Meridian Energy Submission
Transmission Pricing Review: 2019 Issues Paper

1 October 2019

This submission by Meridian Energy Limited (**Meridian**) responds to the Electricity Authority's "2019 Issues Paper: Transmission Pricing Review" of 23 July 2019 (**2019 Issues Paper**).

The submission is divided into the following Parts:

- Part A: Executive Summary
- Part B: Current situation and problem
- Part C: Comments on the proposal
- Part D: Overall drafting of the Guidelines
- Part E: Cost-benefit analysis
- Part F: Compliance with statutory requirements
- Part G: Process for the development of the Transmission Pricing Methodology
- Part H: Attachments
    - NERA Economic Consulting *Review of Electricity Authority's transmission pricing review 2019 papers* (**NERA Report**);
    - Orbit Systems *Review of Schedule 1 modelled beneficiaries of existing transmission assets* (**Orbit Report**); and
    - a mark-up of the Guidelines.

Some of the consultation questions from the Authority's 2019 Issues Paper are addressed in relevant parts of this submission. We have not responded directly to all of the questions asked. Meridian's views should however be apparent.

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Part A: Executive Summary

There are substantial and intractable problems with the current Transmission Pricing Methodology (TPM) that cannot be resolved under the existing TPM Guidelines. Without urgent reform, New Zealand faces the prospect of ongoing inefficient grid use, significant inefficient investments and a development path that costs consumers billions of dollars more than it should.

The HVDC charge has been highly contentious since 1996, when Transpower first attempted to allocate the costs of the HVDC to South Island generators. The HVDC charge is arbitrary as it:

- separates out the HVDC from the rest of the interconnected grid without justification; and
- singles out South Island generators as the deemed sole beneficiaries of the HVDC link, despite significant benefits also accruing to North Island generators and to consumers throughout New Zealand.

The removal of the HVDC charge is a prerequisite to any durable TPM reform and is necessary as a matter of good regulatory practice.

In addition, the current RCPD charge distorts the cost of using the grid, rewards inefficient investments that merely shift transmission costs to other parties, and provides inefficient signals about where to locate new large industrial load and generation. The broad socialisation of transmission costs though a "postage stamp" allocation also provides poor incentives for individual participants to scrutinise grid investment proposals.

The Authority has a duty to issue new TPM Guidelines to address the problems with the current TPM. The anticipated decarbonisation of the economy and increase in electricity demand means there is a wave of investment coming. The problems with the TPM will only become more pronounced over time and any delay in reform will cost New Zealand consumers.

Meridian strongly supports the proposed Guidelines including the benefit-based charge and the Authority's Schedule 1 determination of beneficiaries for the seven identified pre-2019 assets. Orbit Systems has tested the Authority's modelling and input assumptions for Schedule 1 and conclude in the attached summary report that the methodology is robust and objective, and that its assumptions appear reasonable – resulting in a market-like way to identify the beneficiaries of each pre-2019 asset. Meridian also supports the proposed residual charge.

The Authority has run a robust process to develop the guidelines and has met all the statutory requirements. After ten years of consultation by the Authority, and more before that by the Electricity Commission, the issues are well understood. There are compelling reasons to progress the Authority's proposal.

Even under the most conservative assumptions the Authority's proposal will deliver significant benefits to New Zealand consumers. The Authority's central scenario in the cost-benefit analysis estimates net benefit for consumers of $2.7 billion (net present value) between implementation and 2050. The attached report from NERA concludes that the Authority's approach is appropriate, and the quantified net benefits are plausible.

Meridian considers TPM reform to be an urgent priority. Following discussions with Transpower, the Authority has published an indicative timeframe for implementation of a new TPM in 2024. Meridian considers this timeframe too long and encourages the Authority to set shorter timeframes. We observe the Authority's modelling of estimated charges assumes that the proposal would be implemented in 2022. We consider this timeframe to be more appropriate and achievable. Given the substantial efficiency benefits identified by the Authority, every effort should be made to implement a new TPM as soon as possible. NERA estimates that implementing the TPM even one year earlier would increase the net benefits by $163 million. At a minimum, the proposed go-live date for a new TPM could comfortably be brought forward a year to 1 April 2023.

Meridian strongly supports the Authority's proposal and looks forward to the publication of the final TPM Guidelines and to the next stage of TPM development.

Table of contents

Part B: Current situation and problem

There are substantial and intractable problems with the current TPM

The Electricity Authority's 2019 Issues Paper outlines a range of substantial and intractable problems with the current transmission pricing methodology. The Authority's problem definition elaborates on a decade of review and analysis, including previous assessments by the Electricity Commission, the Transmission Pricing Advisory Group (TPAG), and the Authority. There is now a clear, well-considered and evidence-based understanding of the key problems with the current TPM:

- the HVDC charge distorts the cost of South Island generation investments, and is arbitrary and unfair;
- the RCPD charge distorts the cost of using the grid, rewards inefficient investments to reduce grid use that merely shift costs to other parties, and provides inefficient signals about where to locate large industrial load and generation; and
- the broad socialisation of transmission costs (postage stamping) provides poor incentives for individual participants to scrutinise grid investment proposals.

Meridian supports the Authority's description of the problems and agrees that these problems will likely increase as more grid investments are made to support growing regions and the transition to a low-emissions economy, and as distributed renewable generation and batteries become more affordable. Without reform, New Zealand faces the prospect of a vast misallocation of investment and an unnecessarily costly development path for the industry.

The problems with the current TPM cannot be resolved under the existing TPM guidelines. If left unresolved, they will lead to significant additional long-term costs for electricity consumers. In accordance with its statutory objective, the Authority now has a duty to issue new TPM guidelines to address the problems with the current TPM.

The HVDC charge must be removed

The HVDC charge is a major cause of the TPM's inefficiency, unfairness, and lack of durability. For years, South Island generators have subsidised other transmission customers, who receive significant benefits from the HVDC link at zero cost.

The HVDC charge is arbitrary in two senses.

First, it separates out the HVDC assets from the rest of the interconnection system and allocates charges on a different basis from the general methodology. The HVDC is fundamentally an interconnection asset and there is no logical reason to treat it any differently to other interconnection assets – Meridian's submission on the 2016 Second Issues Paper covered this point in detail and concluded that there is no evidence demonstrating HVDC and HVAC assets perform different functions, deliver different benefits, or are different in any way that is relevant to transmission pricing.[1]

Secondly, in allocating those charges, South Island generators have been singled out as the deemed beneficiaries of the HVDC assets and are the sole payers of the charge. The costs of HVDC investments are recovered from an arbitrary subset of the beneficiaries of the HVDC link. North Island generators do not face an equivalent to the HVDC charge and pay nothing for their use of the national transmission grid (other than connection charges). North Island generators clearly benefit from the HVDC given southward power flows (in 14% of trading periods over the four years to June 2018)[2] and national frequency keeping and reserve sharing, but North Island generators do not pay for those benefits. Similarly, both North and South Island consumers benefit from the HVDC through lower electricity prices.

Meridian agrees with the Authority that the HVDC charge is inefficient. The HVDC charge unnecessarily adds around 10% to the cost of South Island generation. This creates a strong disincentive to invest in South Island generation meaning investments in even higher-cost generation in the North Island take precedence, increasing electricity prices for all New Zealanders.

There is simply no good reason for the distinctions that give rise to the HVDC charge. As far as Meridian is aware, there is no reasonable argument available to justify a charge which treats HVDC assets differently to all the other interconnection assets and is imposed on South Island generators only.

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1 Meridian Submission *Second issues paper* 2016, pages 12 – 14.

2 Electricity Authority *HVDC transfer*, available at: www.emi.ea.govt.nz/r/4wers.

Case studies

The present HVDC transmission charge is a tax on South Island generation. Its removal will change the investment case for all South Island generation options. If the HVDC charge is removed Meridian would seriously reconsider all its South Island options, which in recent years have not been given priority.

Lake Pukaki Gate 18

Meridian holds resource consent for a hydroelectric generation option to be built at Gate 18 on Lake Pukaki. The consented option would involve 35MW of installed capacity and generate around 120 GWh per annum. This would increase the total energy that can be generated from the water stored in Lake Pukaki.

Based on the consented configuration, the approximate HVDC charges faced by Meridian at Gate 18 would be $0.8 million per annum.

The current HVDC charges mean that Gate 18 is not a good option for Meridian. However, when the Authority's TPM proposal is implemented, Meridian will reconsider the investment case for Gate 18. The reduction in transmission costs may tip the economics of the investment into the black.

