the price-quantity method is used to assess four classes of benefits. Market benefits are expected to be the class of benefits from new transmission investments that is modelled most frequently.

5.11 Two sub-methods were proposed for assessing market benefits, set out in clauses 51 and 52 of the new TPM. [64] Under the sub-methods, regional groups of beneficiaries are determined based on changes in prices and quantities under scenarios with and without the new investment, and:[65]

- benefits are then allocated between regional groups of beneficiaries under the clause 51 method based on the quantity of load or generation during periods of benefit
- modelled prices are also used to allocate between regional groups of beneficiaries (that is, the clause 52 method is used) if Transpower concludes that quantity alone would not result in an allocation that is broadly proportional to expected positive net private benefits.

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63 See *Reasons* paper, Chapter 7, section 4.1.

64 In the proposed TPM for consultation the corresponding clauses were 52 and 53. The Authority’s reasons in relation to these clauses are in the Authority’s consultation paper at paragraphs 5.12 to 5.16.

65 See *Reasons* paper, page 7.30.

5.12 The proposed approach to defining regions under the standard method (clause 50 of the new TPM)[66] considers important constraints elsewhere in the grid when determining the number of regions (in addition to considering the constraint relieved by the grid investment and the direction of modelled price changes).[67]

5.13 Benefits are allocated to load or generation customers within a region based on allocators that vary depending on the type of benefits (eg, market benefits) and on whether the investment is driven by peak demand or not.[68]

5.14 Allocations to customers within regions are based on allocators that are in proportion to their historical injection or offtake in the five years preceding the investment. The measure of injection or offtake reflects the nature of the investment (eg, whether peak capacity or reliability).

5.15 For the resiliency standard method, the proposed method allocates costs solely to offtake customers in the relevant region (which could be across the entire island in which the system event is being mitigated), in proportion to their historical load. The allocation solely to load would achieve allocations that are broadly in proportion to expected positive net private benefits, "because of the large difference between the value of lost load (~20k/MWh) and the per MWh operating profit of generation….".[69]

Submitters' views and our assessment

5.16 A number of submissions expressed concerns about the complexity and uncertainty related to the proposed allocation methods. These submissions are addressed from paragraph 14.17**.**

5.17 Trustpower questioned the allocation methods' effectiveness, suggesting the charges "will only reflect [customers'] private benefits by chance", and that: "…no attempt has been made to model the future revenue streams of transmission customers with and without the assets in question. This is the only way we [Trustpower] know to assess private benefits".[70]

5.18 However, modelling of future revenue streams for generation customers and future expenditure streams for load customers under different scenarios, at least in aggregate, is in fact what underpins the measurement of market benefits under the standard method, first in identifying regional groupings of customers and, if Transpower considers it necessary, in allocating charges between transmission customers within regions. As Transpower has stated:

We must use a wholesale market model to model the prices, quantities and changes in price and quantities in the wholesale market for electricity between the market BBI's factual and counterfactual under its market scenarios and based on its investment grids. The modelling must cover each year of the market BBI's standard method calculation period (50(3)).[71]

66 Note that in the proposed TPM for consultation the corresponding clause was clause 51.

67 Transpower, 15 September 2021, TPM Proposal 30 June 2021 Decision Part 2 refer-back: Transpower's response, Section 3.

68 See Transpower's Reasons paper, from page 7.58, from paragraph 232.

69 See Transpower's Reasons paper, page 7.65, para 266.

70 Trustpower, p15 and Appendix A p4.

71 See Transpower's Reasons paper para 115-, pp 7.30 onward.

5.19 The Authority notes that the allocation methodology does not require an understanding of, for example, the benefits arising from what electricity consumers then may do with, or get from, cheaper or more reliable electricity (such as increased revenues from increased product sales if a business's costs reduce). For benefit-based allocation, it is enough to know the extent to which consumers and businesses benefit from lower prices or more reliable supply, as indicated by (modelled) changes in prices and quantities.[72]

5.20 As summarised above, variations or sub-methods are available for investments made to reflect their different primary benefits (eg, reliability), as well as the resilience method. The Authority considers that having the different standard methods available will support greater accuracy in allocations, by allowing these to better reflect the benefits of different types of investment than a single generic method would.[73] While all modelling involves some pragmatic choices, more accurate allocations in turn support efficient locational decisions and scrutiny of grid investment proposals. The Authority thus disagrees with Trustpower when it questions if "the patch work of allocations… will provide any clear price signals for locational decisions and grid scrutiny."

5.21 The TPM leaves to Transpower's judgement whether the standard method in clause 51 or the clause 52 method is applied.[74] Vector submitted that this exercise of judgement could have a significant impact on transmission charges so stakeholders should have an opportunity to provide their views as to which method is used. We have decided not to adopt Vector's recommendation. The Authority considers the use of criteria set out in the TPM to guide Transpower's judgement strikes an appropriate balance between the economic benefits and costs of precision and the economic benefits and costs of practical considerations.[75]

5.22 With respect to the proposed allocation method for resiliency investments, Energy Trusts of New Zealand consider a greater share of transmission costs should be allocated to grid-connected generation. Vector also questions why, with respect to the WUNIVM case study, generators are not charged, "given generators will equally benefit from resiliency investments that prevent island wide cascade failure". Paragraph 5.15 above summarises Transpower's reasons for allocating the cost of standard method resiliency investments solely to offtake customers. The Authority continues to agree with these reasons.[76]

5.23 CEC (for Trustpower)[77] suggests that the proposed design of charges means that "what the customer will see is effectively a Tilted Postage Stamp tariff, obscured somewhat by the complexities and uncertainties inherent in the asset-by-asset,

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72 Allocations of benefit-based charges between customers are to be broadly in proportion to their expected positive net private benefits.

73 As discussed further in the next section, in the case of the simple method, the Authority considers the approach in general strikes a reasonable balance between the benefits and cost of accuracy given the nature and lower value of investments involved.

74 In the proposed TPM for consultation the corresponding clauses were 52 and 53. The Authority's reasons in relation to these clauses are in the Authority's consultation paper at paragraphs 5.12 to 5.16.

75 See clause 1(b) of the Guidelines.

76 For the rationale with respect to the case study see also Reasons paper, Appendix E, para 33.

77 See page 32 of Creative Energy Consulting 2021, Review of the Electricity Authority's latest TPM, appended to Trustpower's 2 December 2021 submission.

benefit-based approach", with Long Run Marginal Cost (LRMC)-style price signals for new grid investments. CEC concludes that a simpler method could be implemented instead.

5.24 The Authority does not agree. Appendix B contains the Authority's detailed review of CEC's key claims. In brief, CEC's analysis emphasises simplicity and certainty, but omits other dimensions that are relevant to efficient operation of the industry and fails to engage with explanations the Authority has already provided in earlier TPM consultations and decisions.

5.25 Overall, the Authority considers the price-quantity standard methods and resiliency method can be expected to result in cost allocations that are broadly in proportion to benefits. The Authority also considers that the methods achieve an appropriate balance between certainty and flexibility. It considers the methods are consistent with the Guidelines and with the Authority's statutory objective.

Standard method counterfactual for market benefits

Our decision

5.26 The new TPM adopts the provisions consulted on in 2021 for determining the counter-factual scenario in the BBC standard method for market benefits, as, having considered submissions, the Authority remains of the view that these are appropriate.

What we proposed

5.27 Under the standard method in the proposed TPM, the same demand forecast is to be used in determining the counterfactual and factual scenarios.

5.28 In other words, forecast electricity demand is an input and, as a matter of simplification, is assumed to not depend on whether a grid investment is made or not. This is clearly a simplification of reality, but is similar to other simplifications (eg, the wholesale market model, which requires least-cost dispatch and offer prices based on marginal variable costs). The Authority considers it to be an appropriate simplification, because it strikes an appropriate balance between precision and practical considerations (see below).

Submitters' views and our assessment

Counterfactual

5.29 Unison submitted that the criteria for the counterfactual in the standard method are too restrictive and that Transpower should have greater discretion in determining the counterfactual. Contact Energy cross-submitted that this point warranted further work.

5.30 Unison noted that Transpower's case study of benefit-based allocations for the CUWLP investment produced some apparently counterintuitive results. This included that, in the scenario where the Tiwai point aluminium smelter does not exit, load customers that would disbenefit from the investment would continue to pay for it. To address this issue, Unison submitted that:

"Clause 46 [of the proposed TPM should] be permissive of allowing different load development scenarios between the factual and counterfactual where the BBI would have a material influence on load investment decisions."[78]

5.31 In its TPM reasons paper, Transpower had explained that:

"We will assume the transmission investment does not affect the decision for load to connect to the transmission grid. This is a simplifying assumption which limits the scope of the modelling to the electricity market. If we were to assume the demand forecast is influenced by the transmission investment, we would need to significantly expand the scope and complexity of the model – for example, modelling how the electricity price affects consumption and investment decisions in other markets such as transport and industry ie, a general equilibrium model."

5.32 In its cross submission (para 41), Transpower submitted in response to Unison that:

"We do not have experience with general equilibrium modelling and including a requirement to assess the likely entry/exit of load as a response to transmission investment would significantly impact on the costs of administering and complying with the new TPM (clause 1(b)(iv) of the Guidelines). We consider holding the demand forecast constant between the factual and counterfactual will result in allocations that are broadly proportionate to [benefits]."

5.33 The Authority has discussed with Transpower whether it would be appropriate for Transpower to be given further discretion regarding the counterfactual. Transpower was opposed to being given this discretion, advising that it would add substantial modelling effort and complexity, would not be consistent with standard practice for the Commerce Commission's Investment Test and would not provide additional benefits, noting that it would lead to increased uncertainty and complexity.

5.34 The Authority considers that, rather than raising a general issue with the standard method for market benefits, the CUWLP investment illustrated in the case study is likely very unusual in its degree of dependence on the assumption about the aluminium smelter's departure, given its large share of total electricity consumed, and the modelled impacts of that investment on market benefits.

5.35 The Authority has decided that, consistent with Transpower's advice, the TPM should not provide for additional flexibility to provide different scenarios in the factual and the counterfactual. The Authority considers that the standard method as provided for in the TPM strikes an appropriate balance between the precision and practical considerations (including simplicity and the need to limit discretion), in accordance with cl 1(b) of the Guidelines. In addition, we note that the new TPM is intended to build on modelling undertaken for the investment test under part 4 of the Commerce Act – this type of cross-regime consistency remains preferable.

5.36 If, in future, Transpower's view changes such that in general it considers that using the same demand forecasts in the factual and counterfactual would be expected to result in allocations that do not reflect expected net benefits (and different factual and

78 https://www.ea.govt.nz/assets/dms-assets/29/Unison-TPM-submission-2021.pdf.

counterfactual demand scenarios would), the Authority considers that an operational review would be an appropriate mechanism for reconsidering additional discretion.

Simple method for allocating costs of low value investments

5.37 Reflecting the Guidelines, the proposed TPM provided for a simple method for allocating to customers the costs of grid investments valued under $20m.

5.38 The simple method seeks to strike an appropriate balance between accuracy and administrative costs when allocating benefit-based charges for low value investments, subject to charges being broadly in proportion to expected positive net private benefits.

Our decision

5.39 The TPM includes a simple method for allocating transmission investments with a value less than $20m, as was proposed in the 2021 Consultation paper, with the following changes:

(a) Costs under the simple method are to be split 62.5%:37.5% between load customers and generation customers.

(b) This weighting will not be subject to a scheduled five-yearly review; as with other aspects of the TPM, a different weighting may be proposed through an operational review.[79]

What we proposed

5.40 The proposed simple method would first allocate charges for low value investments to regions that are identified based on historical power flows.

5.41 These amounts would then be allocated to individual customers within regions in proportion to their share of a region's injection or offtake over a recent five-year period. These customer allocations would then be fixed (subject to the TPM's adjustment provisions).

5.42 Transpower also proposed that costs of simple method investments would be split approximately 50:50 between generation and load customers. This weighting would be reviewed every five years based on empirical evidence from allocations under the standard method.

5.43 While it accepted this weighting for the purposes of consultation, the Authority sought feedback and additional evidence on the proposed weighting. The Authority considered that adopting the 50:50 proposal in the proposed TPM was a finely balanced decision because 50:50 was within the range of possible outcomes identified, but there was also analysis suggesting different weightings, eg, 20-30% to generation and thus 70-80% to load. See paras 5.34-5.41 of the 2021 Consultation paper for a fuller discussion of these matters.

79 Provided it has been more than a year since the TPM was last approved.

Submitters’ views and our assessment

Simple method weighting

5.44 Contact Energy and Nova provided additional analysis supporting an allocation of costs to load customers higher than the 50% provided for in the proposed TPM:

(a) Contact (who otherwise submitted that the 50:50 allocation was meaningless as a representation of benefits) built on an analysis undertaken by Transpower (using Transpower’s estimates of adjusted operating profit for generators) to argue generators’ share should be less than 50%, with a base case of 21%.

(b) Nova submitted the load:generation weighting should be 67%:33%, on the basis that a high proportion of low value investments relate to reliability and security of supply, of which load customers are the primary beneficiary. Nova illustrated this point with reference to three grid investments, and the high value of lost load ($20,000/MWh), which is specified in the Code, compared to generation revenue foregone (Nova suggested this would be around $100/MWh).

5.45 Transpower’s cross-submission specifically considered and disagreed with these submissions, noting that:

“the vast majority of our low-value interconnection investments (to which the simple method is required to apply) are to replace aging assets at the end of life, not to enhance the grid. Even if a low-value investment relieves a constraint and reduces nodal prices, that does not mean load customers are the only, or necessarily principal, beneficiaries.”

5.46 Other submissions also suggested a higher than 50% allocation to load:

(a) Mercury suggested that the CBA results point to starting with a greater weighting on load customers, to avoid deterring investment in new generation.

(b) Trustpower submitted the 75:25 weighting be adopted from the outset and reviewed in five years’ time; it noted the CBA’s net benefits for this option are materially higher than under the proposed weighting.

(c) Meridian referred to evidence from NERA it submitted on the 2019 Issues paper specifically that “since consumers ultimately pay for all transmission costs, it is more efficient and direct to assign costs to load customers. This is because the demand-side of the electricity market is more inelastic than the supply side”.

(d) IEGA questioned whether the 50:50 assumption was sound and wanted more information disclosed on why the Authority considered this assumption ‘unusually important’.[80]

(e) Orion too considered more work needed to be done on what would be the most efficient approach to allocation, as “all costs ship home to consumers, one way or another…If we can show that applying charges to load customers only

80 The Authority disclosed the available information on the impact of different weighting factors on indicative charges and the CBA (See discussion around Figure 1 p33 and Appendix D of the 2021 TPM Consultation paper).

provides efficient outcomes, then all charges should be applied to load customers (and vice versa)."

5.47 Some submitters) made arguments supporting a 50:50 allocation (eg, Vector) or a higher allocation to generation (Energy Trusts of New Zealand). For example, Energy Trusts of New Zealand asked the Authority "to ensure that Grid-dependent generators meet the full costs of the transmission equipment required to move their product to the point of sale".[81] Energy Trusts of New Zealand thought this was increasingly important to avoid distortions with respect to the growing demand side and local generation technologies that compete with grid-dependent generators. Vector considered an unequal weighting in the absence of evidence would weaken durability.

5.48 CEC (on behalf of Trustpower) criticised the process the Authority followed with respect to the simple method.[82]

5.49 Counties Energy suggested a different allocation should be able to be applied where an investment is clearly for a specific purpose (for example, where a GXP is for injection); however, the Authority agrees with Transpower when it argues in its cross-submission that a case-by-case approach for low value investments would detract from the purpose of the simple method to balance precision with simplicity and to be implementable at a substantially lower cost to participants than the standard method.

5.50 Nova submitted that a high proportion of low value investments are related to reliability and security of supply, which is valued more highly by load customers than by generation customers. Nova illustrated this with reference to the core grid being built to N-1 security, whereas (with reference to McKee and Junction Road peakers) a single circuit would provide adequate security for generators. To the extent that low value investments are made to avoid deterioration in grid reliability, it follows that a 50%:50% weighting is not an appropriate starting point for the first period, and load's share should be higher.

5.51 Transpower's point that simple method investments are largely about replacement of ageing assets does not assist in resolving the weighting question, as it does not address relative benefits from the original investment in those assets. If, for example, a grid investment was originally undertaken to improve the reliability of supply for the benefit of a load centre, it appears likely that replacing those assets at end of their life would still provide greater benefits to customers in that load centre than to generators.

5.52 Further, the Authority considers that Transpower's point that generation would carry around 15% of total transmission charges inclusive of residual charges (if its proposed weighting was adopted) does not provide relevant evidence that a 50:50

81 Energy Trusts of New Zealand submission, December 2021, p 4.

82 CEC (p.25) considered the proposal to adopt a 50:50 weighting "a major failure of the TPM review process." The Authority disagrees the process for developing or reviewing the TPM on the simple method had any shortcomings. The Authority (and Transpower) followed the TPM review process that is prescribed in Part 12, subpart 4 of the Code, and as expanded on at para 1.7-1.15 of this paper.

weighting broadly reflects net private benefits of grid investments under the simple method (given the different purpose of residual charges).[83]

5.53 In sum, the further evidence provided in submissions did not definitively support a particular weighting, but the Authority considers that on balance a higher weighting for load is more likely to reflect the relative benefits of simple method investments than a 50:50 starting point, noting that:

(a) empirical evidence provided by Transpower in support of its proposed starting point was inconclusive, though the Authority accepted it for consultation purposes in the absence of strong evidence for moving away from the proposal[84]

(b) in circumstances with weak empirical evidence, it is important to consider the relative risks of an estimation error either way.

5.54 The Authority has made a judgement that a load:generation weighting of 62.5%:37.5% is a better estimate of the actual shares of benefit from grid investments subject to the simple method than the 50%:50% option put forward in the consultation, and thus would likely better promote the Authority's statutory objective than the weighting that we consulted on.[85] This judgement is based on:

(a) the underlying logic that outages have a higher impact on consumers than generators (as reflected in the value of lost load relative to wholesale market prices as a broad indicator of relative value)

(b) the harm to consumers of over-allocating costs to generators being likely worse than over-allocating costs to load, given that unnecessarily loading costs on generators inefficiently delays entry of new generation (as also supported by the quantitative analysis in the CBA)[86]

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83 See para 329 of Transpower's Reasons paper. Transpower also notes that this aggregate allocation could potentially change to 12-37% in the 2034/35 pricing year. The substantial change in the ratio of cost recovered via benefit-based vs. residual charges over time further weakens this argument.

84 See para 5.35, 2021 TPM Consultation paper.

85 62.5%:37.5% is the midpoint between the proposed 50%:50% and the alternative weighting put forward in the consultation paper (75%:25%).

86 Material under-allocation to generation would be inefficient also, and so not in consumers' long-term interest. However, the weighting risk is asymmetric (consistent with the CBA results), because over-loading costs on generators inefficiently delays entry of new generation, increasing costs to consumers. This asymmetric risk rationale is consistent with the judgement-based approach the Commerce Commission has taken to estimating the WACC for Transpower and distributors, justifying initially the 75th percentile, later reduced to the 67th percentile at seven-year review (with more evidence).

Table 2 Cross-checks on load: generation weightings

Approach	Generation share	Load share	
Authority 24 May 2021 letter to Transpower[87]			
A. Simple ratio	20%	80%	
	28%	72%	
B. Analytical approach	12.5%	87.5%	
	34%	66% [88]	
C. Evidence on transmission charge shares from other countries/jurisdictions	3%	97%	
	38%	62%	
Transpower TPM proposal[89]			
D. Simple ratio (adjusted operating profit)[90]	40%	60%	
	50%	50%	
E. Schedule 1 allocations (Weighted average by commissioning value of investment)	33%	67%	
F. Shares when ~50% of BBCs and 100% residual charges allocated to load[91]	15%	85%	2021/22
	37%	63%	2034/35
	12%	88%	2034/35
Contact Energy[92]			
G. Simple ratio (adjusted operating profit and consumer surplus)[93]	33%	67%	
	13%	87%	
Nova[94]			
H. N-1 supply security[95]	33%	67%	

87 Para B.11 www.transpower.co.nz/sites/default/files/uncontrolled_docs/46.%2024%20May%202021%20-%20Letter%20from%20EA%20%28Transpower%20TPM%20Checkpoint%202B%20resubmission%20Appendix%20A-D%29.pdf.

88 Where there are two lines against an approach in the table, it gives an upper and lower range.

89 www.transpower.co.nz/sites/default/files/plain-page/attachments/TPM%20Proposal%20Reasons%20Paper%2030%20June%202021.pdf.

90 Adjusted to be an estimate operating profits (spot revenue less operating costs) related to generation only (para 326 on page 7.77)

91 When accounting for the fact that 100% of the residual charge will be allocated to load, generators are estimated to be allocated ~15% of total, non-connection, transmission charges for the 2020/21 pricing year, changing to ~12-37% in 2034/35 (based on indicative pricing estimates).

92 https://www.ea.govt.nz/assets/dms-assets/29/Contact-Energy-TPM-submission-2021.pdf.

93 Based on Transpower's estimates for adjusted operating profit for generators (as a proxy for the net private benefits of generators) and a range of consumer surplus estimates using the ratio of consumer to generator net benefits in Table B.5 of the Authority's 24 May 2021 letter to Transpower. All estimates implied a generator weighting of much less than 50%, with 21% the base case.

94 https://www.ea.govt.nz/assets/dms-assets/29/Nova-TPM-submission-2021.pdf.

95 Values the relative benefits to generators and consumers of n -1 security by considering the impact of a loss of connection, based on VOLL $20,000/MWh vs lost revenue $100/MWh.

(c) the Authority's consistent view that generators should pay for the benefit they receive from transmission assets, as this will promote both competition and efficiency in the generation market. We therefore disagree with submissions that suggest that we should allocate even less costs to generators or over-rely on the CBA results for a 25% allocation to generation. The CBA is only one factor; it is also important for the efficient operation of the electricity market, including given durability considerations, that all customers', including generators', charges are broadly in proportion to the benefits they receive from transmission investments

(d) the range of available evidence as summarised in Table 2, which serves as a useful cross check. While the table does not provide a definitive weighting, it suggests that 62.5%:37.5% is within the expected range and is more consistent with the range of evidence than the proposal we consulted on (ie, 50%:50%).

Review of the simple method weighting

5.55 The proposed TPM provided for a 5-yearly review of the weighting to reflect new evidence on the relative benefits for load and generation of grid investments subject to the simple method. It would draw on evidence from standard method assessments undertaken by Transpower.

5.56 Contact Energy raised concerns about such reviews, noting the risk of the review being biased towards the status quo. Contact Energy also questioned the appropriateness of such reviews relying on evidence derived from standard method investments if high-value investments are different from low-value investments, which include maintenance activities such as tower painting.[96]

5.57 Nova submitted that the five-year review of the assumptions underlying the simple method weighting[97] "will potentially be quite significant for Nova, but it is unlikely to provide confidence that Nova's costs will be reduced or it may simply be too late".[98]

5.58 In our view, regular reviews might serve as an error correction mechanism if, with the benefit of hindsight, it appears that the initial weighting did not appropriately reflect relative benefits between load and generation, or where the relationship changes over time. However, reviews would also introduce uncertainty around future charges.[99] Such uncertainty may discourage efficient investment. That uncertainty would likely be greater if the sector is not confident in the starting point or the relevance of insights from future standard method investments.

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96 The Authority notes that the relevant data point would be an assessment of beneficiaries of the original high value investment that simple method investments (including for maintenance) relate to. The simple method reflects that such information is not available at reasonable cost. Over the long run, the majority of the grid may have a standard method allocation, and all subsequent investments relating to that investment would adopt that allocation.

97 Nova refers to "the review in five years of the assumptions underlying the TPM charges"; from context we infer that Nova refers to the review of the simple method weighting factor.

98 Nova raised this in the context of explaining that the current economics of peaker plants and co-generation plants means the net earnings from these power stations are subject to high uncertainty, and that benefit-based charges will add significantly to this uncertainty.

99 They may also give customers incentives to adjust their consumption or injection to manipulate their share of benefit-based charges allocated to their region, though as explained in footnote 285 at Appendix B customers' capacities and methods to do so will vary.

5.59 Potential uncertainty arising from the complexity of the TPM was also raised as a wider issue in submissions, as noted above including, by Nova, in reference to the review of the simple method weighting factor). Having regard to this wider concern, and given that simple method allocations are expected to make up over one-third of overall charges by 2035, the Authority has reconsidered the merits of the proposed periodic review.

5.60 The Authority has decided to remove the periodic review of the simple method weighting on the basis that:

(a) the Authority considers that the 62.5%:37.5% weighting is the best estimate of the actual shares of benefit given the current evidence

(b) it would improve certainty over future transmission charges[100]

(c) on reflection, we do not consider that upcoming investments assessed using the standard method will necessarily produce materially better evidence (in the first five-year period at least), and thus a better decision, on the weighting than a judgement based on currently available information

(d) the weighting could be reviewed through operational review and potentially other mechanisms,[101] if strong evidence became available over time that outcomes were inconsistent with the Authority's statutory objective.

5.61 In the long term, more and more of the existing grid will be replaced with standard method investments. As this occurs, the role of the simple method weighting in determining allocations for new investments is expected to gradually reduce, as simple method BBIs relating to post-2019 investments may generally be subject to the same allocations as corresponding standard method BBIs.[102]

5.62 Alternatives that the Authority also considered include:

(a) Making the review a one-off, providing a transitional safety-valve on accuracy, but improving certainty longer term (beyond pricing period 1). However, it is unclear sufficient evidence would be produced in the selected time period to overcome the issues described above, and this approach is likely to reduce near-term confidence in the durability of the initial weightings and so bear on investment decisions.

(b) Requiring Transpower to commission an independent expert to review Transpower's analysis before Transpower decides on the weighting after a review. This would mitigate the status quo bias concern raised by Contact Energy but does not address certainty concerns noted above.

100 Fonterra submitted, and Vector in its cross-submission agreed, that to reduce uncertainty the triggering of reviews should be subject to certain criteria rather than just the lapse of time.

101 Transpower can undertake operational reviews of the TPM and propose changes to the Authority. Further, the Authority intends to consult later in 2022 on additional situations in which the Authority may initiate a review of an existing TPM.

102 Clause 37 of the TPM.

Assumptions book

Our decision

5.63 The Authority confirms that the assumptions book, containing the assumptions and detailed methodologies Transpower intends to apply for allocating and adjusting BBCs, will not be binding on Transpower.

What we proposed

5.64 The proposed TPM (cl 39) provided for Transpower to publish an assumptions book that documents assumptions, definitions, and detailed methodologies for allocating and adjusting benefit-based charges. It would not be binding on Transpower (except as otherwise stated in the TPM (cl 39(5)).

5.65 This book would be reviewed at least every seven years. Transpower would be required to consult with customers on the assumptions book or any update of it, and on material departures from the assumptions book when it consults on customer allocations.[103]

Submitters' views and our assessment

5.66 Counties Energy submitted that the assumptions book should be binding on Transpower, as otherwise transmission customers would face uncertainty and risk.[104]

5.67 The question of whether the assumptions book should be binding is essentially a balance between certainty and accuracy. If the assumptions book is binding, then it provides transmission customers greater certainty about assumptions and methods. If the book is not binding, then it gives Transpower some discretion to depart from the assumptions and methods contained in it to make allocations that better reflect benefits.

5.68 Transpower submitted that generally it would prefer less discretion but that it needs to retain some to avoid anomalous allocation outcomes that are not broadly proportional to expected positive net private benefits.

5.69 The Authority has decided that the assumptions book should not be binding. This reflects:

(a) the value of accuracy, given the materiality of allocation decisions under the standard method, and the risk of locking in any perverse results if Transpower did not have some discretion in applying assumptions and methods

(b) a recognition that, in practice, the assumptions book will be a 'work-in-progress' particularly initially, as Transpower develops and refines its allocation process

(c) the risk of a minimalist approach to the assumptions book if it were binding, which reduces the certainty benefit of having the book

103 See pp 7.83-7.85 of Transpower's Reasons paper.

104 A number of other submissions expressed concern about the extent of uncertainty they perceived. This is discussed in chapter 14.

(d) requirements in the TPM that already provide restrictions, transparency and accountability to customers in respect of benefit-based allocation:

(i) structural and fundamental aspects of BBC allocation methods that are included in the TPM itself

(ii) consultation with customers before publishing the assumptions book or any update to it

(iii) consultation with customers before relevant transmission charges are finalised – including on any material departures from the assumptions book and the reason for those departures.[105]

5.70 The Authority has made a minor enhancement to these requirements, requiring Transpower to publish with its final allocation of a benefit-based investment any material departures from the assumptions book and the reason for those departures (closing the loop on the consultation process). This is consistent with requirements in respect of the prudent discount practice manual.

Application of BBCs to grid-connected battery storage

Our decision

5.71 The TPM allocates BBCs to customers with battery storage in proportion to the benefits they receive from the relevant grid investment, as was proposed in the 2021 Consultation paper, with the following clarifications and changes:

(a) clarification that for grid-connected batteries, market benefits under the price-quantity standard method may be calculated by aggregating (netting off) a customer's costs and benefits arising from injection and offtake at the relevant connection location,[106] and a separate regional customer group may be created

(b) in allocating reliability benefits under the price-quantity method, grid-connected battery storage is to be treated as a member of the regional supply group only

(c) clarification that there is no battery-specific treatment for ancillary service benefits and other benefits under the price-quantity method

(d) in allocating benefits under the resiliency standard method, grid-connected battery storage is to be treated as a member of the regional supply group only

(e) clarification that under the simple method, charges are allocated to battery storage within a region in proportion to its share of both the region's injection and the region's offtake.

What we proposed

5.72 The proposed TPM as consulted on (cl 47) provided that for customers with offtake and injection at the same connection location, market benefits under the price-quantity standard method may be calculated by aggregating (netting off) a customer's

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105 Vector submitted that stakeholders should have input into which method is used, given the exercise of judgement by Transpower can have significant effects on charges. The TPM's consultation requirements would provide a vehicle for such input, as would consultation on the assumptions book. Vector also proposed that beneficiaries should have express rights to veto investment plans; however, the approval process of grid investments is not a matter for the transmission pricing methodology.

106 Eg, a battery incurs electricity purchase costs during offtake and obtains sales revenue during injection.

costs and benefits arising from its injection and offtake at the relevant connection location.[107]

5.73 In respect of reliability benefits, ancillary service benefits and other benefits under the price-quantity method or the resiliency method, the proposed TPM addressed allocations to offtake customers and injection customers (it did not set out arrangements that apply only to battery storage).

5.74 The proposed TPM provided for charges under the simple method to be allocated to individual customers within regions in proportion to their contribution to a region's injection or offtake (assessed over a historical five-year period). As batteries make up a share of both a region's injection and its offtake, they would receive an allocation in respect of both.[108]

Submitters' views and our assessment

5.75 Fonterra, Vector, Trustpower and MEUG expressed concerns about the proposed inconsistent treatment of batteries compared with other load customers. According to these submissions, the Authority focused "on increasing competition in flexibility markets on distribution networks"[109] but is creating an environment where batteries are treated differently to other flexibility services on the transmission grid.

5.76 The Authority disagrees with these submissions. In the context of the residual charge, the Authority has been concerned to avoid undermining competitive neutrality for batteries as compared with other generation. The Authority's focus in the context of BBCs is to allocate charges to transmission customers in proportion to the benefits they receive from the relevant grid investment. Battery storage has some of the characteristics of both load and generation, and uses electricity in a range of ways, some of which are unique to battery storage.[110] It follows that the benefits batteries receive from grid investment are different from the benefits received by load or generation, and their allocations of BBCs must reflect that.

5.77 IEGA submitted the Authority should "undertake additional analysis on the treatment of batteries and to publish how batteries are to be treated under BBCs."[111]

5.78 No detail was provided as to the form of analysis IEGA considered necessary; however, in light of this and other submissions, the Authority has considered further the treatment of batteries under the BBC. This is discussed further below. In addition, the Authority notes that Transpower has signalled that further detail around the treatment of batteries under the BBC standard methods will be included in the assumptions book, which it will be consulting on later this year.

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107 This includes grid-connected batteries, which have offtake and injection at one connection location.

108 Indicative charges for 2021/22 published alongside our proposal for consultation included an allocation for the sole grid-connected battery, Mercury's 1MW grid connected battery at Southdown, in respect of both its injection and its offtake. Refer to: www.ea.govt.nz/assets/dms-assets/28/TPM-Proposal-Reasons-Paper-Appendix-B-Indicative-Prices-Transpower.pdf www.ea.govt.nz/assets/dms-assets/28/Simple-BBI-customer-and-regional-allocations-Transpower.xlsx

109 Paragraph 4.20 of the Authority's 'Energy transition roadmap – Supporting an efficient transition to a low-emissions energy system', 9 December 2021. Released since submissions closed on the Proposed TPM https://www.ea.govt.nz/assets/dms-assets/29/Authority-cover-paper-for-roadmap.pdf.

110 For example, see "Refer back letter from Electricity Authority to Transpower (part one - non-BBC)", paragraphs A.51 to A.54 and Figure 2: Transpower's 2017 assessment of the value of battery functions.

111 IEGA cross submission.

5.79 Under the ***standard methods*** in the TPM, battery storage would be assessed as receiving the following benefits:

(a) *Market benefits*: a battery can expect to receive allocations in proportion to its expected operating profit (if the battery is primarily performing energy arbitrage).[112]

(b) *Reliability benefits*: the TPM requires treating batteries as members of the regional supply group, which recognises that batteries are likely to benefit from increased reliability in a similar magnitude to generators, not load customers.[113]

(c) *Resiliency benefits*: grid-connected batteries (just like generators) will receive no allocation under the resiliency method.[114]

5.80 For further details, see Appendix D.

5.81 The ***simple method*** is designed to allocate costs based on customers' use of the existing grid. This reflects the purpose of most low-value investments, being to maintain the service provided by the grid as it is, not to enhance it. Regional benefits under the simple method (and the regions themselves) are determined based on power flows, to which it is expected batteries (grid-connected and embedded) will make material contributions in future, both through their offtake and their injection.

5.82 Consistent with the proposed TPM consulted on, the Authority considers it is appropriate to include grid-connected batteries in both demand and supply groups under the simple method. The Authority considers that this allocation appropriately reflects the benefits batteries receive from the grid (which arise from batteries' offtake as well as their injection – and potential injection in the case of reserves). The simple method allocates costs based on customers' use of the existing grid. This reflects that most low-value investments maintain the grid as it is. By contrast, major (standard method) investments are typically aimed at enhancing the grid. We consider use of the grid to be a reasonable proxy for benefits under the simple method.

5.83 For these reasons, the Authority does not consider that the BBC simple method results in any competitive disadvantage to battery storage.