Meridian expects there to be considerable benefits of increased hydro storage in a low-emissions future where hydro is increasingly used to flex around intermittent renewables like wind and solar.

Hurunui windfarm

Meridian holds resource consent for Hurunui windfarm. As currently consented, the option would involve 17 turbines for a total installed capacity of 71MW and likely generation of 224GWh per annum.

Based on the consented configuration the approximate HVDC charges faced by Meridian for the windfarm would be $1.6 million per annum. Removing these charges pushed Hurunui up the list of options Meridian would build next.

The HVDC charge has been contentious since its inception.[3] The removal of arbitrary treatment for one part of the interconnected grid is a prerequisite to a durable TPM and is necessary as a matter of good regulatory practice. In particular, the sums of money at stake are simply too large for any stakeholder to quietly tolerate a serious discrepancy between cost and benefit. Conversely, a transmission pricing methodology that aligns benefits and costs will be durable and avoid the significant disruption of frequent regulatory challenges.

The interconnection charge is inefficient and rewards cost shifting investments

Meridian agrees with the Authority that the RCPD charge:

- over signals the cost of consuming grid-supplied electricity at peak times;

[3] Meridian Submission *Second issues paper* 2016, Appendix 1 "History of the HVDC dispute".

- leads customers to inefficiently invest in distributed generation and batteries to avoid transmission charges; and
- distorts decisions about where to locate energy-intensive industry or generation.

These problems are a form of "rent seeking" that cause inefficiencies and result in significant costs to consumers in the long-term. The examples of these problems provided by the Authority are compelling.

The RCPD charge is not linked to customer benefits and is a poor signal of the actual economic cost of the transmission grid. In particular, the RCPD charge over signals the value of 100 specific peak periods and can be as much as $2,180/MWh according to the Authority. The charge also leads to unpredictable outcomes based on the timing of the top 100 half hour demand periods.

Transmission customers are strongly incentivised to avoid those 100 peaks, even when there is spare capacity. Furthermore, in the absence of capacity constraints, actions such as investment in distributed generation or batteries will not reduce grid costs, but instead simply shift transmission charges to other parties. Such investments are a rational private response to the RCPD charging structure but are bad for the electricity system and for consumers as a whole.

Investment in distributed generation or storage is strongly incentivised to avoid contributing to demand during peaks and thus avoid transmission charges, without those assets necessarily reducing total transmission costs or being the most efficient way to meet energy needs. As the Authority has noted, the problem of cost shifting will increase as the price of storage and other emerging technologies falls.

The socialisation (postage stamping) of interconnection charges also causes significant issues. The burden of recent transmission investments is socialised to all consumers including those in the lower North Island and South Island, despite the beneficiaries being predominantly consumers based in the upper North Island. This inevitably means that low growth regions in New Zealand subsidise the transmission investments that are required in high growth regions – exacerbating wealth distribution issues in regional New Zealand.

Lack of scrutiny for new transmission investments

The "postage stamping" of interconnection costs means there is a lack of consumer scrutiny for new transmission investments. Meridian agrees with the Authority that the current TPM provides poor incentives to scrutinise grid investment proposals.

The current RCPD charge spreads the costs of investments across all customers regardless of where they live. Customers who would benefit from a proposal know the proposal is to a large extent subsidised by the rest of the country. This creates strong incentives for stakeholders to support grid investments that they would benefit from even to only a very small degree – regardless of the costs and benefits to others. Furthermore, since each of the "others" pays only a small amount individually there is little incentive to engage in the capex approval process.

Postage stamping of interconnection costs undoubtedly makes Transpower's role easier. Spreading the costs of grid investment across all businesses and consumers regardless of whether they are impacted by that investment allows Transpower to plan and make transmission investments with minimal engagement or opposition. The Commerce Commission's grid investment approval process is intended to test the costs and benefits of Transpower's investment proposals. However, with costs smeared across the country, there is little incentive for businesses or consumers to engage with the Commission's process. On the contrary, because those directly impacted by transmission investment receive the full benefit but pay only a fraction of the cost in means that transmission investments will invariably be supported. If a benefit-based charge was adopted instead, the Commission's process would be enhanced as customers would have:

- a better appreciation of the costs and benefits of each major investment and upon which parties those costs and benefits will rest;
- incentives to consider the merits of transmission alternatives on an equal footing to transmission solutions;
- incentives to submit more fulsome and accurate information on a proposal's net benefits relative to alternatives.

Changes in the industry increase the urgency of TPM reform

Meridian agrees with the Authority that changes in the industry and the broader economy necessitate changes to the TPM, in particular:

- the transition to a low emissions economy with significant electrification;

- rapidly changing technology; and
- growth of the transmission grid.

The need to reduce emissions is increasingly urgent and reflected in numerous government initiatives and legislative developments. The transition to a low or net zero emissions economy will require economy-wide efforts but the most obvious first steps are the electrification of transport and heat for industrial processes. This will have implications for the electricity industry, and notably will require significant new investment in renewable generation and in the transmission grid.

Several recent reports have forecast the need for considerable investment in generation to meet anticipated demand growth in the next three decades.[4] Given the rapid increase in new generation and large industrial load expected over the next three decades, it is all the more critical that transmission pricing does not interfere with efficient locational signals, and avoids distortions so that investments are made in a way that delivers the required increase in generation to consumers at least cost.

Battery storage capacity is improving and prices are falling. As a result, grid-scale batteries and behind-the-meter batteries (including in Electric Vehicles) may well play a role in smoothing the daily electricity demand profile. However, the incentives given through transmission pricing should be such that investments in these technologies occur where there are real efficiency benefits and not where an investment is only viable because of the benefits of shifting transmission costs to others.

Transpower's *Transmission Tomorrow* report also notes that significant investment will be required in existing and new transmission assets over the next two decades. Several major capex investments are already under investigation.[5] Transpower's strategy to support the growth of Auckland *Powering Auckland's Future* has also identified significant maintenance of transmission in and around Auckland as well as likely investment between 2020 and 2050 including:[6]

- reconductoring of the Otahuhu to Whakamaru A and B 220kV line;
- a Huntley to Otahuhu A 220kV cable to supply Bombay;

4 See Ministry of Business, Innovation and Employment *Electricity demand and generation scenarios (EDGS)*; Productivity Commission *Low-emissions economy*; Independent Climate Change Committee *Accelerated Electrification*; Transpower *Te Mauri Hiko – Energy Futures.*

5 https://www.transpower.co.nz/keeping-you-connected/projects.

6 Transpower *Powering Auckland's Future*, available at: https://www.transpower.co.nz/keeping-you-connected/auckland-strategy/our-auckland-strategy.

- an Albany to Pakuranga 220kV cable;
- a Brownhill Rd to Otahuhu 220kV cable; and
- reconductoring of the Henderson to Otahuhu A 220kV line.

Transpower's regulatory asset base has increased from $2 billion in 2005/06 to $4.7 billion in 2018/19. For the next regulatory control period from 2020 to 2025 Transpower proposes base capital expenditure of $1.2 billion, seeks approval to include an estimated additional $135 million of possible projects over the period, and estimates that $177 million worth of major capex proposals may be submitted during the period.[7] Transpower has also signalled that there is likely to be a significant uplift in capex from 2025 to 2035.[8]

Meridian agrees with the Authority that efficient prices, at all points in the electricity supply chain, are necessary to ensure that this wave of investment occurs at least cost to New Zealand consumers. The sooner efficient transmission price signals are implemented, the sooner consumer benefits will be realised, and long-term inefficient costs avoided.

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7 Commerce Commission *Transpower IPP reset issues paper* 2019, page 98 https://comcom.govt.nz/__data/assets/pdf_file/0023/120785/Transpower-IPP-reset-Issues-paper-7-February-2019.PDF.

8 Ibid, page 99.

Part C: Comments on the proposal

The Authority has identified its preferred approach to transmission pricing, comprising three charging components – a connection charge, a benefit-based charge, and a residual charge – along with a prudent discount policy (PDP), a transitional cap to limit any initial price changes, and a range of optional components such as a transitional peak signal.

Meridian strongly supports the Authority's overall proposal. We consider it will address the key problems identified with the current TPM and deliver substantial benefits for New Zealand electricity consumers. We encourage the Authority to finalise the guidelines and implement the proposed TPM as soon as possible.

Transmission pricing is a cost allocation problem – the TPM does not alter the size of Transpower's allowable revenue, only the share of costs faced by different parties. In the short-term, this is a zero-sum game of who pays what, but in the longer term the allocation methodology will impact on what investments are made, by whom, and where. That is, it will drive the total transmission costs faced by consumers and will affect the path of the entire industry.

We are conscious that there will be further consultation on the TPM itself and considerable discretion has been left to Transpower to develop a TPM consistent with the guidelines. Meridian's comments in this Part C are focused mainly on the proposed components that will be required under the guidelines, namely the:

- connection charge;
- benefit-based charge;
- residual charge;
- prudent discount policy; and
- price cap.

Connection charge

The Authority proposes to retain the current connection charge. Meridian continues to support this proposal. The connection charge is efficient and stable; it has stood the test of time.[9]

[9] Meridian Submission *Second issues paper* 2016, pages 29 – 30.

Previous consultation rounds have identified potential tweaks to the connection charge. Examples are the mode of calculating depreciation (pooled or asset-based), and whether to address a potential “first-mover disadvantage”.[10] Although issues like these could be dealt with now and may further optimise the connection charge, Meridian considers these are very much second order in terms of the operation of the TPM overall. Given that participants have not raised substantial practical problems with the connection charge, Meridian supports the status quo remaining in place during the current reform process.[11]

Similarly, Meridian would recommend deciding now to defer the four potential additional components that the Authority has proposed for Transpower’s consideration that relate to the connection charge.[12] That is, additional components: A (staged commissioning); B (charging method for assets principally providing connection services); C (alignment of recovery method for new connection assets and benefit-based charge); and F (method for allocating opex).

The Authority’s proposal is that Transpower must incorporate these components if, in Transpower’s reasonable opinion, including that component would better meet the Authority’s statutory objective than not including that component.[13] While it is possible that some or all of the proposed components could improve aspects of charging for connection assets,[14] Meridian recommends that Transpower defer consideration of these components for a set time in order to simplify and speed Transpower’s initial implementation of the TPM.

The Authority’s proposal risks unnecessarily delaying TPM reform for two reasons. First, it is not clear whether the additional components will substantially improve the connection charge. For instance, additional component A is aimed at only assisting with weakening unwanted incentives, additional component B seems not to be sought by the customer for

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10 First mover disadvantage describes a scenario where although it may be efficient in the medium to long term for a new connection investment to be constructed at a scale large enough to accommodate multiple new generators, the first generator to connect may be subject to high charges in the initial period before others connect, or for a longer period if the other generators do not connect, and thus might inefficiently reduce the number of new generation connections. It appears this reasoning could also apply to load though it may be less likely in practice.

11 See Meridian Submission *Second issues paper – Supplementary ‘Refinements’ Consultation* 2017, paragraphs 109 – 110.

12 In accordance with clause 29 of the draft guidelines.

13 Electricity Authority *2019 Issues Paper*, page 98 (clause 54 of the draft guidelines). We comment on this wording further at page 27 below.

14 Meridian Submission *Second issues paper* 2016, pages 30 and 44.

whom it appears to be designed (the Waipa Networks example),[15] and component F is described as "a relatively low-priority issue".[16]

Secondly, the potential delay to TPM reform as a result of Transpower assessing these additional components is undesirable because it risks coming at the cost of implementing urgent, core TPM reform.

The TPM review is well-advanced and already contains major components which address pressing areas in need of reform (removal of the HVDC charge and development of a benefit-based charge being key among them). These components will require Transpower's urgent and careful consideration. They should precede consideration of the proposed additional components relating to the connection charge. The proposed additional components relating to the connection charge could be programmed in for consideration by Transpower as part of future refinement of the TPM.

Benefit-based charge

Meridian has consistently supported the principle that transmission customers should be charged in accordance with their private benefit. This principle is critical to achieving a fairer, more efficient and more durable TPM. The benefit-based charge of the proposed TPM would effectively implement this principle by allocating the costs of an investment in the interconnected grid to those who benefit from it, in proportion to the size of their net private benefit from the investment. NERA notes that a beneficiaries-pay approach is "in accord with workably competitive market outcomes"[17] and is also promoted by the Federal Energy Regulatory Commission (FERC) in the United States.[18]

The Authority has identified seven existing assets to which the benefit-based charge will apply. The Authority has identified the beneficiaries of those existing assets in Schedule 1 of the proposed guidelines. The benefit-based charge would also apply to new transmission investments.

15 See Electricity Authority *2019 Issues Paper*, at B.298.
16 See Electricity Authority *2019 Issues Paper*, at B.351.
17 NERA *Review of Electricity Authority's transmission pricing review 2019 papers* 2019, at 4.1.
18 NERA *Review of supplementary paper* 2017, paragraph 117.

Options for existing assets

The Authority has identified three options for the recovery of the costs of existing transmission assets:

1. apply the benefit-based charge only to future grid investments and recover the costs of existing investments through the proposed residual charge on load customers;
2. apply the benefit-based charge only to future grid investments and recover the costs of existing investments through a shaped residual charge that reflects the current HVDC and RCPD charges;
3. apply the benefit-based charge to significant pre-2019 investments and to future investments with the remainder recovered through the proposed residual charge on load customers (this option is the Authority's preference).

Meridian supports the Authority's preference for option three for all the reasons given by the Authority in paragraph 54 of Appendix B. Option one would also be a viable alternative and significant net benefits have been modelled by the Authority for this option. However, Meridian considers recovery of the costs of existing assets through the residual to be less durable in the long-term as the initial allocation of transmission costs to consumers would be greater and regions that do not benefit from certain assets would continue to pay for them.

Meridian strongly opposes option two or any other option that recovers the cost of existing assets through a shaped residual charge to reflect the current HVDC and RCPD charges. Any attempt to lock in, for the life of the relevant assets, the current HVDC and RCPD charges would perpetuate all the problems identified by the Authority and the associated inefficiencies and costs to consumers. As noted above there is no principled justification for treating the HVDC differently from all other interconnection assets and imposing the burden on an arbitrary subset of beneficiaries. Any option that perpetuates the current HVDC charge is therefore unjustifiable and will not be durable.

Identification of existing investments that are subject to the benefit-based charge

Meridian supports the benefit-based charge applying to significant pre-2019 grid investments and considers the methods proposed by the Authority to be reasonable. Meridian supports the proposed post 2004 and over $50 million thresholds for the inclusion of existing assets under the benefit-based charge. This is a pragmatic trade-off that captures the bulk of the value of transmission assets commissioned since 2004 without incurring excessive implementation costs. Meridian notes that Pole 2 of the HVDC was commissioned prior to 2004 and therefore does not meet the threshold for inclusion. However, Meridian supports the costs of Pole 2 being recovered under the benefit-based charge on the basis that it is appropriate to treat Pole 2 and Pole 3 consistently – these assets jointly provide energy and ancillary services and any attempt to charge separately for them could encourage distortions in their use. The inclusion of Pole 2 under the benefit-based charge will promote durability.

Covered costs of existing benefit-based investments and conversion to annual charges

To spread the recoverable costs of a pre-2019 asset over its lifetime, the Authority has considered two options:

- Indexed historic costs (IHC): Under IHC Transpower would set the annual benefit-based charges for an investment by dividing the expected benefit-based charge into equal annual amounts over the benefit-based investment's expected life; or
- Depreciated historic costs (DHC): Under DHC Transpower would pass on the capital cost and cost of capital for an asset in each year to reflect Transpower's RAB values and annual recovery of capital components under Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act. DHC means that charges are higher in earlier years and lower in later years.

Meridian strongly supports the use of DHC to spread the costs of existing assets over their lifetimes. This is desirable because it would:[19]

- ensure that depreciation to date is accounted for, that Transpower does not recover more than the assets are worth, and that transmission customers do not "pay twice" for an asset;
- be consistent with the approach of the Commerce Commission and therefore consistent with clause 12.89 of the Code;
- align revenue recovery rules under the Commerce Act with the cost allocation method and avoid the need for complex adjustments to residual charges to prevent misalignment and divergence from the revenue requirement;
- be simpler for Transpower to implement; and

19 See Meridian Submission *Supplementary 'Refinements' Consultation* 2017, paragraphs 36 – 69 for further details; and see Meridian Cross-Submission *Supplementary 'Refinements' Consultation* 2017.

- avoid the issue of switching from DHC to IHC part way through the asset's life and recipients of benefit-based charges having to pay more under DHC pre-TPM reform and then more under IHC post-TPM reform, with the result that they end up paying far in excess of net benefits derived from the asset.

Identification of beneficiaries and allocation of costs for existing assets

The Authority has included in Schedule 1 of the proposed guidelines an allocation between transmission customers of the costs of the seven pre-2019 investments that are proposed to be subject to the benefit-based charge.