5.84 Overall, the TPM places battery storage on a more level playing field with other generation, embedded generation, cogeneration and load customers. Benefit-based charges are allocated to battery storage in various ways that appropriately reflect the various benefits batteries receive from the grid. Residual charges are allocated to battery storage only to the extent that it finally consumes electricity (its losses) – which avoids double-counting. In aggregate, the Authority is satisfied that battery storage will not be inappropriately advantaged or disadvantaged by the TPM.

112 In other words, batteries will receive an allocation when their revenue from injection of electricity minus electricity purchase costs from charging increases due to a BBI.

113 Battery offtake is likely to occur at non-peak times and the potential for later grid injection is likely to assist reliability.

114 The rationale for allocating resiliency benefits to offtake customers in the proposed new TPM is based on the difference between VoLL and the per MWh operating profits of generators. The lost operating profit due to a battery being unable to charge due to an interruption will be similar to generators, rather than "normal" types of offtake.

5.85 In general, ***embedded battery storage*** is not explicitly accounted for in calculating BBC allocations.[115] Allocations for embedded battery storage are implicit in the allocations of the relevant direct connect or distribution customers. The Authority is satisfied that no specific issue arises with how the standard or simple methods implicitly allocate charges to embedded battery storage.

5.86 The Authority's distribution pricing workstream is considering how distributors pass on transmission charges, and any embedded battery storage concerns can be raised in the context of this work. As part of this work the Authority will consider, and monitor, whether distribution pricing is creating potential incentives for batteries (or generators) to choose to embed mainly or exclusively for the purpose of avoiding charges.

5.87 ***Adjustments*** to benefit-based and residual charges, including in relation to batteries, are discussed in chapter 8. For example, for a summary of the application of Schedule 1 (pre-2019) BBI adjustment provisions to grid-connected batteries, refer to paragraphs 8.36-8.37.

Additional component E

5.88 The Guidelines' Additional component E would extend the application of benefit-based charging to other pre-2019 investments in addition to the seven major historical investments specified in Schedule 1 of the Guidelines, if that would better achieve the Authority's statutory objective.

5.89 The proposed TPM did not extend the application of benefit-based charging to other pre-2019 grid investments, because the costs of implementing were expected to outweigh the benefits (see para 5.50 2021 Consultation paper).

5.90 Only a few submissions commented specifically on Additional component E. Mercury opposed extending benefit-based charging to pre-2019 grid investments, on the basis that it would be inconsistent with economic theory to reallocate sunk costs, and reallocation could not be an objective exercise (p3, p4).

5.91 Vector had a similar view, noting also the complexity of implementing Additional component E. It suggested the option should not be left open for a later date as this would create uncertainty.

5.92 Network Waitaki submitted that socialising the costs of some investments but not others (ie, the seven major historical investments) is a selective approach and that converting all transmission assets for inclusion in benefit-based charges should be considered. It considers that the "full introduction of the whole benefit picture would result in more averaged prices across the country, with better price stability and an opportunity to test the benefit/effort equation of the proposed TPM right from the outset." (p 5)

5.93 The Authority has decided that that the TPM should not extend benefit-based charging to the remaining historical assets given the costs of implementing it are

[115] An exception is that as part of modelling standard method market regional benefits, Transpower may model embedded plant as if it were grid-connected (clause 49(5)). If Transpower does this, the modelled market benefits and disbenefits in respect of the plant must be attributed to the relevant customer to which the plant (eg, the battery) is connected (eg, distributor or direct connect customer).

likely to exceed the benefits. The option remains open to revisit this later (as it does for any Additional Components), through an operational review under the Code, if doing so would promote the Authority's statutory objective.[116] However, as the historical assets in the residual charge continue to depreciate over time, any possible benefit of the Additional Component will diminish.

[116] See footnote 100 of the 2021 TPM Consultation paper for an example.

6 Benefit-based charge: covered costs

6.1 Benefit-based charges recover the costs of post-2019 grid investments and seven historical grid investments.

6.2 This section focuses on which costs are to be associated with benefit-based investments and recovered through benefit-based charges – covered costs. These comprise capital charges, depreciation and operating costs, and other costs attributable to a benefit-based investment (including taxes).

6.3 Covered costs are directly attributable costs, those with a verifiable causal relationship, and a share of overhead opex.[117]

6.4 The Authority has decided to adopt the approach to covered costs as proposed in its 2021 Proposed TPM consultation paper, without modification.

6.5 The sections below consider the key matters on covered costs which the Authority sought to test with stakeholders.

Relevant sections in the Guidelines and the new TPM

Guidelines	TPM
Clauses 15-17	Clauses 39-41
Additional component F: Clause vii, 54, 64	

Recovery of overhead opex

Our decision

6.6 The Authority has decided that covered costs will include a share of overhead opex.

What we proposed

6.7 The proposed TPM provided that overhead opex would be recovered through benefit-based charges, allocated to a benefit-based investment in proportion to the size of the investment as reflected in annual depreciation.

6.8 The share of overhead opex not attributed to benefit-based investments (and hence recovered through benefit-based charges) will be recovered through residual charges.

6.9 The rationale for this approach, which was proposed by Transpower, was that all of Transpower's investments and services (including benefit-based investments) contribute in some way to its overhead opex.

6.10 The Authority also sought feedback on an alternative option where all overhead opex would be recovered through the residual charge, on the basis that overhead opex may not be 'reasonably attributable' to benefit-based investments. The Authority had discussed this option during the Guidelines phase of the TPM reform.

117 Detailed reasoning for the covered costs provisions is set out in chapter 6 of the 2021 TPM Consultation paper (with further detail in Chapter 6 of Transpower's Reasons paper and its 25 August and 21 September 2021 submissions response to the Authority's refer-backs).

Submitters' views and our assessment

6.11 Several submitters (eg, Contact, Mercury, Meridian, Nova) supported the recovery of overhead opex entirely through the residual charge, rather than allocating a share to benefit-based investments.[118]

6.12 This was on the basis that this approach was more consistent with the Authority's previously stated policy intent (during the Guidelines phase of TPM reform), and that allocating overhead opex via benefit-based charges would add unnecessary complexity, be inefficient, and inconsistent with the Authority's statutory objective (in that increasing costs on generation would delay investment and increase costs to consumers).[119] Meridian therefore submitted it would be simpler and more direct to allocate these costs to load via the residual charge.

6.13 Some other submissions supported the Authority's proposal (Orion, Fonterra, Transpower):

- Orion preferred the Authority's proposal to such costs being socialised via the residual charge.
- Fonterra thought all Transpower's costs should be recovered through benefit-based charges, and overhead opex not applied to just one customer group.
- Transpower in its submission noted that attributing overhead opex to benefit-based investments was consistent with the approach taken in the telecommunications sector.

6.14 Transpower also did not support recovering overhead operating expenditures entirely through the residual charge, as it thought it could lead to cross-subsidisation of generators by consumers. This was on the basis that, if generators contributed to overhead costs through benefit-based charges, generators would not be able to pass all those costs on to consumers (whereas consumers would face all those costs directly if they were recovered through the residual charge).[120]

6.15 As the Authority noted at para 6.16 of the 2021 Consultation paper, the choice between the two options was a finely balanced judgement. Both options could likely be considered consistent with the Authority's statutory objective. The amounts involved are relatively small, and the CBA found there was little difference between the options.[121] Ultimately, submissions reiterated the matters the Authority had already identified as part of developing the proposal, rather than raising new

118 However, Contact Energy also submitted the connection charges generally worked well and that there was thus no justification to remove the injection overhead component that are part of connection charges under the current TPM. See paragraph 4.5 onward for reasons there is no injection overhead component in the new TPM.

119 Grid-connected generators do not pay residual charges (except to the extent they are load), so that if overhead operating expenditures are recovered through benefit-based charges, it would increase generators' transmission charges.

120 The Authority considered questions of pass-through in the context of the decision that residual charge should apply only to load customers, noting that increased costs on generators would mean investors in new generation would delay their entry until energy prices were expected to cover the additional costs (see the Authority's 2020 Decision paper, Chapter 10). However, benefit-based charges are intended to operate differently to residual charges and should impact on competition in the generation market. If a charge is reasonably attributable to a BBI, then it is consistent with the Authority's statutory objective for a generator to pay it.

121 2021 Consultation paper para 6.12.

concerns. Having considered these submissions, the Authority remains of the view set out in the 2021 Consultation paper, and as such the TPM adopts the proposal consulted on.

Opex for fully depreciated assets that remain in use

Our decision

6.16 Opex that is attributable to fully depreciated benefit-based investments will be recovered through the residual charge.

What we proposed

6.17 The decision adopts the proposal in the 2021 Consultation paper (page 39).

Submitters' views and our assessment

6.18 Few submissions addressed this proposal directly.

6.19 Contact supported the proposal although it questioned the basis for Transpower's estimate that this would initially involve 15% of total opex. The Authority notes the basis for the estimate is set out para 34 and footnote 23 of Transpower's Reasons paper page 6.10.[122]

6.20 Vector questioned why opex attributable to fully depreciated assets would be recovered via the residual charge rather than assigned to the beneficiaries of those assets.

6.21 Fonterra supported the alternative option set out in the Authority's 2021 Consultation paper (para 6.23) where this portion of opex would be allocated using the simple method, rather than allocation via the residual charge. This was because Fonterra prefers that to the extent possible all costs should be recovered through benefit-based or connection charges.

6.22 In relation to Vector and Fonterra's submissions, the lack of information on fully depreciated assets that remain in use means it is unclear how to allocate opex for those assets in a way that broadly reflects net private benefits, including whether the simple method would do this.[123] Hence the Authority's decision is, consistent with its proposal, to recover these costs through the residual charge.

Additional component F

6.23 The TPM will not include a method for the allocation of opex in relation to connection assets and benefit-based investments to the designated transmission customers paying charges in relation to those particular assets (Additional component F). This is on the basis that the potential efficiency benefits of attributing opex to the asset it was spent on cannot be justified given the practical difficulties and expense that would be involved.

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122 Transpower's rationale is at para 34 and footnote 23 of Transpower's Reasons paper page 6.10.

123 See para 6.22 and 6.23 of the 2021 TPM Consultation paper.

7 Residual charge

7.1 The residual charge recovers any of Transpower's recoverable revenue not gathered through other transmission charges, in a manner intended to limit effects on transmission customers' decision-making.

7.2 The residual charge would, for example, cover:

(a) non-network capex

(b) historical investments (other than the seven named in Schedule 1 of the Guidelines), and overhead opex attributable to them

(c) any decrease in other charges as a result of the application of adjustment provisions (eg, as a result of a reassignment) (whereas increases in other charges may reduce the amount of the residual).

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
Clause v of Authority's Intent	Part E: Clauses 68-74
Clauses 27-30	Definition of battery storage
	Clauses 4(1),4(2), 4(5) and 4(6) concerning load customers, gross energy and maximum gross demand

General provisions

Our decision

7.3 The provisions for the residual charge, with some exceptions discussed below, reflect the proposal consulted on and the Guidelines. In particular, there has been a change to the calculation of load for multiple GXPs at the same location.

7.4 The proposal consulted on reflected the provisions of the Guidelines, except that the proposed TPM based the residual charge on gross final consumption of electricity. The effect of this change was to base the residual charge for batteries on their electrical losses rather than their total intake of electricity for charging (as discussed with respect to batteries below).

7.5 Residual charges are to be paid by all transmission customers to the extent they are load customers. The allocation is fixed-like (based on each customer's historical gross anytime maximum demand, averaged across four financial years from 2014-2017).

7.6 The initial allocations are updated annually, based on changes in customers' lagged four-year rolling average of gross energy usage,[124] with this four-year period commencing the financial year eight years prior.[125]

7.7 The reasons for this approach are set out in the Authority's earlier papers.

124 Gross energy includes all consumption behind a customer's point of connection (not just grid offtake).

125 Elsewhere in this document, we refer to this adjustment as the "standard 5-8 year lagged adjustment".

What we proposed

7.8 With some exceptions, discussed further below, the TPM provisions on the residual charge are consistent with what we proposed in the 2021 Proposed TPM consultation paper.

Submitters' views and our assessment

7.9 Some submitters (eg, Fonterra, MEUG, Network Waitaki, NZ Steel, Oji Fibre Solutions, Pioneer Energy) were concerned about the overall size of the residual charge. We acknowledge that the residual charge will initially generate a large share of Transpower's regulated revenue. However, as we have previously demonstrated, its share will fall away over time as historical investments depreciate and as new investments are undertaken. We are of the view that including the investments listed in Schedule 1 of the Guidelines within the benefit-based charge, but not other historical investments, strikes a reasonable balance in the transition to the new TPM.

7.10 Submitters also raised other issues that we have previously considered in the decisions on the Guidelines and the proposed TPM. These included arguments that:

(a) the residual charge should be levied on generation as well as or instead of load[126]

(b) the residual charge allocator should not be based on gross load (eg, it should net off embedded generation, especially co-generation)[127]

(c) the residual charge allocator should not be based on AMD, should be based on coincident AMD across all of a customer's points of connection, or should be measured at a point other than the point of connection (such as the ICP).[128]

7.11 These submissions largely cover ground previously raised in submissions and that we have previously taken into account. We address issues that we consider merit further discussion above and below. Aside from these, while we have carefully considered any nuances or further details set out in these submissions, we do not consider that any argument has been raised that would warrant any other changes in the proposed TPM.

7.12 In addition, some submitters (eg, Oji Fibre Solutions, Network Waitaki, Refining NZ) suggested that the baseline period for calculating the residual charge should be later than 2014-2017, for example to allow for changes in the intervening period. We do not think this is necessary because the TPM allows Transpower to take account of a "reduction event" if there is a reduction in a customer's anytime maximum demand between 2014 and the start of the new TPM.[129]

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126 Submitters included ETNZ, Oji Fibre Solutions, NZ Steel, Vector.

127 Submitters included Fonterra, Horizon, IEGA, Nova, Oji Fibre Solutions, Orion.

128 Submitters included Buller, MEUG, Network Waitaki, NZ Steel, Oji Fibre Solutions.

129 Refining New Zealand submitted that it should be mandatory for Transpower to take a reduction event into account. We do not think this is necessary as customers will have an incentive to inform Transpower of a reduction event and Transpower will have an incentive to listen to its customers.

Generation with embedded load and co-generation

Our decision

7.13 The new TPM adopts the approach to generators with embedded load and co-generation that was proposed in the 2021 Consultation paper.[130]

What we proposed

7.14 To avoid inefficient connection incentives, the proposed TPM provided for the residual charge to be applied to grid-connected generators with embedded load, treating them as 'supplying load customers.'[131] It also applied the residual charge to load supplied by embedded generation, including co-generation.

Submitters' views and our assessment

7.15 Several submitters provided feedback on this proposal. Some submitters considered using gross load was inappropriate because embedded generation and particularly co-generation may not make direct use of the grid. Relatedly, some submitters considered that the residual charge should not apply to load embedded behind generation.[132] For example, Oji Fibre Solutions submitted that "OjiFS site cogeneration … is effectively a byproduct of the [production] process….. The electricity generation … therefore …. has extremely limited ability to increase generation in response to pricing signals. Our view is that this any calculation methodologies should reflect the fact that cogeneration is an intrinsic part of the site process and should be netted off in setting charges."

7.16 Orion submitted that "Embedded electricity is not delivered by Transpower but the approach charges customers as if it were. This approach conflicts with the distribution pricing practice note which promotes locational pricing…. The proposed TPM approach applies residual asset based charges to customers who are not using the assets…. In this respect, we do not think the approach is reasonable."

7.17 NZ Steel considers the Authority's reasoning for basing the residual charge allocator on gross load was "illegitimate". It pointed out that "cogeneration is not the same as distributed generation", being a by-product of on-site processes.

7.18 Nova submitted that "it is incumbent on the Authority to review its position on co-generation plants and not impose a charge on load that by design does not place demand on the grid if the co-generation plant is not running". Nova proposed that the residual charge provisions should ignore any "dependent load" that can only exist when the generating plant is operating and is physically connected to the generating plant, such as load that cannot exist in the absence [of] steam being supplied from a co-generation plant. Similarly, Teichert for Nova at para 21 states "The Authority suggests that it is only load customers, and not generators who pay the Residual Charge. This, in this description, at least as far as cogeneration and embedded generation are concerned, is incorrect and distorts the competitive market." He goes on to say at para 25 that "The criticisms listed in paragraph 10.19 of the [Authority's 2020] Decision apply equally here to generators with embedded load. The proposed

130 See chapter 7 of the Proposed TPM consultation paper 2021.

131 See Transpower's Reasons paper, section 5 "Grid-connected generators with embedded load".

132 Submitters included Contact Energy, Fonterra, Horizon, IEGA, NZ Steel, Nova, Oji Fibre Solutions, Orion, Pioneer, Trustpower.

Residual Charge subsidises non embedded load and risks premature exit of the relevant co-generator supplying the embedded load."

7.19 We agree with the factual situation described by these submitters; that is, the residual charge is imposed on gross load, even when some of that load is supplied by embedded generation or co-generation. We also accept that co-generation by its nature will only run when the load exists.

7.20 However, the Authority does not agree that the residual charge charges co-generation or indeed other embedded generation. Rather, it charges grid-connected customers based on the electricity use which occurs behind their point of connection, regardless of whether that electricity is supplied from the grid or by distributed generation or co-generation. Some submitters view this as charging for embedded generation (or co-generation), since demand supplied by embedded generation will still be counted. However, it is not the embedded (or co-) generation which is resulting in the charges, it is that the transmission customer has load.

7.21 In other words, the transmission customer incurs charges because it has load behind its point of connection. Thus, the arguments that co-generation should be treated a particular way are misplaced – they amount to arguments that load behind the customer's point of connection should be measured differently to how other load is measured. Ultimately that would mean the connected party's load customer would receive special treatment compared to other load customers.

7.22 The reason we have adopted a gross approach, (and not provided an exemption for load supplied by co-generation as several submissions propose) are:

(a) As we have previously described, the benefit-based charge seeks to influence customer behaviour by setting charges related to their expected use of, and benefit from, the grid.

(b) The Commerce Commission allows Transpower to recover its recoverable revenue, which is more than the costs associated with benefit-based and connection investments. Some of these costs cannot be usefully attributed to those investments, and others are costs associated with pre-2019 interconnection assets that (as noted above) are not being allocated to customers on the basis of net private benefits. Accordingly, as described in the 2019 Issues Paper and elsewhere, the residual charge is intended to cause the least distortion to the operation of the electricity market (and thus least risk of unnecessarily increasing costs to consumers in the long run). Where the benefit-based charge seeks to create incentives, the residual charge looks to avoid distortions. To that end, it sought an approach which reflected participants' size as a proxy for average ability to pay.

(c) In particular, the residual charge is intended to avoid creating incentives for parties to change their use of or connection to the grid to avoid charges (which would not save costs overall, but would simply shift the costs of transmission onto others while increasing overall economic costs, to the ultimate detriment of consumers). If the residual charge allocator was based on load net of embedded generation, it would encourage a transmission customer to favour such generation over electricity from the grid, because using embedded generation would reduce its residual charge.

(d) To implement the above aims, the residual charge takes a gross load approach, by assessing all of a customer's load regardless of whether the electricity came from the grid or embedded generation. That is, the allocation is neutral to the source of the electricity consumed, and therefore avoids creating incentives to unnecessarily invest in embedded generation.

(e) This rationale, that load customers should not be able to avoid the residual charge by using embedded generation, applies equally to all forms of embedded generation, including co-generation. The load remains the same size, and its ability to pay does not reduce because it is supplied by co-generation rather than other embedded generation or the grid.

(f) If a customer decides to invest in co-generation, this will potentially be reflected in lower benefits from any new grid investment, and so a lower benefit-based charge for it. It also results in the customer having reduced wholesale electricity costs due to lower purchases of electricity from the grid. However, it does not affect any of the costs recovered by the residual charge. If investment in co-generation had the effect of reducing a customer's residual charge allocator, this would provide it with an unwarranted financial advantage over other forms of electricity supply, with the risk that co-generation would be undertaken in part based on reducing transmission charges (and shifting them to other customers) rather than the intrinsic merits of co-generation.

(g) Where co-generation is the most efficient means of supplying a particular customer, the market will ensure it remains profitable to continue such arrangements.

7.23 Moreover, there are a number of specific provisions in the TPM that allow a customer's individual circumstances to be taken into account, including:

(a) The prudent discount policy: where it would be commercially beneficial for a customer to inefficiently bypass the grid in favour of alternative supply or else where a customer's transmission charges exceed the standalone cost of supplying them, those customers would be able to apply for a prudent discount.

(b) The transitional cap on transmission charges: this is intended to prevent customers experiencing undue price shock at the time the new TPM comes into effect.

7.24 In short, parties with load and embedded generation or co-generation still have a connection to the grid from which they benefit (even if only to the extent of having that connection available to them, for backup and the like). As such, the Authority considered that they should be treated like other similar parties who also have load and a connection to the grid, rather than be given special treatment. This approach is not inconsistent with the approach to benefit-based charges, but merely reflects that the two charges have different purposes and are therefore designed differently.

Embedded generation that injects into the grid

Our decision

7.25 The new TPM adopts the approach to this issue that was proposed in the 2021 Consultation paper.[133]

What we proposed

7.26 In the situation where an embedded generator injects into a distribution network (or other load customer) and the injection passes through into the grid, the proposed TPM provided for the grid injection to be netted off. This means it is not counted as part of gross load (which is used to allocate the residual charge).[134]

Submitters' views and our assessment

7.27 Some submitters provided feedback on this issue.[135] Submissions were largely supportive. For example, Contact commented that "as the residual charge is intended to be allocated based on a customer size (as a proxy for ability to pay), the residual allocator should capture a load customer's final electricity demand. That means it should capture electricity source from embedded generation that is consumed by the load customer and not electricity that is reinjected into the grid at that load customer's GXP." We agree.

7.28 Having considered submissions, the Authority has decided to adopt its proposal on this issue. As we discussed in the consultation paper, the Authority considers that this decision will promote its statutory objective – and is consistent with the intent of the Guidelines – as it will produce a residual charge that is allocated based on load customers' final electricity demand (which is intended to be a proxy for the customer's size and ability to pay).

Information sources for the calculation of allocation data

Our decision

7.29 The Authority has included a provision in the TPM that clarifies what information sources Transpower may use to calculate data about a customer's supply, demand, injection, offtake or gross energy that affects the customer's allocation of transmission charges (allocation data) (clause 10(4)).

7.30 The provision also provides that Transpower is not required to (but may) use any other information to calculate allocation data. The provision is subject to other provisions in the Code.

What we proposed

7.31 The proposed TPM required transmission charges to be calculated based on information about customers' supply, demand, injection, offtake, and gross energy. Under the proposed TPM as consulted on, Transpower was required to perform the calculations, with reference to the information participants provided to it or it was reasonably able to obtain, but otherwise at its sole discretion.

133 See chapter 7 of the Proposed TPM consultation paper 2021.

134 See Transpower, 15 September refer-back part 2 response submission, section 5.2, paras 54-58.

135 Submitters included Contact Energy and Pioneer Energy.

7.32 Transpower would therefore have needed to make calculations based on the information currently available to it to set the initial residual charge. It would then have required further information to over time calculate the adjustments to residual charges.

7.33 The Authority was aware that there might be additional information about behind-the-meter generation and consumption that, if available to Transpower, may improve the residual charge calculations, and signalled it intended to consult on a Code amendment on this topic.

Submitters' views and our assessment

7.34 Transpower in its submission proposed adding a new clause to the proposed TPM that is intended to improve certainty on which information sources it may use to calculate allocation data. Transpower proposed to use information from the specified list but that it would not be required to (but may) use any other sources of information.[136] This provision was subject to any contrary provisions in the TPM.

7.35 The Authority considers this 'safe harbour' is a sensible inclusion which will improve certainty and reduce the scope for potential disputes in the implementation.

7.36 However, noting that a limited amount of additional information is likely to improve the initial calculation of the residual charge, the Authority has made the safe harbour subject to the Code, and intends to progress a separate Code amendment to facilitate Transpower's access to additional information that may be relevant to calculating charges.[137] The Authority is also aware that the TPM, and other parts of the Code may more generally benefit from better information about embedded generation and batteries over time, and intends to address this at a later stage (see paragraph 15.11(c)).

Allocation where customer has multiple points of connection at the same geographic location

7.37 Some customers have multiple GXPs at the same connection location that can serve the same load (that is, the extra GXPs essentially provide redundancy). Several submissions identified that under the proposed TPM these customers' co-located GXPs were measured non-coincidentally to establish the customers' AMDR baseline, which may double-count the same load, and which could result in a disproportionately high residual charge allocation (compared to for example customers who serve the same load through a single GXP).

Our decision

7.38 The TPM (clause 70) will determine a customer's AMDR baseline by measuring the maximum gross demand at each connection location where that customer connects.

136 Transpower stated in its submission: "This clause brings some certainty to the data sources Transpower may use to calculate gross load, and will insulate Transpower from potentially recurring disputes about the proper data sources to use. The first four listed data sources are either reconciled or derived from certified metering. The fifth is SCADA data, which we intend to use only as a "gap filler" where required (as it may be, particularly for historical gross load). We note this clause protects Transpower from disputes about data sources, not from disputes about errors in the calculation."

137 See para 15.11(c)(i).

This approach treats each connection location as one point of connection, which has the effect of:

(a) Measuring coincident maximum gross load between different GXPs at the same connection location.

(b) Measuring non-coincident maximum gross load between different connection locations calculated in (a) above.

What we proposed

7.39 The proposed TPM calculated a customer's AMDR baseline non-coincidentally at the GXP level. Transpower would measure and sum the customer's maximum gross demand at each of their GXPs, regardless of whether these peaks were in different trading periods.[138]

7.40 The non-coincident approach is generally an appropriate proxy for the customer's size and ability to pay[139], as it results in a broadly equivalent allocator between a customer with load diversity and a similarly-sized customer with no load diversity.[140]

Submitters' views and our assessment

7.41 Several submitters identified a situation where the non-coincident approach to measuring AMDR could overstate the residual charge allocator.[141] This is because where customers have a single load that is served by and can be shifted between multiple GXPs, the same load may be counted in the AMDR baseline for multiple GXPs, which are then added together. This can result in the load being "double counted" and the customer incurring an anomalously high AMDR (and therefore residual charge) compared to a customer with a similar load that is supplied by a single GXP.

7.42 In these circumstances a non-coincident approach could effectively penalise customers with n-1 redundancy engaging in load shifting (usually considered good practice) during the relevant measurement period.

7.43 For example, Network Waitaki has two GXPs at the Waitaki connection location (being WTK0111 and WTK0331), with load being switched between the two. As shown in panel a of Figure 2 on the next page, the WTK0331 GXP had no demand except for when the WTK0111 GXP was not operating.[142] Under a non-coincident measure, there would be an allocation based on maximum gross demand for each GXP, even though both maximum gross demand figures represented the same load.

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138 This would be calculated for each financial year between 2014 and 2017 (inclusive) and later averaged to get an annual figure.

139 2019 Issues Paper paragraphs B.207-B.209 and 2020 Decision Paper paragraphs 10.47-10.48.

140 As an illustrated example, consider a customer that has two 10MW factories that each connect to their own GXP. If one factory only operates during the day and the other factor only operates at night (load diversity), the maximum coincident demand across both GXPs is only 10MW. However, a customer that has two 10MW factories that operate simultaneously (no load diversity) will have a coincident maximum demand of 20MW, despite being the same "size" as the first customer. Under a non-coincident approach, both customers would have the same maximum demand of 20MW.

141 Buller Electricity, Network Waitaki, NZ Steel and Oji Fibre Solutions. Contact, Nova and Trustpower also raised this issue in their cross-submissions.

142 The maximum gross demand at WTK0331 for the 2017 financial year occurred in October 2017. During this trading period, demand at WTK0111 was zero, although it is difficult to observe this in the graph.

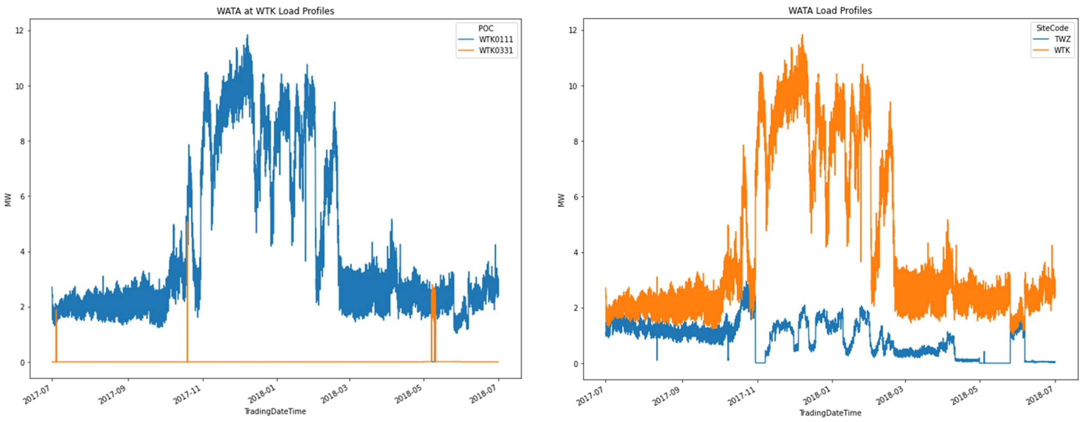
Therefore, summing these non-coincident peaks would result in an AMDR that may not be representative of Network Waitaki's size or ability to pay.

7.44 Oji Fibre Solutions proposed that connection locations such as these should measure AMDR based on the "coincident peak demand for the GXPs at that site".[143] This would effectively measure maximum demand at a less granular level (connection location rather than GXP).

7.45 The Authority has decided to adopt this less granular measure of AMD. As we have noted before, no approach can provide a perfect proxy for customer size and ability to pay. A less granular measure of maximum gross demand means it is less likely that the same load will be double-counted. However, this may benefit transmission customers with multiple GXPs in the same location that do serve distinct loads, as it may then understate their size or ability to pay.

Figure 2 Network Waitaki's load profile 2017-2018

a. Waitaki 0111 and 0331 GXPs **b. Waitaki and Twizel GXPs**



Source: Electricity Authority

7.46 This location-based approach will not result in a lower AMDR where there is load shifting between a customer's GXPs if these GXPs are situated at different connection locations. For example, Network Waitaki also shifts some load between the Waitaki GXPs and the Twizel GXP, as shown by the load profile in panel b of Figure 2 (although we note that not all load is shifted between these two GXPs, in contrast to the co-located Waitaki GXPs, indicating the Twizel and Waitaki GXPs also serve different distribution customers).[144]

7.47 We did consider approaches that would allow a coincident approach to be taken across different locations. However, such approaches would, in the Authority's view, allow load diversity to have too great an effect, allowing distribution networks and other customers with GXPs at multiple locations to benefit substantially from load diversity at the expense of other customers. This would result in a lower residual charge for customers with more locations at the expense of customers with fewer

143 Transpower also proposed this solution during further engagement with the Authority outside of the consultation period.

144 We expect Network Waitaki's residual charge to be smaller under the new approach as a result of aggregating the Waitaki GXPs (but excluding the Twizel GXP).

locations. In the Authority's view, this would not result in a residual charge allocation that is well aligned with customer size and ability to pay.

7.48 The Authority considers that treating each connection location as a single GXP strikes the best balance between these competing considerations. Under this approach, the residual charge allocators for some customers will reduce (compared to if a fully non-coincident approach was taken),[145] and the residual charge allocators for other transmission customers will increase. These customers' indicative charges for 2021/2022 will increase by up to about 2% due to this change.[146]

Application of residual charge to battery storage

Our decision

7.49 The TPM provides for the allocation of the residual charge to batteries in much the same way as was proposed in the 2021 Consultation paper (with some minor changes). This allocation is based on batteries' final consumption (ie, energy losses) rather than their total consumption (ie, energy intake when charging). This is achieved by not counting battery injections as embedded generation.

7.50 Minor changes/clarifications that have been made to this approach include:

(a) Where energy injected from a behind-the-meter system into a network is thought to come from either a battery or a (non-battery) generator, but the true position is unknown, Transpower must assume the latter. This treats such injections as embedded generation so they will be counted towards the customer's gross energy (and so its residual charge).

(b) When estimating the residual charge's AMDR baseline for new customers with batteries, large grid-connected batteries <u>and</u> large embedded batteries will have only their losses counted towards the customer's AMDR.

What we proposed

7.51 In the 2021 Consultation paper, we proposed that the TPM allocate the residual charge based on gross energy in accordance with the Guidelines. Gross energy is essentially the sum of grid offtake and embedded electricity (ie, embedded generation that is consumed by the customer and not injected back into the grid).

7.52 However, we proposed allocating the residual charge to batteries based on energy losses (energy ultimately consumed) rather than their total energy consumption (energy intake when charging). This avoids the double-counting of electrical energy that passes through batteries and is later consumed by other load.[147] In practice, this

145 We expect that Aurora, Buller, Contact, Counties Power, EA Networks, Genesis, Mainpower, Mercury, Meridian, Network Tasman, Network Waitaki, NZ Steel, Orion, Powerco, Powernet, Unison, Vector, WEL Networks, Wellington and Westpower all have connection locations with multiple GXPs that will experience a decrease in their AMD under the updated approach (compared to previous indicative estimates). However, not all of these customers will experience decreases in their total AMDR baseline if the demand at these GXPs is small compared to the customer's demand at their other GXPs.

146 Refer to chapter 12 for further detail on indicative prices.

147 2021 proposed TPM Consultation Paper, paragraphs 7.25 to 7.34.

is achieved by not counting generation from battery injections as embedded generation, and therefore not counting these injections towards gross energy.[148]

7.53 When estimating a new load customer's AMDR baseline, we proposed applying this final consumption approach as follows:

(a) Energy taken off the network when charging large batteries would not count towards the AMDR estimate (subject to the below).

(b) Energy losses from grid-connected batteries would count toward the AMDR estimate, but losses from embedded batteries would not.

7.54 The rationale for not counting losses from embedded batteries was that during periods of peak demand, embedded batteries were considered unlikely to charge as energy is likely to be expensive due to high demand.

Submitters' views and our assessment

7.55 Support for our "final consumption" approach to batteries was mixed. Several submitters largely supported the proposal,[149] while others raised concerns around competitive neutrality with non-battery technology, the measurement of injections from batteries that are part of behind-the-meter systems and the application of the final consumption approach when estimating a customer's AMDR baseline.[150,151]

The competitive neutrality problem identified by the Authority

7.56 The change to the final consumption approach is a departure from the Guidelines, so must be done through clause 2 of the Guidelines by demonstrating that this change better meets the Authority's statutory objective.[152] The Authority set out its reasons for considering such a departure was justified in the 2021 Consultation paper.