Meridian supports the allocation determined by the Authority and agrees that it should expedite implementation of a new TPM. Early implementation would ensure that the benefits associated with the new TPM are achieved earlier.

Meridian supports the methodology used by the Authority to populate Schedule 1 by identifying each customer's share of the positive net private benefits resulting from the investment estimated using the Authority's version of the Scheduling, Pricing and Dispatch model (vSPD). Meridian commissioned Orbit Systems to rerun some of the vSPD modelling used by the Authority and test the input assumptions and alternatives. Orbit's summary report concludes that the vSPD methodology applied by the Authority is robust and objective, and that its assumptions appear reasonable – resulting in a market-like way to identify the beneficiaries of each pre-2019 asset. No model is perfect, and modelling assumptions are necessarily made about the behaviour of market participants. However, Meridian agrees that the allocation of costs in Schedule 1 reflects the distribution of benefits from those investments and will result in a more durable TPM.

Meridian has considered the alternative "approximate regional method" for allocating the costs of the seven pre-2019 investments. Meridian agrees that this alternative is inferior to the proposed vSPD method and that it:

- spreads charges across each of four regions in an arbitrary manner rather than identifying benefits on a nodal basis using a market-like method;
- relies on blunt and non-market-like judgements that are only weakly connected to the principle that a customer's charges should reflect its benefits from each grid investment; and
- could create boundary distortions.

As an example, the "approximate regional method" for allocating the cost of the HVDC link allocates 50 percent to South Island generation, 40 percent to North Island load, and 10 percent to South Island load. This would mean that North Island generators continue to pay for none of the HVDC link despite that link enabling southward transfer of energy in 14 percent of trading periods in the four years to June 2018[20] as well as enabling the creation of national markets for ancillary services such as frequency keeping and reserves (in which North Island generators are significant participants).

New investments

In terms of new investments, Meridian supports the Authority's proposal that the cost of all new transmission assets be recovered under the benefit-based charge. A benefit-based charge for new grid investments will promote efficiency and the long-term benefit of consumers. Meridian agrees that this charge would mean transmission customers:

- have an incentive to take transmission costs into account when making decisions about their own investments and use of the grid; and
- have a stronger incentive to engage with the Commerce Commission's decision-making process for proposed grid investments.

Meridian also considers a benefit-based charge, aligned with the net private benefits each transmission customer is expected to receive from transmission investments, to be the most durable and reasonable way to allocate interconnection costs.

Transpower will have a number of decisions to make in developing a benefit-based charge for post-2019 investments (including both standard and simple methods). Our comments in the remainder of this section focus on the parameters set in the Guidelines for Transpower to follow in developing a benefit-based charge for the TPM.

Standard and simple methods

The Guidelines require Transpower to use a standard method to allocate the benefit-based charges for high-value post-2019 benefit-based investments. "High-value" is defined to mean an investment that at the time of commissioning exceeds the base capex threshold set by the Commerce Commission in Transpower's capex input methodology determination. Currently that value is $20 million dollars.

[20] Electricity Authority *HVDC transfer*, available at: https://www.emi.ea.govt.nz/r/4wers.

The standard method requires the allocation of the costs of benefit-based investments to be in proportion to the expected net private benefits that a transmission customer will receive from the investment. The simple method on the other hand may be applied to investments below the high-value thresholds and must approximate the standard method but with lower implementation costs and with exemptions allowed for transmission customers that do not receive a major net private benefit from an investment.

Transpower is not required to use a simple method and can use the standard method, simple method, or a combination of both to allocate the cost of benefit-based investment under the high-value threshold.

Meridian supports the alignment of the high-value threshold for use of the standard method with the Commerce Commission's base capex threshold.

A standard method that uses vSPD to calculate the difference in producer and consumer surplus in "with asset" and "without asset" scenarios, applies a mathematical calculation based on wholesale market prices and offers. While several assumptions would still need to be made in deploying such an approach, it is possible to adopt a robust and well-justified basis for these assumptions. Meridian agrees that perfect objectivity should not be expected from the methods for the allocation of the benefit-based charge. However, to the extent possible, a high degree of objectivity and mechanical calculation is desirable. The vSPD approach is familiar to participants both as a market tool and as a means to determine beneficiaries of a transmission asset, as demonstrated by the Authority's development of Schedule 1 of the proposed Guidelines. It is difficult to see how a different approach by Transpower would attain similar levels of objectivity. Meridian would therefore support Guidelines that are more prescriptive about the use of a vSPD method to allocate the costs of new investments. This could enable Transpower to more quickly develop and implement the TPM, rather than spend time considering a broad range of alternative methods.

IHC or DHC for new investments

The Authority proposes that for post-2019 investments Transpower would set the annual benefit-based charges for an investment by dividing the expected benefit-based charge into equal annual amounts over the benefit-based investment's expected life. This is an IHC-based methodology. Meridian has reservations about this approach on the basis that it would:

- be inconsistent with the approach of the Commerce Commission and therefore less consistent with clause 12.89 of the Code; and
- misalign revenue recovery rules under the Commerce Act with the cost allocation method and therefore necessitate adjustments to residual charges to prevent divergence from the revenue requirement – more residual would need to be charged initially to make up Transpower's maximum allowable revenue, while later as an asset depreciates the residual charge would have to be cut to avoid over recovery (this will be more challenging over time as the size of the residual charge shrinks).

Using IHC for post-2019 investments would also create difficulties when it comes to upgrades of assets. Under the proposed Guidelines Transpower would be able to treat upgrading expenditure as additional capital expenditure on an existing investment. It is not clear how this would work for pre-2019 assets, for example if there were upgrades to the existing HVDC assets the benefit-based charge for the pre-2019 investments would be recovered over time using the Commerce Commission DHC method but the benefit-based charge for any upgrading investment would be recovered using IHC.

Meridian considers it is simpler to use the DHC method for both existing and new investments.

Reopeners

The proposed Guidelines require that once a transmission customer's share of the benefit-based change has been allocated, that share will not change except in limited circumstances allowed by the Guidelines. Reopeners may be available:

- in the case of a substantial and sustained change in grid use affecting the net private benefits derived by customers;
- for the entry or exit of a transmission customer;
- when a transmission customer changes its point of connection;
- following the partial sale of a business; or
- when Transpower carries out a reassignment of charges on application by a customer.

The proposed Guidelines distinguish between:

- Transpower-led reviews of the allocation of benefit-based charges in the case of a substantial and sustained change in grid use; and

- reassignment of benefit-based charges to the residual charge on application from a transmission customer.

It is not entirely clear the circumstances under which each process will apply and the extent of overlap between the two. It is also not entirely clear how the "80% of current value" threshold would be applied in practice. Meridian considers there to be some scope to consolidate and clarify the reopener provisions. Part D of this submission provides further details.

It is important that there is some ability to update the allocation of benefit-based charges should there be a significant and unforeseen change to the relative benefits to transmission customers. Otherwise, there is a risk that over time a new TPM will misalign benefits and charges, which is the same fundamental problem that characterises the current TPM. We therefore support the inclusion of reopeners in specific circumstances. Meridian considers this will improve the durability of the TPM. However, Meridian considers that the durability and adaptability of the benefit-based charge would be further improved by providing for a regular review and update of the benefits assessment.

In previous submissions Meridian has also noted the merits of a regular (say five-yearly) review mechanism for the assessment of benefits under a benefit-based charge.[21] The benefits of a more mechanistic review process include:

- maintaining closer alignment of benefits and charges in situations where the substantial and sustained change in grid use threshold has not been triggered;
- reducing the number of times that Transpower must carry out assessments for a substantial and sustained change in grid use;
- reducing the degree of contention during Transpower's initial assessment of beneficiaries because customers will know that their share of charges for the lifetime of an asset would be updated over time.

We recognised in 2016, and continue to acknowledge, that there may be perceived disadvantages with a regular review, including the potential for upcoming reviews to incentivise transmission customers to alter their behaviour to reduce their assessed benefits. This concern seems to be driving the Authority's preferences for a more fixed charge with only significant and sustained changes in grid use justifying a reassessment of the allocation of the benefit-based charge. However, Meridian continues to believe that a regular review

21 Meridian Submission *Second Issues Paper* 2016, page 35 – 36.

is unlikely to cause behavioural distortions. Wholesale market participants have more pressing considerations like selling energy or producing goods and under the proposed TPM the relative benefit of reduced transmission charges would in our view seldom outweigh the costs of the change in behaviour, for example a reduction in generation output. The type of behaviour required to reduce benefit-based charges is very different to the behaviour that might be expected to avoid an RCPD charge using batteries to avoid or reduce consumption over a set number of peak periods – the change in behaviour would have to be much more sustained and would therefore be far less economic.[22]

Residual charge

The Authority has proposed the TPM include a residual charge on load customers to allow Transpower to recover any remaining maximum allowable revenue not recovered through the connection and benefit-based charges.

Meridian supports the use of a residual charge that minimises distortions on behaviour and the inefficient avoidance of transmission charges. Meridian also supports the allocation of the residual charge to load. NERA considers that levying a residual charge on load is supported by economic theory and is the norm internationally.[23] NERA also found that load has more inelastic demand for transmission services than generation, and load tends to benefit from the connection of new generation more strongly than generation benefits from the connection of load (known as positive network externalities).[24]

Meridian supports the proposed residual charge based on a customer's demand prior to July 2019 as this is simple, efficient, and minimises incentives on a customer to change their use of the grid purely to reduce their contribution to the residual charge.

The Authority has considered allocating the residual charge using different measures of historical demand:

- Anytime maximum demand (AMD) – a peak measure that would mean a load customer might pay less if it were embedded than it might if it were grid-connected, distorting load customers' decisions on location and connection.

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22 One potential exception is the embedding of generation within a distribution network or at an industrial site. However, the terms of a regular review could be crafted to specifically avoid inefficiently incentivising such generation investments. For example, the impact of embedded generation could be ignored in a review unless evidence is provided that the embedding of generation was economic regardless of any change in transmission costs following a review.

23 NERA *Review of Electricity Authority's transmission pricing review 2019 papers* 2019, at 4.5.

24 Ibid.

- Annual electricity consumption – which would treat grid-connected and embedded load customers in the same manner but would tend to have a greater impact on large industrial consumers with flat load profiles rather than peakier demand sources.

The Authority's preferred option is to base the residual allocator on historical AMD, as this may reduce the likelihood of disconnection of some large loads. However, Transpower is left with discretion to propose an alternative that is consistent with the Authority's statutory objectives.

For customers with multiple points of connection, the Authority proposes a 'non-coincident peak' measure of AMD, that measures peak demand for each point of connection separately and allocates a residual charge for each point of connection.

The Authority also proposes a gross load approach to measuring the residual allocator.

Meridian does not have a strong view on the use of AMD or annual consumption, over each point of connection individually or in combination, or on a gross or net basis. However, we agree with the Authority that the residual charge should be tax like, avoid distortions, and be allocated in proportion to a customer's size. Meridian is therefore comfortable with the Authority's preferred design elements. We also agree with the Authority that the residual charge should not be an explicit peak-based charge as sufficient transmission usage signals will already be sent through nodal prices.

Prudent discount policy

The Authority proposes that the TPM must provide for a prudent discount policy (PDP) that removes the incentive for customers to inefficiently bypass the grid.[25] Meridian continues to support having a PDP as part of the TPM.[26]

We support the proposed criteria that a PDP is available where:

- it would be technically and operationally feasible, and commercially beneficial, for a customer to bypass the grid in favour of alternative supply; and

25 Electricity Authority *2019 Issues Paper*, page 96 (clause 46 of the draft guidelines).
26 See Meridian Submission *Second Issues Paper* 2016, pages 40 – 42.

- doing so would be inefficient given Transpower's economic costs of providing the customer with access to the interconnected grid and the economic costs incurred by the customer if it bypassed the grid.

These criteria are less prescriptive than those in the Authority's 2016 proposal. While Meridian supported the Authority's former set of criteria including in respect of linkage to key factors (such as world prices) and the applicant taking significant steps to eliminate unnecessary costs, we have also cautioned against linking a prudent discount to factors that are too "tightly calibrated".[27]

We consider the Authority's present formulation of guidelines for the criteria for a PDP strikes an appropriate balance. The risk of an applicant seeking to game the PDP is further reduced by the fact that the onus of establishing the criteria rests on the applicant.

The Authority also proposes that a prudent discount will apply for the remaining life of the investment unless Transpower and the party receiving the discount agree to a different period. Meridian continues to support this default rule.[28]

Price cap

The Authority proposes a cap on the rate of change of transmission prices. The price cap is intended to limit increases in charges due to the reallocation of existing transmission costs resulting from the proposal.[29]

As a matter of economic principle, Meridian considers that a price cap is undesirable as it will slow the introduction of efficient benefit-based charges and may undermine grid price signals.[30] We do not consider that the Authority's three reasons in favour of a price cap outweigh the economic downsides:

- As to certainty, although Transpower is given discretion in developing the TPM, when the TPM has been developed by Transpower the Code requires Transpower's TPM proposal to include indicative prices, "to allow the Authority and interested parties to understand the impact of the methodology" on customers.[31] Customers are therefore likely to know their charges in advance with relative certainty even without

27 Meridian Submission *Second Issues Paper* 2016, page 41.
28 Meridian Submission *Second Issues Paper* 2016, page 40.
29 Electricity Authority *2019 Issues Paper*, B.260.
30 Meridian Submission *Supplementary 'Refinements' Consultation* 2017, paragraph 128.
31 Electricity Industry Participation Code 2010, clause 12.89(2).

a price cap. Furthermore, the need for change and the broad direction of change has been signalled by the Authority for around seven years now.

- As to the cap being an alternative to the PDP for customers who may go out of business, it is not clear why the price cap should perform the function of an additional limb to the PDP in circumstances where the Authority does not favour including that in the PDP itself.
- As to potential efficiency effects from price shocks, the Authority's modelling suggests this is unlikely to be an issue. Figure 14 in the Issues Paper indicates the price cap would only slightly protect consumers in three distribution networks (Buller, Horizon, and Westpower). In every other distribution network, the Authority's analysis indicates that residential end consumers will be slightly worse off under a cap. The only notable financial relief provided by a price cap is for major industrials, whose charges would be $13.8m lower as a group if a cap is imposed.[32] The possible concern about price shocks therefore appears unlikely to eventuate for most customers.

However, Meridian acknowledges that a price cap may be justifiable for pragmatic reasons to address concern about potential price jumps providing it applies for a limited time and that there is a clear pathway to uncapped charges. That should be the sole purpose of a price cap, if a cap is to be imposed.

Given that the rationale for a price cap is pragmatic only, the working out of the cap should be as simple as is practicable. Assessed against that criterion, the Authority's basic idea for the cap appears to be workable although some features may require further refinement (either by the Authority or by Transpower):

- The idea that transmission charges are capped over the charge paid in 2019/2020 to no more than 3.5 percent of the estimated total electricity bill is comprehensible and appears to be workable.
- Pegging the cap to transmission charges, but expressing it as part of the overall electricity bill, might also be justifiable on pragmatic grounds.
- However, parts of the proposal are complex. Different approaches are taken as between distributors and direct connect customers. Transition paths differ for the expiry of the cap between those customers. An alternative, prescriptive approach is also up for consideration.

32 Electricity Authority *2019 Issues Paper*, paragraph 5.13 (see Table 10 and the "Cap fund/(support)" column).

Given the above features of the proposed cap the Guidelines should set an explicit expiry date to reflect the fact that a cap is an interim, transitional mechanism.

Other matters

The Authority proposes a number of additional components. The proposed guidelines require Transpower to propose each additional component if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective.

Meridian recommends that this formulation should be amended. First, it should be expressly stated in the Guidelines that the Authority has the final say in approving these optional components of the TPM. Secondly, we recommend the removal of the reference to Transpower's "reasonable opinion" – this is unnecessary where the Authority is the final decision-maker and invites debate as to the reasonableness of Transpower's opinion.

In terms of each component specifically, we have addressed components A, B, C and F above, as they relate to the connection charge. We now address the remaining additional components.

Additional component D: Transitional peak charge

The Authority proposes including a transitional peak charge as an additional component. It replaces the Authority's 2016 proposal that Transpower consider introducing an LRMC charge as an additional component.[33] We support the Authority's proposal that Transpower includes a temporary peak charge, targeted to those areas where it is needed to influence grid use, if including this charge would better meet the Authority's statutory objective than not including it.

As the charge would have a transitional function, and because inclusion in the TPM will depend on whether there are net benefits in introducing such a charge, we support the Authority's preference to include this charge as an additional component and not as a core component of the TPM or as a permanent charge.

We also support the Authority's requirement that any such charge is phased out from the end of year one, and fully phased out by a deadline such as five years.

[33] Meridian has previously supported Transpower considering a LRMC charge. See Meridian Submission *Second Issues Paper* 2016, page 44.