7.57 Trustpower did not agree that the final consumption approach better meets these statutory objectives (ie, by improving competitive neutrality between batteries and other technologies and therefore preventing adverse effects on battery investment).[153] It preferred a total consumption approach where batteries would be charged for their entire demand while charging (rather than just losses). Trustpower argued that this approach does not create competitive neutrality issues for batteries in the wholesale market as the residual charge is an input cost for battery generators,

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148 As explained in the 2021 Consultation Paper, final consumption is measured as "grid offtake + embedded electricity (excluding battery generation)". This equates to "load + battery losses" (ie, final consumption) but is a more practical way of measuring it.

149 For example, Contact, Mercury, Meridian, Orion, and Transpower.

150 ETNZ was unclear how the residual charge applied to pumped hydro storage. As with all battery storage, the residual charge (based on losses only) will be allocated to the customer that owns the pumped hydro, not the load customers supplied by the storage. The residual charge will be the same regardless of whether the pumped hydro storage is "charged" from grid offtake or embedded generation such as run-of-river generation.

151 Vector's submissions appeared to have interpreted that the residual charge was being allocated to batteries based on gross energy but allocated other load customers based on gross anytime maximum demand. All load customers (including batteries to the extent that they consume energy – i.e. losses) are being allocated a residual charge the same way, based on their initial AMDR baseline and updated annually based on their lagged change in total gross energy.

152 Transpower, 2021, *TPM Development Residual Charges and the Treatment of Batteries Options Consultation*, paragraphs 59-64.

153 Trustpower referred to its submission under Transpower's Residual Charges and the Treatment of Batteries Options Consultation process.

just as gas transmission charges are a cost for gas generators, and differences in input cost "create the basis for competition; they do not distort it."[154]

7.58 The Authority agrees that, in general, generators (including batteries) should face their costs of supply, including relevant transmission charges.[155] In principle, a grid-connected gas generator and a grid-connected battery should *both* pay charges associated with the electricity transmission network – including residual charges. The competitive neutrality problem arises because non-battery generators are – for good reasons (discussed elsewhere) – exempted from paying the residual charge. To solve this problem, the Authority has decided to largely exempt batteries from paying the residual charge (except on the electricity they actually consume). The competitive neutrality problem does not go away just because gas generators are also required to pay costs relating to other inputs (gas) which battery storage does not require.

7.59 Trustpower argued that batteries providing ancillary services are not disadvantaged compared to other providers, as ancillary services tend to be offered based on incremental costs (not capital costs), and the residual charge is set by the battery's AMD when it first charges. Trustpower also argued the total consumption approach does not competitively disadvantage batteries in the transmission services market as Transpower determines how to provide transmission services using the Investment Test, which does not take into account wealth transfers between parties. However, the Authority's primary justification for partially exempting batteries from the residual charge using clause 2 of the Guidelines was (and is) the competitive neutrality issue faced by batteries against generation in the wholesale electricity market. Even if the residual charge did not affect batteries in the ancillary services or transmission markets, this does not mean a departure from the Guidelines is not justified.

7.60 Trustpower argued that even if there was a competitive neutrality issue under the total consumption approach, it could be better dealt with by prudent discounts than by changing the residual charge.

7.61 The Authority disagrees. While some battery owners may be able to demonstrate a viable business case to disconnect from the grid or demonstrate that their charges are above standalone cost, the threshold for prudent discounts under the proposed TPM is reasonably high. Battery owners that could not meet this threshold would likely still be competitively disadvantaged compared to non-battery generators under the total consumption approach. Prudent discounts are not expected to address all competitive neutrality issues. One of the key objectives of prudent discounts is to minimise incentives for customers to inefficiently shift how they connect their plant to the grid, but they are intended to be a tool of last resort.[156] The rest of the TPM should be designed to minimise these incentives also.[157]

7.62 The Authority considers the total consumption approach to allocating the residual charge would competitively disadvantage batteries compared to other generators,

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154 Creative Energy Consulting, 2021, *Advice on application of Residual Charge to Batteries.*

155 For grid-connected storage, "relevant transmission charges" means charges relating to the electricity transmission network. For a grid-connected gas generator, "relevant transmission charges" includes charges relating to both the gas transmission network and the electricity transmission network.

156 See the Authority's 2020 Decision Paper at para 11.10.

157 Clause 33(g) of the Guidelines.

and therefore could have adverse effects on battery investment. This justifies changing to the final consumption approach under clause 2 of the Guidelines.

Does the Authority's solution create other competitive neutrality problems?

7.63 Some stakeholders[158] argued that the final consumption approach in relation to batteries would provide batteries with a competitive advantage over other competing energy storage systems such as "thermal batteries" (ie, stored heat) and over other ancillary services providers such as load customers that provide interruptible load.

7.64 We do not consider that the final consumption approach gives a competitive advantage to batteries over other energy storage systems. All other things being equal, under the TPM the gross energy of a customer with a thermal battery will be the same as the gross energy of a customer with an electrical battery of an equivalent size and efficiency. A thermal battery draws from the grid when it "charges" but does not generate electricity when it "discharges". An electrical battery is treated the same way – its grid offtake while charging is measured, but its injection when discharging is expressly not counted as embedded generation. The Authority's approach ensures the energy intake of both batteries is counted once – but not twice.

7.65 We also do not consider that the final consumption approach would provide batteries with a competitive advantage in the ancillary services market. We do not agree with MEUG's argument that load customers that provide interruptible load are competitively disadvantaged because they will have a higher AMDR baseline than batteries that provide instantaneous reserve. A load customer's AMDR baseline is set when the customer operates at full capacity. This baseline would be the same whether the customer was providing interruptible load or not, so the customer's residual charge in its capacity as an ancillary services provider is zero.

7.66 IEGA submitted that the residual charge is applied inconsistently between battery customers and load customers because battery generation is not counted towards gross energy while other embedded generation is counted. We do not consider there to be any competitive neutrality problems here. Gross energy is measured as grid offtake plus embedded generation. The distinction for battery customers is that battery injections do not count as embedded generation, as to do so would double count the same energy (ie, first when the battery charges and again when the battery discharges).[159] The TPM applies consistent treatment in that it ensures energy is counted only once for both batteries and embedded generation.

Measuring injection from behind-the-meter systems

7.67 Where there is both generation and batteries behind a meter, information on where injection from this meter comes from (and thus whether it should count towards gross energy) may not be readily available. Orion submitted, depending on the Authority's measurement approach, there was a risk of disincentivising embedding batteries on the DC side of an inverter, which is often the most efficient place to install them.

7.68 We consider that if total embedded generation can be measured or accurately estimated (even if it is behind the meter) then gross energy can be accurately calculated without information on battery flows or exactly where energy passing

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158 For example, Fonterra and MEUG.

159 See paragraph 7.52 above and footnote 148.

through the meter has come from. The Authority is separately considering proposals to further improve available information around embedded generation.

7.69 In the meantime, the TPM provides that Transpower must assume that energy injected into the network from behind a meter is from non-battery generation in the absence of reliable information to the contrary. This approach has both pros and cons depending on how any battery is likely to operate:

(a) Where batteries do not inject back into the network (ie, there are no batteries or all energy stored by batteries is consumed by load behind the meter), this approach will correctly treat all injections at the meter as embedded generation. We expect many batteries will operate in this way to a greater or lesser extent.

(b) To the extent that a battery behind the meter both charges from and discharges to the network, this approach may over-measure gross energy by double-counting battery flows. The resulting higher residual charge may inefficiently discourage investment in batteries that operate in this way. However, such customers will be incentivised to provide accurate behind-the-meter information to avoid this double counting.

(c) To the extent that a battery behind the meter is charged by behind-the-meter generation, this approach may under-measure gross energy (by failing to count battery losses). While such circumstances may be relatively common, the under-measuring is likely to be relatively minor as losses are only a small proportion of total load.

7.70 However, alternative approaches would have more serious downsides. For example, treating all such injections as coming from batteries would fail to count embedded generation towards gross energy. This would create strong inefficient incentives to locate embedded generation behind meters and not to reveal information about them to avoid transmission charges.

Estimating AMDR baselines for new customers with batteries

7.71 Transpower submitted that ignoring losses from large embedded batteries[160] for a new customer's estimated AMDR baseline may create an incentive for new customers to embed large batteries. It proposed that losses from large embedded batteries (as well as large grid-connected batteries) be included in AMDR estimates.

7.72 We agree with this assessment.[161] The incentive to embed large batteries could result in these batteries being embedded where it is not efficient to do so. More embedded batteries would also mean (under the proposed TPM) fewer batteries being allocated a residual charge, resulting in other customers having to pay a higher residual charge. We consider these effects to carry more weight than the original rationale for excluding embedded batteries (ie, that embedded batteries are less likely to be charged during periods of peak demand). Large embedded batteries' losses are therefore included in the estimation of a new customer's AMDR baseline.

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160 The entire contribution (not just losses) from charging or discharging small batteries, whether embedded or grid-connected, is included when estimating the AMDR baseline for new customers. This is because AMDR baselines for existing customers may include some energy used to charge small batteries (as they were not separately metered during the measurement period). This discussion is therefore only relevant to the treatment of losses in large embedded/grid-connected batteries.

161 This proposal was not raised in submissions or cross-submissions by other parties.

8 Adjustments

8.1 In general, connection, benefit-based and residual charge allocations between designated transmission customers are intended to be relatively fixed. This is desirable, because it means that there is no incentive on transmission customers to take actions to inefficiently avoid their charges.

8.2 However, there are some circumstances where it is necessary for allocations to change (eg, because a party exits). In addition, it is desirable to strike a balance between charges being relatively fixed (and so unavoidable) and adjusting to reflect transmission customers' changing circumstances. The new TPM provides for circumstances in which charges can be adjusted.

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
Clauses 11-12, 29, 31-44	Part F: Clauses 75-95

General approach to benefit-based and residual charge adjustment provisions

(a) A transmission customer's allocators for benefit-based and residual charges are generally not intended to change.

(b) If a transmission customer exits (completely stops using grid-supplied electricity), Transpower will immediately cease to charge it benefit-based and residual charges.

(c) If a party becomes a transmission customer, it will immediately face benefit-based charges that are the same as an otherwise identical incumbent. Its residual charge will adjust with a 5 to 8-year lag to be the same as an otherwise identical incumbent – see (g).

(d) If a transmission customer substantially changes its use of the grid, its benefit-based charges adjust immediately, while its residual charges adjust with a lag – see (g).

(e) If a large party becomes or is indirectly connected to the grid through a transmission customer, the latter's charges typically adjust in the same manner as the large party's charges would have changed if it were connected directly to the grid.

(f) Following an adjustment, the allocators of all other relevant transmission customers adjust proportionately so that the allocators for each benefit-based charge and the residual charge sum to 100%.

(g) A customer's residual charge allocation updates gradually with a 5 to 8-year lag in line with its use of the grid (relative to that of others).

(h) If there is a general substantial sustained change in grid use, benefit-based charges are reallocated. This is expected to occur rarely.

(i) If a benefit-based investment is substantially damaged or proves to be over-engineered, or if Transpower chooses to voluntarily under-recover its charges, its benefit-based charge can be adjusted accordingly.

8.3 Because the treatment of these charges in respect of large embedded parties parallels the treatment of grid-connected parties, the discussion below focuses on grid-connected parties.

General provisions

Decision on the definition of "large" and "substantial sustained" change

8.4 The TPM adopts the definitions of "large" and "substantial sustained" change as proposed in the 2021 Proposed TPM consultation paper.

What we proposed

8.5 The adjustment provisions generally apply only in respect of "large" plant or in respect of a "substantial sustained" change in use.

8.6 Large means a plant that is connected to the grid or has a capacity of at least 10 MW, or the upgrade or derating of a plant's capacity of at least 10 MW compared to the plant's capacity before the upgrade/derating.

8.7 A substantial, sustained increase is proposed to be an increase in a large plant's expected annual electricity consumption or generation of at least 25% since the last time the relevant customer's benefit-based investment customer allocations for one or more benefit-based investments were calculated, with the increase expected to be sustained, ie, expected to last for at least five years.

Submitters' views and our assessment

8.8 Few submitters commented specifically on these definitions. Refining NZ and Contact supported the definitions we have adopted. Trustpower suggested that the "bright line" caused by these definitions "are likely to trigger inefficient investment and operational decisions". We consider that it is impossible to efficiently avoid such a boundary in a TPM that has fixed-like charges and that can accommodate the entry and exit of new customers. The Authority considers the 10 MW threshold (chosen as it aligns with the threshold for generator offers in the Code) strikes a balance between being large enough to ensure charges remain fixed like, and small enough to not encourage inefficient investment and operational behaviours.[162] Furthermore, we consider that having clear definitions will reduce uncertainty.[163]

8.9 Given this, we have decided to adopt the definitions in the proposed TPM.

Decision on accelerated depreciation

8.10 The proposed TPM took account of accelerated depreciation due to write-down in setting connection and benefit-based charges. However, the interaction of write-down

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162 2021 proposed TPM Consultation paper, para 8.20-8.23, and Transpower's Reasons paper, p10.17 para 44.

163 CEC (p13) suggests that if a new customer is not large, it is unclear what its charges will be as reopeners provide for adjustments to a distributor's benefit-based charges when it adds or expands a grid exit point. CEC is correct that the TPM does not specify how distributors set prices for their customers, because the TPM concerns the prices Transpower charges its customers, and not the relationship between a distributor and its customers.

Northpower submitted that it was not clear whether "customer" meant a Transpower customer or was more general. The TPM defines "customer" to mean designated transmission customer, so that the definition is restricted to customers of Transpower, unless the context otherwise requires.

of a benefit-based investment with the reassignment provisions could have been clearer.

8.11 To clarify it, we have explicitly defined the term “write-down” to mean a reduction in an asset’s value due to damage to, or destruction, stranding or decommissioning of, the asset before the end of its economic life. Accelerated depreciation due to the write-down of a connection asset or a benefit-based investment will be recovered through the residual charge. We have also specified more explicitly the interaction between write-downs and reassignment. This is discussed further below.

What we proposed

8.12 Clauses 40 and 41 of the proposed TPM provided that accelerated depreciation of a benefit-based investment would not be recovered through the benefit-based charge. Implicitly it provided that accelerated depreciation of a benefit-based investment would be recovered through the residual charge and accelerated depreciation of a connection asset would be recovered from the connection pool.

Submitters’ views and our assessment

8.13 Transpower submitted that accelerated depreciation due to the write-down of a connection asset or a benefit-based investment should be recovered through the residual charge. It noted that this was a departure from the requirements of clauses 11 and 15 of the Guidelines. It considered that the departure could be justified under clause 2 of the Guidelines. There were no cross-submissions on this point.

8.14 We agree with Transpower that our decision is a departure from the strict wording of clauses 11 and 15 of the Guidelines as the (implicit) provision for accelerated depreciation in those clauses (such as the provision for reassignment) is more restricted than that now allowed for in the TPM. However, write-downs are likely to be small, and so will not materially influence the incentives transmission customers will have to scrutinise investments. The Commerce Commission has a role in certain circumstances - in the case of stranded assets - to specify the service life potential such that a change can be reflected in Transpower’s regulatory revenue.[164] Further, aligning the TPM treatment of write-downs with Transpower’s normal accounting treatment of them is likely to simplify administration of the TPM.

8.15 We therefore consider that the proposal is justified under clause 1(b) of the Guidelines. Even if it were not, we consider it could be justified by clause 2 of the Guidelines.

Adjustments to a customer’s connection charge

Our decision on adjustments to the connection charge

8.16 The TPM provides for adjustments to the connection charge on the entry of a customer, exit of a customer and the partial sale of a business. It also allows Transpower to voluntarily under-recover the connection charge. The Guidelines do not explicitly provide for adjustments of the connection charge, but such provisions are consistent with the Guidelines and their intent.

164 Refer to Transpower input methodologies, cl 2.2.6(1)(d) https://comcom.govt.nz/__data/assets/pdf_file/0020/91181/Transpower-input-methodologies-determination-2010-consolidated-29-January-2020.pdf

What we proposed

8.17 Our decision is largely the same as what we proposed. The main differences are discussed below.

Submitters' views and our assessment

8.18 Submitters made limited comments on the proposed adjustment to the connection charge. Refining NZ proposed that the reassignment provisions applicable to the benefit-based charge should also apply to the connection charge. Northpower had similar concerns about the connection charge.[165]

8.19 We have decided not to provide for reassignment of the connection charge. Unlike benefit-based investments, new connection investments can be and often are undertaken as normal commercial contracts that are freely entered into by the connecting customer. This means that the customer has appropriate incentives to ensure that the investment is right-sized. After the connection investment is completed, the cost is sunk and cannot be avoided. It is appropriate that this cost is borne by the contracting parties, so that they take the risk of not right-sizing into account at the time they enter into the contract.[166]

8.20 However, we have decided to extend the prudent discount policy so that it applies to all transmission charges, including connection charges. This provides for a discount in transmission charges if a customer's charges exceed stand-alone cost or if it can inefficiently bypass the grid. Providing such an extension is consistent with the logic of providing the prudent discount in the first place.

Adjustments to a customer's benefit-based charge

Our decision on adjustments to the benefit-based charge

8.21 The TPM provides that a customer's benefit-based charges would adjust in response to a number of different circumstances, including: a large increase in use of energy; a shut down or de-rating of a large plant, causing a large decrease in use of energy; or a change in its point of connection.

8.22 These adjustments would in general be immediate, unless the relevant benefit-based investment was less than 10 years old, in which case any decrease would normally be deferred until the investment was 10 years old.

8.23 This is consistent with the Guidelines, with some exceptions. The significant exceptions relate to the following issues, discussed below: adjustment provisions for distributors; charges for a new entrant; derating, reduced use of an investment that is

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165 Refining NZ made a submission on the connection asset de-rating provision, saying the de-rating provision for connected load should also apply to large embedded load. We have provided for this, consistent with the general approach that the treatment of large embedded parties should parallel the treatment of grid connected parties. The former provision has the effect of altering the allocation of the connection charge for a single connection between the parties connected to it, so would have no effect on a customer's connection charge when it is the only customer connected by the connection asset. Refining New Zealand also suggested that the TPM provide for pass through of charge reductions in respect of embedded parties, and about rights of the embedded parties under the TPM. The TPM concerns the prices Transpower charges its customers, and not the relationship between a distributor and its customers.

166 Nova made this distinction between a regulated investment and a commercial environment in commenting on the adjustment of the benefit-based charge.

less than 10 years old, and the application of the Schedule 1 benefit-based investments adjustment provisions to batteries.[167]

What we proposed

8.24 Our decision is the largely the same as what we proposed. The main difference is that we have decided not to make the upgrading of a distributor's transformer an adjustment event, and we have made some other minor changes. These are discussed below.

Submitters' views and our assessment

Distributor's increase in use

8.25 As we proposed in our consultation, the TPM extends the adjustment provisions to distributors who connect to a new GXP. Some submitters who commented on this (eg, Contact, Network Waitaki[168]) agreed with this approach.

8.26 Orion also offered qualified support for making the connection of a distributor to a new GXP an adjustment event, but was concerned that it might be inappropriate in some circumstances. Orion submitted (page 8 of its submission):

> "The substantial and sustained trigger for change is pegged at an increase of 25% energy consumption. This could lead to a significant number of reviews where load is transferred between GXPs. For example, where a new GXP is established, load will be progressively transferred to the new GXP over a number of years as feeders on adjacent constrained GXPs are transferred. We would like to submit that Transpower does not carry out an adjustment where it reasonably considers that in the absence of load shifting by a customer, the movement would not have exceeded the 25% trigger".

8.27 We do not think this is correct, because the "substantial sustained" provision applies in respect of large plant. However, we consider the same issue could arise in respect of the "new GXP" adjustment provision. We have dealt with Orion's concern in this provision by providing that the estimate of a distributor's allocators for the connection at the new GXP must be adjusted to take account of its reduction in offtake at its other GXPs.

8.28 We have decided not to make the upgrading of a transformer an adjustment event. This is because:

(a) The adjustment events already provide for the adjustment of a distributor's charges in respect of the connection of large plant to or the upgrading of large plant in a distributor's network.

(b) When Transpower is setting the benefit-based charges, it may take into account organic growth of a distributor, whether or not it necessitates a transformer upgrade.

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167 We have also clarified that sale of all of a business is treated the same way as sale of part of a business, with all the relevant charges being allocated to the purchaser. We consider this to be consistent with the Guidelines. Even if it were not, we consider it could be justified under clause 2 of the Guidelines.

168 Network Waitaki did so in the context of its "overall disapproval of the proposed TPM".

8.29 These provisions mean that if we also provided for a transformer upgrade to be an adjustment event, it may mean that a distributor is charged twice for the same growth. To avoid this, we have reverted to the Guidelines position that there be no adjustment event for a transformer upgrade.

New entrant "whole of life" issue

8.30 In our consultation on the proposed TPM we proposed setting benefit-based charges for a new entrant so that they are the same as an equivalent incumbent in each year from the time it entered. However, we sought views on whether providing for an equal annualised charge (a "whole-of-life" approach) would be better.

8.31 Contact supported a whole-of-life approach on the grounds that the approach in the proposed TPM would impose additional costs on an incumbent compared to a new entrant. CEC for Trustpower appears to see some merit in a whole-of-life approach (pages 21-22)[169] although Trustpower at para 2.5.3(c) of its submission appears to consider a whole-of-life approach to be discriminatory.[170] Conversely, Transpower opposed a whole-of-life approach because it considers that it "would not increase our levels of confidence that BBCs reflect the share of net private benefits each customer is expected to receive from a BBI across the whole of its life".

8.32 We have retained the approach in the proposed TPM because, while it is not a perfect solution, it is simpler to administer and understand. As noted in the 2021 Consultation paper para 8.18 " …a new entrant will face benefit-based charges for new transmission investments as well as a range of existing investments, so the benefits of adopting a more precise but more complex implementation of clause 33 of the Guidelines are likely to be diluted. The advantage of the approach in the proposed TPM is that it is simpler to implement and more predictable and so better meets clause 1(b) of the Guidelines".

De-rating vs decrease in use

8.33 The proposed TPM provided for an adjustment to a customer's benefit-based charge for an investment if the customer closed a large plant or de-rated it. We sought views on whether the adjustment to the benefit-based charge was appropriate if the customer's plant was de-rated (as proposed) and whether the adjustment should also apply to a large and sustained decrease in energy use.

8.34 A number of submitters (eg, Contact, Nova, OceanaGold) expressed the view that charges should be adjusted whenever there is a decrease or a large decrease in use.

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169 CEC at page 24 suggests that under the proposed approach "whilst future customers will shoulder some of the burden, if and when they enter, their contribution will be disproportionately small, due to the impacts of discounting and depreciation. Since it is future customers…who primarily benefit from excess capacity, this runs counter to the EA's beneficiary pays philosophy, and exacerbates the generational equity problem of current customers paying for assets that only future customers benefit from." The Authority considers CEC overstates the consideration that the Authority's alternative whole-of-life options sought to address. As we have previously noted (for example, at pages 147-149 of the 2019 Issues paper), "Even with a high degree of approximation, we consider that the benefit-based charge would still provide much better incentives for grid users than is possible under the [2006] guidelines". Current customers are also likely to be customers in the future, will have an opportunity to scrutinise proposed benefit-based investments, and will be allocated benefit-based charges that reflect their expected positive net private benefits. They will only support a new benefit-based investment if the positive private net benefits they expect to get from the investment exceed the charges they will face.

170 This and other examples of provisions that Trustpower considers to be discriminatory are discussed further in chapter 14.

As we proposed, we have decided to treat de-ratings the same as closure but not other decreases in use. The reason is that, relative to decrease in use, a de-rating is simpler to identify and more likely to be sustained. Further, for incentive-based reasons, transmission charges are intended to be fixed-like, and not vary with use.

10-year minimum for benefit-based charge

8.35 Few submitters commented specifically on this issue, although more commented more generally on the desirability of adjusting charges in line with use. Contact stated that if a customer has a large reduction in use (closed plant or large de-rating), its benefit-based charges should reduce immediately even if the relevant benefit-based investment is less than 10 years old. For example, Contact considers that "Once a large plant has closed it is no longer drawing electricity from the grid and the transmission customer should not, in our view, continue to be liable forthe benefit-based charges…". We considered submissions on this point in depth in our June 2020 Decision paper on the Guidelines. As we said there, "shorter periods would not provide customers with sufficient incentive to reveal key information during the investment approval process".[171] Because of this, we have retained the approach we proposed.

Application of Schedule 1 (pre-2019) BBI adjustment provisions to batteries

8.36 In the discussion of the benefit-based charge above, we clarify the treatment of batteries. In general, the benefit-based charge adjustment provisions provide for a battery to be treated as if it were both a load customer for its offtake and a generation customer for its injection, with any disbenefits being netted off against the benefits it receives for the standard method but not for the simple method.

8.37 However, the adjustment provision for Schedule 1 benefit-based investments provides for a benefit-based charge to be allocated separately for both load and generation. The "benefit factor" mechanism requires finding a comparator customer that has already received an allocation of the costs of pre-2019 investments under Appendix A of the TPM at the relevant connection location.[172] The comparator customer is assumed to be either a generator or a connected asset owner (distributor or direct consumer). A grid-connected battery is both. However, charging BBCs for these Schedule 1 investments on the basis of the energy offtake of battery storage is inappropriate.[173] The TPM makes clear that charges relating to Schedule 1 investments are to be allocated to a battery based on its injection and not its offtake. This treats the battery the same way as a generator with an alternative fuel source. This is not a perfect solution but is a fit-for-purpose adjustment for a limited pool of assets that will ultimately depreciate out of the residual charge.

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171 Pioneer submitted that it remains "sceptical that transmission customers will engage in constructive supportive assessments of the need for new transmission investment when it is clear that they are going to be directly charged for this investment".

172 Appendix A of the TPM specifies the starting benefit-based investment customer allocations for seven historical investments.

173 If the allocation was based on offtake, a downstream battery could be (inappropriately) assessed as benefitting from a congestion-relieving Schedule 1 investment, when the effect of the investment is to squeeze the margin between the price it gets for injection and the price it pays for its load.

Adjustments to the residual charge

Our decision

8.38 The standard 5-8 year lagged adjustment of the residual charge will apply in all situations where a (new or existing) transmission customer increases its use of the grid or an existing customer decreases its use of the grid. The only exception is when a customer exits entirely, in which case the residual charge ceases immediately, or when Transpower voluntarily chooses to under-recover the residual charge. This treatment is consistent with the Guidelines.

What we proposed

8.39 Our decision is largely the same as the proposed TPM. The main exception is when a transmission customer de-rates or closes a large plant but remains a customer.

8.40 The proposed TPM provided that such a transmission customer should be treated in the same manner as if it exited entirely; that is, the residual charge relating to that plant would cease immediately. However, we expressed concern at the time that this created a disparity between the treatment of a customer depending on whether they close a large plant (but remain a customer), de-rate a plant, or simply reduce output without de-rating its plant.[174] We therefore were also considering the option of not providing any special treatment for a plant closure, so that the residual charge of a customer who closed a plant but remained a customer would adjust with the standard 5-8 year lag.

Submitters' views and our assessment

8.41 Of those who commented, submitters had mixed views on the lag in the residual charge adjustment. As a generalisation, apart from Transpower, submitters who wanted a change in treatment tended to favour the residual charge adjusting with a lag to increases in use, but adjusting immediately to decreases in use.

8.42 For example, Contact, Mataura Valley Milk and Nova supported a lagged adjustment for a new customer, as we proposed, whereas Transpower favoured a step change in the residual charge for a new customer. Conversely, Northpower submitted that the residual charge of a directly connected customer and in respect of an embedded customer should cease immediately upon disconnection. Similarly, Transpower, Contact and Nova supported treating de-ratings and plant closure in the same manner as the exit of a customer, so the residual charge would decrease immediately. Network Waitaki submitted that there should be an adjustment to the residual charge when a customer closed a plant.

8.43 We agree that, other things equal, it is desirable to treat plant closure, plant de-rating and decreased use in the same way, so it creates no incentive to favour one action over the other.[175] We also consider it is desirable to treat decreases in use symmetrically with increases in use. This has the effect of eliminating any possible incentive to vary energy use to "game" the charges.

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174 Transpower and Refining New Zealand pointed out correctly that the proposed TPM provided for an adjustment to the residual charge on de-rating as well as shut down of a large plant.

175 Nova made the same point, but with respect to plant expansion "…there needs to be equivalence to minimise incentives for avoidance tactics. The sums involved are likely to be significant enough for them to seek alternative structures…"

8.44 In addition, as we explained at paragraph B.134 of the 2019 Issues Paper "Nodal prices should give the customer incentives to use the grid relatively efficiently. So any other charge that is based on use of the grid (such as a per kwh charge) would risk inefficiently discouraging use of the grid." Since we are proposing that the benefit-based charge generally adjusts immediately on de-rating or closure of a large plant, we consider that adjusting the residual charge immediately as well would make transmission charges too much like use-based charges, and so would create inefficient use-based incentives (when the residual charge is meant to be incentive neutral) and interfere with the operation of nodal prices.

8.45 We have therefore decided to apply the standard 5-8 year lagged adjustment both to increases and decreases in energy use.[176]

Reassignment

Our decision

8.46 The TPM provides for Transpower to reassign part or all of the cost of a benefit-based investment to be recovered by the residual charge if the investment turns out to be utilised significantly less than Transpower had originally anticipated, provided certain conditions are met. A key condition is that a post-2019 investment must normally be more than 10 years old.

8.47 The final TPM clarifies the relationship between reassignment and the normal accounting treatment of impairment of assets. As we discuss above under the heading "decision on accelerated depreciation", this involves the new defined term "write-down".

8.48 In particular, the TPM now:

(a) prevents a write-down from having the effect of a de facto reassignment in circumstances where reassignment is not available, in particular because the benefit-based investment does not meet any of the conditions in subclause (b) of the definition of an "eligible BBI"

(b) prevents reassignment where a write-down is effecting a de facto reassignment

(c) reverses a reassignment if a subsequent write-down effects a de facto reassignment.

8.49 Otherwise, the capital costs attributable to the written-down part of the relevant investment (accelerated depreciation and capital charge) are recovered through the residual charge.

What we proposed

8.50 The reassignment provisions are similar to what we proposed. The key difference is that we have clarified their interaction with the new write-down provisions, discussed above. The effect of this clarification is that write-downs will not affect the benefit-based charge in circumstances that would justify reassignment if the investment does not meet any of the requirements of subparagraph (b) of the definition of an eligible

176 This also has the effect of applying the standard lagged adjustment in respect of an embedded party that reduces its use, including if it disconnects entirely.

BBI, but otherwise to let the capital costs attributable to the written-down part of the relevant investment be recovered through the residual charge.

Submitters' views and our assessment

8.51 As we discuss above, Transpower proposed a number of changes related to write-downs in its submission on the proposed TPM. Our assessment of these proposals is discussed above. The additional changes discussed here simply clarify the relationship between reassignment and write-downs. This makes the interpretation of the TPM clearer and so more certain.

9 Prudent discount policy

9.1 The prudent discount policy (PDP) allows Transpower to discount the transmission charges of designated transmission customers by approving:

(a) an inefficient bypass prudent discount, or

(b) a standalone cost prudent discount.[177]

9.2 The purpose of an inefficient bypass prudent discount is to help ensure the TPM does not provide incentives for a customer to invest in an alternative project that would allow the customer to reduce their transmission charges, by bypassing existing grid assets, while increasing total economic costs.

9.3 The purpose of a standalone cost prudent discount is to help ensure the TPM does not result in a customer paying transmission charges that exceed the efficient standalone cost of the transmission services the customer receives.

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
Clauses iv, 45-48	Clause 3: general definitions
	Clause 114-126: common rules
	Clause 127-132: inefficient bypass
	Clause 133-137: stand-alone costs
	Clause 134: funding of prudent discounts

Overview of decision

Our decision

9.4 The new TPM adopts the PDP largely as proposed in the 2021 Proposed TPM consultation paper, although the Authority has decided to make some changes and clarifications after considering submissions. Key amongst these changes and clarifications are:

(a) Connection charges are included in the standalone cost prudent discount assessment.

(b) Customers cannot jointly apply for a standalone cost prudent discount.

(c) Customers can terminate both an inefficient bypass prudent discount agreement and a standalone cost prudent discount agreement before the end date of the agreement.

(d) If Transpower approves a prudent discount application that is received within six months of Transpower publishing the application requirements, and any application fee, for that type of prudent discount, then the prudent discount agreement may be backdated to the start of the new TPM.

(e) Transpower must publish a non-binding prudent discount practice manual.

177 Refer to clause vi of the Guidelines.

(f) Transpower must publish the application requirements and any application fee by 1 April 2023 at the latest.

What we proposed

9.5 The proposed TPM in the 2021 TPM consultation adopted the PDP proposed by Transpower.[178]

9.6 The Authority also sought feedback on the following potential amendments to the proposed TPM, as the Authority considered these may better promote its statutory objective:

(a) Requiring Transpower to prepare and publish a prudent discount practice manual (as opposed to leaving the publication of such a manual to Transpower's discretion).

(b) Making 15 years the *default* maximum period for the term of a prudent discount and for the prudent discount calculation period.

(c) Not allowing a customer to terminate a standalone cost prudent discount agreement.

Submitters' views and our assessment

9.7 Key matters raised in submissions, and the Authority's analysis and decisions on these, are set out below. [179]

Connection charges part of standalone cost prudent discount

9.8 Under the proposed TPM a standalone cost prudent discount could reduce only the benefit-based charges and residual charges of a designated transmission customer. The connection charges of a customer applying for a standalone cost prudent discount were not included in the sum of the customer's transmission charges that were compared with the customer's standalone cost of supply.

9.9 Rio Tinto and Refining NZ proposed connection charges be included when a prudent discount applicant's transmission charges are compared with the applicant's standalone cost of supply. This is because standalone arrangements could substitute for connection assets and connection charges are included in the scope of clause 47(c) of the Guidelines.

9.10 Transpower in its cross-submission argued for connection charges to not be included as clause (vi)(a) of the Guidelines states that the intent of a standalone cost prudent discount is to reflect the transmission services received 'from the interconnected grid.' However, the Authority agrees with Rio Tinto that the wording of clause 47(c) of the Guidelines is capable of including connection charges.[180]

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178 See chapter 9 of the 2021 Proposed TPM consultation paper and chapter 13 of Transpower's Reasons paper.

179 Submissions on the proposed PDP included those from Contact Energy, Energy Trusts of New Zealand, Fonterra, Horizon Networks, Mercury, Network Waitaki, Northpower + Top Energy (joint submission), Nova Energy, New Zealand Steel, Refining NZ, Rio Tinto, Southern Generation, Transpower, Trustpower, and Vector. Cross-submissions on the proposed PDP were received from: Contact Energy, Nova Energy, New Zealand Steel, Refining NZ, Transpower, and Trustpower.

180 The Authority notes there is therefore no need to look to clause 2 of the Guidelines, and the Authority's intent section.