Additional component E: Including additional pre-2019 investments in the benefit-based charge

The Authority proposes that the benefit-based charge will apply to the HVDC link and six other pre-2019 investments. Additional component E provides that the TPM may include a method for extending the definition of benefit-based investment to other pre-2019 investments.

Meridian does not support this proposed additional component. We consider that the determination of which historic assets are subject to the benefit-based charge is appropriately made by the Authority and we continue to support the Authority's post-May 2004, $50 million value threshold as an appropriate measure for the inclusion of existing assets into the benefit-based charge. It is a pragmatic trade-off that captures the bulk of the value of transmission assets commissioned since May 2004 without incurring excessive implementation costs.[34]

Additional component G: kvar charge

Meridian has previously supported Transpower considering the introduction of a kvar charge.[35] We note the Authority's view that "there would be no immediate, material benefit in introducing a kvar charge".[36] Given that view, and for the same reasons that we gave for additional components A, B, C and F, we consider that the question of a kvar charge would be better left for future refinement of the new TPM.

Potential Code amendments

Alongside the new proposed TPM the Authority has proposed three potential Code amendments. The Authority is not proposing that the Code be amended at this stage, but seeks comment on "our proposal as a whole" and has indicated it may consult again on these matters.[37] In those circumstances we provide the following high-level feedback on the potential Code amendments.

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34 Meridian Submission *Second Issues Paper* 2016, page 31; Meridian Submission *Supplementary 'Refinements' Consultation* 2017, pages 5 – 10; NERA *Transmission pricing methodology – review of supplementary paper* 2017, section 3.1.

35 See Meridian Submission *Second Issues Paper* 2016, page 44.

36 Electricity Authority *2019 Issues Paper*, B.352.

37 Electricity Authority *2019 Issues Paper*, F.3 – F.4.

LCE

The Authority proposes amending the Code to provide that the grid owner must allocate any LCE it receives in a year amongst investments in proportion to the LCE generated by each investment (including where the cost is recovered through the residual charge), and in respect of each investment, amongst customers in proportion to the transmission charges they pay in that year for that investment. The proposed amendment would also provide that the allocation is deemed to be the prevailing methodology for distribution of LCE payments for the purpose of the benchmark agreement.

We support this Code amendment. Meridian continues to support codification of LCE credits, the use of LCE to offset transmission charges, and agrees that LCE is a market based approach to transmission pricing.[38] We also continue to support[39] crediting LCE against the charges for the assets that give rise to the LCE as a market based approach, and the monthly averaging period, which we confirm has not given rise to issues in respect of LCE attributed to HVDC charges.[40]

Meridian would like the proposed Code amendment to go further and resolve the practical issue of whether and how to pass LCE back to end consumers through invoicing. Currently, LCE for connection and interconnection assets is paid to distributors and directly connected consumers through a separate credit note from Transpower. For distributors, the Commerce Commission's input methodologies do not include rules on the treatment of this LCE credit and as a result distributors' treatment of LCE is varied and lacks transparency – some pass through LCE credit to retailers, others retain LCE as unregulated revenue, and some that retain LCE attempt to give it directly to consumers on their network by posting cheques or demanding that retailers post cheques on their behalf.

The sums of LCE involved are significant. The Authority should address the absence of rules for regulated monopoly recipients of LCE and prescribe a process for the treatment of

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38 See Meridian Submission *Second Issues Paper* 2016, page 28 and footnotes 85 and 86.

39 The same logic requires that LCE credits received by the South Island generators who pay HVDC charges should only be removed if the HVDC charge is also removed. We have previously supported the Authority's LCE proposal on the basis that "the new TPM will remove the present distinction between HVDC and HVAC assets for charging purposes": see Meridian Submission *Use of LCE to Offset Transmission Charges* 2014; and see Meridian Submission *Second Issues Paper* 2016, page 29.

40 Meridian Submission *Second Issues Paper* 2016, page 29; NERA *Review of second issues paper* 2016, page 22.

LCE. The simplest way to ensure consumers benefit from LCE would be to amend the Code and TPM to require Transpower to charge transmission costs net of LCE so that distributors receive a lower transmission charge rather than a separate LCE credit note.[41] Transmission charges are a recoverable cost under the Commerce Commission's *Electricity Distribution Services Input Methodologies Determination 2012* and form part of the regulated revenue that is passed on to retailers for recovery from consumers.[42] A lower transmission charge, net of LCE, would therefore result in a lower lines component of consumers' electricity bills.

ACOT

The Authority rightly observes that the proposed TPM guidelines "would change the basis for ACOT payments" because "[c]urrently, ACOT payments are based on reductions in distributors' RCPD charges ... [whereas] ... distributors would no longer pay RCPD charges".[43] Under the Authority's proposal, distributors would pay charges with largely fixed allocations (the connection, benefit-based and residual charges). Only if Transpower included additional components D (transitional peak charge) and G (kvar charge), would distributors also pay variable charges. Accordingly, the Authority has signalled a Code amendment to clarify that distributors are not required to make ACOT payments to owners of distributed generation in respect of benefit-based, residual and connection charges, but are required to make ACOT payments in respect of the variable charges (if they are included in the TPM).

Meridian agrees that ACOT payments should not be made in respect of the fixed charges in the proposed TPM given that the very basis for those payments is peak based RCPD charges which will not feature in the proposed TPM. We also see merit in the Authority's proposal that distributed generation should be treated alike, regardless of the date of installation and whether or not it appears in the lists of covered distributed generation.[44]

41 Clause 12.78 of the Code may also need to be amended so that the purpose of the transmission pricing methodology is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services (net of LCE) are allocated in accordance with the Authority's objective in section 15 of the Act.

42 Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* consolidated 31 January 2019: https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-January-2019-31-January-2019.pdf

43 Electricity Authority *2019 Issues Paper*, F.27.

44 Electricity Authority *2019 Issues Paper*, F.32 – F.33.

However, Meridian cautions against the need for a Code amendment specifying that ACOT payments must be made in respect of the variable charges if included in the TPM. First, this Code amendment may prove to be unnecessary if the kvar and transitional peak charge are not included. Secondly, particularly in respect of the peak charge, it is intended to be a temporary and transitional measure. Its inclusion for transitional reasons may well defer the benefits of the new TPM. We have previously submitted why it would be inappropriate for TPM to be (in this case, further) watered down by virtue of ACOT.[45] To the extent that this Code amendment may have this effect, Meridian does not support the prospect of future Code amendment in this respect.

TPM "workability" amendment

Finally, the Authority proposes a Code amendment allowing it to review an approved TPM if it considers it has become unworkable in its implementation or has been implemented inconsistently with the Authority's policy objective contained in the guidelines. The Authority believes this amendment is necessary to cover the risk of an issue arising that could not be corrected absent a material change in circumstances. We support the introduction of this safety valve.

45 See Meridian Submission *Second Issues Paper* 2016, pages 23 – 25; NERA *Review of second issues paper* 2016, page 30.

Part D: Overall drafting of the Guidelines

The Authority has proposed draft TPM Guidelines in Appendix A of the 2019 Issues Paper. We have reviewed the Guidelines and make the following general comments.

General comments

First, the overarching sequence of the Guidelines is broadly appropriate. It is logical that the Guidelines begin with an express statement of the purpose of each component of the TPM, followed by guidelines relating to each component, and finally guidelines on additional potential components and consequential matters.

We recommend the Authority provide expressly for the process to be followed by Transpower to implement the TPM, including timeframes. These are matters about which the Authority could either set guidelines or publish a process under clause 12.83 of the Code to assist Transpower in implementing the TPM as soon as possible so that the benefits of the proposal can be realised without further delay.

Secondly, we continue to support a TPM which minimises Transpower's operational discretion where possible. In respect of the main features of the TPM proposal, we support the Authority specifying the assumptions, methods, modelling inputs (or sources of modelling inputs), thresholds and detailed mechanics of the TPM components which are to be set out in the TPM itself.[46] That includes the guidelines relating to the connection charge, benefit-based charge, residual charge, and PDP.

There are other matters, however, where the TPM proposal could usefully be further considered by Transpower in developing its TPM, without the need for very specific guidance from the Authority in the Guidelines. The transitional price cap and the various adjustment and reassessment mechanisms referred to in the Guidelines are both within this category. In terms of the transitional cap, it may be sufficient for the Guidelines to set out the purpose, rate and broad nature of the cap, and to leave Transpower to develop the detailed mechanisms. That is because the cap is a temporary and largely pragmatic measure to be introduced to the new TPM. In terms of adjustment and reassessment mechanisms, the current Guidelines appear not to cover all scenarios where processes allowing for adjustment would or might be appropriate. Clause 42 refers, for example, to

46 Meridian Submission *Second Issues Paper* 2016, pages 28 and 31.

adjustments where there are increases in usage or generation, or a sale of business, but the Guidelines do not address the situation where a business shrinks rather than expands or is purchased.