9.11 Trustpower did not support inclusion of connection charges – it generally opposes the basis for the standalone cost prudent discount. Trustpower considers the standalone cost prudent discount is simply a discretionary discount available to some designated transmission customers (eg, New Zealand Aluminium Smelters) but not others, depending on what scenarios are assumed to apply when assessing standalone costs of hypothetical investments.[181]

9.12 The Authority has decided connection charges should be included when assessing a standalone cost prudent discount, as doing so better promotes the Authority's statutory objective than not doing so.

9.13 We have concluded that prudent discount transaction costs will be lower under the decision (the assessment of a standalone cost prudent discount includes connection charges) than under the counterfactual (the assessment of a standalone cost prudent discount excludes connection charges).

9.14 If connection charges were not included when assessing a standalone cost prudent discount, a designated transmission customer applying for a standalone cost prudent discount would also have to apply for an inefficient bypass prudent discount if the customer believed they were paying connection charges that exceeded standalone cost. We consider the transaction costs associated with the preparation and assessment of two prudent discount applications would be higher than the preparation and assessment of a single albeit larger prudent discount application.

No joint applications for standalone cost prudent discount

9.15 Rio Tinto submitted the TPM should allow multiple designated transmission customers to apply jointly for a standalone cost prudent discount, as they can for an inefficient bypass prudent discount.

9.16 Transpower opposed this in its cross-submission, noting it would be contrary to the Guidelines which at clause 47(a) refer to alternative projects to supply solely that customer. Also, it could result in one or more customers in a consortium receiving a discount, despite their transmission charges being below standalone cost when assessed on an individual customer basis.

9.17 The Authority considers a consortium of designated transmission customers should not be able to jointly apply for a standalone cost prudent discount. The intent of this discount is to ensure a customer does not pay more than the efficient standalone cost of supplying transmission services to that customer alone.[182] A standalone cost prudent discount is not intended to be an avenue for re-optimising large sections of the grid that serve multiple customers.

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181 *The Authority does not agree with Trustpower's view. As we noted in our 2020 Decision paper (at para 12.15):*

> *This new [standalone cost prudent discount] 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.*

182 See the Authority's 11 February 2020 supplementary consultation on the 2019 Issues paper, p. 16.

9.18 An application by a consortium of applicants remains an option for inefficient bypass prudent discounts. Those discounts are intended to prevent "real world" inefficiencies from occurring. By contrast, the standalone cost prudent discount is a back-stop to prevent a customer paying more than the conceptual economic limit for transmission charges – it is not intended to be more flexible than this.

Customer may terminate agreement before end date

9.19 Under the proposed TPM customers would have been able to terminate a standalone cost prudent discount agreement before its end date, but not an inefficient bypass prudent discount agreement. The reason was that the former relates to a hypothetical alternative project for which the costs may change over time, whereas under the latter the customer is placed in a similar situation to what they would be in if they had made the investment to bypass the grid.[183]

9.20 The Authority noted this difference in its consultation, including asking whether a customer with a standalone cost prudent discount should also be committed to the agreement for the full term, so that the commercial discipline on the customer reflects reality as closely as possible.

9.21 Contact Energy and Nova Energy argued that customers should be able to terminate any prudent discount agreement before its end date, should they wish to do so. Rio Tinto and Transpower held this view in relation to a standalone cost prudent discount agreement. Mercury disagreed because it considered that customers might then seek a standalone cost prudent discount for frivolous reasons.

9.22 The Authority has decided Transpower and designated transmission customers should be able to terminate both an inefficient bypass prudent discount agreement and a standalone cost prudent discount agreement before the end date.

9.23 If there was no right of termination, it would be possible for a customer's transmission charges to become inefficiently high (or low) by reference to standalone cost, or at a level that is materially misaligned with the inefficient bypass level of charges. That could then cause the customer to make inefficient decisions (eg, disconnection) simply due to the continuation of a prudent discount that is no longer fit for purpose.

Backdating applications received during the transition

9.24 Some submitters raised issues associated with the transition from the current PDP arrangements to the PDP arrangements under a new TPM.

9.25 Northpower+Top Energy's submission raised concerns about requiring a participant to wait until a new TPM was implemented before applying for a new prudent discount. This meant Northpower would be best placed to disconnect from the Bream Bay GXP and connect at the Marsden GXP. However, this action would likely be an inefficient outcome because it would result in the decommissioning of working assets and the removal of capacity at the Bream Bay GXP, which other parties may want to utilise in the future for new generation or load developments.

9.26 Refining NZ shared these same concerns in its submission. In its cross-submission Contact Energy said the potential for stranded transmission assets raised in the

183 2021 TPM proposed Consultation paper, paras 9.5-9.10, pp83-84.

submissions of Northpower+Top Energy and Refining NZ warranted further consideration.

9.27 Southern Generation Limited Partnership submitted that it was concerned about Transpower's limited resources being distracted preparing a prudent discount practice manual prior to a new TPM coming into effect, instead of considering applications for reset prudent discounts.

9.28 As a transitional measure, the Authority considers it good regulatory practice for the new TPM to provide for backdating, to the start of the new TPM, any prudent discount agreements applied for within six months of Transpower publishing the application requirements and any application fee for that type of prudent discount.[184]

9.29 This backdating ensures that parties with a valid reason for a prudent discount under the new TPM are not disadvantaged due to the time required to assess a prudent discount application during the transition from the current TPM to the new TPM.

9.30 Any prudent discounts that are backdated will require a wash-up of transmission charges of the recipient of the backdated prudent discount, to ensure the recipient is not over-charged for the relevant pricing years. The TPM requires Transpower to carry out such a wash up in the earliest practicable pricing year.[185]

9.31 The wash-up of a backdated prudent discount will also require a wash-up of the transmission charges of other designated transmission customers, so that Transpower is able to ultimately recover the prudent discount in its revenues. To avoid unnecessary complexity in Transpower's systems and processes, the TPM does not require a full wash-up adjusting all customers' charges in the relevant year. Instead, our expectation is that any such wash-ups of backdated prudent discounts would be achieved via the use of Transpower's regulated 'economic value' (EV) account.[186]

9.32 If a designated transmission customer receives a prudent discount that is backdated, Transpower will under-recover its revenue until it revises the charges to other designated transmission customers to recover the prudent discount. This under-recovery will be recorded in Transpower's EV account as part of Transpower's annual revenue wash-ups under its individual price-quality path.

9.33 The Authority notes that the balance in Transpower's EV account will be carried forward from year to year in the regulatory control period and the balance at the end of the five-year regulatory control period will be recovered from, or returned to, designated transmission customers via the TPM residual charge in the following five-year regulatory control period.

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184 Ie, an inefficient bypass prudent discount or a standalone cost prudent discount.

185 Refer to clause 122 of the TPM.

186 Transpower's EV account is a memorandum account. As Transpower's revenue and expenses do not necessarily equate in each financial year, the EV account is used to record the accumulated surplus or deficit in Transpower's revenue. A surplus in the EV account represents after-tax money that needs to be returned to designated transmission customers. A deficit in the EV account represents after-tax money that needs to be recovered from designated transmission customers.

For further information on Transpower's EV account, refer to the Transpower Input Methodologies Determination 2010, consolidated as of 29 January 2020, and the Transpower Individual Price-Quality Path Determination 2020.

9.34 The Authority has concluded the recovery of back-dated prudent discount charges via the TPM residual charge as a result of the backdating provision is acceptable. This is because the amount of back-dated prudent discount charges is likely to be relatively small as there will only be one or two years of under-recovery per back-dated prudent discount and only a relatively small amount of back-dated prudent discount charges is likely to be for benefit-based transmission investments, with the rest going into the residual in any event. Hence, the economic cost of recovering benefit-based prudent discount charges via the residual as a result of the backdating provision is expected to be minor.

Transpower must publish a non-binding practice manual

9.35 The proposed TPM provided that Transpower *may* publish a prudent discount practice manual containing detailed methodologies and assumptions for the PDP.

9.36 A number of submissions considered the publication of the manual should be mandatory (Contact Energy, Energy Trusts of New Zealand, Fonterra, Network Waitaki, Nova Energy, Trustpower). Reasons included that the manual would help designated transmission customers assess whether their particular circumstances warrant a prudent discount application and it would inform applicants of what is expected in an application, including the level of detail. Nova Energy considered the preparation of the manual should be subject to consultation, which would help ensure it provides a useful purpose.

9.37 Transpower did not support making the manual mandatory. Reasons include that Transpower considers it would be better to develop the manual in the context of real applications and that preparation of a comprehensive manual would place a burden on Transpower's resources at a time when these are heavily committed to essential TPM implementation tasks.

9.38 Southern Generation Limited Partnership agreed a prudent discount practice manual with prescribed minimum content could provide prudent discount applicants with more certainty. However, Southern Generation Limited Partnership considered Transpower must be able to dedicate the required resources to process applications for prudent discounts as soon as the Code amendment is approved.

9.39 The Authority has decided that Transpower *must* publish a manual, as that will provide transparency and clarity to prospective applicants on what is expected in prudent discount applications (for example, see Network Waitaki's and Nova Energy's submissions). The TPM therefore provides that Transpower is required to publish the manual.

9.40 However, noting Transpower's concerns the Authority considers that the contents of the initial manual could be a limited subset of the more comprehensive manual that the Authority expects will eventually be published. The initial manual should contain enough information to meet the needs of those transmission customers who wish to apply for a prudent discount with effect from the start of the new TPM; however, it need not cover all possible topics from the outset.

9.41 The Authority's expectation of Transpower is that it will make best endeavours to prepare and publish an initial prudent discount practice manual by 1 February 2023, which contains the following content in relation to an inefficient bypass prudent discount and a standalone cost prudent discount:

(a) The application requirements, with additional explanatory material on process-related matters relevant to prudent discount applications.

(b) The application fee, if any.

(c) A schematic showing the steps associated with a typical application for each of an inefficient bypass prudent discount and a standalone cost prudent discount, with supporting explanatory text elaborating on these steps and the associated Code provision(s).

(d) Definitions of key terms, particularly economic terms used in the context of the standalone cost prudent discount (such as “brownfields” optimisation).

9.42 The Authority intends that these matters will be agreed with Transpower outside of the codified TPM (through an exchange of letters).

9.43 As a backstop, the TPM provides that Transpower must publish the application requirements and any application fee by 1 April 2023 at the latest.[187] This provides potential applicants with information they need and is relevant to the backdating provisions discussed above.[188]

9.44 Some submitters considered the prudent discount practice manual should be binding on Transpower (Contact Energy, Energy Trusts of New Zealand, Fonterra). Contact Energy considered this would provide certainty. Transpower considered the prudent discount practice manual should not be binding, for the reasons set out in the 2021 TPM Consultation paper.

9.45 The Authority confirms the prudent discount practice manual will not be binding on Transpower, for the reasons set out at para 9.20 of the 2021 Consultation paper (including that the TPM sets out key requirements for prudent discounts and to avoid unintended consequences, especially as it is assessing the first few applications, if Transpower is constrained from learning from practical experience).

15 years as the *default* maximum period

9.46 The proposed TPM specified 15 years as:

(a) For an inefficient bypass prudent discount, the *maximum* period for the term of a prudent discount and the prudent discount calculation period.

(b) For a standalone cost prudent discount, the *term* of a prudent discount and the calculation period.

9.47 The Guidelines had left the duration of a prudent discount unspecified so it could be subject to commercial negotiation.[189] The reasons for proposing a maximum 15-year term were because this facilitates adjustments to changes in conditions over time

187 The Authority expects that Transpower will seek to charge a fee to recover the costs it would reasonably expect to incur in assessing a prudent discount application, noting that it might not need to charge a fee in some circumstances (for example, circumstances in which it would not incur any significant costs).

188 As discussed above, the new TPM provides for backdating, to 1 April 2023, any prudent discount agreements applied for within six months of Transpower publishing the application requirements and any application fee for that type of prudent discount.

189 See the 2020 Decision paper, para 12.9.

(eg, changes in the power system), and because a customer can apply to renew the agreement before it expires.[190] However, the economic life of an applicant's alternative project may be longer than 15 years and uncertainty about renewal of a prudent discount agreement may cause inefficient outcomes.

9.48 The Authority therefore sought feedback on whether the proposed TPM should be amended to make 15 years a *default* maximum term, which could be made longer if this reflected the economic life of the alternative project.

9.49 Contact Energy, Nova Energy, Southern Generation and Network Waitaki agreed with a 15-year *default* maximum period, Transpower agreed with 15 years as the default period. Refining NZ agreed there should be flexibility to negotiate longer discounts, while Rio Tinto believe customers should be allowed to enter into standalone prudent discounts of less than 15 years. Northpower+Top Energy considered prudent discount agreements should match the usable life of the alternative project because, if the term is arbitrarily short, a consumer may bypass the grid to lock in lower costs for itself for a longer period.

9.50 The Authority has decided that 15 years should be the *default* maximum period for the term of a prudent discount and for the prudent discount calculation period. Customers would be able to apply for a longer term where this reflects the economic life of the alternative project. The Authority considers this decision will reduce the risk of inefficient bypass, and so better promote the Authority's statutory objective.

Alternative project to provide same or substantially similar level of service

9.51 New Zealand Steel and Rio Tinto submitted that the TPM should allow designated transmission customers to obtain a prudent discount based on the alternative project providing a lesser quality of supply (at a reduced cost). This is because customers may not require the same level of service as they receive from Transpower. New Zealand Steel submitted that new technologies provide grid-based security and quality of supply options for designated transmission customers, enabling customers to supplement the quality of supply they receive from the grid.

9.52 Transpower disagreed with New Zealand Steel and Rio Tinto - an alternative project should result in equivalent benefits for the prudent discount applicant (eg, supply security for both network and generation stock) as the applicant receives from electricity supplied via the interconnected grid. Vector and Trustpower disagreed with New Zealand Steel and Rio Tinto in respect of standalone cost prudent discounts.

9.53 In its cross-submission Nova Energy said a party seeking a prudent discount should not have to be able to duplicate a service from the grid that it does not require.

9.54 The Authority has decided that the alternative project considered as part of a prudent discount application should provide the same or substantially similar level of service to the customer as the customer is receiving at the time of the application. The transmission services Transpower is to have regard to include access to electricity

190 See Transpower's 30 June 2021 Reasons paper, para 59, p. 13.11.

(including access to security of supply), and electricity quality, reliability and security.[191]

9.55 The hypothetical nature of a standalone cost prudent discount means that, should a discount be approved, the customer will continue to receive the level of service provided currently (regardless of the quality assumed under the standalone cost prudent discount). It would be inefficient and perverse if a customer was able to nominate a lower level of service, receive a discount and effectively shift costs onto other customers, yet continue to receive the existing service.

9.56 The Authority is aware of the incentive effects associated with a customer receiving an inefficient bypass prudent discount based on the alternative project providing a lower level of transmission services. This has the potential for inefficient cross-subsidies from other customers to the prudent discount recipient.[192] The Authority is also conscious that if a customer truly is prepared to accept a lower level of service than what it receives at the time of application, granting a prudent discount is consistent with the PDP's intent of avoiding inefficient disconnection from the grid.

9.57 The Authority has concluded that Transpower would have no realistic way of establishing definitively whether a customer applying for an inefficient bypass prudent discount truly is prepared to accept a lower level of service than that currently provided by Transpower. Hence, the Authority considers the risk of cross-subsidies from granting a prudent discount based on a lower level of service is likely greater than the risk of inefficient disconnection.

9.58 The Authority notes a designated transmission customer wanting to move to a lower level of transmission services can discuss with Transpower the decommissioning or de-rating of connection assets.

Valuation of transmission assets and corridors

9.59 Rio Tinto submitted that the efficient standalone cost of transmission services should be able to be determined using optimised depreciated replacement cost valuations of existing (ie, used) assets. Trustpower does not support alternative project costings based on used rather than new assets.

9.60 The Authority considers an efficient outcome requires that a standalone cost prudent discount application is based on the lowest cost assets that would give a customer a substantially similar level of service to what it receives at the time of application.

9.61 That is, the applicant's alternative project should be based on an investment in equivalent assets to those used by Transpower in supplying the customer with transmission services, rather than being based on investment in new assets.

191 In this context "security" refers to the resilience of the power system to adverse events — ie, where power outages are avoided despite significant adverse events occurring (refer to footnote 11 of the Authority's interpretation of its statutory objective, available at https://www.ea.govt.nz/assets/dms-assets/9/9494statutoryobjective.pdf). Power system security should not be confused with security of supply, which refers to the electricity industry providing appropriate electricity system capabilities (such as generation and transmission capacity) and storable fuel supplies (such as water, gas and coal) to maintain normal electricity supply to consumers. Refer to (https://www.ea.govt.nz/operations/wholesale/security-of-supply/what-is-security-of-supply/).

192 The economics literature defines a cross subsidy to be where the prudent discount recipient pays charges below the incremental cost of the transmission services received from Transpower.

9.62 Rio Tinto also submitted that no costs should be attributed to corridors or easements to be used by the alternative project, if Transpower does not face a cost for them. Where the alternative project uses another transmission corridor, Transpower should adopt the least cost option for consents and property rights.

9.63 Trustpower submitted it did not support cost-free access to existing corridors. Transpower also did not support this, noting that where it no longer faces such costs, this is part of the real-world efficiency of the existing grid, which should not be ignored in a standalone cost prudent discount application.

9.64 The Authority considers that where the alternative project in a standalone cost prudent discount application uses existing Transpower corridors, the present-day cost of obtaining property rights and resource consents for the corridors should be used in calculating the alternative project's cost. An efficient alternative project would not incur the historical cost (ie, in some cases cost-free access to existing transmission corridors)[193] - instead the project would face the present-day cost of obtaining the necessary property rights and resource consents (using the least cost option).

Funding of prudent discounts

9.65 Prudent discounts will be funded as proposed in the 2021 Consultation paper – that is, through benefit-based and residual charges. Each customer's contribution will be proportional to their share of the benefit-based charges in respect of investments for which the customer receiving the prudent discount also pays such charges, and the residual.

9.66 Contact Energy and Nova Energy agreed with the proposal. Trustpower considers prudent discounts are best funded through residual charges, whereas Refining NZ stated that, with prudent discounts reflecting inefficient grid design, the cost should be borne by Transpower's shareholders.[194]

9.67 The Authority considers funding prudent discounts through benefit-based and residual charges as proposed in the 2021 Consultation paper is consistent with the intent of the Guidelines and with the Authority's statutory objective.

9.68 As noted in the 2021 Consultation paper, the Authority considers the proposed funding option achieves the best practicable trade-off between compliance with clauses 8 and 15 of the Guidelines[195] and limiting the distortionary effects of transmission charges levied to fund prudent discounts. These distortionary effects are limited by spreading the charges over a large pool of designated transmission customers and limiting the extent to which generators subject to a prudent discount charge[196] are likely to incorporate the charge in their offers.[197]

193 Ie, the amount paid for the corridors at the time they were acquired.

194 The Authority notes this option is outside the scope of the TPM.

195 See Transpower's 30 June 2021 TPM proposal reasons paper, para 143, p. 13.23.

196 Ie, the generator is a beneficiary of the grid investment(s) for which the prudent discount recipient pays benefit-based charges.

197 The prudent discount charge is likely to vary across the generators, based on their varying benefits from the grid investment. The Authority notes a generator operating in a competitive market such as the New Zealand electricity market has little scope to pass on a cost increase that only affects itself (rather than all generators).

Other matters raised in submissions

Whether prudent discounts should automatically renew

9.69 Network Waitaki and Rio Tinto submitted that a new prudent discount application should not be required where the economic life of the alternative project continues post the agreement where the conditions of Transpower's approval continue to be satisfied. Rio Tinto considered this would improve certainty of re-contracting. Transpower considered a prudent discount should not be allowed to automatically renew, even if conditions were not materially changed from when it was approved. Transpower considered that the best way to determine if conditions have materially changed is through repeating the prudent discount application process and applying the applicable tests again.

9.70 The Authority has decided prudent discount applications should be submitted to Transpower in respect of a prudent discount that a designated transmission customer wants to renew. This will provide Transpower with the opportunity to confirm the conditions relating to the approval of the prudent discount that is ending remain valid.

9.71 The Authority considers the transaction costs associated with this approach should not be disproportionate. The designated transmission customer can submit the same application to Transpower as for the prudent discount that is ending, if the customer considers the conditions relating to the approval of the prudent discount remain valid.

Whether the threshold for, and transaction costs of, a prudent discount are too high

9.72 Network Waitaki expressed concern that "the proposed TPM contains relief mechanisms that appear to be almost unachievable, eg, the very high threshold to qualify for prudent discounts." Rio Tinto submitted that setting a high bar for successful prudent discount applications for a standalone cost prudent discount is inconsistent with economic theory.

9.73 Several submitters raised concerns about the transaction costs associated with prudent discount applications. Network Waitaki, New Zealand Steel and Refining NZ were concerned the cost and time involved in preparing an application, with no guarantee of success, creates a significant barrier for applicants. Nova Energy supported these concerns in its cross-submission. Trustpower was concerned that the nature and scope of the verification required for a prudent discount application should be proportionate to the scale, materiality and complexity of each application.

9.74 The Authority considers the general application requirements and assessment criteria for prudent discounts to be reasonable and appropriate.[198] In relation to the application requirements, the Authority considers it reasonable to expect a prudent Board of directors considering an investment in an alternative project would typically want to see similar information to that set out in the TPM's general application requirements.

9.75 In relation to the assessment criteria, the Authority considers the tests are consistent with achieving the respective purposes of an inefficient bypass prudent discount and a standalone cost prudent discount. Put another way, a prudent discount application that does not meet the assessment criteria should not result in a designated

198 Refer to clauses 114-118 of the TPM.

transmission customer either finding it beneficial to bypass or disconnect from the grid, or paying transmission charges that exceed standalone cost.

Designated transmission customers seeking prudent discounts because of their customers

9.76 Refining NZ submitted that distributors should be required to make prudent discount applications to Transpower where this was appropriate because of distributors' customers applying for discounts against their distribution charges. If these prudent discount applications to Transpower were approved, distributors should also have to pass them on to their customers in a fair and reasonable manner consistent and in line with the intent of the TPM. In contrast, Transpower considered the manner in which distributors passed transmission charges on to their customers was outside the scope of the TPM.

9.77 The Authority has decided to not require distributors to make prudent discount applications to Transpower where distributors' customers apply for discounts to their distribution charges. The Authority considers a distributor should have sufficient incentive to make prudent discount applications (for material amounts) to Transpower if a distributor's customer applies for discounts to their distribution charges because of grid bypass opportunities (because otherwise the distributor would have to recover the prudent discount from its other customers or else incur a revenue drop).

9.78 The Authority intends to address the manner in which distributors pass transmission charges on to their customers as part of its review of distribution pricing arrangements.

Calculation of the annuity in the prudent discount

9.79 Refining NZ and Rio Tinto submitted that assessing the present value of an alternative project should recognise the residual value of the alternative project at the end of the prudent discount period. Rio Tinto noted that by not including a terminal value, it becomes necessary for the term of a prudent discount to be equal to the economic life of the alternative project in order to get the correct valuation and annuity. Rio Tinto also considered that the formula for assessing the present value of an alternative project should use a post-tax weighted average cost of capital.

9.80 In its cross-submission, Transpower agreed the alternative project should not be required to be fully amortised over the prudent discount calculation period, and that a post-tax weighted average cost of capital should be used.

9.81 However, Transpower did not agree the present value calculation for the alternative project's costs should include a residual value for the non-amortised costs over the remainder of the alternative project's economic life. If this was required, Transpower would have to do the same for the present value of the avoided transmission charges, to ensure the commercial viability test in the TPM compared 'apples with apples'. Transpower considered that estimating avoided transmission charges out to 50+ years would not be possible with a reasonable level of confidence.

9.82 The Authority has decided that, in carrying out the present value calculations to determine whether the alternative project proposed in a prudent discount application is commercially viable, Transpower should:

(a) use a pre-tax discount rate if the cash flows being discounted are pre-tax and a post-tax discount rate if the cash flows being discounted are post-tax

(b) not assume the alternative project is fully amortised over the prudent discount calculation period - this avoids erroneously inflating the annual costs of the alternative project where the economic life of the alternative project extends beyond the prudent discount calculation period

(c) not have to include a terminal value for expected cash flows over any remaining economic life of the alternative project beyond the term of the prudent discount period - this is consistent with Transpower amortising the alternative project over the project's economic life and factoring this into the present value calculation used in assessing the alternative project's commercial viability.[199] Not requiring a terminal value also acknowledges the likely inaccuracies in calculating a terminal value for both the alternative project's future cash flows and Transpower's future transmission charges.

Consideration of transmission alternatives

9.83 Refining NZ and Rio Tinto submitted that the proposed TPM gave no guidance on how a transmission alternative (eg, local generation) would be assessed. Rio Tinto noted alternative projects that include transmission alternatives could have other significant benefits and costs, such as avoided energy costs and market impacts. Rio Tinto considered the requirements around Transpower's assessment of an efficient standalone investment to be extremely narrow in their application.

9.84 In its cross-submission Transpower noted that, for standalone cost prudent discounts, the TPM Guidelines do not contemplate any assessment of the impact of the alternative project on wider costs or prices. Transpower considers this should also apply to inefficient bypass prudent discounts, despite the TPM Guidelines being "more liberally worded for inefficient bypass prudent discounts".

9.85 The Authority considers the TPM sufficiently provides for the assessment of transmission alternatives, such as local generation, in relation to inefficient bypass prudent discounts and standalone cost prudent discounts. Refer to clauses 129 and 134 and the definition of "alternative project" in the Code.

9.86 The Authority considers the drafting of clauses 116-118 of the proposed TPM is sufficiently clear as to exclude non-transmission benefits and costs, such as avoided energy costs and non-transmission market impacts, from the assessment of the alternative project's viability.

Inefficient cross-subsidies prevented and transparency promoted

9.87 Energy Trusts of New Zealand submitted that the Authority should prevent prudent discount arrangements that have the effect of cross-subsidising particular industries or plants in an economically inefficient manner.

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199 Refer to clause 118 of the TPM.

9.88 The Authority considers the PDP addresses this concern of Energy Trusts of New Zealand. The PDP does so in particular through the various assessments Transpower must undertake of an alternative project put forward by a prudent discount applicant.[200] An inefficient prudent discount arrangement would not satisfy the tests that must be met under these assessments. Energy Trusts of New Zealand also submitted that there should be total transparency applying to all prudent discount arrangements, including independent and publicly accessible audits of them. In contrast, New Zealand Steel raised some concerns about the requirement for applications to be published upon receipt. A prudent discount applicant could not reasonably expect to have in the public arena the financial, consenting, commercial, and stakeholder aspects envisaged at the initial stages of a prudent discount application being considered.

9.89 The Authority considers the TPM strikes an appropriate balance between transparency around applied-for and approved prudent discounts, and the protection of commercially sensitive information.

9.90 Under clause 115 of the new TPM, Transpower must publish an accepted prudent discount application and any information the designated transmission customer provides to Transpower.

9.91 Under clause 124 Transpower must publish its decision to approve or reject a prudent discount application, including:

(a) any conditions in relation to an approved prudent discount

(b) Transpower's analysis supporting its decision

(c) any report prepared by an independent expert.

9.92 However, these transparency requirements are subject to clause 125, which says Transpower is not obliged to publish any information about an applied-for or approved prudent discount if:

(a) the designated transmission customer identifies the information as commercially sensitive, and

(b) Transpower determines the disclosure of the information would be likely to commercially disadvantage the customer or any other person (materially).

The treatment of existing prudent discounts under a new TPM

9.93 Several submitters raised concerns about the treatment of existing prudent discounts under a new TPM.

9.94 In its submission Horizon Networks suggested the proposed new TPM would compromise the viability of the prudent discount agreement relating to the notional embedding of Southern Generation's Aniwhenua generation and Trustpower's Matahina generation. The corresponding avoided cost of transmission (ACOT) agreement would also be compromised.

9.95 Network Waitaki submitted that its largest customer[201] might have decided to bypass the grid rather than enter into a Notional Embedding Agreement in 2006, had the

200 See in particular the assessments of equivalence, feasibility and commercial viability contained in clauses 129 and 134 of the TPM.

201 The North Otago Irrigation Company.

customer anticipated the huge regulatory change and consequential price impact on them from the proposed new TPM.

9.96 Southern Generation Limited Partnership suggested that grandfathering existing prudent discount agreements under a new TPM would dramatically reduce uncertainty for transmission customers and pressure on Transpower in implementing any approved TPM by 1 April 2023.

9.97 The Authority intends to address the issue of the treatment of existing prudent discount agreements and notional embedding contracts via a separate Code amendment process.

10 Transitional congestion charge

10.1 The Guidelines provide for a Transitional Congestion Charge (TCC) to be included in the TPM if there is a significant likelihood of congestion occurring, with grid demand not able to be efficiently controlled by other means, including nodal pricing and administrative load control associated with scarcity pricing. Transpower must also consider that including a TCC would better meet the Authority's statutory objective than not doing so.

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
Clause viii (d): transitional congestion charge	No provisions
Clause 54, 58-61: Additional component D	

Our decision

10.2 Consistent with Transpower's June 2021 proposal, the TPM does not include a Transitional Congestion Charge.

10.3 However, Transpower is able to propose a TCC later, via an operational review of the TPM as already provided for by the Code (see cl 61 of the Guidelines and cl 12.85 of the Code). An operational review can occur at any time provided it is more than 12 months after the TPM was last approved.

What we proposed

10.4 The proposed TPM did not include a TCC as the threshold for the inclusion of Additional component D had not been met.

10.5 Transpower did not include a TCC in its proposed TPM as it had concluded that any heightened short-term congestion risk from removal of the RCPD charge can be effectively controlled by other means available to it, in a way that limits load shedding, ensures the grid is secure, and efficiently limits adverse impacts on consumers.

10.6 The Authority accepted this conclusion, having also taken into account:

- The upcoming implementation of real time pricing which will provide location-based scarcity pricing and support more diverse participation in dispatch.
- Analysis by Transpower (2021) and Concept Consulting (2020) of the impact on peak winter load from the removal of the RCPD price signal.
- Other evidence that ripple control will continue to be available should the system operator need it at times of congestion.[202]

Submitters' views and our assessment

10.7 A small number of submissions commented on this topic.[203]

202 See 2021 TPM proposed consultation paper, chapter 10.

203 See in particular Contact Energy, Orion, Hiringa Energy, Northpower+Top Energy, Vector, Oji Fibre Solutions, Trustpower, IEGA, NZ Steel.

10.8 Contact Energy submitted the "issue has been well traversed and we are comfortable with where the Authority and Transpower have landed on this issue".

10.9 Vector suggested a peak price signal is needed to reward the uptake of peak shifting technologies and flexibility services. Hiringa Energy made a similar submission. Vector also commented that the 9 August 2021 outages should give pause for proceeding without some incentive to shift peak load (to replace the RCPD charge). Other submitters made similar points about the 9 August outages (Oji Fibre Solutions, Trustpower, NZ Steel). For example, Oji Fibre Solutions argued that outages would have been worse if participants had not already reduced load in response to RCPD signals.

10.10 It is clear from inquiries into the outages on 9 August that while forecast prices were volatile early in the day, final price signals were not the issue. The submissions also do not acknowledge the alternative opportunities for demand response that already exist or will soon be in place. This includes offering ripple control as interruptible load and improved engagement of demand response. The Hodgson report on the 9 August outages found there was untapped demand response that could have been used better.[204]

10.11 The Authority considers nodal prices – which provide the efficient signals to motivate demand response – will reward efficient investment in peak shifting technologies and flexibility market solutions more generally.[205]

10.12 The impending implementation of real time pricing and dispatch notification will further promote and deepen opportunities for demand response, and better reflect how much consumers value demand.[206] Demand response opportunities will develop further as other barriers to participation by flexibility traders are addressed.[207]

10.13 In this context, the Authority also notes the risk that a TCC could be counterproductive to promoting the development of such services. As emhTrade stated in a 2020 workshop hosted by Transpower on the TCC, a TCC could slow down the price signals that parties will be exposed to eventually, which would reduce incentives to make the changes.[208]

10.14 Northpower and Top Energy jointly submitted that the risk of removing transmission peak charges entirely is greater than the Authority might think, as peak load could increase by 10% or 700MW, more than double the 300MW estimated by Transpower in July 2021.[209]

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204 https://www.mbie.govt.nz/dmsdocument/17988-investigation-into-electricity-supply-interruptions-of-9-august-2021.

205 Professor Hogan noted that "[a]dding another variable charge on top of [nodal prices] would create perverse real-time incentives for load management to avoid such transmission charges…". See Electricity Authority 2020, Peak charges under proposed TPM guidelines, information paper.

206 NZ Steel submitted it is concerned the direct and indirect costs to consumers from (administrative) demand curtailment are not measured, though this would be addressed by scarcity pricing associated with the implementation of real time pricing.

207 See IPAG on improving flexibility in this area (https://www.ea.govt.nz/assets/dms-assets/28/Transpower-DR-programme-review-slide-pack.pdf) and the Authority's discussion paper on updating regulatory settings for distribution networks (https://www.ea.govt.nz/assets/dms-assets/28/Updating-the-regulatory-settings-for-distribution-networks.pdf).

208 Transpower Reasons paper para 26, page 15.8.

209 TPM - Removal of RCPD.pdf (transpower.co.nz).

10.15 However, the Authority notes that Northpower and Top’s 700MW figure is a simple extrapolation from their own use of ripple control, and so does not reflect circumstances across the whole industry. The Authority has instead relied on Concept Consulting's detailed report on the possible impacts on the Winter Capacity Margin and Transpower’s ‘prudent estimate’ of the impact on winter peaks from removing the RCPD charge, and which concluded any heightened short-term risk could be effectively controlled through existing means (Transpower), and is not in general expected to have a material impact on the reliability of supply in peak periods (Concept).

10.16 Consideration of these submission has thus not changed the Authority’s view, expressed in the 2021 Consultation paper, that the TPM should not include a TCC as the threshold for the inclusion of Additional component D had not been met.

11 kVAr charge

11.1 A kVAr (kiloVolt Ampere reactive) charge would charge those that cause a deterioration in the power factor, to account for the cost they impose on other grid users.

11.2 The Guidelines require a kVAr charge to be included in the TPM if Transpower considers this would better meet the Authority's statutory objective.

Relevant sections in the Guidelines and new TPM

Guidelines	TPM
Clause viii (g): kVAr charge	No provisions
Clause 54, 65: Additional component G.	

Our decision

11.3 The TPM does not include a method for a kVAr charge on reactive power.

11.4 Transpower would be able to propose a kVAr charge later via an operational review.

What we proposed

11.5 The proposed TPM did not include a method for a kVAr charge on reactive power.

11.6 Transpower considered that "static voltage stability concerns can generally be managed by relatively low cost transmission components (capacitors and reactors)…[and]…a kVAr charge would add significant complexity (and so development and implementation cost) to the new TPM that is unlikely to be offset by material efficiency or reliability benefits."[210]

Submitters' views and our assessment

11.7 The few submissions which commented on the proposal to not include kVAr charges were supportive of the proposal not to include such charges (see Contact Energy, Fonterra, Trustpower).

11.8 The Authority considers Transpower as generally best placed to assess the merits of a kVAr charge and concluded a kVAr charge should not be included in the final TPM.

210 Para 19, page 14.7 of Reasons Paper.

12 Prices and the transitional price cap

12.1 The new TPM will mean a rebalancing of transmission charges between customers. This chapter covers:

(a) a limited update to indicative charges under the proposed TPM for 2021/22

(b) the impact of these indicative charges on typical household bills

(c) our decision on the form of the transitional cap.

Indicative prices and impacts on typical household bills

12.2 The 2021 Proposed TPM consultation paper provided indicative prices prepared by Transpower, estimating the charges that would have applied to each transmission customer under the proposed TPM if it had been in place in 2021/22. This was to enable customers to compare their charges under the proposed TPM against their actual transmission charges under the then current TPM. We also provided the estimated impact of these indicative charges on typical household bills.

12.3 As explained in chapter 15, Transpower intends to publish indicative charges under the new TPM for pricing year 2022/23 (ie, the pricing year commencing 1 April 2022) later in April. We consider that this information will provide further valuable insight for stakeholders into how their charges will be likely to change under the new TPM compared with the current TPM. These indicative charges will:

(a) include pricing consistent with the final TPM

(b) incorporate an additional year of benefit-based investments

(c) reflect technical refinements, including feedback from stakeholders.

12.4 To ensure stakeholders understand the pricing implications of the key changes since the TPM was proposed for consultation in 2021, we have prepared a limited update of some of the 2021/22 indicative pricing information we published in support of our consultation.[211] The update reflects anytime maximum demand (AMD) baseline data that Transpower has provided to the Authority and reflects the final TPM.[212]

Changes with implications for indicative pricing in 2021/22

12.5 The following policy changes impact on indicative charges for 2021/22:

(a) **Approach to AMD (residual charges)**. The new TPM requires the allocation of residual charges based on maximum gross demand at each connection location, ie, a coincident approach is used to measure AMD across GXPs that are at the same location. The 2021 proposed TPM took a fully non-coincident approach. For a discussion of this change refer to paragraphs 7.37 to 7.48.

(b) **Approach to disconnections of large plant (residual charges).** Under the new TPM when a party disconnects plant but remains a customer, the residual charge continues until the standard 5-8 year lagged adjustment has worked through. This means some load that has already been disconnected continues to be reflected in AMDR baselines (and residual charges) on a temporary basis.

211 Refer to the two workbooks published alongside this decision paper on the Authority's website.

212 Transpower is consulting with customers on this data during April 2022. The data has not been subject to formal assurance.

The proposal for consultation provided for step changes for disconnected plant, and as such the measurement of load for indicative prices did not include some disconnected load. For a discussion of this change refer to paras 8.38 to 8.45.

(c) **Load:generation weighting (BBC simple method).** The new TPM adopts the 62.5%:37.5% (load:generation) simple method weighting, instead of the previously proposed 50%:50%. This is discussed from para 5.37 to 5.62.

12.6 In addition, the updated indicative pricing also reflects technical/operational updates:

(a) operational data updates to annual maximum demand (AMDR) baseline;

(b) technical updates to Appendix A benefit-based allocations and customers incorporated in the final TPM.[213] For a summary of changes since the proposed TPM for consultation, refer to Appendix A.[214]

12.7 Transpower is consulting with customers on AMDR baseline data during April 2022.

Indicative charges

12.8 In Chapter 12 of the 2021 Consultation paper, in tables 6 to 8, we presented indicative prices under the proposed TPM compared with prices under the current TPM for 2021/22. The tables that follow here are an update to these tables, showing charges for each customer under the current TPM, the TPM proposed in 2021, the new TPM and the change from the 2021 TPM to the new TPM.

213 Appendix A of the TPM specifies the starting benefit-based investment customer allocations for seven historical investments (based on Schedule 1 in the TPM Guidelines and Transpower applying relevant adjustment clauses in the TPM).

214 Note that the Appendix A allocations do not reflect some recent changes, such as the exit of Norske Skog (which is still formally a transmission customer), the entry of Kawerau Generation, and Trustpower's change to Manawa Energy Limited. Transpower will make adjustments to account for these changes before setting prices for 2023-24.

Table 3 Lines businesses: indicative and actual charges PY2021/22

Customer name	A. Current TPM ($m)	B. TPM proposed in 2021 ($m)	C. New TPM ($m)	D. Change ($m)(C - B)	E. Change (%) (D:B)
Alpine Energy Ltd	12.3	12.6	12.8	0.2	2%
Aurora Energy Ltd	22.1	25.4	23.9	-1.5	-6%
Buller Electricity Ltd	0.6	1.6	1.4	-0.2	-13%
Centralines Ltd	2.7	2.2	2.2	0.0	1%
Counties Energy Ltd	11.0	11.3	11.2	-0.1	-1%
EA Networks Ltd	4.6	10.7	10.7	0.0	0%
Eastland Network Ltd	5.5	4.0	4.1	0.1	2%
Electra Ltd	7.5	9.0	9.2	0.2	2%
Horizon Energy Distribution Ltd	3.5	7.7	7.9	0.2	3%
Mainpower New Zealand Ltd	12.3	12.1	11.8	-0.3	-2%
Marlborough Lines Ltd	6.7	5.4	5.5	0.1	2%
Nelson Electricity Ltd	1.0	0.9	1.0	0.0	2%
Network Tasman Ltd	11.8	10.7	10.8	0.0	0%
Network Waitaki Ltd	4.2	5.3	5.2	-0.1	-1%
Northpower Ltd	16.3	18.3	18.5	0.2	1%
Orion New Zealand Ltd	61.6	53.5	53.8	0.3	1%
Powerco Ltd	92.2	81.3	83.1	1.8	2%
Powernet Ltd	24.3	22.3	22.0	-0.4	-2%
Scanpower Ltd	1.9	1.7	1.7	0.0	1%
The Lines Company Ltd	4.7	6.1	6.2	0.1	2%
Top Energy Ltd	4.9	5.9	6.0	0.1	2%
Unison Networks Ltd	29.8	27.0	27.3	0.4	1%
Vector Ltd	172.1	179.9	177.7	-2.2	-1%
Waipa Networks Ltd	7.7	6.3	6.4	0.1	2%
WEL Networks Ltd	19.9	20.0	20.3	0.3	1%
Wellington Electricity Lines Ltd	54.4	46.3	46.8	0.6	1%
Westpower Ltd	2.0	4.1	3.9	-0.1	-4%
Lines business total	**597.7**	**591.5**	**591.4**	**-0.1**	**0%**

Table 4 Direct-connects: indicative and actual charges PY2021/22

Customer name	A. Current TPM ($m)	B. TPM proposed in 2021 ($m)	C. New TPM($m)	D. Change ($m)(C - B)	E. Change (%) (D:B)
Beach Energy Resources NZ (Holdings) Ltd	0.9	0.7	0.7	0.0	1%
Daiken Southland Ltd	0.8	0.8	0.9	0.0	2%
GTL Energy (NZ) Pty Ltd	0.005	0.009	0.009	0.0	0%
KiwiRail Holdings Ltd	2.8	3.5	3.5	0.0	0%
Methanex New Zealand Ltd	0.7	0.9	0.9	0.0	1%
New Zealand Aluminium Smelters Ltd	58.3	44.7	45.5	0.8	2%
New Zealand Steel Ltd	3.1	10.0	10.0	0.0	0%
Norske Skog Tasman Ltd	1.2	3.8	3.8	0.0	0%
OMV NZ Production Ltd *	1.2	1.1	0.5	-0.6	-57%
Pan Pac Forest Product Ltd	2.8	4.2	4.2	0.0	0%
Southpark Utilities Ltd	0.0	0.0	0.0	0.0	0%
Whareroa Cogeneration Ltd	0.2	0.9	0.9	0.0	0%
Winstone Pulp International Ltd	3.3	3.5	3.6	0.0	1%
Direct-connect total	**75.5**	**74.2**	**74.4**	**0.2**	**0%**

* Charges for OMV NZ Production Ltd now reflect that, as a new customer, it does not pay a residual charge initially. As proposed in 2021, the residual charge is phased in gradually for new customers with a 5-8 year lag.

Table 5 Generators: indicative and actual charges PY2021/22

Customer name	A. Current TPM ($m)	B. TPM proposed in 2021 ($m)	C. New TPM ($m)	D. Change ($m)(C - B)	E. Change (%) (D:B)
Contact Energy Ltd	24.6	29.8	30.0	0.2	1%
Genesis Energy Ltd	10.3	14.5	14.5	0.0	0%
Mercury NZ Ltd	3.5	12.3	12.2	0.0	0%
Mercury SPV Ltd *	0.1	0.6	0.5	-0.1	-20%
Meridian Energy Ltd	81.1	67.5	67.5	-0.1	0%
Nga Awa Purua Joint Venture	0.4	2.5	2.5	0.0	0%
Ngatamariki Geothermal Ltd	0.3	1.4	1.4	0.0	0%
Nova Energy Ltd	0.3	0.7	0.7	0.0	1%
Southern Generation GP Ltd	0.2	0.2	0.2	0.0	0%
Tararua Wind Power Ltd	0.1	0.3	0.3	0.0	2%
Todd Generation Taranaki Ltd *	0.1	1.0	0.9	0.0	-5%
Trustpower Ltd	4.5	2.0	2.0	0.0	0%
Waverley Wind Farm Ltd *	0.1	0.4	0.3	-0.1	-18%
Generator total	**125.5**	**133.1**	**133.0**	**-0.1**	**0%**

* Charges for Mercury SPV Ltd, Todd Generation Taranaki Ltd and Waverley Wind Farm Ltd now reflect that these new customers do not pay a residual charge initially. As proposed in the 2021 Consultation paper, the residual charge is phased in gradually for new customers with a 5-8 year lag.

12.9 In summary, the impact of the TPM policy changes made since the 2021 consultation are as follows:

(a) **Approach to AMD (residual charges)**. This change results in a broad rebalancing of charges. Several customers' residual charges reduce significantly as a result of the change, notably Aurora Energy, Buller Electricity and Westpower.[215] Other customers' charges, ie, those with no change in their AMD, increase by up to 2.6% as a result of this change.

(b) **Approach to disconnections of large plant (residual charges).** Under the new TPM the residual charges in relation to the disconnected load will phase out completely once 8 years since the disconnection have passed. [216]

(c) **Load:generation weighting (BBC simple method).** The change from a 50%:50% to a 62.5%:37.5% weighting increases load customers' 2021/22 indicative charges by about $1.4m and reduces generation customers' charges by around $1.4m.[217]

12.10 For further information (eg, charges broken down by charge type), please refer to the more detailed information published with this paper on the Authority's website.[218]

Impact on typical household bills

12.11 In Chapter 12 of the 2021 Consultation paper, to illustrate the impact of the proposed TPM on households, the Authority estimated expected changes in the electricity bills of the typical household served by each distributor. Below we set out our re-estimates of these impacts based on the updated indicative pricing

12.12 Impacts would vary across New Zealand. Some households' bills would increase, and some would decrease. In the distribution network regions that would pay more in transmission charges under the new TPM (compared to the current TPM), annual household electricity bills would increase $12 on average, whereas in local networks that would pay less in transmission charges under the new TPM, annual household electricity bills would be $18 lower.

12.13 The impact across the country is illustrated in Figure 12, which shows the estimated change (compared to the current TPM) in a typical household bill in each distribution network, if the proposed TPM applied in 2021/22 under:

(a) the new TPM (left panel); and

(b) the TPM that was proposed in 2021 (right panel).

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215 21 customers have co-located GXPs that result in a decreased AMD. However, eight of these customers have co-located GXPs that make up a relatively low proportion of their total AMD, so overall these customers' residual charges increase.

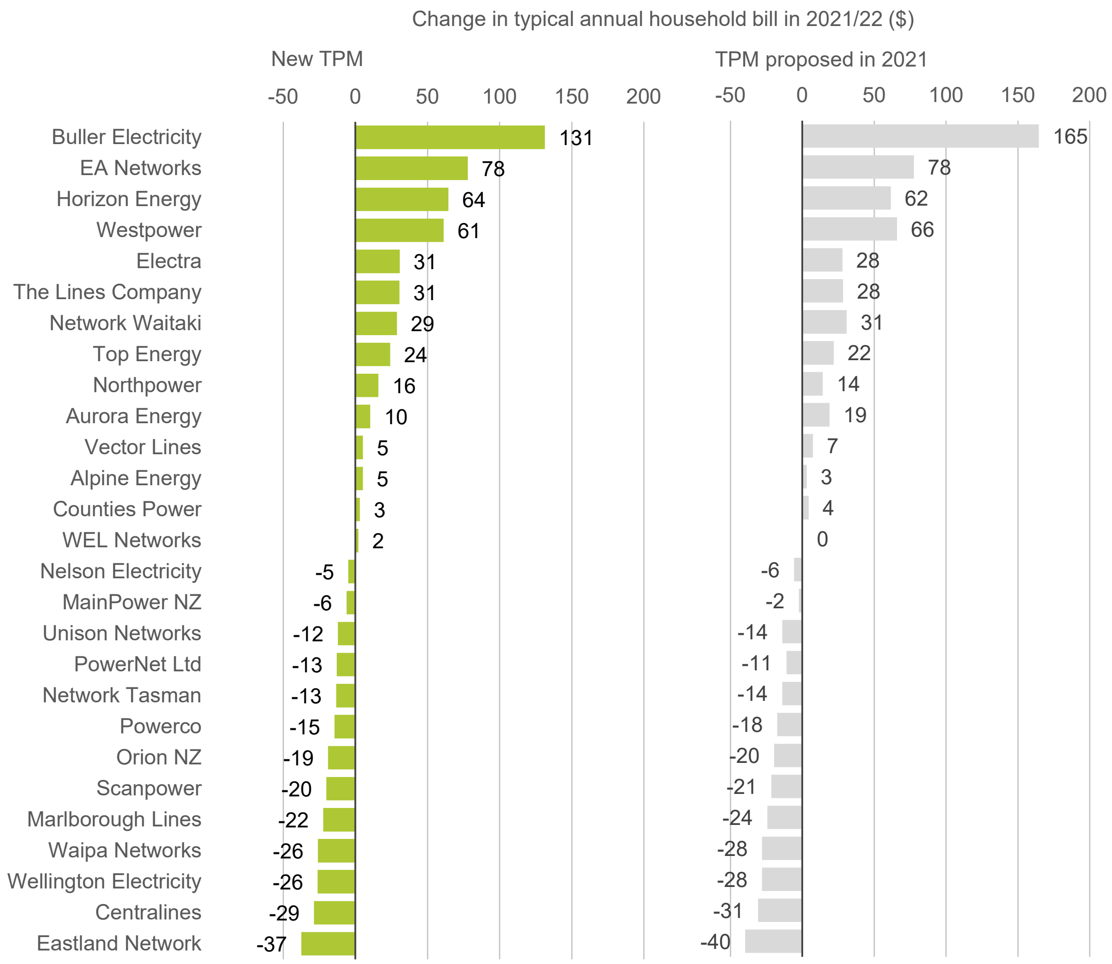
216 Impacted customers are (connection ID and expected final pricing year in brackets):

- Buller Electricity Ltd (BUELWPT; PY24/25)
- Contact Energy Limited (CTCTOTA;PY25/26)
- Powerco Limited (POCONPL; PY28/29)
- WEL Networks Limited (WELEMER; PY26/27)

217 Charges for simple method benefit-based investments in the 2021/22 indicative charges are a small fraction of overall charges ($11.2m of $798.9m).

218 See the Authority's website: Transmission Pricing Methodology — Electricity Authority (ea.govt.nz)

Figure 3 Change in typical annual household bill in 2021/22 ($)



Transitional cap

12.14 The remainder of this chapter concerns the Authority's decision on the proposed application of the transitional cap on transmission charges.

Relevant sections in the Guidelines and TPM

Guidelines	TPM
Clauses 49 – 53	Part H: Clauses 110-112

Our decision

12.15 The TPM adopts the transitional cap provisions included in the 2021 proposed TPM. These implement the Guidelines on the transitional cap.

What we proposed

12.16 The TPM includes a 3.5% cap on the amount customers' total electricity bills may increase relative to 2019/20 charges as a direct result of the new TPM being implemented (after allowing for inflation and volume growth).

12.17 The proposed TPM limits the increase in distributors' notional electricity bills (ex GST) since 2019/20 due to changes in the TPM to 3.5% plus inflation (while accounting for volume growth).[219] For direct consumers, the 3.5% cap would increase by 2 percentage points each year from 2025.

12.18 Customers' reductions in charges due to the cap are recovered from other transmission customers in proportion to their total cap-relevant charges (annual residual charges and benefit-based charges for Schedule 1 investments).

12.19 The cap does not apply to benefit-based charges for post-2019 investments or connection charges.

Submitters' views and our assessment

12.20 Submitters raised several related concerns with the transitional cap, including that:

(a) it will have a negligible effect in limiting price shocks, due to inflation (NZ Steel, Nova) and the choice of base year (ENA, Orion, Northpower)

(b) it does not provide enough protection to large distribution-connected customers (Network Waitaki, with reference to the North Otago Irrigation Company), or to those with cogeneration (NZ Steel, Nova[220], Oji Fibre)

(c) a more gradual transition to the new TPM would be appropriate (eg, Orion, Network Waitaki).

12.21 The cap was consulted on at length as part of the development of the Guidelines, and detailed requirements for the cap were set out in the Guidelines. Addressing submitters concerns above would require a departure from the Guidelines under clause 2. However, the Authority does not consider the case has been made for that because overall the proposed transitional cap is expected to work as intended, as explained below.

12.22 Some submitters have argued that setting the baseline for the cap by applying wholesale market prices to a customer's total electricity use is not relevant where a proportion of the customer's electricity is supplied by cogeneration (for which market rates do not apply).[221] However, the Authority considers that the cap is designed to provide a customer with a certain level of protection based on the estimated total (or *notional*) electricity bill, based on its gross load).[222] So the Authority considers that the cap should not be affected by how much of the customer's load is supplied by co-generation.[223]

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219 Under the TPM an estimate is made of the aggregate electricity bill of consumers by multiplying a distributor's or direct consumer's total gross energy for pricing year 2019 by the volume weighted average of final prices at these customers' connection locations.

220 For example, Nova is concerned that 'direct consumer' is defined in the Code which applies to a generator only if it is supplied with electricity for its own consumption, whereas a co-generator supplies electricity for consumption by others.

221 See NZ Steel, Oji Fibre Services.

222 See 2020 TPM Guidelines, clause 50 (a-b).

223 Nova submitted that under the current drafting, the cap does not assist co-generators such as Nova. However, the TPM allows Transpower to determine the status of a customer with 'intermingled' load and generation, such as Whareroa co-generation (which is part-owned by Nova). Whareroa Co-generation is treated as a direct supplied load customer, and on that basis the transitional cap applies to this customer, according to Transpower's indicative prices.

12.23 In response to submitters, the choice of 2019/20 base year reflects the timing of the Authority's 2019 proposal and subsequent decision in 2020.[224]

12.24 The cap is not intended to insulate customers from general consumer price inflation, as that is unrelated to the effects on electricity bills due to transmission pricing reform. The cap is intended to protect consumers from large increases in their total electricity bill (over and above inflation) due to a new TPM.

12.25 The cap is also not intended to protect transmission customers from increases in transmission costs related to new grid investments that may have been made since the 2019 pricing year (as these investments would reflect improvements in capacity or reliability for those who will be charged for them).

12.26 Network Waitaki submits that the design of the cap discriminates against customers embedded in distribution networks (by comparison with direct connect customers). It provided the example of the North Otago Irrigation Company (NOIC) – a single customer at the Black Point GXP – which Network Waitaki submits would face a 15% increase in its notional total electricity bill due to a 126% increase in transmission charges. The cap does not apply directly to NOIC as it is not a transmission customer.[225]

12.27 The Authority considered submissions on whether the cap should apply to large customers that are connected via distributors in making its decision on the Guidelines and decided that it should not, noting that arguments in favour of doing so are outweighed by the disadvantages of such an alternative approach to the cap that the Authority considered.[226] The Authority does not consider that the situation of NOIC justifies a different design for the cap. Network Waitaki acknowledges that the increase in NOIC's charges assumes the termination of the Black Point notional embedding contract. That contract has enabled Network Waitaki – and so NOIC – to avoid paying RCPD charges in the past, but the residual charge under the new TPM is set on a different basis. Network Waitaki will have the option to apply for a prudent discount under the new TPM in respect of Black Point.[227]

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224 This year was before the Commerce Commission's RCP3 decision (ie, before Transpower regulated revenue path stepped down the following year). The 2019/20 charges reflected the weighted average cost of capital for regulatory control period RCP2 (7.19%). This was reduced for RCP3 (to 4.57%), reducing transmission charges all else constant. Figure 14 on p105 of the 2021 proposed TPM Consultation paper compares the estimated impact on household bills in 2021/22 with prior years and illustrates how the 2019/20 base year compares to other years.

225 As an embedded customer, NOIC pays charges that are set by Network Waitaki, which will include a share of Network Waitaki's transmission charges. The 2021 proposed TPM Consultation paper reported Network Waitaki's 2021/22 indicative charges under the proposed TPM would be $5.3m compared to actual 2021/22 charges of $4.2m (assuming the notional embedding contract would not carry over).

226 See the Authority's 2020 decision paper on the guidelines, page 83, para 13.17.

227 Some prudent discounts may be backdated to the start of the new TPM. See chapter 9.

13 Other TPM provisions

13.1 Part A of the TPM contains the preliminary clauses covering general definitions, and general topics such as the calculation of charges, consultation and information requirements, the treatment of transmission alternatives and the adjusting of customer data under exceptional operating circumstances.[228]

13.2 These matters received relatively little attention in submissions.

Relevant sections in the Guidelines and TPM

Guidelines	Proposed TPM
Clause 5, 6, 9	Part A: Clauses 1-16

Consultation on transmission charges

Our decision

13.3 The new TPM generally adopts the specifications with respect to consultation on transmission charges that were proposed in the 2021 Proposed TPM consultation paper.[229]

What we proposed

13.4 The proposed TPM specified which interested parties Transpower must at a minimum consult with before transmission charges or adjustments to those charges are finalised. Where appropriate, the minimum obligation focuses on those with a material financial interest, and where the set of interested parties is less predictable Transpower is required to consult with the public.

Submitters' views and our assessment

13.5 Having reviewed submissions, the Authority has identified no reason to depart from what was proposed in 2021. The Authority considers these consultation requirements provide sufficient opportunities for participants to engage on key matters and are consistent with the Guidelines.

Information about transmission charges

Our decision

13.6 The new TPM adopts materially the same requirements on information about transmission charges as were proposed in the 2021 Consultation paper.

What we proposed

13.7 The proposed TPM required Transpower to provide each customer with sufficient information to enable them to understand the basis for their charges. For load customers this must include otherwise unallocated operating costs and reassignment amounts in the residual revenue.

228 See chapter 13 of the 2021 Proposed TPM consultation paper.

229 We have refined some of the requirements to improve workability or to reflect policy decisions. For a summary of changes and the reasons for those changes refer to the table of changes to the TPM in Appendix A (clause 15 Consultation on Transmission Charges).

Submitters' views and our assessment

13.8 Having reviewed submissions, the Authority has identified no reason to depart from what we proposed in 2021. Provision of information about charges promotes the efficient operation of the electricity industry by enabling customers to scrutinise the basis of charges, including through transparency on the make-up of residual charges. The Authority considers that the clause in the new TPM is consistent with the Guidelines and with its statutory objective.

Treatment of transmission alternatives

Our decision

13.9 The new TPM treats transmission alternatives in the same way as was proposed in the 2021 Consultation paper.

What we proposed

13.10 Under the proposed TPM, the costs of transmission alternatives were to be assigned to the relevant connection or interconnection investments. The operating costs of transmission alternatives in connection investments were to be shared between customers at the relevant connection locations in proportion to their total connection charges. The costs of any transmission alternatives were to be directly attributed to the relevant BBI. Where the transmission alternative is an alternative for both connection and interconnection assets, Transpower may apportion the operating costs between these asset types.

Submitters' views and our assessment

13.11 Having reviewed submissions, the Authority has identified no reason to depart from what we proposed in 2021. The Authority considers that the treatment of the cost of transmission alternatives in the TPM is consistent with the Guidelines and promotes the efficient operation of the electricity industry by allowing participants and Transpower to consider the most efficient solution without such choices being distorted by differential funding. The Authority notes that the approach is the same as in the current TPM.

Exceptional operating circumstances

Our decision

13.12 The new TPM adopts the provisions on exceptional operating circumstances that were proposed in the 2021 Consultation paper.

What we proposed

13.13 The proposed TPM contained a provision that allows Transpower to adjust a customer's allocation data in case of an 'exceptional operating circumstance' in the power system, if it considers this may have distorted the allocation data.

Submitters' views and our assessment

13.14 Having reviewed submissions, the Authority has identified no reason to depart from what we proposed in 2021. The Authority considers that adopting the provisions on exceptional operating circumstances in the TPM will be likely to better promote its statutory objective by avoiding materially distorted charges.

Other preliminary provisions

Our decision

13.15 The new TPM largely adopts the other preliminary provisions that were proposed in the 2021 Consultation paper.

What we proposed

13.16 Section A of the proposed TPM covered a range of other topics and general definitions to support the interpretation and operation of the proposed TPM.

Submitters' views and our assessment

13.17 Having reviewed submissions, the Authority has identified no reason to depart from what we proposed in 2021. The Authority considers that these other preliminary provisions are consistent with the Guidelines (to the extent they have not been addressed specifically in this or other chapters).

14 Regulatory statement

14.1 The 2021 Proposed TPM consultation paper included at Chapter 14 a regulatory statement in accordance with section 39(2) of the Electricity Industry Act 2010.

14.2 The regulatory statement included in the 2021 Consultation paper:

(a) set out the objectives for a new TPM, and how the proposed TPM would give effect to these objectives

(b) provided an evaluation of the costs and benefits of the proposed TPM, finding that the proposal's benefits outweigh its costs

(c) provided an evaluation of alternative means of achieving the objectives, noting that the substantial assessment of alternative means had been part of the decision on the Guidelines, and finding that the proposed TPM was preferable to the other options that had been considered in developing the proposed TPM

(d) summarised how the proposed amendment complies with s32(1) of the Act (see Table 11 on p113 of the 2021 Consultation paper); this included a summary of how the proposal would promote competition in, the reliable supply of, and the efficient operation of the electricity industry for the long-term benefit of consumers

(e) documented the Authority's consideration of the Code amendment principles, namely that the proposal is lawful, addresses clearly identified problems, and identifies and quantifies net benefits within ranges.

Submitters views and our assessment

14.3 Only a few submissions engaged directly with the Authority's regulatory statement.

14.4 Trustpower submitted that it does not consider the Authority has complied with section 39(2) of the Act (p11 Appendix C to its submission). It considers that:

(a) prior assessments of alternatives were not fit-for-purpose

(b) the CBA cannot be relied on as it repeats past errors and introduces new ones

(c) the proposed TPM is "riddled with discriminatory treatment of transmission customers" (para 2.5.3 of its submission)) that are "antithetical to competition and will lead to poor outcomes for consumers" (para 2.5.4).

14.5 Several other submissions[230] related to the assessment of the benefits of the proposed TPM, commenting in particular that the proposed TPM's complexity and uncertainty would weigh on investment in generation and industrial plant.[231]

14.6 These matters are discussed below. Overall, the Authority considers the regulatory statement in the 2021 Consultation paper is fit for purpose.

230 These include Contact Energy, Counties Energy, IEGA, Mercury, Meridian, Network Waitaki, Nova, Orion, Oji Fibre Solutions, Tauhara North No 2 Trust, Trustpower and Vector.

231 Network Waitaki submitted that the regulatory statement should acknowledge the potential for unintended consequences. This was because it noted its customer at Black Point would experience a significant price shock, even though the regulatory statement states price shocks would be avoided through the transitional cap. This matter is discussed from para 12.26 to 12.27.

Prior assessment of alternatives were fit for purpose

14.7 Many of the points raised by Trustpower related to the regulatory statement and the CBA have been considered in-depth previously and relate to the Authority's decision on the Guidelines.

14.8 The Authority does not agree that its prior assessments of alternatives were not fit-for-purpose. The Authority considered many options in considerable depth over the course of the TPM review, and did so in light of its statutory objective. Appendix B of the 2020 Decision paper summarises the Authority's analysis of the main alternatives proposed as a means of achieving the objectives of the TPM review.

CBA can be relied on

14.9 The Authority also does not agree with Trustpower that the Authority's CBA cannot be relied upon, for the reasons discussed in the Authority's previous papers, particularly in the CBA Revisions information paper published in April 2020.[232]

14.10 The Authority has thus already responded to many of Trustpower's claims in respect of the CBA and does not repeat those responses here.[233]

14.11 Trustpower also submitted that the CBA in the 2021 Consultation paper introduces new errors, citing a consultant report (from HoustonKemp) provided by Trustpower in support of its claims regarding the CBA and assessment of alternatives. The Authority's assessment of the claims in that consultant report is provided at Appendix C. In brief, the Authority does not agree with HoustonKemp's conclusions. The Authority is satisfied that the assumptions and methods it has used in the CBA are appropriate and reasonable and that the CBA produces reliable results.

14.12 Mercury submitted the CBA was inadequate, in part because it thought the proposed TPM would increase, rather than reduce, uncertainty for investors in the short to medium term. This was because "even large stakeholders like Mercury struggle to fully understand the workings of [the proposed TPM's] charges…".[234] For the reasons set out from paragraph 14.17 on, the Authority disagrees such transitional uncertainty is material in the long run considered in the CBA.[235]

Authority favours options that promote competition

14.13 The Authority disagrees with Trustpower that the TPM is "riddled with discriminatory treatment".

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232 See Electricity Authority, April 2020, Response to feedback on the 2019 cost benefit analysis, information paper, at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/revisions-to-cba-in-response-to-feedback/.

233 Vector too does "not consider the proposed TPM is in the long-term benefit of consumers as it will result in a substantial wealth transfer from consumers to generators." It considers the Authority should revisit the 2020 Guidelines. However, CBA results in the 2021 TPM Consultation paper indicates the TPM would result in material net benefits as compared with the status quo; as Table 13 showed, this was after adjusting for transfers. The CBA in the 2020 Decision paper also adjusted for transfers, as discussed in the 2020 CBA Revisions paper in response to concerns on this topic. It therefore does not agree with Vector's submission.

234 Mercury submission p1.

235 Mercury further submitted that investment efficiencies were also overstated because the implications for the grid of investing in certain areas on grid investments are already top of mind for investors. Be that is it may, as set out in the 2019 Issues paper and 2020 Decision paper, the RCPD and HVDC charges provide inefficient price signals, and so distort locational decisions.

14.14 The TPM in general treats equivalent customers the same, as the Authority recognises the role of competitive neutrality in promoting competition and efficient resource allocation.

14.15 The 2021 Consultation paper has explained in-depth how the Authority has sought to avoid, to the extent possible, uneven treatment of incumbent and new entrant transmission customers. Where design choices presented trade-offs, the Authority has favoured arrangements that avoid creating barriers to entry. Similarly, it has favoured options that are technology-neutral,[236] ensuring the TPM avoids creating unequal treatment of, for example, battery storage and intermittent generation with high capital and low operating cost.

14.16 The Authority's approach appropriately addresses the specific examples that Trustpower raises as in its view demonstrating discrimination between transmission customers that will harm competition. For example:

(a) Charging selected connection charge counterparties for anticipatory capacity:

The TPM would charge 50% of the cost of anticipatory capacity to customers who have been identified as benefiting from it and 50% of the cost to all customers, until subsequent movers connect and are charged in line with their net benefit. This is efficient and competitively neutral over time as between first and subsequent movers. It also promotes the efficient operation of the electricity industry, by encouraging scrutiny that supports the right-sizing of the investment.

(b) Charging new entrants with backdated benefit-based charges:

Trustpower has incorrectly characterised the proposal, which does not involve backdating. The TPM would "allocate BBC for a new entrant… based on the allocation of charges that an equivalent incumbent would pay in the same year".[237]

(c) Trailing exit charges, whereby some parties are charged for some years after they have left the market:

When a customer exits entirely, it is no longer liable for transmission charges. The Guidelines specified that when a transmission customer closes a plant but remains a customer then it will continue to be allocated the benefit-based charges of the closing plant until ten years after the commissioning date of the grid investment/s in question. This is akin to investment risk-sharing approaches common in a commercial environment.[238] The proposed TPM extends this to related parties of the plant owner to avoid companies resorting

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236 Nova had submitted that "The TPM largely meets its objectives, but it fails to be technology agnostic by penalising the co-generation of electricity and steam together…[which] will have a significant impact on the future economics of co-generation plants." (p11)

237 2021 TPM Consultation paper, para 8.15.

238 Nova made this point in its submission in the context of the lagged adjustment to the residual charge. It states "In a commercial environment with counterparties on an equal footing, it is relatively common for long-term supply contracts to provide for the consumer to pay a termination fee payable in event it wishes to terminate the contract prior to the contract expiry. The early termination fee relates to parties' earning an economic return over the term of the contract." However, Nova thought that it should not apply to the residual charge because a lagged adjustment provided an incentive for a customer to inefficiently bring forward the derating or closure of their plant. Derating is discussed in Chapter 8.

to corporate restructuring to avoid (and shift) charges. Such behaviour would be inefficient and stifle competition where it results in uneven treatment of customers.

(d) Thresholds for adjustments that create distinctions between larger and smaller participants:

Trustpower submitted that the thresholds for adjustments in effect create variable charges for larger but not smaller market participants. The Authority disagrees with this submission. We have designed the distinctions so that adjustments will generally be rare one-off occurrences such as the connection of a large plant or a large upgrade of a plant. Such adjustments do not create variable charges. The adjustments to all other customers' charges will be mechanical and unavoidable, so do not create inefficient incentives for those other customers.

Furthermore, the distinction between large and small plant is designed to avoid inefficiency.[239] The distinction means that the way charges in respect of large plants change is the same whether they are embedded or grid-connected, so the TPM creates no inefficient incentive to embed or grid connect. By definition, small plants are expected to be embedded, so their charges are a matter between them and the distributor, and their size means they are unlikely to take inefficient actions to try to alter their distributor's transmission charges.

We consulted explicitly on whether the distinction between large and small is appropriate. While Trustpower agreed with the view of its consultant CEC that a complete rethink was required, some other submitters supported the definition of "large" (eg, Refining NZ) and others did not comment.

(e) A bespoke treatment for grid-connected batteries 'not afforded to other load with similar characteristics':

The Authority is satisfied that its proposed final consumption approach is the best option for ensuring batteries are on a level playing field with competing generation and other technologies. The Authority responds to submissions on this matter from paragraph 5.75 in chapter 5 and from para 7.55 to para 7.72.