Thirdly, we do not support some of the content of the general matters section of the Guidelines. Clause 2 allows Transpower to propose a TPM which "differs in its details" from the Guidelines, if Transpower considers "in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the Guidelines in their entirety". Meridian opposes this clause being included in the Guidelines. The reference to design "details" is inherently ambiguous. It will be difficult to determine in any particular case whether Transpower has proposed a different "detail" or something more substantive. More fundamentally, it is wrong in principle for the Authority to abdicate its regulatory function by deferring to Transpower's "reasonable opinion" about how best to achieve the Authority's statutory objective. We recommend the Authority removes this clause from the Guidelines.

We have prepared some possible amendments to the Guidelines in a marked-up version attached to this submission. They present the main changes that should be made to the Guidelines. Not all of Meridian's suggestion have been marked-up. In places we have inserted drafting notes. Further comments appear below.

Additional amendments to the Guidelines

Other amendments could be made to the Guidelines and we encourage the Authority to consider the following matters:

Policy objectives section

- This section should identify defined terms in the same way as has been done in later sections of the Guidelines, so that it is clear that they are intended to have the same meaning as in the interpretation section which appears at the end of the Guidelines.
- The high-level description of the transitional price cap could be less detailed in this general section of the Guidelines. The purpose of the transitional cap does not need to include reference to the year to which the cap will be pegged, or to clause 49 which sets out the features of the cap in more detail.
- The naming of some of the proposed additional components could be improved. These components should be worded so that they more explicitly describe a charging component rather than a situation that gives rise to that component

applying. For example, “Adjustment to prices for staged commissioning”, “Charges for assets that in substance provide connection services”, “Charges for connection assets are to use a method substantially the same as for benefit-based charges”, and “Allocation of opex”.

General matters section

- Clause 2 of this section should be deleted, for the reasons outlined above.
- Clause 3 is unnecessary and should be deleted. It is plain from the terms of clause 1 that Transpower must follow the general matters set out in that clause.
- The clauses relating to allocating annual benefit-based charges could be more simply expressed by stating in general terms what is meant by a standard and simple method and directing the circumstances in which each method should be used.
- The requirement for consultation in clause 5 could be better expressed as a requirement for Transpower to undertake consultation or to allow rights of challenge to the application of the TPM in any particular instance. Other than that, we recommend leaving it to Transpower to decide the precise form in which it will engage with customers on each occasion. We prefer this over the current wording of clause 5 which requires consultation in every case. Consultation will not always be the appropriate response to each of the situations described in the clause, for example charges for new assets may require more engagement with a customer than allocation of the residual charge or the parameters used in calculating charges. Clause 5 (and clause 6) should also make it clear that the consultation and other obligations to be referred to do not apply to the initial development of the TPM. The Authority has the task of consulting on the initial proposed TPM under clause 12.92 of the Code and to require Transpower to also consult would be duplicative.

Sections on main components

- All the provisions throughout the Guidelines relating to adjustments of various kinds to each of the charges could be brought together into a standalone section of the Guidelines dealing with adjustments or changes to charges. This could include the current sections dealing with damage to benefit-based investments (clause 18), reassignment (clauses 33-38), scaling back of charges (clauses 43-45), and the general section on adjusting benefit-based and residual charges (clause 42). This structural amendment is likely to make it clearer to understand the full range of changes that may be made to all charges under the new TPM.

- The provisions about adjustments to the benefit-based and residual charges could be drafted to expressly cover a greater number of situations that may arise. Alternatively, adjustments and reopeners may be appropriately left to Transpower to develop and describe in detail in the TPM.
- Leaving it to Transpower to develop the various adjustment mechanisms that are proposed will allow for further consideration to ensure that the mechanisms work as well as possible. Taking the reassignment provisions as an example, clauses 33 to 38 are not particularly clear on important aspects of this mechanism, as presently drafted. Neither those clauses nor the definition of "reassignment" defines what will trigger the reassignment process in the first place. The definition of "reassignment" refers to "a reduction in the value of an asset" but this is imprecise. Moreover, aspects of reassignment may have arbitrary outcomes. For instance, clause 32(b)(i) captures the situation where a single party's disconnection causes the value to be less than 80 per cent, but the provisions on reassignment do not provide for a situation where multiple parties' disconnection would cause the value to be less than 80 per cent or more. Finally, the Guidelines do not make it clear whether reassignment can occur in conjunction with other adjustment mechanisms contained in the TPM. All of this indicates that the Guidelines on adjustment mechanisms should be general in nature and should leave it to Transpower to flesh out the precise scope of each mechanism.

Potential additional components section

- We have proposed deferring consideration of the additional components relating to the connection charge (components A, B, C and F) and component G (kvar charge) in order to expedite development of the TPM. We also oppose the introduction of component E. Moreover, as we have submitted, the decision whether to incorporate any of these components should not depend on Transpower's "reasonable opinion" (clause 54).
- If our submissions are accepted, clauses 54 to 65 should be amended and/or deleted. The Authority could add a clause to this section providing that those deferred components can be considered at a later time by Transpower.

Part E: Cost-benefit analysis

The Authority is required to evaluate the costs and benefits of its proposal.[47]

Its cost-benefit analysis has found that the Authority's proposal, compared with the status quo, would generate an estimated quantified net benefit for consumers of $2.7 billion NPV (within a range of between $0.2b and $6.4b net benefit) between implementation in 2022 and 2050.

The Authority has also considered the costs and benefits of a variant of the Authority's proposal – applying the benefit-based charge to future investments only (with existing assets being recovered via the residual). This analysis resulted in similar benefits to the Authority's proposal ($2.73b) but has been assessed as having a very substantial, unquantified, additional cost: the lack of durability of such a proposal.

Meridian asked NERA to review the Authority's cost-benefit analysis. In summary, NERA's view is that the Authority's broad approach is appropriate, and the quantified net benefits are plausible.

NERA notes that:[48]

- The single largest quantified benefit of the proposal is more efficient grid use.
- At a conceptual level, it is appropriate to consider the broader electricity market benefits that TPM reform would bring (the energy price effect).
- The Authority's approach to disentangle transfers from efficiency effects by taking the average of the grid price and energy price effects is, if anything, likely to be conservative.
- A benefit of the magnitude calculated is plausible when considered in light of other economic analyses of allocative efficiency effects.

Meridian agrees with NERA's assessment and adds three general comments about the Authority's cost benefit analysis.

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47 Electricity Industry Act, section 39.

48 NERA *Review of Electricity Authority's transmission pricing review 2019 papers* 2019, at 5.1 and 5.2.

First, the direction and magnitude of benefits from the Authority's proposal are clearly in favour of change. In all scenarios, including with the most conservative assumptions, the proposal results in net benefits.

Secondly, the Authority's assessment of benefits is realistic. The quantified benefits have been presented as a range. Where the Authority considers in its judgment that the net benefits are more likely to be skewed toward one or other end of the range, it is entitled to take that into account.[49] In this case the benefits arise from a TPM where customers that benefit from an investment would be charged for it, recovery of revenues would no longer distort grid use or investment decisions, and better targeted price signals of grid congestion will be provided. Those are substantial improvements from the status quo. It is important to bear in mind that the quantified net benefits could be as large as $6.4b, being the top of the available range.

Thirdly, the Authority has had appropriate regard to qualitative, or unquantified, benefits and costs. In particular, it has reasoned that the proposal must include certain existing investments in order for the proposed TPM to be durable. This approach is undoubtedly correct. Courts have confirmed that relevant factors must still be given weight even if they are not quantifiable.[50] For example, in the resource management context, courts have said that "it is simply not possible to express some benefits or costs in dollar or economic terms" but that this does not "disparage, as a lesser means of decision making" the need to evaluate all the merits of the proposal against the relevant criteria.[51] Indeed, in the merger authorisation context the courts have said that qualitative factors "can be given independent and, where appropriate, decisive weight".[52]

The present reform is an instance where it is decisive that one of the qualitative costs of a future-investments-only TPM proposal is the cost of lack of durability of the entire proposal. The Authority acknowledges that durability is undermined in that scenario because "it would require some customers to continue paying for existing assets … from which they do not benefit, while also paying the full cost of future investment from which they do benefit."[53] In the case of the HVDC assets, the durability harm is even greater because, as we have

49 See *Ravensdown Corp Ltd v Commerce Commission* HC Wellington AP 168-96, 9 December 1996 at page 50.
50 See Meridian Submission *Second Issues Paper* 2016, footnote 127 for case law.
51 *Meridian Energy Ltd v Central Otago District Council* [2011] 1 NZLR 482 (HC) at paragraphs [107] and [111].
52 *Godfrey Hirst NZ Ltd v Commerce Commission* [2016] NZCA 560, [2017] 2 NZLR 729 at [38].
53 Electricity Authority *2019 Issues Paper*, paragraph 4.174.

previously submitted, in addition to the usual concerns about durability and fairness, HVDC charges have been contentious from the outset and under review for most of the current TPM's life.[54] Accordingly, HVDC costs should either be recovered through the benefit-based charge or the new residual.