Certainty and predictability of charges

14.17 Several stakeholders submitted that the proposed TPM's complexity and uncertainty makes it difficult to forecast transmission charges, which would inhibit investment in generation and industrial plant. [240]

Transitional uncertainty

14.18 The Authority acknowledges that, like any change, the transition to the new TPM involves uncertainty. Over time, we consider the new TPM will increasingly support reasonable predictions and projections of charges.

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239 Reasons paper page 10.17, para 44 notes "…we consider [10MW for embedded plant] to be appropriate threshold for embedded plant because it aligns with the thresholds for generator offers [in the Code] and there are few current examples of grid-connected plant less than 10 MW."

240 These include Contact Energy, Counties Energy, IEGA Mercury, Meridian, Network Waitaki, Nova, Orion, Oji Fibre Solutions, Tauhara North No 2 Trust, Trustpower and Vector.

14.19 With the new TPM finalised, Transpower will, over time, work to establish what further information could be produced to help stakeholders understand the new TPM, and within what timeframes. Transpower will carry out its normal customer engagement in the lead up to the first pricing year under the new TPM, including consultation on inputs to transmission charges. An overview of some of this information and indicative timing on when this information will likely be published is included in Table 6 in chapter 15.[241]

14.20 Stakeholders will continue to invest time and resources to the extent they consider it necessary in understanding the factors that matter to them in particular during the transition and the start of the new TPM. We expect stakeholders will continue to engage on investment proposals and scrutinising their costs and benefits.

General predictability of transmission charges

14.21 We consider that uncertainty about future transmission charges is more driven by stakeholders' initial unfamiliarity with a new TPM during the transitional period and by uncertainty about the location, timing and size of transmission investments (which would exist even if the TPM did not change) than by the methodologies for the *allocation* of transmission costs in the TPM. A business case for an investment (in generation or other plant) must take into account uncertainty around many relevant parameters.[242] Any uncertainty around transmission charges is not out of step with other uncertainties typically considered in investment business cases.

14.22 Below we show the projected shares of charges load customers (as a group) and generators (as a group) are projected to pay over the period to 2035.[243] The make-up of charges illustrates how the potential variability of each charge relates to the overall predictability of charges over different time windows.[244]

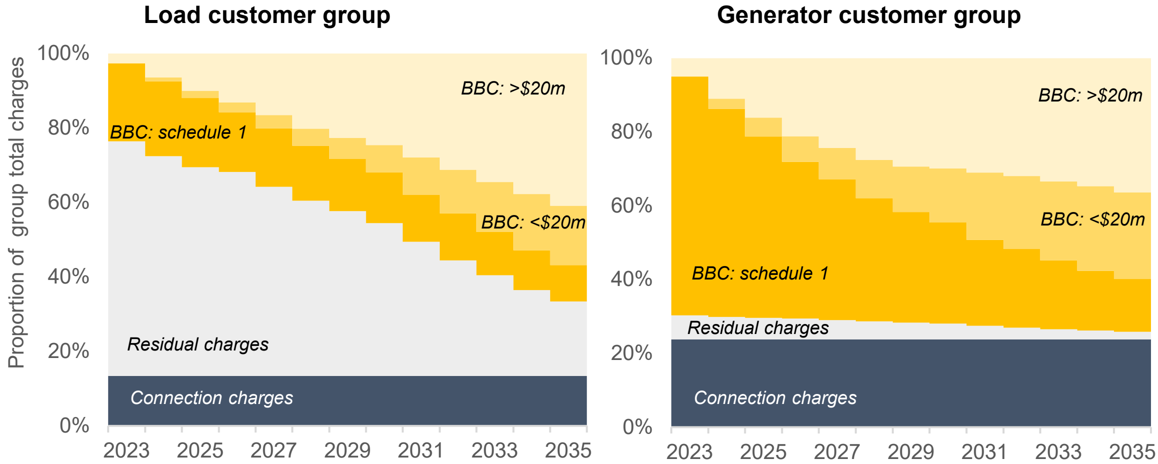
241 Counties Energy (para 18) submitted specific suggestions of information Transpower should provide that would help stakeholders better understand their charges. The new TPM requires Transpower to provide a range of information and consult with stakeholders. Stakeholders will be able to provide feedback as part of Transpower's consultation on specific information they would find useful.

242 For example, to the extent the recent volatility witnessed in capital and commodity markets is likely to have enduring effects (and will be reflected in the regulatory settings under Part 4 of the Commerce Act, such as the regulatory WACC), it will also have a bearing on the timing or viability of efficient and prudent electrification/decarbonisation projects.

243 The illustration builds on Transpower's projection of the proportion of charges that was published alongside the Authority's proposal for consultation. Transpower has explained the assumptions and limitations of its projections, which also apply to the Authority's illustration. Refer to pages B.17- B.18 of TPM-Proposal-Reasons-Paper-Appendix-B-Indicative-Prices-Transpower.pdf

244 The shares shown in these charts (and the corresponding overall chart in Transpower's 30 June reasons paper), depend on the level of new investment, which is subject to a high degree of uncertainty (due to non-TPM factors). Also, while indicative of these two broad groups, the specific profile varies with the specific circumstances of each individual customer.

Figure 4 Material components of charges are relatively certain and predictable



Note: The generator customer group charge includes an illustrative residual charge, reflecting generators' charges in their capacity as load customers. In the 2021/22 indicative prices the share of generators' charges made up by residual charges varied widely across generators from 3% to over 50%. Depending on circumstances, some generators' projected charges will more closely resemble that of the load customer group.

14.23 The Authority is confident the new TPM will not ultimately lead to uncertainty that would be a barrier to future electricity-related investments. We note that:

(a) Allocations (and overall charges) are reasonably predictable for the connection charge, residual charge,[245] and BBCs for Schedule 1 historical investments. These will likely make up a significant portion of charges overall, in particular during the early years of the TPM (see Figure 3).

(b) Ongoing benefit-based allocations of simple method BBIs will also be predictable with allocators set for five years. The location and timing of investment are less certain.

(c) Allocations related to investments under the BBC standard method will be more challenging to predict; investments will be flagged in advance (eg, through the ITP).[246] Stakeholders, as they engage with the new TPM, will become increasingly familiar with the new TPM allocation methodologies over time.

Other submissions on uncertainty

14.24 The Authority disagrees with Vector's assertion (p1) that 'the long term and cumulative impact of price increases under the TPM remains unclear and falls well short of regulatory best practice". The Authority disagrees for the following reasons:

(a) The 2021 Consultation paper at para 12.16 set out the possible evolution of different types of charges out to 2035 (see also Figure 3 above). It also

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245 Costs related to adjustments are likely to be material for the customers whose actions precipitate adjustments in charges (eg, by entering or expanding) and are likely predictable by them (based on rules and processes in the TPM and discussion with Transpower). Other customers paying for adjustments (in aggregate) are likely to have less visibility of potential future adjustments. However, these will be spread across a wider base, and the overall scheme of the TPM seeks to limit adjustments to the extent possible (ie, to preserve the fixed-like nature of charges).

246 The most recent ITP was published in 2021: RCP3 updates and disclosures | Transpower. Transpower's 2022 ITP will be published during September for consultation as part of preparing Transpower's base capex proposal for RCP4.

explained at para 12.20-12.21 why Transpower considered it not practicable to project indicative charges by customer out to 2035, and that "as part of consultation on prices under any new TPM and on an ongoing basis, Transpower would provide more granular pricing projections (covering regulatory control periods), which will promote certainty for customers."

(b) The CBA did provide an analysis of the impact of the proposed TPM on the cost of transmission over time and by backbone node, and this also provided details of, among other things, distributional effects over time in a form that suitable to inform regulatory analysis.

14.25 Counties Energy (p 2) submitted that the proposed TPM places all the uncertainty on investors to the benefit of Transpower despite Transpower being a natural monopoly with guaranteed revenue through the residual change as well as a guaranteed rate of return on assets. The Authority notes that the scope of the TPM includes the allocation of transmission costs between transmission customers. The scope does not include the broader matter of which party is best placed to deal with uncertainty and risk.

14.26 Counties Energy (p 2) also submitted that Transpower should provide a five-year BBC commitment to provide "certainty that investors require". Transpower disagreed with this suggestion in its cross-submission (para 10):

(a) Given the investment-specific basis for BBCs (as to timing, covered cost and allocations) the certainty introduced by a mechanism like this would be artificial and create winners and losers.

(b) It would also work against the role of BBCs in encouraging investment scrutiny.

14.27 We agree with Transpower's reasons for why a five-year BBC commitment is not appropriate, and have not included a five-year BBC commitment in the new TPM.

Impact of changes from the proposed TPM on the cost benefit analysis

14.28 Following consideration of submissions (see paras 14.9-14.12 and Appendix C) the Authority is satisfied that the assumptions and methods it has used in the CBA are appropriate and reasonable and that the CBA produces reliable results.

14.29 The Authority also considered whether any of the amendments it made to the proposed TPM in light of submissions may have impacted on the assessment provided in the 2021 CBA. The Authority's decision on the simple method weighting factor was identified as likely material for the CBA.

14.30 As part of the regulatory statement included in the 2021 Consultation paper, the Authority had estimated that:

(a) in the central scenario (which assumed an approximately 50:50 simple method weighting as to between load and generation), the TPM would provide net benefits with an average present value of +$1.25b over 28 years, with a range of $0.4b-$2.9b

(b) in a scenario where the weighting would be 75%:25% as to between load and generation, the net benefits would have an average present value of +$2.4b over 28 years[247], which falls in a range of $1.0b-3.7b.

14.31 The Authority has now decided that the initial allocation of costs for grid investments to which the simple method applies should be 62.5% to load customers and 37.5% to generation customers (Paragraph 5.39 on).

14.32 This allocation falls between the two scenarios set out in the paragraph 14.30. The Authority also re-ran the CBA model's central scenario with the 62.5%:37.5% weighting (but no other changes) and estimated this would result in net benefits with an average present value of +$1.8b over 28 years, with a range of $1.1b-$3.7b[248]

14.33 As the Authority has explained in the 2021 Consultation paper, the quantified CBA estimates exclude unquantified benefits, which are considered to be significant. Unquantified benefits include those from: removing incentives for mass-market consumers to invest in technologies to avoid transmission charges; avoided costs of inefficient undergrounding; reductions in unpredictable transmission charge volatility; and durability (which would be undermined if consumers in some regions would have to pay for new investments made for their benefit and continue to pay for major investments they did not benefit from).

14.34 While the quantified net benefits are substantial, the quantified CBA remains one of a number of factors the Authority considered in approving this proposed TPM for consultation, alongside its qualitative assessments.

14.35 Overall, the Authority is satisfied that it has met the requirements of a regulatory statement in section 39(2) of the Electricity Industry Act 2010, and that it has had proper regard for the Code amendment principles as required by the Authority's Consultation Charter.

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247 See footnote 277 of the Authority's 2021 proposed TPM Consultation paper.

248 As noted in the 2021 proposed TPM Consultation paper (para 5.37), there are other considerations at play beyond the quantitative CBA estimates, including durability considerations. Ultimately what is a reasonable weighting for simple method investments is an empirical matter, and further empirical evidence will be provided over time through standard method assessments where they can be assumed to provide insights relevant to simple method investments.

15 Next steps and commencement date

Commencement date

15.1 The Authority has determined that the new TPM will take effect on 1 April 2023 (the commencement date proposed in the 2021 Proposed TPM consultation paper).

15.2 Some submissions supported this commencement date.[249] Other submitters argued that 1 April 2023 is too early and that commencement should be deferred, because:[250]

(a) metering equipment upgrades may be required to measure data required for some transmission charges – requiring time to approve, procure and install

(b) substantive consultation on avoided cost of transmission (ACOT) payments should occur before the new TPM comes into force

(c) distributors need to give customers sufficient warning as to whether there will be an RCPD charge so they can adjust (or not adjust) their load accordingly

(d) a staged approach would reduce uncertainty around application of the TPM

(e) the TPM is not yet fit for purpose (noting the complexity and depth of submissions).

15.3 The Authority's position on these submissions is as follows:

(a) The Authority intends to pursue improvements to data availability via a separate Code amendment process; in the meantime the TPM includes a list of information which may be used to calculate allocation data, improving certainty and reducing the scope for disputes in implementation.[251] The Authority considers that this list is sufficient for implementation.

(b) The Authority intends to consult on the ACOT provisions in the Code later in calendar year 2022. We expect this consultation will be complete before the TPM commencement date.

(c) The Authority has been transparent about its expected commencement date, so distributors' customers have had as much information as possible. We acknowledge that this information was not complete until now, however, we do not consider this is a strong enough reason to justify delaying the commencement date for a further year (and so delaying the expected benefits of the new TPM).

(d) The Authority considers that a staged approach of the type suggested by submitters would increase complexity of TPM implementation and commencement and further delay the benefits of more efficient pricing. The Authority has already considered alternative transition paths, such as those advanced by submitters.[252] We are confident that any uncertainty will be

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249 ENA, OceanaGold and Powernet (provided that due consideration is given to all issues raised in consultation).

250 For example: Fonterra, Horizon, Orion, Pioneer Energy, Refining New Zealand, Trustpower.

251 Data availability is discussed further at paragraph 15.11 and also in Chapter 7 at paragraph 7.34.

252 See the Authority's 2020 decision paper, paragraph 13.24.

resolved: following this Decision Paper, Transpower will now be able to provide certainty as to how the TPM will apply.[253]

(e) The Authority has carefully considered the matters raised in submissions, including the uncertainty concerns discussed in the previous chapter, and is confident that the new TPM is fit for purpose.

15.4 Transpower's submission noted the 1 April 2023 date would be challenging to meet considering the large number of tasks that it would have to complete before then. It requested that the Authority carefully consider adding additional components to the TPM and only do so where the benefit it will provide will outweigh the associated administrative cost and risk of delay. The Authority considers that it has properly considered which additional components should be included in the TPM, in line with the TPM Guidelines, as well as considering Transpower's submission more broadly.

15.5 As required by the Code, the Authority has consulted with Transpower on its proposed commencement date of 1 April 2023, in a letter of 22 February 2022.[254] In its response on 18 March 2022, Transpower stated that it would "continue to work positively with the Authority and other stakeholders to achieve the successful implementation of the new TPM by 1 April 2023", but stressed that this assumes "no material obstacles, unforeseen or otherwise."

15.6 Transpower outlined challenges and risks associated with a 1 April 2023 start date that it considered would support a later commencement date. These included:

- The compressed timeframe to complete audit-ready transmission charges by 1 October 2022.
- The impact of any significant departures from the Authority's previously conveyed positions on the TPM.
- Little or no time to iron out any problems discovered during implementation.
- Little or no time for customers to come to grip with the new TPM and settlement residual allocation methodology (SRAM) and the implications for their own pricing and contracts.
- An increased likelihood of wash-ups in the first year, such as for prudent discounts.

15.7 The Authority has considered the challenges and risks raised by Transpower in its letter, and notes:

- the changes in the TPM from that proposed that are most likely to impact on calculations of charges at commencement are discrete (simple method weighting and the treatment of load at a location with multiple GXPs)
- as discussed at para 15.3, the Authority has been transparent about the expected starting date and the key structure of the TPM has been known to transmission customers for some time. Further, Transpower intends to have proposed, consulted and completed audit-ready charges in line with its usual

[253] Questions around uncertainty are considered further in chapter 14 of this paper.

[254] Required under clause 12.94 of the Code.

pricing cycle. Transmission customers now have a further year to get to grips with the details of other aspects of the TPM

- the Authority has recently consulted on SRAM principles and intends to consult on a new SRAM later in 2022. At this point, this would allow a new SRAM to be settled (including any transitional measures if required) by 1 April 2023. However, the implementation of the TPM does not depend on the SRAM having been completed by then, as the TPM includes transitional provisions that mean the effect on settlement residual rebates need not be taken into account in the initial benefit-based charge allocations
- any use of wash-ups (in relation to the backdating to the TPM commencement date of any early prudent discount applications)[255] are to facilitate Transpower meeting the commencement date and so mitigate rather than increase time risk
- the TPM includes other transitional provisions to facilitate Transpower meeting the commencement date, such as limits on initial requirements for the prudent discount policy practice manual
- delay brings costs, by delaying certainty about the transmission charges that transmission customers will face and delaying the benefits to consumers that come from more efficient transmission price signals.

15.8 Having considered submissions, and the challenges and risks raised by Transpower, the Authority considers the benefits of setting a commencement date of 1 April 2023 outweigh the benefits of delaying implementation by another year.

Next steps for Transpower

15.9 Following the Authority's decision to incorporate a new TPM into the Code, Transpower will need to implement the new TPM and engage with its customers about their transmission charges. After carrying out its own internal assurance processes Transpower must publish transmission prices consistent with the TPM.[256]

15.10 The following table summarises Transpower's next steps and estimated timeframes. for Transpower to calculate charges for the first pricing year (2022/23) under the new TPM. We note that the calculation of final charges for the two intervening BBIs may be delayed until the subsequent pricing year if the consultation and assurance processes take longer than expected. [257]

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255 The TPM only provides for wash-ups in relation to prudent discounts (see para 9.24 on), and we expect any such wash up would be achieved via the use of Transpower's regulated 'economic value' (EV) account rather than by adjusting all customers' charges in the relevant year.

256 Code Clause 12.96.

257 For certain grid investments that have been approved since 23 July 2019, Transpower may not have sufficient time to allocate the costs relating to these investments under the standard method. As such, the new TPM provides that Transpower can initially allocate costs relating to these investments under the simple method to make the 1 April 2023 commencement date feasible. When the full standard method allocation process has been completed for these investments, the costs will be retroactively reallocated using a wash-up mechanism. Nova supports the initial allocation of new grid investments using the simple method provided this allocation is updated using the standard method and wash-ups are made. Trustpower also agrees.

Table 6 Next steps for Transpower

What	Indicative timing
Indicative charges under the new TPM for pricing year 2022/23 (ie, the pricing year commencing 1 April 2022).	Publish: April 2020
Determine initial assumptions book that sets out inputs and assumptions for benefit-based charges (including simple method regions and allocations for the first simple method period)	Consult May 2022 Publish September 2022
Benefit-based charges for intervening BBIs with partial or full commissioning in the 2021/22 (CUWLP and Otara-Flatbush conductoring) projects	Consult May 2022 Publish September 2022
Determine pricing inputs for pricing year 2023/24	Consult September 2022
Determine initial prudent discount practice manual, including application requirements and any application fees	Consult November 2022 Publish February 2023
Communicate final transmission charges for pricing year 2023/24 to customers	Publish December 2022
Determine reassignment application fees and requirements, and a list of BBIs eligible for reassignment in pricing year 2023/24	Publish March 2023

Related Code amendment proposals: next steps and timing

15.11 The Authority expects to consult on proposed Code amendments on the following TPM-related subjects, with indicative timing for beginning consultation as follows:

(a) May - June 2022:

(i) *Gross energy information (immediate):* The Authority has identified that additional information on activity behind the GXP in relation to a small number of transmission customers would likely better enable the effective working of a new TPM (in particular, the allocation of the residual charge). Future improvements to data requirements are to be addressed through a later Code amendment (see below), however an earlier minor Code amendment is intended to improve matters for the first pricing year of a new TPM.

(ii) *System operator data*: The Authority is considering a Code amendment to expressly enable the System Operator to disclose to the Grid Owner information about matters that may be relevant to the calculation or adjustment of transmission charges (as suggested by Transpower).[258]

(iii) *PDA/NEC agreements*: The Authority intends to propose a minor Code amendment to address the situation of the existing Notional Embedding Contract and two existing Prudent Discount Agreements with customers.

258 Transpower, submission in response to the 2021 Proposed TPM consultation paper (pp38-39).

(iv) *Urgent and/or non-controversial amendments to the TPM*: The Authority is considering whether a Code amendment may be required to address potential errors and workability problems that may be identified during Transpower's implementation of the new TPM. In particular, the Authority is considering whether a Code amendment may be appropriate to make it clear that the TPM may be amended via an urgent amendment (section 40 of the Act) and/or a technical, non-controversial amendment (s 39(3) of the Act).

(v) *Distribution pricing*: The Authority intends to work with distributors (and the ENA) on appropriate pass-through of transmission prices by distributors to their customers.[259]

(b) June - Oct 2022:

(i) *ACOT:* An amendment to the ACOT provisions in Part 6 of the Code, which in practice are linked closely to existing transmission charges, will look to clarify how these provisions will apply in respect of the new TPM.

(ii) *SRAM:* The current settlement residual allocation methodology (SRAM) for allocating residual loss and constraint excess (LCE) under the new TPM, will be obsolete once the Guidelines have been implemented. The Authority has recently consulted on proposed new SRAM principles which will guide the development of a new SRAM (expected to be consulted on in the third quarter of calendar 2022).

(iii) *Future TPM reviews:* A Code amendment would make provisions for future reviews to ensure the implementation of the TPM remains workable and continues to promote the Authority's statutory objective.

(c) Oct 2022 – June 2023:

(i) *Gross energy information (future requirements):* A further Code amendment relating to information disclosure requirements is expected to improve these matters (discussed above) for the longer term.

(ii) *Review of the Benchmark Agreement*, which is a default transmission agreement between Transpower and a transmission customer that includes service levels and includes obligations on customers to comply with technical connection requirements, provide information, and pay prices calculated in accordance with the TPM (*under consideration*).

259 Submissions (including cross-submission) requesting further work on pass-through by distributors included submissions from Alliance, Contact Energy, IEGA, Mataura Valley, Mercury, Network Waitaki, Orion, Powernet, and Refining NZ.

Appendix A Table of changes to the TPM since consultation

Table 7 Table of changes to the TPM since consultation

Clause	Explanation of changes
1 Purpose	Clarification that it is the costs recovered under investment agreements that are not recovered under the TPM.
3 General Definitions	
accelerated depreciation	This definition has been included to clarify what is meant by accelerated depreciation in the TPM and is formulated to align with the relevant provisions of the Commerce Commission regime.
alleviated price	This new definition and the related new definition of "exacerbated price" are intended to provide greater precision for the calculation of market regional NPB under clause 51 (calculation based on quantity). The definitions and the changes to clause 51(3) reflect the methodology Transpower used in its CUWLP case study (that was released at the same time as the consultation on the TPM).
allocation data	Clarification that a customer's allocation of transmission charges can be affected by data other than the customer's own data.
allowance	This amendment has been made for consistency with the description in Schedule D of the IPP determination.
alternative project	Clarification that stand-alone cost prudent discounts can cover 1 or more transmission alternatives rather than just one transmission alternative.
anticipatory connection asset	Used in clause 26(2). See comment on clause 26.
Appendix A allocation	This definition has been included for clarity. See comments on clauses 42 and 83.
Appendix A BBI	Correction to two dates that were incorrectly transposed.
Appendix A beneficiary	This definition has been included for clarity. See comment on clause 42.
Appendix A customer	Used in amended clause 83(6). See comment on clause 83.
avoided transmission charges	This definition has been amended to reflect that stand alone cost prudent discounts now also cover connection charges, and the drafting has been simplified.
BBI customer allocation	This definition has been amended to simplify and clarify it and the adjustment limb extended to post-2019 BBIs.
back-dated prudent discount	This definition defines prudent discounts that would qualify for back-dating, which may be IBPDs or SACPDs. The substantive provisions are in new clause 122.

Clause	Explanation of changes
cap recovery-relevant charges	Clarification that cap recovery-relevant charges are net of any prudent discount of transmission charges. This means that customers with existing discounts get the benefit of them in terms of the cap provisions.
CMP C	This definition has been amended to provide that all CMP Cs should end with the second most recent capacity year to ensure Transpower has enough time to complete the calculations, consultation and audit for the next simple method period.
capital charge	"Grid asset" has been generalised to "asset" in appropriate instances throughout the TPM to capture assets comprised in transmission alternatives.
capped charges	This definition has been amended to clarify that capped charges include the "annual" cap recovery charge.
compliance investment	This definition has been amended to clarify that compliance investments means an investment by Transpower in an "existing" grid asset or transmission alternative.
connection charge	This definition has been amended to correctly refer to connection transmission alternative.
connection investment	This definition has been amended to cover investments in connection transmission alternatives.
cut-off date	This definition has been inserted to more clearly define the point at which Transpower would consider a charge "committed" for the first pricing year (in the sense that any further adjustment events cannot practicably be incorporated and will have to be carried into the first pricing year). As a backstop, the definition provides that the latest this will be is the start of consultation for the first pricing year's charges.
demand factor	This definition has been redrafted for clarity and to implement the Authority's approach regarding the simple method weighting factors. See comment on clause 64.
eligible BBI	The definition has been amended to correctly refer to asset instead of gird asset and BBI reassignment factor.
embedded	Clarification that Transpower may treat plant as part embedded and part grid-connected.
enhancement investment	This definition has been redrafted for clarity and to make use of the newly defined term "transmission investment".
exacerbated price	See comment on the definition of "alleviated price".
exempt post-2019 investment	This definition has been included for the reason set out in section 4.2 of Transpower's submission on the proposed TPM. See also comment on clause 37.
expected effective full commissioning date	This definition has been inserted for use in the definition of "standard method calculation period". See comment on definition of "standard method calculation period".

Clause	Explanation of changes
final investment decision	The definition has been amended to also cover decisions on anticipatory connection capacity.
full commissioning date	This definition has been inserted for use in the definition of “expected effective full commissioning date”. See comment on definition of “standard method calculation period”.
grid investment	This definition has been deleted and replaced with the more general definition of “transmission investment”.
high-value	This definition has been amended to capture all potential cost components of a BBI, not just capex.
ID WACC	This definition has been amended to refer to it being post-tax or pre-tax as the context requires it.
independent verification	This definition has been amended to explicitly provide that the person must be independent of the customer making the application.
injection	This definition, and related definitions and clauses, have been amended to accurately reflect that injection/offtake netting off per trading period happens at both the PoC and connection location level.
injection customer	See comment on definition of “injection”.
interconnection investment	This definition has been amended to cover investments in interconnection transmission alternatives.
investment test	See comment on definition of “tested investment”.
low-value	See comment on definition of “high-value”.
nominated peak kVar	This definition has been amended to correctly reference capacity year. This value is relevant to intra-regional allocators calculated over CMP B, which is measured in capacity years.
offtake	See comment on definition of “injection”.
offtake customer	See comment on definition of “injection”.
peak offtake period	This definition has been deleted because of changes to clause 65(8). See comment on clause 65(8).
periods of benefit	Used in amended clause 51. See comment on clause 51.
post-2019 BBI	This definition has been amended for clarity and to accommodate the new definition of exempt post-2019 investment. See also comment on clause 37.
pre -commencement adjustment event	This definition is used in the definition of “cut-off date” and clause 75(4). See comment on clause 75.
pre -existing customer	This definition has been amended to correctly reference capacity year. CMP B and CMP C are measured in capacity years.

Clause	Explanation of changes
previous discount	This definition has been included for use in clauses 10(5) and 110(6).
prudent discount	This definition has been amended to clarify the meaning of the phrase “the amount of a prudent discount”, which is then used elsewhere in the TPM, including clause 138.
recent customer	This definition has been amended to correctly reference capacity year. CMP B and CMP C are measured in capacity years.
reduction event	Rather than relying on former clause 8 (which has now been deleted) to define the term “sustained”, this definition now specifically requires Transpower to determine that a change is reasonably likely to persist for at least 5 years.
regulatory asset base	Clarification that asset values as contained in the RAB are the depreciated values used to calculate maximum revenue.
Schedule 1 allocation	See comment on definition of “Schedule 1 customer”.
Schedule 1 beneficiary	See comment on definition of “Schedule 1 customer”.
Schedule 1 customer	This definition has been inserted for clarity and to make clear that a Schedule 1 customer means a person specified in Schedule 1 of the 2020 guidelines, even if not a current customer at the time this definition is applied.
standard method calculation period	This definition has been amended to enable Transpower to determine a date between a BBI’s expected commissioning date and expected full commissioning date by which sufficient grid assets and transmission alternatives comprised in the BBI are expected to have been commissioned such that all of the BBI’s principal benefits will have been released. This date then determines the start date for the standard method calculation period (the first 1 January following this date). This is to provide greater clarity and to align with Transpower’s operational practice.
start pricing year	This definition has been amended to clarify what the start pricing year is for connection investments, inefficient bypass prudent discounts, and stand-alone cost prudent discounts.
substantial sustained increase	Rather than relying on former clause 8 (which has now been deleted) to define the term “sustained”, this definition now specifically requires Transpower to determine that a change is reasonably likely to persist for at least 5 years.
substantial sustained change in grid use	Rather than relying on former clause 8 (which has now been deleted) to define the term “sustained”, this definition now specifically requires Transpower to determine that a change is reasonably likely to persist for at least 5 years.
TA opex	Removes specific reference to a clause of the Transpower IMs as the reference was overly specific and may become outdated.
tested investment	This definition has been amended to clarify that it also covers investments approved by the Electricity Commission under section III of Part F of the Electricity Governance Rules 2003.

Clause	Explanation of changes
transmission investment	This definition replaces the previous definition of “grid investment” to make clear it covers investments by Transpower in both the grid and transmission alternatives.
WACC	This definition has been inserted for clarity. Clauses that previously referred to “weighted average cost of capital” have been amended to use this definition.
write-down	This definition has been included here and in relevant clauses to clarify the impact of write-downs on the calculation of transmission charges (see clauses 39, 82, 101, 102, 108). **See paragraphs 8.10 – 8.15 of the Decision Paper.**
4 Benefit Factor	This clause has been moved into clause 83(7) due it more appropriately sitting alongside the provisions in that part of the TPM.
4 Load Customers, Gross Energy and Maximum Gross Demand	This clause has been corrected by enabling embedded electricity to go below 0. This needs to occur to ensure calculations over periods where embedded batteries are discharging to the grid are correct. A new subclause (3) has been inserted to clarify that where there is insufficient information for Transpower to determine whether a particular amount of electricity is generated by battery storage, Transpower must assume none of that specific amount of electricity was generated by battery storage. **See paragraphs 7.67 – 7.70 of the Decision Paper.**
8 Sustained Change	This clause has been deleted with the specific provisions that deal with change (definitions of “reduction event”, “substantial sustained increase”, “substantial sustained change in grid use”, clauses 87(4), 101(2), and 107(1)) amended to specify the length of time the change is expected to be in place for directly.
7 Large Plant	Clarification that a reasonableness test applies to Transpower when determining whether a plant etc. is large. This is consistent with the amended test in clause 23 (discretion to reclassify interconnection assets as connection assets).
8 Interpretation	Clarification that “Transpower” in the TPM means Transpower in its capacity as a grid owner.
9 Transmission Charges Calculated Separately	See comment on definition of “injection”.
10 Calculations and Estimations	Subclause (2) has been inserted to clarify there is no obligation on Transpower to maintain modelling tools merely to verify previous calculations using those tools. Subclause (4) has been inserted to identify information that Transpower may rely on when calculating allocation data (although Transpower is not limited to considering this data). **See paragraphs 7.29 – 7.36 of the Decision Paper**.

Clause	Explanation of changes
	Subclause (5) inserts the provisions of the former clause 116(2). This provision more naturally sits in this clause as it sets out how prudent discounts, and now more generally previous discounts (prudent discount-like arrangements), affect calculations of charges. Subclause (7) has been amended to account for inevitable small rounding anomalies that result from the precision of the allocators as required under subclause (6). The Appendix A allocations are an example. Subclause (8) has been included to bind Transpower to use its more precisely calculated allocations for the Appendix A BBIs instead of the less precise figures in Appendix A. Subclauses (9) and (10) have been included to clarify the effects of the tax treatment of regulated WACC on calculations under the TPM.
12 Reverse Flow	New subclause (3) has been inserted to provide that subclause (2) does not apply to any allocation data used to calculate regional NPB for a regional customer group under the simple method. This clause has been amended as a result of Transpower's submission that "It is not appropriate to apply the reverse flow adjustment mechanism to the inputs to the regional NPB calculations for the simple method. Doing that would require re-assessing all of the branch flows that go into calculating those allocations, which would be a difficult task and would likely result in only very minor changes. This adjustment mechanism is intended to apply to individual allocation data only."
13 Exceptional Operating Circumstances	This clause has been amended to provide that the EOC mechanism extends to system operator requirements as well as grid owner ones. This is consistent with how the mechanism is applied under the current TPM. New subclause (2) has been inserted to provide that subclause (1) does not apply to any allocation data used to calculate regional NPB for a regional customer group under the simple method. This clause has been amended as a result of Transpower's submission that "It is not appropriate to apply the EOC adjustment mechanism to the inputs to the regional NPB calculations for the simple method. Doing that would require re-assessing all of the branch flows that go into calculating those allocations, which would be a difficult task and would likely result in only very minor changes. This adjustment mechanism is intended to apply to individual allocation data only."
15 Consultation on	Two public consultation requirements have been deleted because the TPM provides for the covered cost of BBIs to be updated

Clause	Explanation of changes
Transmission Charges	automatically. This means there is no need for consultation every time this occurs. Subclause (2) has been amended to reflect the Authority's decision that the demand factor should now be fixed at 62.5/37.5, subject to any operational review. Subclause (4) has been inserted instead to provide that certain other consultations instead must include an estimate of the high-value post-2019 BBI's covered cost when fully commissioned.
16 Information about Transmission Charges	This clause has been amended to clarify that information may be provided to a customer as part of Transpower's obligation under a transmission agreement but that it might be provided in a different way. This is to futureproof the clause.
17 Grid Assets and Land and Buildings	Clause 17(1) has been amended to clarify that Transpower's fibre optic network is not a grid asset. Clause 17(3) clarifies that non-Transpower assets previously treated as "grid assets" will continue to be treated as such under the new TPM, even if there is no agreement with Transpower in place. Any future non-Transpower assets will not be grid assets unless Transpower agrees otherwise as contemplated in subparagraph (1)(b)(ii).
23 Discretion to Classify and Reclassify as Connection	The clause has been amended to clarify the circumstances in which Transpower may exercise discretion to classify or reclassify an asset that would otherwise be an interconnection asset as a connection asset, and to include consultation requirements and review rights. **See paragraphs 3.11 – 3.22 of the Decision Paper.**
24 Calculation of Connection Charges	Clause 24(4), definition of TAC in the equation has been amended to provide that the TA opex for the connection transmission alternative and preceding financial year, is less any contribution to the TA opex under investment agreements. This is because investment agreements may extend to transmission alternatives, in which case there should not be double-recovery of opex costs through both connection charges and the relevant investment agreement.
25 Start of Connection Charges	This clause has been included for clarity and is consistent with the way the components of connection charges are calculated (i.e. looking back to the previous financial year).
26 Asset Component	This clause and clause 27 have replaced previous clauses 27 and 27A. These amendments are to implement a change from the previous allocation of 100% of costs relating to anticipatory capacity to regional beneficiaries to instead allocate 50% of the costs relating to anticipatory capacity to all transmission customers via an addition to

Clause	Explanation of changes
	the asset component to the connection charge and the remaining 50% to identified regional beneficiaries via a benefit-based approach. **See paragraphs 4.22 – 4.38 of the Decision Paper.**
27 Anticipatory Capacity BBIs	See comment on clause 26.
29 Funded Asset Rebate	Clause 29(3) (and other similar clauses) has been amended to allow for the customer potentially having both AMDC and AMIC for a pricing year. This is for consistency with clause 9, and Transpower's current practice. It is possible for a customer to be both an offtake customer and an injection customer at a connection location for CMP A (a capacity year) and therefore have both AMDC and AMIC for a pricing year. Note that the AMDC and AMIC allocators are only relevant when connection assets are shared at a connection location.
32 Connection Customer Allocations	See comment on clause 29(3).
33 De-rating	Clause 33(1) has been amended to provide that it also covers notification of the assets of an embedded customer connected to a distribution network. The amendment is restricted to a large derating of an embedded plant. The intention of this change is that in a scenario where there is a shared connection asset the derating of, for example, an embedded industrial load customer's plant would affect the allocation of the connection costs between the transmission customers connected at that point of connection. Clause 33(3) has been amended to allow derating of embedded customers' plant to be taken into account in allocating the connection charge for a shared connection asset, between the 2 or 3 customers that share that connection on the basis that derating reduces the customer's AMDIC and so potentially its CA immediately (rather than making it wait for a year or two).
36 Start of Benefit-based Charges	Clause 36(1) has been amended to clarify that this subclause does not apply to charges under an investment agreement.
37 Capital Expenditure on Existing BBIs	Clause 37(5) has been inserted in response to section 4.2 of Transpower's submission on the proposed TPM. This clause will result in the cost of the exempt post-2019 investment being recovered through residual charges, except if the investment relates to an Appendix A BBI in which case the cost will be added to

Clause	Explanation of changes
	the covered cost of the Appendix A BBI and recovered through its BBCs.[260]
39 Covered Cost	Clause 39(3) has been amended to exclude accelerated depreciation from some of the terms in the formula. Clause 39(7) has been inserted to prevent write-down affecting the BBI's covered cost in certain circumstances (e.g. where a reassignment type event within 10 years of a BBI's commissioning date results in the BBI being written down). This subclause is intended to help ensure incentives for BBI investment scrutiny are not eroded by the possibility of an early write-down and to implement the policy decisions made in the TPM Guidelines around reassignment.
40 Attributed Opex Component	Clause 40(1), definition of TA in the equation has been amended to provide that TA opex for the interconnection transmission alternatives and preceding financial year, is less any contribution to the TA opex under investment agreements. This is because investment agreements may extend to transmission alternatives, in which case there should not be double-recovery through both benefit-based charges and the investment agreement.
42 BBI Customer Allocations for Appendix A BBIs	Clause 42(1) and (2) have been amended for clarity, by using new definitions "Appendix A allocation" and "Appendix A beneficiary". Clause 42(3) has been deleted with a provision dealing generally with BBC adjustment events that happen before the new TPM's commencement date being included instead in clause 75(4) – (5).
43 BBI Customer Allocations for Post-2019 BBIs	Clause 43(5) has been amended to clarify that, where Transpower considers that using the assumptions/other inputs used for the investment test would not produce BBI customer allocations which are broadly proportionate to customer's net private benefits, it may use different assumptions/other inputs which applied prior to the BBI's final investment date, provided they do not contradict what Transpower determines were its key drivers for proceeding with its investment in the post-2019 BBI as at the post-2019 BBI's final investment decision date. This will eliminate any incentive a beneficiary may have to change its behaviour after a post-2019 BBI is committed with the aim of reducing its BBC allocation. In most cases Transpower expects the allocations will already have been determined by the final investment decision date, but that may not be the case for the high-value intervening BBIs, for example. Clause 43(6) has been included to clarify that, while the clauses specifying the standard methods and simple method, especially the price-quantity method, have been drafted in a broadly linear way, they do not mandate a strict order of steps.

260 Where this change requires the use of clause 2 of the TPM Guidelines the Authority is satisfied that this is appropriate for the reasons set out in section 4.2 of Transpower's submission on the proposed TPM.

Clause	Explanation of changes
44 Overview of Price-quantity Method	Clause 44(2) has been amended to provide that calculation of reliability regional NPB is now optional, same as for ancillary service NPB, in circumstances where the reliability benefits of a BBI are far outweighed by the market benefits, in which case the reliability benefits are not required to calculate an allocation that reflects benefits, and the effort of calculating reliability regional NPB will not be justified. Clause 44(3) has been added to clarify that Transpower must always calculate one NPB and that it must calculate ancillary service regional NPB or reliability regional NPB if necessary to produce customer allocations broadly proportionate to NPB.
46 Scenarios	Clause 46(1) has been amended to require that only a market BBI's market scenarios must include variations in load growth, generation expansion and hydrology. This is because it will not always be relevant to include all of these variations in the scenarios for an ancillary service BBI, reliability BBI or resiliency BBI.
47 Offtake and Injection at Same Connection Location	This clause has been deleted and replaced with more specific provisions that provide for setting off of a customer's expected market disbenefit against the customer's expected market benefit where the customer has injection and offtake at the same connection location. For the calculation of market regional NPB based on quantity this is at clause 51(7). For the calculation of market reginal NPB based on price and quality this is at clause 52(9), or 50(4) and 52(5) for grid-connected battery storage. The new provisions also now provide for the setting off to only happen at the regional level.
49 Modelling for Market Regional NPB	Clause 49(5) has been inserted to expressly allow for modelling to be performed by moving embedded generation notionally to the grid. This is because doing this is sometimes necessary to achieve the best result.
50 Modelled Regions and Regional Customer Groups	The table in clause 50(2) has been amended for clarity (by listing the modelled region and regional customer groups separately). Clause 50(4) has been inserted to prescribe that grid-connected battery storage is classified under a supply group and not a demand group when calculating benefits under clause 52. Alongside clause 52(5) this allows their benefits to be calculated as the change, due to the BBI, in operating profit from energy arbitrage. For battery storage, this is an enhancement of the previous clause 47 under which benefits could only have reflected energy arbitrage if there was no change in volume between the factual and the counterfactual.
51 Calculation of Market	Clause 51(2) has been inserted to clarify that the reference to the regional supply groups in paragraph (1)(a) is not intended to imply

Clause	Explanation of changes
Regional NPB based on Quantity	those groups must have been determined before Transpower decides which clause to apply to calculate regional NPB. Clause 51(3) has been amended and new clause 51(5) has been inserted to clarify that there may only be one period of benefit and the benefit generated during a period (changes in prices and quantities versus the counterfactual) may manifest outside the period (but still within the relevant calculation period). In other words, what is required is a causal relationship but not necessarily a temporal one. Clause 51(4) has been inserted to ensure that benefits due to changes in quantity calculated under clause 51(3)(e) are not double counted for battery storage performing energy arbitrage. Clause 51(7) has been inserted to deal with injection and offtake at the same connection location. See comment on clause 47.
52 Calculation of Market Regional NPB based on Price and Quantity	Clause 52(2) has been inserted for the same reason as clause 51(2). Clauses 52(3) and (4) have been amended to exclude changes to consumer benefit due to the settlement of FTRs. This is because part of the loss and constraint excess is allocated to FTR settlement. It would not be possible for Transpower to predict future availability or prices of FTRs or customers' future FTR positions and thus what benefit they might obtain from contributing to FTR settlement costs. Clause 52(5) has been inserted to clarify that when calculating market NPB under clause 52, despite grid-connected battery storage belonging to a supply group and not a demand group under new clause 50(4), the impact of price changes during grid offtake will be accounted for as a change in operating cost for the battery storage. Clause 52(9) has been inserted to deal with injection and offtake at the same connection location. See comment on clause 47.
53 Ancillary Service Regional NPB	The table in clause 53(3) has been amended to account for the fact that generators with capacity of 60MW or less are not allocated costs of instantaneous reserve. Clause 53(4) has been inserted, and clause 53(6) been amended to introduce the concept of future regional customer groups to the calculation of ancillary service NPB. Previously, future regional customer groups were only explicitly used for calculating market NPB. This facilitates allocation of a share of benefits (and charges) to customers that enter in future.
54 Reliability Regional NPB	Clause 54(1) has been amended to clarify that clause 54 only applies if Transpower decides to calculate reliability regional NPB for the reliability BBI.

Clause	Explanation of changes
	Clause 54(3) has been amended to take account of the probability of the outage scenario occurring. Clause 54(4) has been amended to exclude grid-connected battery storage from the regional demand group. See comment on clause 47. Clause 54(4) has also been amended to allow for multiple regional demand or supply groups (other than future regional customer groups) in the same modelled region for reliability BBIs. These changes are equivalent to clause 50(2) for market BBIs. Clause 54(5) has been inserted and clause 54(7) amended to introduce the concept of future regional customer groups to the calculation of reliability NPB. Previously, future regional customer groups were only explicitly used for calculating market NPB.
55 Other Regional NPB	Clause 55(1) has been amended to clarify that clause 55 only applies if Transpower decides to calculate or estimate other regional NPB for the BBI
57 Individual NPB	This clause has been amended to remove unneeded variable notation.
58 Modelled Region and Regional Customer Group	Clause 58 has been amended to exclude grid-connected battery storage from the regional demand group. See comment on clause 47.
59 Overview of Simple Method	Clause 59(1)(b)(ii) has been inserted to clarify that the relevant clauses also capture the high-value intervening BBIs to which the simple method is temporarily applied, consistent with the TPM's transitional provisions.
61 Individual NPB	Clause 61(3) has been inserted to ensure that adjustment events that occur in the interregnum between CMP C and the start of a simple method period are accounted for when calculating simple method factors for that simple method period. Clause 61(4) has been inserted for clarity.
62 Modelled Regions	Clause 62(4)(e) has been amended to clarify that it is only intended to apply where a low-voltage region is connected to a high-voltage region by more than one interconnection branch. It is not intended to operate to divide up a low-voltage region that already has only one connection to a high-voltage region. Clause 62(4)(f)(iii) has been amended for clarity.
64 Regional NPB	Clause 64(2) has been amended to remove an additional variable not used in the relevant formula and clause 64(3) inserted to clarify that calculations must be carried out for all periods for which Transpower has reliable values.

Clause	Explanation of changes
	Clause 64(4) has been amended to reflect the move to costs under the simple method being split 62.5%/37.5% between load and generation. **See paragraphs 5.37 – 5.62 of the Decision Paper.** Clause 64(7) has been amended for the reason in the comment on the definition of "injection".
65 Intra-regional Allocators	Clause 65(5) and (6) have been amended for the reason in the comment on the definition of "injection". Clause 65(7) and (8) have been amended to provide Transpower with the discretion to determine the number of trading periods (between 1 and 100 inclusive) across which to calculate the coincident peak offtake IRA. Clause 65(10) and (11) have has been amended for the reason in the comment on the definition of "injection".
70 Anytime Maximum Demand (Residual) Baseline	Clause 70(3) has been amended so that the losses from large embedded batteries (as well as large grid-connected batteries) contribute to a new customer's estimated AMDR baseline. **See paragraphs 7.71 – 7.72 of the Decision Paper.** Also some minor rewording to improve clarity.
72 Reduction Events	Clause 72(1) has been amended to provide consistency with the definition of "reduction event", which allows for prospective reduction events (provided they are expected to happen before the start of the first pricing year).
73 Re-estimating for Recent Load Customers	This clause has been amended to provide Transpower with the ability to re-estimate where false or misleading information has been provided.
75 Adjustment Events	Clause 75(4) has been inserted to clarify the treatment of adjustment events occurring after transmission charges have been calculated but before the commencement of the TPM. Clause 75(5) has been inserted to ensure the inclusion of the Appendix A allocations in the TPM does not frustrate the proper calculation of transmission charges for the first pricing year or the operation of subclause (4).
76 Connection Charge Adjustment Events	This clause and following clauses have been amended to explicitly provide for adjustments for the sale of all as well as part of a business.
79 Connection Charge Adjustment	This clause has been amended for the reason in the comment on clause 76.

Clause	Explanation of changes
Event: Sale of Business	
81 Benefit-based Charge Adjustment Events	See comment on clause 76. Clause 81(1)(h) has been deleted because this adjustment event would be the result of either organic load growth (which will be factored into initial allocations), new large embedded plant or a substantial sustained increase (which are covered by other adjustment events), or some combination of these. Whichever it is, there will be double-counting if this adjustment event applies as well. The new GXP adjustment event however is retained in case a distributor connects its network in a new modelled region. See changes to clause 87.
82 Benefit-based Charge Adjustment Event: Material Damage	This clause has been amended to reflect changes to the TPM to clarify how write-downs affect adjustments resulting from material damage. **See paragraphs 8.46 – 8.51 of the Decision Paper.**
83 Benefit-based Charge Adjustment Event: New Customer	Clauses 83(6) and (7) have been inserted to make the benefit factors static based on the Appendix A starting customers and allocations. This means the benefit factors do not need to be updated every time there is an adjustment event. The benefit factors are only necessary to calculate a Schedule 1-consistent starting allocation for new customers and large plant, so it is not necessary for them to stay up to date with reality. For example, a benefit factor for an Appendix A customer can still be utilised to calculate an charges for an equivalent new customer even if the original customer is no longer connected to the grid or has expanded or contracted its operation. Clause 83(7) was previously set out in clause 4. Clause 83(8) has been inserted to clarify how clause 83(6) applies if a new customer's assets are battery storage.
87 Benefit-based Charge Adjustment Event: Distributor Transformer Upgrade	This clause has been deleted for the reason discussed in the comment on clause 81(1)(h).
87 Benefit-based Charge Adjustment Event: Distributor Connection at GXP	This clause has been amended for the reason discussed in the comment on clause 81(1)(h). Clause 87(3) has been amended to deal with load shifting between GXPs in different modelled regions.

Clause	Explanation of changes
89 Benefit-based Charge Adjustment Event: Sale of Business	See comment on clause 76. Clause 89(2)(c) has been inserted to provide that if there is an apportionment of BBCs between vendor and purchaser there should also be an apportionment of the cap recovery charges.
92 Residual Charge Adjustment Events	See comment on clause 76. Clause 92(1)(b) and (c) have been deleted for the reason discussed in the comment on clause 96 Residual Charge Adjustment Event: Large Plant Disconnected.
94 Residual Charge Adjustment Event: Sale of Business	See comment on clause 76.
96 Residual Charge Adjustment Event: Large Plant Disconnected	This clause has been deleted to implement the decision that the standard 5-8 year lagged adjustment of the residual charge will apply in all situations where a (new or existing) transmission customer increases its use of the grid or an existing customer decreases its use of the grid. The only exception is when a customer exits entirely, in which case the residual charge ceases immediately. **See paragraphs 8.38 – 8.45 of the Decision Paper.**
101 Assessment	Clause 101(2) has been inserted to prevent reassignment from happening in the unlikely event the same circumstances have resulted, or are likely to result, in a write-down of the BBI. This avoids write-down/reassignment duplication. See also explanation in comment on clause 8 Sustained Change.
102 Forecast Peak Loading and Reassignment Factors	Clause 102(3) has been amended to require Transpower to factor previous impairments of an investment into the investment reassignment factor calculation. This means that, if customers are not paying "full price" for the investment owing to previous write-downs, this is reflected in an adjustment to the investment's replacement cost, to avoid it being "artificially" high.
107 Reversal for Increased Forecast Peak Loading	For the amendment to clause 107(1) see explanation in comment on clause 8 Sustained Change.
108 Reversal for Subsequent Write-Down	This clause has been inserted to allow for a reassignment to be reversed if a write-down occurs later (for example due to a change in regulation or GAAP).
109 Application Fees, Application Requirements and Reassignment	This clause has been inserted to specify when Transpower must publish the application requirements and the application fees, if any, for reassignment applications.

Clause	Explanation of changes
Practice Manual	
110 Cap and Cap Condition	Former subclause (5) has been moved to subclause (3) and has been amended to use the new definition of "previous discount".
113 Effect of Prudent Discount Agreements	The content of clause 113(2) has been moved to clause 10(5).
116 Assessment	Clause 116(2) has been amended to clarify the factors Transpower must consider in determining whether an alternative project would provide the same or a similar level of service as existing transmission services.
117 Calculation of Alternative Project Costs	Clause 117(2)(b) has been inserted to clarify that an efficient transmission services provider is not assumed to have any of Transpower's historic statutory rights. Clause 117(3) has been amended for clarity.
118 Assessment of Commercial Viability	Clause 118(3) has been inserted for clarity, specifically to make clear that there is no assumption that the alternative project is fully amortised over the prudent discount calculation period and that any residual value is ignored.
121 Prudent Discount Agreement	New clause 121(2)(a) and clause 121(3) have been inserted to clarify that a prudent discount agreement will have no effect until conditions precedent are met. The type of conditions that are anticipated might be imposed are those that need to be met before an alternative project is considered viable, for example waiting for a particular merger to occur. Clause 121(2)(e) has been amended to provide that any prudent discount may be terminated at the start of a pricing year. **See paragraphs 9.19 – 9.23 of the Decision Paper.**
122 Back - dated Prudent Discounts	This clause has been inserted to provide for back-dating of prudent discounts in certain circumstances. **See paragraphs 9.24 – 9.34 of the Decision Paper.**
125 Commercially Sensitive Information	Clause 125(2)(b)(i) has been amended to clarify that only reasonable details of the alternative project and alternative project costs must be published. This is the information most likely to be considered commercially sensitive under subclause (1) so it is likely not all details will be appropriate for publication.
126 Application Fees, Application Requirements and Prudent Discount Practice Manual	This clause has been inserted to specify when Transpower must publish the application requirements and the application fees, if any, for prudent discount applications, and a requirement on Transpower to publish a prudent discount manual. These timeframes tie into eligibility for back-dated prudent discounts. See comment on clause 122.

Clause	Explanation of changes
133 Purpose of Stand-alone Cost Prudent Discount	This clause has been amended to clarify that consideration of the efficient stand-alone cost of the transmission services the customer currently receives is not limited to interconnection investments, and that a stand-alone cost prudent discount also replaces the prudent discount recipient's connection charges.
134 Assessment of Equivalence, Feasibility and Commercial Viability	Clause 134(3) has been inserted to clarify that in calculating the alternative project costs, Transpower must value any optimised grid that forms part of the alternative project in a way that accounts for depreciation according to the age of the part of the existing grid that is optimised. Clause 134(4) has been inserted for the avoidance of doubt, further clarifying that the assessment of whether the alternative project for a stand-alone cost prudent discount is an efficient stand-alone investment etc. is done on a single customer basis. **See paragraphs 9.15 – 9.18 of the Decision Paper.**
135 Assessment of Efficient Stand-alone Investment	This clause has been amended to cover both grid assets and transmission alternatives. Clause 135(1) has been amended clarify that an efficient stand-alone investment can also be an investment in a combination of both the grid and 1 or more transmission alternatives.
138 Prudent Discount Recovery Charges	New clause 138(1) has been inserted to assist in explaining the formulae that follow. "annual" has been inserted before "benefit-based charge" in multiple places in the formulae for clarity. Clause 138(2), "A" in the formula has been deleted as the definition of "prudent discount" now clarifies what the "amount of a prudent discount" is (i.e. net of the annuity).
Appendix A – Appendix A BBIs and Starting BBI Customer Allocations	In addition to changes below, new clause 10(8) requires Transpower to use BBI customer allocations (provided by Authority) that, unlike Appendix A, are not rounded to two decimal places. Some minor differences in allocations arise due to the removal of rounding in Appendix A.
Counties Energy Ltd	Counties Power Ltd has been replaced with Counties Energy Ltd reflecting that entity's name change.
EA Networks Ltd	EA Networks has been replaced with EA Networks Ltd to reflect its full and correct legal name as it appears in the Companies Register.
GTL Energy New Zealand Pty Ltd	GTL Energy New Zealand Ltd has been replaced with GTL Energy New Zealand Pty Ltd to reflect its full and correct legal name as it appears in the Companies Register.
Mercury NZ Ltd	This entity's allocation has been adjusted to include amounts formerly allocated to Southdown Cogeneration Ltd which amalgamated with

Clause	Explanation of changes
	Mercury NZ Ltd in 2007.[261] Southdown Cogeneration Ltd has been removed from Appendix A
Meridian Energy Ltd	This entity's allocation has been adjusted to include amounts formerly allocated to MEL (Te Apiti) Ltd and MEL (West Wind) Ltd which both amalgamated with Meridian Energy Ltd in 2011. MEL (Te Apiti) Ltd and MEL (West Wind) Ltd have been removed from Appendix A.
New Zealand Aluminium Smelters Ltd	NZ Aluminium Smelters Ltd has been replaced with New Zealand Aluminium Smelters Ltd to reflect its full and correct legal name as it appears in the Companies Register, and the name has been moved to be in correct alphabetical order.
OMV NZ Production Ltd	OMV NZ Production Ltd is a post-Schedule 1 customer and owns the Pohokura production station connected at Motunui. OMV's starting allocations are calculated based on the plant's capacity of 13 MW and using Beach Energy Resources (Kupe natural gas processing plant) as a comparator customer. OMV New Zealand Production Ltd has been replaced with OMV NZ Production Ltd to reflect its full and correct legal name as it appears in the Companies Register.
Tararua Wind Power Ltd	Tararua Wind Power has been replaced with Tararua Wind Power Ltd to reflect its full and correct legal name as it appears in the Companies Register.
Waverley Wind Farm Ltd	Appendix A reflects an update to Waipipi wind farm's capacity, which is now known to be 133 MW. Waverley Wind Farm's starting allocations were calculated based on the plant's capacity of 130 MW and using Tilt Renewables (Tararua wind farm) and MEL Te Apiti (Te Apiti wind farm) as comparator customers. Waverley Wind Farm has been replaced with Waverley Wind Farm Ltd to reflect its full and correct legal name as it appears in the Companies Register.
Winstone Pulp International Ltd	Winstone Pulp International has been replaced with Winstone Pulp International Ltd to reflect its full and correct legal name as it appears in the Companies Register.

261 The allocation related to the former Southdown thermal station, which was decommissioned at the end of 2015. The Authority is satisfied that this allocation is appropriate; however, even if use of clause 2 of the TPM Guidelines were required to give effect to this change, the Authority considers this would be appropriate as this minor departure better meets the efficient operation limb of its statutory objective.

Appendix B Assessment of the Creative Energy Consulting report

Introduction and summary

B.1 Trustpower's submission on the 2021 proposed TPM on 2 December 2021 appends a report by Creative Energy Consulting (CEC), titled *Review of the Electricity Authority's latest TPM*.

B.2 CEC's review explores the impacts of the proposed TPM from the viewpoint of customers. We agree it is useful to consider matters from the customer's viewpoint. Indeed, ensuring that existing and future transmission customers face efficient incentives has been central to the Authority's analysis and decisions with respect to the TPM.

B.3 In brief, CEC considers that the proposed TPM is "ramshackle" and "confused" and that "what the customer will see is effectively a Tilted Postage Stamp tariff[262], obscured somewhat by the complexities and uncertainties inherent in the asset-by-asset, benefit-based approach" (page 32). CEC also considers that the proposed TPM provides Long Run Marginal Cost (LRMC)-style price signals for new grid investments.[263] CEC concludes that a simpler method could be implemented instead, where customers pay posted tariffs based on their actual load or generation.

B.4 While we found it useful to consider CEC's report, we did not ultimately find it convincing, for a range of general and specific reasons:

- its assessment approach is limited, with an emphasis on simplicity and certainty, but omitting consideration of other dimensions that are relevant to efficiency and practical considerations (such as set out in clause 1 of the guidelines)
- CEC is unclear about the specifics and practicalities of the simpler charges that it compares and prefers to the proposed TPM
- its conclusions are often over-stated or unsupported or fail to engage with explanations the Authority has already provided in earlier TPM related consultations and decisions.

B.5 For example, while we appreciate that there are, deliberately, some adjustment provisions in the proposed TPM, the Authority does not accept that the proposed TPM can be characterised as setting up pricing arrangements with incentives that are similar to what CEC terms 'conventional variable charges'.

262 Postage stamp tariffs smear the cost of any grid investment across all customers, who all pay the same charge per MWh. A premium can be added to that charge for customers in regions that because of predominant patterns tend to drive more investment over time, hence 'tilting' charges.

263 LRMC charges provide forward looking price signals, based on the cost of future changes in the capacity of the grid to meet future demand. See the Authority's 2014 working paper on LRMC charges for further detail: https://www.ea.govt.nz/assets/dms-assets/18/18259TPM-LRMC-working-paper.pdf

B.6 This Appendix reviews six key claims made in the CEC report and the Authority's response to them. Those claims (and responses) in brief are:

- **Claim 1 Conventional transmission pricing gives customers more certainty** – Disagree. There is uncertainty in any transmission pricing. The Authority's proposed TPM seeks to balance certainty with other considerations, set out in the Guidelines, to promote its statutory objective.
- **Claim 2 TPM gives load customers a 50% price cut by double charging them –** Disagree. Customers pay for access to the grid this year by paying this year's charges. The lagged adjustment is to avoid inefficient actions to avoid and shift residual charges (a significant issue with the current TPM). Customers in 2023 are not paying again for costs that Transpower had already recovered in 2018.
- **Claim 3 There has been no full examination of simpler alternatives –** Disagree. This overlooks the Authority's extensive analysis of options, published in the decade leading up to the Authority 2020 Decision paper, including the tariffs CEC mentions.
- **Claim 4 Full costs of new benefit-based investments are levied over 4 years –** Disagree. Under the proposed TPM, costs of benefit-based investments are also spread and recovered over the lifetime of the investment and charges stop as soon as a customer exits.
- **Claim 5 Proposal implements the rejected LRMC charging by proxy –** Disagree. By contrast to LRMC charges, benefit-based charges apply only to beneficiaries of the investments, they are paid only once the actual investment is made, and as fixed-like charges are incentive neutral. Anticipated benefit-based charges are broadly proportional to expected benefits and would not affect nodal prices, so customers can make efficient trade-offs.
- **Claim 6 Proposal is a convoluted way to implement tilted postage stamping –** Disagree. Under tilted postage stamping all transmission customers would share in the cost of any grid investment wherever it occurred, whereas under the TPM costs are assigned only to the beneficiaries. The "smearing" of transmission costs across all transmission customers is a significant problem under the current TPM which the Authority is seeking to fix.

B.7 Other suggestions in the CEC report on particular parts of the proposed TPM are considered alongside other submissions on those parts, particularly CEC's conclusions in relation to first mover disadvantage (refer Chapter 4), the allocation between generation and load for benefit-based charges (refer Chapter 4.38), and uncertainty about future TPM charges (refer Chapter 14).

B.8 For the avoidance of doubt, where the Authority has not specifically responded to a point made by CEC, that does not mean that we agree with CEC.[264]

[264] For example, the Authority does not consider it appropriate for CEC to suggest on p26 that stakeholders in their submissions would distort the truth or that Transpower's (or the Authority's) role is to discount some submissions, rather than treat all submissions at face value and engage even-handedly with these contributions.

Assessment of claims made by CEC

Claim 1 Conventional transmission pricing gives customers more certainty

B.9 CEC presents (on page 2) a dichotomy between:

- 'a conventional transmission pricing regime with a simple schedule of posted tariffs' so that customers know '*immediately*' how their short-term actions affect their transmission charges[265], and
- the proposed TPM where uncertainty about prices adds 'substantial risk to customer decision-making and associated profitability' (page ii).

B.10 CEC does not explain exactly what 'conventional transmission pricing' it has in mind, or the detail of how a customer's charges would be determined. This is important, as the effect of transmission pricing depends very much on the details of the approach. However, we can confidently say it is unlikely that under the approaches to pricing CEC mentions (such as tilted postage stamp or LRMC charges) customers would know '*immediately'* how their decisions would affect their charges.[266]

B.11 To illustrate, both the current RCPD and HVDC charges for the year are set by dividing the total amount of revenue allowed to be recovered in respect of that charge in that year by total quantities consumed or generated in a past year. It means that customers' charges depend not only on their own consumption or generation in a past year, but also that of other customers.[267]

B.12 The same uncertainty will apply to a greater or lesser degree to any transmission pricing design with variable pricing, where customers' transmission bills are determined by the interplay between changing volumes and regulated revenue requirements. Thus charges cannot be known 'immediately' under such an approach.

B.13 By contrast, fixed-like charges under the proposed TPM may help to give customers certainty about their charges:[268]

- allocators for benefit-based charges are fixed, and can only be adjusted under particular situations
- grid investments are already signalled well in advance, and in future this will also include implications for customers' benefit-based charges
- the adjustment to the residual charge allocators is gradual by design, smoothing out any year-on-year variability

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265 Emphasis is CEC's. CEC notes that for their investment and divestment decisions, customers would also need projections of future charges.

266 For convenience, in this paper we adopt CEC's term 'conventional' transmission pricing to refer to the approaches to pricing CEC mentions (such as tilted postage stamp or LRMC charges). However, we do not necessarily agree with the description of such approaches as 'conventional'. We note that a beneficiaries-pay approach has been adopted for a number of overseas transmission networks, including several in the United States.

267 The Authority set out in its 2019 Issues paper and 2020 Decision paper how these arrangements create material year-to-year variability in customers' RCPD charges. Electricity Ashburton offered one example of the issues this was creating for its customers, although it is not the only customer who experienced material variability in charges.

268 See also discussion of certainty and predictability in Chapter 14.

- nodal prices signal the locational marginal cost of using the grid in real time, ie, close to immediately.

B.14 While CEC therefore overstates the extent of uncertainty, it also ignores the efficiency costs of the types of approaches to charging that CEC appears to prefer, for example, those caused by poor incentives created when costs are smeared across all customers rather than beneficiaries.

B.15 The larger point is that the objective of the TPM is to promote the Authority's statutory objective. While avoiding uncertainty is an important part of this, it is only part. To the extent the proposed TPM is more complex or its charges more uncertain than simple schedules of posted tariffs, as the Authority has explained in the process leading up to its decision, it considers the resulting additional costs to be justified by charges that better promote its statutory objective, including the efficient operation of the electricity industry.[269]

Claim 2 TPM gives load customers a 50% price cut by double-charging them

B.16 Under the proposed TPM, an existing load customer's residual charge allocator is based on historical anytime maximum demand, as a proxy for size/ability to pay. To address changes in customers' ability to pay, the allocator is adjusted using lagged, rolling average rates of change in customers' electricity use. This acts to mute inefficient incentives to cost-shift[270] by altering energy consumption to avoid residual charges.

B.17 CEC (p 5) suggests that the lagged adjustment means that the customer gets a 50% discount when a customer increases consumption today, as that is the approximate value of the resulting future increase in its residual charges discounted to present day values. It calls this a 'buy now, pay later' deal.

B.18 This 'price cut' is said to be made possible because load customers are 'double charged' for their consumption, once in the past (before the implementation of the proposed TPM), and a second time around 5-8 years later. "This double-charging then gives Transpower a "war chest" which it uses to fund its buy-now-pay later offer under the new TPM" (p 5).

B.19 In our view, CEC's interpretation is surprising and wrong.

B.20 From a customer perspective, the residual charge is one part of a fixed fee for access to the grid. The customer buys access to the grid this year by paying this year's fee. There is no 'buy now, pay later'. Customers will know that if their consumption grows over time, they may be liable for a larger share of fees in future. But when that time comes, they have a choice about whether to buy access to the grid and pay that year's access fee.[271]

B.21 A 'buy now, pay later' scheme would require the customer to somehow be consuming something for which costs are being recovered later. That is not the case here. Because the residual charge mainly relates to pre-2019 investments, the total

269 The need to accommodate the entry and exit of customers or other changes in customers' specific circumstances also creates uncertainty and complexity. Such exceptions and adjustments are also part of other 'conventional' pricing methodologies, including the existing methodology.

270 Cost-shifting is a significant problem under the current TPM which the Authority is seeking to fix.

271 For example, if the customer completely disconnects from the grid, they pay nothing in future – there is no "pay later".

amount that Transpower recovers with the residual charge in ten years' time will be unaffected by how much customers consume today. Consumption decisions only affect customers' future *shares* of that cost at that time.[272]

B.22 It is the case that, in present value terms, the benefit[273] to the customer of the future change in residual charges is roughly 50% less[274] than if the adjustment to charges was made immediately. By design, the lagged adjustment approach significantly mutes the incentive to reduce energy consumption to avoid future residual charges.

B.23 But this is not a 'price cut' or discount on today's cost that results in a shortfall that then needs to be funded in a different way, as CEC seems to suggest. Load customers are not being double-charged to give Transpower a war chest to fund these discounts. Customers in 2023 are not paying again for the operating costs and the return on and of capital that Transpower already recovered in 2018. And Transpower's maximum allowable revenue each year remains regulated by the Commerce Commission.

B.24 CEC suggests a conventional tariff of 0.5 x $X/MWh would be simpler than the complexity of lagged rolling averages. This suggestion is flawed – it does not make an allowance for recovering the other 50% to add up to total residual revenue for the year. Also, a variable $/MWh tariff would give customers less, not more, certainty about charges from year to year,[275] whereas the four-year rolling averaging in the proposed TPM smooths out year-to-year variability.

Claim 3 There has been no full examination of simpler alternatives

B.25 On page 6 of its report CEC argues in the context of residual charges: "Perhaps a flat tariff is more efficient than an RCPD, perhaps not. Possibly other structures are more efficient than either. It is odd that such a critical decision has not been fully examined or justified."

B.26 On page 10, having asserted that benefit-based charges as proposed are an extreme form of an LRMC-style tariff[276], CEC states that "it is remiss of the EA not to have properly considered these simpler alternatives."

B.27 However, the Authority clearly has undertaken a full examination of flat tariffs, LRMC charges, and other options.

B.28 In particular, CEC's claim overlooks the problem definition and detailed analysis of alternatives in the 2020 Decision paper and the working- and issues-papers leading up to that. Further, the 2019 Issues paper and 2020 Decision paper explicitly included a quantitative cost benefit analysis of an option where interconnection revenues would be recovered through a flat $/MWh charge.[277]

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272 In our view this issue is a good example of CEC over-stating a concern: what is actually at issue is only marginal adjustments to the future shares of the residual charge that will be paid by each transmission customer.

273 Or cost, in case of increases in consumption relative to other load customers.

274 The exact amount depends on each customer's discount rate.

275 See discussion above under Claim 1.

276 An assessment of this claim follows below.

277 In fact, as a simplification and conservatively, beside the 'Alternative' option (in which the HVDC charge was retained but the RCPD charge was diluted to be a per MWh charge), the other options were also

Claim 4 Full costs of new benefit-based investments are levied over 4 years

B.29 CEC states (p 8) that a customer's contribution to the cost of a benefit-based investment is 'entirely based on its consumption in the few years leading up to the investment'.

B.30 CEC then claims on page 9 that this means that the full cost of a new BBI is levied "over just four years' consumption" in contrast to 'conventional transmission tariffs' that would spread a BBI's cost over 40 years.[278]

B.31 Under the proposed new TPM the allocation of benefit-based charges for a new investment among customers in regional customer groups is based on their average injection or consumption metrics over a five-year historical measurement period. Customers' allocations are then fixed as long as they remain customers (except for the limited set of adjustments provided for in the proposed TPM).[279]

B.32 But a customer is not made liable on day 1 for the full cost or full stream of fixed charges across the investment's lifetime as CEC implies on page 9. Under the proposed TPM, the costs of benefit-based investments are also spread and recovered over the lifetime of the investment.[280] Further, charges would stop as soon as a customer exits.[281]

B.33 CEC also states it is unclear whether the Authority intends that the expectation of increased benefit-based charges should elicit a customer response (p 8). The Authority has been explicit that such response is desirable – if anticipated charges are broadly proportional to benefits, customers can make efficient trade-offs.[282] (Customer responses could begin prior to the five-year measurement period, where locational circumstances indicate grid investments are likely.)

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analysed as if load customers' benefit based and residual charges were recovered as a flat per MWh charge, rather than as fixed charges.

278 The reference to four years is likely a typo, as CEC notes on p 7 that the measurement period is five years.

279 A customer's benefit-based charge allocators may be adjusted when there is a substantial sustained change in use, or a large upgrade or derating of grid-connected large plant. Entry and exit of customers also affect shares.

280 CEC's Figure 1 which is intended to illustrate these claims is difficult to interpret. However, it has a number of issues:

- the 'pricing' box should be the same area as the 'payment' triangle, to the extent it depicts the sum of future costs. More likely, the pricing box would be smaller and with an upward slope, once payments in the 'payment' triangle (which we understand from CEC's paper to be nominal amounts) are discounted to present values.
- on page 8, CEC suggests the 'pricing box' represents 'the equivalent tariff' and compares this to a LRMC tariff; but in that case these costs need a denominator (such as MWh) to be a price. Time is a reasonable denominator if the charges are fixed per period costs. But the point being made is that future costs will impact consumption decisions and are not therefore fixed per period charges. So, time is not a reasonable denominator when referring to incremental costs or pricing incentives.

281 Where a transmission customer closes one of its plants but remains a customer, it would remain liable for benefit-based charges in respect of that plant until 10 years from the grid investments' commissioning date.

282 See also S14.4 para 246 of Transpower's Reasons paper.

Claim 5 Proposed approach implements the rejected LRMC charging by proxy

B.34 CEC says there are obvious similarities between the chosen TPM and the LRMC approach that was rejected by the Authority. It sees benefit-based charges as an extreme version of LRMC (p 8) and claims that the Authority "has implemented [an LRMC approach] by proxy" (p ii).

B.35 Under the new TPM the incentives on customers – caused by basing a customer's allocation of benefit-based charges on grid use in the five years before the investment is commissioned – bear some resemblance to those from LRMC charges. However, this is where any similarities end. Being similar does not mean being the same. Indeed, the difference in methodologies and the resulting charges, incentives, and outcomes, are deliberate.

B.36 CEC does not define the type of LRMC that it has in mind or explain its detailed operation. This is problematic as there are many LRMC variants, each with different implications for charges and their incentives. For the purpose of assessment, we assume CEC refers to the marginal incremental cost approach to LRMC. This is on the basis that this approach was identified as most efficient in the Authority's 2014 working paper on LRMC charges, and because it would result in see-saw like charges that resemble the pattern drawn by CEC in its Figure 1.[283] [284]

B.37 Under the marginal incremental cost approach, LRMC would cover all changes to the cost of supplying (bringing forward) transmission services due to a permanent increase in demand. When the investment is far off, the LRMC is low, and it rises as the investment nears, that is, as spare grid capacity reduces. Once the grid investment is made, the LRMC charge falls to some minimum level or zero.

B.38 The LRMC charge provides a variable price signal ahead of an investment, which is an incentive for customers to adjust their consumption and generation. To the extent that transmission charges for a new investment are to be shared among all customers (via a tilted 'postage stamp' charge, see below) rather than beneficiaries, the LRMC signal would be inefficient. Further, the role of nodal prices in efficiently restricting grid use to capacity would be undermined and grid use would be suppressed inefficiently by such a charge.

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283 The 2014 LRMC working paper also discusses the average incremental cost and long run incremental cost approaches, which produce smoother signals of the cost of future investments. We have not assessed here how these different approaches may dampen, exacerbate, or introduce other differences compared to the proposed TPM. https://www.ea.govt.nz/assets/dms-assets/18/18259TPM-LRMC-working-paper.pdf

284 CEC's Figure 1 is difficult to interpret. While in that figure the LRMC's saw-tooth shape is familiar, without further detail about what the y-axis is meant to represent, it is difficult to know what the LRMC line represents, and whether its height relative to the other shapes is meaningful

B.39 The expectation of benefit-based charges also provides a signal ahead of a planned investment. But in contrast to the LRMC charge described above, anticipated charges are broadly proportional to expected benefits and would not affect nodal prices, so customers can make efficient trade-offs.[285]

B.40 By contrast to LRMC charges, benefit-based charges are paid only once the actual investment is made. Being fixed-like, these charges are then incentive neutral. In contrast to the rising LRMC signal, the fixed charges would fall over time (and any capacity constraints are signalled through nodal prices).

B.41 We note at this point that CEC continually characterises the proposed TPM charges as being essentially variable. Indeed, CEC's broader thesis is the Authority's 'vision' of having fixed TPM charges has essentially not survived implementation. We strongly disagree with this proposition. Implementation of a benefit-based approach to the TPM has, inevitably, led to some practical choices, many of which were reflected in the 2020 TPM guidelines through the adjustments section. We are satisfied that in aggregate the proposed TPM does implement a regime of fixed-like charges, with the incentives that go along with such charges.[286]

B.42 On this basis, we note the question posed by CEC in their report – *"The basic question that the customer wishes to answer is: "if I consume an additional 1kWh of load in a particular trading* period*, how much will my transmission charge increase as a result?""* For the most part this small increase in consumption will not be reflected in the customer's transmission price. If there is congestion though, the customer will get important nodal pricing signals. The relevant customers (in aggregate) can then choose how they respond to those signals – if they continue increasing consumption, they will bear the cost of any extra transmission capacity required.

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285 The discussion of 'equivalent tariffs' and comparison with LRMC-based tariff raises questions about the extent of customers' incentives to reduce consumption or injection during the five-year measurement period to manipulate their share of benefit-based charges allocated to their region.

These incentives are quite different to those from LRMC charges, which CEC does not acknowledge. Customers' capacity to influence their share of charges is affected by:

- an assessment of their region's share of benefits (a regional allocation factor)
- their share of regional activity (eg, offtake or injection)
- the amount of planned transmission investment and expenditure.

Customers' capacities and methods to affect these different components will vary. All else equal:

- a small customer within a region has a stronger incentive to reduce its share than a large customer, because the former's change in demand has a more limited proportional impact on total regional volumes
- larger customers have a much-reduced incentive to manipulate their share because, for example, their demand reductions have a material impact on total regional demand. That is, they would find it difficult to reduce their share of costs, and they could inadvertently impact on investments that would benefit them
- in the extreme, a single customer in a region (such as Top Energy, with respect to Northland high voltage assets) cannot directly reduce its share of benefit-based charges allocated to the region.

CEC's claim of similarity between incentives of BBCs and LRMC charges amongst other things overlooks these important aspects.

286 We note that the Authority's distribution pricing reform workstream is considering further guidance for distributors about how transmission charges under a new TPM, and the incentives within them, would be passed through to their customers.

Claim 6 Proposal is a convoluted way to implement tilted postage stamping

B.43 CEC claims that the Authority's "preferred TPM gives outcomes quite similar to [a tilted postage stamp], but with more complexity and a much longer transition period...", and that the Authority "could have provided substantially the same long-term incentives simply by designing a Tilted Postage Stamp style variable tariff with equivalent prices."[287]

B.44 In making this claim, CEC puts much weight on entry / investment decisions and gives little weight to the every-day efficiency costs of using variable tariffs for recovering sunk costs (see p 16).

B.45 For a new load customer deciding whether to enter, its expected transmission charges will have similar incentives as variable charges before entry, which may influence a customer's decisions on location and capacity.[288] After entry, benefit-based charges and residual charges are fixed-like, with residual charges adjusting only very gradually with a material lag. This design seeks to minimise inefficient incentives.

B.46 Again, CEC's lack of specifics about the charge it has in mind makes it difficult to assess CEC's claim. However, we infer from the report that CEC has in mind that transmission costs could be assigned through some variable charge with a geographic tilt that reflects predominant power flow patterns.[289]

B.47 With this model in mind, CEC's claim at para B.43 above does not stand up to scrutiny:

- under a tilted postage stamp variable tariff all customers would share in the cost of any grid investment and pay the same charge (with a premium for customers in regions that over time tend to drive more investment)[290] whereas under the proposed TPM costs of each investment are assigned only to beneficiaries
- variable charges affect customers' decisions on an ongoing basis; the proposed TPM affects new (or expanding) customers' locational and capacity decisions at the time of entry, but not ongoing consumption decisions:
    - new customers are unlikely to have incentives to underinvest in plant capacity to manipulate and minimise their shares of fixed-like transmission charges. But under postage stamping, with or without a regional tilt, new customers would not face the full cost of any required grid upgrades of their capacity or locational choices, and that can lead to inefficient outcomes for society
    - the cost of any incentives on large energy-intensive consumers to avoid investing or locating in a region that has had recent grid investments was

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287 The transition period reflects the cost of historical assets being recovered through the residual charge.

288 Indeed, it is intended to affect the customer's choice of location.

289 See for example para E.125-E.130 of the Authority's 2019 Issues Paper.

290 The "smearing" of transmission costs across all transmission customers is a significant problem under the current TPM which the Authority is seeking to fix.

estimated in the Authority's CBA to be very small, and only a fraction of the efficiency benefits of benefit-based charges.[291]

- CEC is wrong to downplay the everyday efficiency costs of conventional variable tariffs to recover transmission costs because long-run price elasticity is greater than short-run elasticity (p 16). The Authority's CBA has shown quantitatively that the order of magnitude of the cost of the distortionary RCPD charge on grid use decisions is material.

291 This contrasts with footnote 49 in CEC's report suggesting the Authority has not considered these matters.

Appendix C Assessment of the Houston Kemp review of CBA

Introduction

C.1 Trustpower's submission on the 2021 proposed transmission pricing methodology (TPM) on 2 December 2021 appends a report by HoustonKemp: *Review of the cost benefit analysis of the transmission pricing methodology.*[292] In this report, HoustonKemp concludes that they have "important concerns with the CBA that affect its reliability and warrant further review by the Authority" (p.4) and that the Authority relied too heavily on qualitative, rather than quantitative, criteria to justify its choice of TPM.

C.2 HoustonKemp's report includes considerable discussion of previous cost-benefit analyses (CBAs) of TPM guidelines proposals. HoustonKemp's claims in relation to the previous CBAs are not covered in this appendix as they have already been considered in-depth previously, and the Authority's response provided in previous papers, including particularly the CBA Revisions information paper published in April 2020.[293]

C.3 Instead, this appendix focuses mainly on the arguments by HoustonKemp that relate to the changes in the assumptions and methods used in the Authority's CBA of the TPM proposed in 2021 (the CBA),[294] compared to those used in the CBA of the TPM guidelines in 2020 (the guidelines CBA).[295] This appendix reviews key claims in HoustonKemp's report about various aspects of the CBA, including:

- assumptions about fixed transmission charges
- scope of costs included in the CBA
- treatment of transfers
- unreliable estimates of maximum prices used in the calculation of welfare effects
- decision criteria.

C.4 In summary, the Authority does not agree with HoustonKemp's conclusions.

C.5 The Authority is satisfied that the assumptions and methods it has used in the CBA are appropriate and reasonable, and that the CBA produces reliable results. The reasons for the Authority's views on HoustonKemp's claims are set out below.

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292 When referring to HoustonKemp's report in this Appendix, it is abbreviated as HK.

293 Authority (2020) "Response to feedback on the 2019 cost benefit analysis: Revisions to CBA in the 2019 Issues paper Transmission pricing review", Information Paper, April 2020. https://www.ea.govt.nz/assets/dms-assets/26/26659TPM-response-to-feedback-on-2019-CBA.pdf

294 Electricity Authority (2021), "Proposed Transmission Pricing Methodology – Consultation paper", 8 October 2021. https://www.ea.govt.nz/assets/dms-assets/29/Proposed-Transmission-Pricing-Methodology-Consultation-paper-v2.pdf.

295 Electricity Authority (2020), "Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM - Decision", 10 June 2020, https://www.ea.govt.nz/assets/dms-assets/26/26851TPM-Decision-paper-10-June-2020.pdf.

Assessment of claims made by HoustonKemp

Claim 1: Unreliable assumptions made about fixed charges

C.6 An assumption of the CBA is that transmission prices under the proposed TPM will have both fixed and variable components and that the fixed components of transmission prices do not distort consumers' consumption decisions.

C.7 In its report, HoustonKemp states that these assumptions are unreliable because:

- "there is little reason to expect that benefit-based charges will remain fixed in the long run as the Authority assumes" (HK, p.4)
- "many electricity customers (ie, mass-market customers) will not directly face charges calculated under the proposed TPM" (HK, p.20)
- they differ from the assumptions used in the guidelines CBA and "The Authority does not clearly explain why it has made these changes…" (HK, p.19).

Benefit-based charges are not modelled as wholly fixed

C.8 HoustonKemp's interpretation of the assumptions about benefit-based charges in the CBA – that benefit-based charges are modelled as "wholly fixed" (HK, p.20) – is not correct. In fact, the CBA assumes that consumers will treat new benefit-based charges as if they are variable per-MWh charges at the time they are allocated.[296] New benefit-based charges are allocated frequently, for each new grid investment that is made (including low-value investments, which are made frequently). It follows that, in aggregate, benefit-based charges will always have some variable component

C.9 HoustonKemp is correct in their observation that benefit-based charges are subject to adjustments under the TPM, and that these adjustments are not modelled in the CBA (HK p.20).[297] The CBA does not examine the impact of adjustments to benefit-based charges. However, we consider that this is a reasonable simplification that does not have a material impact on CBA results, given that adjustments apply only in a narrow range of circumstances. This means they will in general affect a relatively small proportion of benefit-based charges.[298] This simplification in the CBA does not validate HoustonKemp's erroneous claim that BB charges are modelled as "wholly fixed".

Consumers will face charges that align with the TPM

C.10 The Authority has previously addressed HoustonKemp's point that not all consumers would directly face electricity prices that reflect the proposed TPM. While retail prices can and do vary, retailers' commercial incentives to pass costs on to their customers – and distribution companies' cost allocation methodologies –

296 Electricity Authority (2021) "CBA approach, methods and assumptions. Proposed TPM 2021, Technical Paper" (hereafter, CBA technical paper) 2.12 (b), and 2021 TPM Consultation paper, paras D43-D49.

297 Consumers' shares of benefit-based charges can change retrospectively if, for example, there is a substantial change in a load customer's electricity demand or a change in the number of load customers.

298 It is possible to conceive of large adjustments for some customers in some parts of the country under quite precise circumstances. But in general, adjustments to allocators will be proportionally very small.

mean that it is reasonable to assume that retail customers will face charges that broadly align with the transmission pricing methodology.[299]

The Authority has explained the change in assumptions

C.11 The effects of fixed versus variable charges are a more material consideration for this CBA than for the Guidelines CBA – as the Authority has previously explained.[300] For example, the CBA technical paper includes an explanation of how the CBA modelled the effects on electricity demand of changes to transmission charges (paras 2.2-2.15), concluding that:

2.14 Differentiating between fixed and variable charges is necessary for distinguishing the different effects of BBCs and residual charges and thus to account for trade-offs embedded in the proposed TPM. For example, higher residual charges and lower BBCs may mean lower costs on producers, higher rates of generation investment and lower prices for consumers in the long run. But higher residual charges reduce consumption and can also delay such generation investment.

2.15 These considerations are much more material under the proposed TPM, relative to the Guidelines CBA, given that the proposed TPM envisages potentially substantial increases in generators' transmission charges. Albeit the size of any increase will be contingent on final design decisions such as the balance of benefits from base capex between load and generation, and the extent to which overhead costs should be recovered in benefit-based charges.

C.12 The 2021 TPM Consultation paper, at para D.49, further explains that: "This detail in modelling the effect of different allocation mechanisms in this CBA [is] to reflect the detailed proposal. This detail, which includes some material design choices […] had yet to be developed at the time the Guidelines CBA was prepared." The details being referred to in para D.49 were:

- the proposed simple method for allocating benefit-based charges, including assumptions about generation customers' shares of benefits from transmission investments, as reflected in the CBA technical paper's para 2.15 reference to "the balance of benefits from base capex" (cited in 2.6 above)
- the proposal to recover a material proportion of overhead operating costs through benefit-based charges, as reflected in the CBA technical paper's para 2.15 reference to "the extent to which overhead costs should be recovered in benefit-based charges" (cited in 2.6 above).

C.13 The Authority thus disagrees with HoustonKemp (on page 21) that the changes in modelling were in response to concerns it had raised previously.

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299 See eg, p.45 in Authority (2020) "Response to feedback on the 2019 cost benefit analysis: Revisions to CBA in the 2019 Issues paper Transmission pricing review", Information Paper, April 2020.

300 CBA technical paper, para 2.14 and para 2.15 and paras D43-D49 of the 2021 TPM Consultation paper.

Claim 2: CBA does not properly account for costs of electricity generation

C.14 In its report, HoustonKemp claims that the CBA should "deduct the additional cost of generation from its estimate of net benefits" (HK p.34). HoustonKemp estimates that the increased costs of generation under the proposed TPM would be $435 million (in present value terms), comprising increased capital costs ($586 million) and reduced variable costs (-$131 million) (HK pp. 34-35).

C.15 The Authority considered this argument in 2020, in the context of the Guidelines CBA. The Authority's position is that deducting the additional costs of generation from net benefits would amount to double-counting of costs that are already captured in prices faced by consumers.[301]

C.16 HoustonKemp has addressed the Authority's position and set out the following counter-arguments in its report:

- "costs and benefits accounted for in a CBA should reflect the use of resources (that is, the value derived from their consumption and the costs incurred in their supply) rather than monetary payments for these resources (that is, their prices)" (HK, p.35)
- "Since offers are not based on costs, neither are the prices that the Authority calculates using this approach" (HK, p.35).

C.17 The Authority has considered HoustonKemp's counter-arguments, but does not agree with them, for the following reasons.

C.18 "Economists ordinarily consider market prices as the most accurate measure of the marginal value of goods and services to society".[302] It follows that, in general, prices are a good starting point for measuring costs and benefits, including in a CBA.

C.19 It may be appropriate to depart from this general approach in some circumstances. The Authority is aware that in some circumstances prices may overstate or understate real resource costs, such as when a firm exercises market power or taxes distort markets.

C.20 However, HoustonKemp does not state a view on, or provide evidence on, whether the prices in the CBA either overstate or understate real resource costs. Given that HoustonKemp advocate deducting generation costs from the CBA's net benefits, this might suggest that they consider the prices in the CBA understate costs. However, this is hard to square with the fact that HoustonKemp also notes the fact that energy prices rise in the CBA (as HoustonKemp notes at HK, p.15), due to rising costs of generation to meet increased demand. [303]

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301 Prior discussion of this matter can be found at for example. p.25 of Authority (2020) "Response to feedback on the 2019 cost benefit analysis: Revisions to CBA in the 2019 Issues paper Transmission pricing review", Information Paper, April 2020.

302 This sentence is a quotation from United States Office of Management and Budget, Regulatory analysis, Circular A-4, 17 September 2003, p 21. HoustonKemp's observations about differences between resource costs and prices cites this document.

303 HoustonKemp notes that these higher prices are consistent with the CBA's increases in producer surplus (HK, p.30). HoustonKemp also states that the scale of the increases in producer surplus are "entirely inconsistent with the Authority's changes in generation costs [of $435 million]" (HK, p.30). It is unclear what HoustonKemp means by "entirely inconsistent with". The producer surplus changes calculated in the CBA are consistent with higher prices needed to encourage increased electricity

C.21 HoustonKemp provides little explanation for its view that there is a deviation between prices and real resource costs in the CBA. All that is said is that generation offers are not based on costs.

C.22 In general, the Authority disagrees with the claim that generation offers are not based on costs (while noting that offers may diverge from costs in limited circumstances). Typically, generation offers reflect a range of real resource costs including generation operating costs and opportunity costs. The Authority's CBA documentation makes clear the connection between prices and costs in the CBA analysis.[304]

C.23 Prices in the wholesale electricity market (as modelled in the CBA) sometimes do rise beyond the level of short run operating cost and generators' opportunity costs. This is at times when modelled demand growth exceeds supply and before the resulting investment eventuates. At these times prices provide a return on capital invested in generation. It follows that prices also reflect long run capital costs. That relationship is appropriately reflected in the CBA.

C.24 For these reasons, the Authority is satisfied that the calculation of consumer surplus in the CBA does directly account for the increased costs of electricity generation, through higher energy prices.

C.25 If HoustonKemp's arguments were accepted, and increased generation costs (ie, increased costs of energy supply) were deducted from the CBA's net benefits, then to prevent double-counting these costs an adjustment would also have to be made to the CBA's net benefits, to "back out" increased costs to consumers from higher energy prices (ie, increases in costs of energy supply) that had already been taken into account in the calculation of net benefits. In the Authority's view, such a double adjustment would complicate the analysis and offer no obvious additional analytical insight.

Claim 3: The CBA counts transfers of transmission charges as benefits

C.26 HoustonKemp reflects upon its earlier claims that the Guidelines CBA incorrectly treated transfers to consumers as benefits and says that "As a matter of principle, we expect that the Authority's estimate of net benefits would still contain transfers" (HK, p.33).

C.27 In making this statement, HoustonKemp cites its own observations regarding the extent to which the proposed transmission charges will be fixed and the observation that consumer prices fall while producer (energy) prices rise (HK, p.33). In making these observations, HoustonKemp appears to be implying that the CBA's consumer surplus calculations do not properly account for the costs of fixed transmission charges. That is, HoustonKemp appears to believe that some of the CBA's

generation investment to meet higher electricity demand and to cover increased transmission charges faced by new generation investments (total increase in transmission charges of $1.2 billion as noted in paragraph D.11 of the 2021 TPM Consultation paper). Higher prices will increase revenue for existing generators as well as new investors. Producer surplus changes will thus reflect both investment costs and changes in operating surpluses (revenue less variable operating costs) for existing generators. Therefore, producer surplus changes will be larger than increased investment costs and in this regard the producer surplus changes are consistent with the changes in generation costs.

304 CBA technical paper paras 2.177-2.179.

observed benefits from the proposed TPM may simply be reallocations of transmission charges (ie, transfers). HoustonKemp also says “The Authority’s technical paper leaves unclear how it has addressed these issues, since it does not indicate that it has deducted these fixed charges from consumer surplus under its proposed TPM.” (HK, p.33). It appears from these statements that HoustonKemp’s main argument in this area is that the CBA treats fixed charges as costless.

C.28 The Authority does not agree that this is a correct characterisation of the CBA. Rather, in the CBA, those transmission charges that are modelled as fixed charges reduce demand via an income effect (that is, consumers have less money to spend on electricity).[305] It follows that the CBA does not treat fixed charges as costless.[306] The CBA takes account of the fact that fixed charges must be funded out of consumers’ incomes. In addition, when reporting on the overall results of the CBA, the Authority deducts from consumers’ benefits any reductions in the total amount of transmission revenue recovered from consumers.[307] This ensures that the CBA does not count (as net benefits) any wealth transfers resulting from a reallocation of transmission charges between load and generation customers.

Claim 4: Unreliable estimates of maximum prices

C.29 HoustonKemp questions the reliability of the CBA’s calculations of the change in consumer welfare (resulting from the proposed TPM), arguing that the assumptions used in the CBA about maximum prices (at which demand is assumed to fall to zero) are based on inconsistent evidence.

C.30 In the CBA, consumer surplus is approximated by the area of a triangle made up of three data points: a market price, a market quantity, and a maximum price at which demand is assumed to be zero.[308] This calculation assumes that demand is a linear (straight line) function of price. The maximum prices are calculated using an estimate of the long-run elasticity of demand.[309]

C.31 HoustonKemp criticizes these calculations, arguing that:

- the assumption that demand is linear is “inconsistent with the basis on which the Authority has estimated the relationship between demand and price” (HK, p.24), that is, the long-run elasticity of demand is estimated using a model in which the relationship between demand and supply can be represented by a curve, not a straight line (HK, Figure 5.3, p.25), and the elasticity of demand is constant
- “the Authority has assumed that the elasticity of demand remains constant at -0.74 at every quantity at or below its estimate of electricity consumption” but “the elasticity of demand changes along a linear (or straight line) demand curve…” (HK, p.25)

305 Variable charges, by comparison, are those amounts of transmission interconnection revenue that affect consumption decisions (whether or not explicitly invoiced as such), and which are modelled as dollar per MWh charges.

306 See para 2.103 in the CBA Technical paper.

307 See paras D.11-D.12 in the 2021 TPM Consultation paper.

308 See Equation 9 in CBA technical paper (p. 30) for the description of the change in consumer surplus.

309 CBA technical paper, para 2.120.

- “the Authority finds prices that exceed those that it cites as a ‘maximum price’” (HK, p.26).

C.32 The Authority considers that HoustonKemp’s observations about the differences between linear and constant elasticity demand functions overlook the practical considerations and context behind the CBA’s assumptions. When these matters are considered more closely, the apparent inconsistency between assumptions that is highlighted by HoustonKemp disappears (this is explained further below). Further, the Authority’s approach is consistent with standard practice in empirical analysis.

C.33 The estimated long-run elasticity of demand is indeed estimated by a model that could be interpreted as assuming a constant elasticity of demand (CED), given that quantities and prices in the model are transformed by natural logarithms. However, natural logarithms were used for practical statistical reasons, as is often the case for empirical analysis.[310] The use of natural logarithms in this way need not be – and is not – a claim that demand must have a single, restrictive, functional form that applies at all prices and quantities. Generally speaking, CED is not considered to be an accurate description of demand.[311] However, CED can be a useful form for a model estimating localised (non-extreme) relationships between changes in prices and quantities.[312] The CBA uses the CED assumption for this latter purpose, but it does not attempt to use it to fully describe electricity demand. The Authority considers this to be a reasonable approach that is consistent with standard practice in empirical analysis.[313]

C.34 HoustonKemp states that “the Authority has assumed that the elasticity of demand remains constant”. The Authority does not agree with this characterisation of its approach. The Authority did not make such an assumption. Further, such an assumption is not necessary for estimating maximum prices based on observed quantities and prices. Maximum prices were estimated using historical average prices, a point estimate of long run price elasticity, and an assumption of linear demand. These data points describe an ordinary demand curve along which the price elasticity of demand <u>does</u> vary.

C.35 HoustonKemp’s also makes a point that the Authority finds prices that exceed those that it cites as a ‘maximum price’. We agree that the CBA does produce prices that – in the short term – exceed the long-run 'maximum price’. However, this is an expected outcome and not an inconsistency, for the reasons explained below.

C.36 The CBA’s use of long run elasticities to calculate maximum prices has the effect that maximum prices used to calculate consumer surplus changes are long run

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310 Transformation by natural logarithms reduces the severity of problems associated with using linear models when there is unequal variance in the data (heteroskedasticity). In this way, transformation can be a practical alternative to using more complicated non-linear models that introduce practical problems of their own. Log transformation is also commonly used because of the convenient interpretation of model coefficients as percentage changes in response to percentage changes (elasticities).

311 Not least because CED implies that demand will only get near to zero as prices rise to infinity, which is very unlikely for any good or service. See also Deaton, A., & Muellbauer, J. (1980). Economics and Consumer Behavior. Cambridge University Press.

312 See eg, Blundell, R., Horowitz, J. L., & Parey, M. (2012). Measuring the price responsiveness of gasoline demand: Economic shape restrictions and nonparametric demand estimation. Quantitative Economics, 3(1), 29–51.

313 See eg, Zhu, X., Li, L., Zhou, K., Zhang, X., & Yang, S. (2018). A meta-analysis on the price elasticity and income elasticity of residential electricity demand. Journal of Cleaner Production, 201, 169–177.

maximum prices and lower than maximum prices in the short term. In the CBA modelling, short-term prices in any given year can and do rise above the long-run maximum price. This is because options to use alternative energy sources are limited in the short term by existing infrastructure, plant and machinery or contracts. Over the long term, persistently high prices would cause consumers to invest in alternative energy supply arrangements (which would tend to reduce long-term prices). The CBA focusses squarely on the long-term consumer surplus and so sets consumer surplus equal to zero when modelled prices rise above the long-run maximum.

C.37 The Authority's approach is conservative, in terms of the overall net consumer benefits produced by the CBA. An alternative approach, which we considered, that would have avoided producing modelled short-term prices in excess of the assumed long-term maximum would have been to calculate the sum of short-run consumer surpluses. This would require much smaller elasticities and by extension would produce much higher maximum prices and much higher consumer surpluses. However, this would then have been less consistent with our focus on long-run consumer surplus outcomes.

C.38 HoustonKemp notes that, in the CBA, prices rise above the assumed maximum price from time to time, and suggests that this implies an upward sloping demand curve and negative consumer surplus (HK, p. 26). This is not an accurate description of the demand analysis or methodology in the CBA. Rather, observing that short-run prices can rise above long-run maximum prices is in fact an argument that (for the reasons discussed above) *supports* the decision taken to estimate <u>long-run</u> changes in consumer surplus.

Claim 5: Insufficient regard for the results of the CBA options analysis

C.39 In its report, HoustonKemp argues that the Authority has given insufficient weight to the results of the CBA and that this “raises questions as to whether the Authority’s reliance on its CBA in support of its proposed TPM is reasonable” (HK, p.3). HoustonKemp’s views are based on the CBA’s finding of higher estimated net benefits from a scenario where generators’ share of charges under the simple method (for allocation of the benefit-based charge) are set at 25% (the 75:25 scenario) as compared to 50% in the central scenario.

C.40 The Authority considered this result as well as other evidence alongside Transpower’s assessment that a roughly equal split of charges, between generation and load, was a reasonable starting point for the TPM.[314] The Authority noted that this was a finely balanced decision amidst uncertainty and invited further clear and robust evidence on this matter.[315]

C.41 The Authority fully considered the options and the relevant considerations. The Authority's weighing of the different considerations is outlined at paras 5.31- 5.41 of the consultation paper on the proposed TPM.

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314 2021 TPM Consultation paper, para 5.34-5.41.

315 2021 TPM Consultation paper, para 5.41.

C.42 HoustonKemp argued that "the CBA should be the framework for the Authority's decision-making process, and should incorporate (either quantitatively or qualitatively) the factors that the Authority considers relevant to its objective" (HK, p.8). Further, HoustonKemp states that "The relegation of the CBA to just one of several factors to which the Authority may have regard does not appear to be consistent with this standard of evidence-based decision-making" (HK, p.8).

C.43 However, we would observe that the legislative requirements for amending the Code do not prescribe a quantitative CBA as the sole basis for a decision and do not require that a quantitative CBA be treated as the framework for the decision-making process. Rather, section 39(2)(b) of the Electricity Industry Act 2010 requires an evaluation of the costs and benefits of the proposed amendment, and section 39(2)(c) of the Electricity Industry Act 2010 requires an evaluation of alternatives.

C.44 The Authority does not agree that a CBA necessarily can or should incorporate all factors relevant to its objectives – what matters is that the Authority has considered those factors elsewhere in its analysis. The Authority also does not agree that its consideration of factors outside the quantitative CBA (in considering the proposed weighting of charges under the simple method or in considering any other aspect of the TPM that the CBA sought to quantify) is in any way inappropriate. It is simply that, as discussed in the Authority's earlier papers, a quantitative CBA inevitably has its limitations and can therefore only be one component of the analysis. The Authority must also consider benefits and costs more generally, including qualitative analysis, in reaching its final decision.

Appendix D BBC standard method allocation approach: grid-connected batteries

D.1 The approach to grid-connected battery storage under standard method benefit-based charges and reasons for that approach are summarised in the table below.

Table 8 Standard method allocation approach for grid-connected batteries

NPB type	Summary of approach	Comments
Price-quantity method		
Market	Battery-specific treatment for customers with offtake and injection at the same connection location. Discretion to: • Net off offtake/injection benefits and injection/offtake disbenefits for customers with offtake and injection at same connection location at stage of calculating regional NPB • Create a separate regional customer group for customers with offtake and injection at same connection location No change to intra-regional allocators	Allows for the calculation of individual NPB on a customer "like for like" basis (rather than, for example, grouping grid-connected batteries with non-battery direct consumers). The effect of this provision is that grid-connected battery storage can be expected to receive allocations on the basis of its expected operating profit (if the battery is primarily performing energy arbitrage). In other words, batteries will receive an allocation when their revenue from injection minus costs from charging increases due to a BBI.
Reliability	Battery-specific treatment for grid-connected batteries: treat the battery as a member of the regional supply group only	Battery offtake is likely to occur at non-peak times and the potential for later grid injection is likely to assist reliability. Treating batteries as members of the regional supply group recognises that batteries are likely to benefit from increased reliability in a similar magnitude to grid-connected generators, not loads.
Ancillary service	No battery-specific treatment	Ancillary service NPB is based on changes in allocatable cost for certain participant types (eg, grid-connected generators) and reflects the actual allocation methodologies in Part 8 of the Code, in which there is no special treatment of batteries. Ancillary service NPB is calculated based on changes in the allocable cost of instantaneous reserves (IR), frequency keeping (FK) and voltage support (VS), and is allocated to the customer type that pays the allocable cost for each ancillary service. Grid-connected batteries will receive an allocation of ancillary service NPB (if there is any) for IR as a grid-connected generator.

NPB type	Summary of approach	Comments
Price-quantity method		
		For FK and VS, a grid-connected battery will receive an allocation of ancillary service NPB as it is a direct consumer (at least as to the battery's losses).
Other	No battery-specific treatment	Grid-connected batteries can be expected to receive an allocation like other customers in proportion to their injection and/or offtake if Transpower expects them to receive another benefit.[316]
Resiliency method		
Resiliency	Battery-specific treatment for grid-connected batteries: Treat the battery as a member of the regional supply group only.	The rationale for allocating resiliency benefits to offtake customers in the proposed new TPM was based on the difference between VoLL and the per-MWh operating profits of generators. The lost operating profit due to a battery being unable to charge due to an interruption will be similar to generators, rather than "normal" types of offtake. Grid-connected batteries will receive no allocation under the resiliency method.

316 As Transpower explains in its 30 June 2021 reasons paper (page 7.20, para 69) other benefits are either benefits that are unforeseen at this time or are not one of the electricity market benefits it can consider under the Capex IM. Transpower expects to use the "other benefits" class infrequently.

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
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

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