In those circumstances, a realistic cost benefit analysis should treat durability of the proposed regime as a prerequisite to consideration as an option for reform. That is because a cost benefit analysis presupposes comparison of a counterfactual against durable options. A proposal that is not durable leads to regulatory uncertainty,[55] and can call the regulatory regime itself into question.[56] There is little sense in evaluating the costs and benefits of such a proposal. Where there are specific and obvious durability concerns it is appropriate that the Authority has given the qualitative "cost" substantial weight. In particular, any TPM that maintained the present arbitrary and inefficient treatment of the HVDC link would be a "non-starter".

Based on the Authority's quantitative cost-benefit assessment, NERA's review and endorsement of the approach, and the Authority's description of the additional qualitative benefits of its proposal, and the unquantified costs of a new-investments-only variation to the proposal, Meridian considers there is a clear and robust case that the proposed TPM will deliver significantly greater benefits to New Zealand electricity consumers than the current TPM or other alternatives.

54 See Meridian Submission *Second issues paper* 2016, Appendix 1 "History of the HVDC dispute".

55 NERA *Review of second issues paper* 2016, page 27.

56 Stephen Littlechild *Report on the Electricity Authority's Transmission Pricing Methodology Review* 2016, paragraph 36.

Part F: Compliance with statutory requirements

The Authority has met all requirements to amend the TPM guidelines

Meridian considers the Authority has met all the necessary statutory requirements in developing the TPM to date.

The Authority may amend the Code, including the TPM which is a schedule to the Code, at any time subject to consultation.[57] Clause 12.86 of the Code specifies the Authority may review the TPM if it considers there has been a "material change in circumstances". Changes which are significant, relevant, or more than de minimis are likely to be material changes in circumstances.[58]

Meridian agrees that this threshold has been surpassed including for the reasons given by the Authority:[59]

- Over $2 billion worth of transmission investment has been approved since the current TPM came into force. The inefficient behaviours and outcomes caused by the current TPM will be amplified by the scale of the recent and projected growth of Transpower's asset base.
- The regulatory framework has changed significantly since the current TPM was introduced, including the establishment of a new regulator operating to a new statutory objective under the Electricity Industry Act 2010 (Act). The function of approving grid investments has also been transferred to the Commerce Commission.
- Advances in technology mean that consumers are fundamentally changing the way people engage with electricity markets including by way of small-scale distributed generators, batteries, electric vehicles and so on. The current TPM pre-dates this period of innovation.
- Advances in computational power mean that more sophisticated options are now available for calculating TPM charges by measuring transmission services and identifying who is receiving those services.
- New climate change Government objectives affect the demand for and use of the grid.

57 Electricity Industry Act, section 38.
58 See Meridian Submission *Second issues paper* 2016, footnote 18.
59 Electricity Authority *2019 Issues Paper*, Appendix C.

Each of these developments is a material change in circumstances and, taken together, there is clearly a material change in circumstances justifying a full review of the TPM. In any event the changes identified by the Authority are so broad-ranging in their nature that they would not limit the scope of the review of the TPM.

In terms of process the Authority has also:

- Defined the problems with the current TPM (chapter 2, and see Second Issues Paper, chapter 6);
- Consulted on draft proposals (including in 2012, 2016 and now in 2019);
- Evaluated the costs and benefits of the present proposal (chapter 4 and technical paper);
- Assessed alternatives (appendix E);
- Assessed the proposal against its statutory objective (chapter 4 and appendix D).

The Authority has previously proposed that it will publish a regulatory statement when it consults on the proposed TPM itself.[60] This would include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. These matters have been addressed comprehensively to date and we would anticipate that the regulatory statement would draw heavily on the Authority's prior work.

Meridian considers the Authority's approach to date to be consistent with the Code amendment principles.

Decision-making and economic framework

The Authority continues to support the essence of its DME analysis described in the second issues paper, and has further elaborated on it in this issues paper by distilling six "principles for transmission pricing" as follows:

- Each user should pay the cost of connecting it to the grid.
- Locational marginal prices are generally the best means of restricting the use of the grid to its capacity.
- The charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment.

60 Electricity Authority *2019 Issues Paper*, at 6.24.

- Charges for a transmission investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment.
- Charges for a transmission user should be similar to those for other competing users after adjusting for their size and location.
- Any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.

We continue to support the Authority's use of the DME framework and its elaborations throughout the various rounds of consultation, including the six principles for transmission pricing, which are consistent with the underlying principles of cost-reflective and service-based pricing. The DME framework and its elaborations are useful tools for identifying and evaluating different options and have been used appropriately by the Authority to date for that purpose.

The DME framework should not, however, be treated as a strict hierarchy of preferred methods of charging. That is because pragmatism is required in developing an acceptable TPM. Trade-offs will be required between competing requirements that a TPM will address. Nor does the DME framework replace the Authority's ultimate test, which is to determine the pricing option that best meets the Authority's statutory objective.[61]

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61 See Meridian Submission *Second issues paper* 2016, at pages 3 – 4.

Part G: Process for the development of the TPM

Process to date

Meridian supports the Authority undertaking its review of transmission pricing. We note the current review process has been underway since 2009. Over this period, the Authority has undertaken considerable research, analysis, modelling and engagement with stakeholders. All this work has contributed to developing the TPM proposals to their current state. Meridian considers that the time and effort expended reflects the complexity and importance of this issue as well as the vested financial interest that some parties have in delaying reform and retaining the status quo.

Meridian acknowledges the significant opportunities the Authority has provided for stakeholders to engage in the TPM reform process. We note that 17 rounds of consultation have been undertaken since early 2012, as well as a conference and numerous regional and technical workshops. These processes have generated input from a wide range of industries, experts, consumer organisations and individuals.

Meridian considers the current proposal is robust and balanced because of the Authority's inclusive and responsive approach to developing the TPM.

Process for development and approval of TPM

Implementation timeframe and the costs of delay

The Authority has published an indicative timeframe that shows implementation of a new TPM in 2024. Meridian considers this timeframe too long.

We observe the Authority's modelling of estimated charges assumes that the proposal would be implemented in 2022 (i.e. in the 2021/2022 pricing year).[62] Certainly we consider a shorter timeframe to that indicated in the paragraph above to be more appropriate and achievable.

Given the substantial efficiency benefits identified by the Authority, every effort should be made to implement a new TPM as soon as possible. Earlier implementation of a new TPM

62 Electricity Authority *2019 Issues Paper*, at 5.6.

would result in additional efficiency benefits for consumers. For example, supposing the same stream of consumer welfare gains were brought forward by one year, the net benefits would increase by approximately $163m.[63] The delays of TPM reform to date mean consumers have already foregone years of potential benefit. Further delays should be avoided wherever possible.

Remaining steps to implementation

The Authority has proposed giving Transpower 12 to 18 months to develop a TPM once the guidelines are set. We observe that the Code envisages a 90-day period (or longer if allowed by the Authority) for this step. Against that starting point, Meridian considers that a 12 to 18-month TPM development period may be too long, given the extensive consultation to date and the level of detail contained in the proposed guidelines for Transpower to use in developing a TPM. Furthermore, any Transpower work that does not depend on the precise detail of the TPM guidelines can start immediately.

Whatever length of time is given for Transpower to develop the TPM, we do not consider that additional informal engagement by Transpower with stakeholders is likely to be useful while Transpower develops the TPM.[64]

Transparency and accountability are important. However, these benefits are likely to be achieved in any event, because Transpower is required to develop a TPM consistent with the Authority's statutory objective and the Guidelines. The Authority is also able to refer the proposed TPM back to Transpower and we note there will be further consultation by the Authority once a TPM has been developed and published. In these circumstances, we consider that additional informal participation by stakeholders at the intermediate stage of TPM development is duplicative and is not necessary or desirable. It may allow dissatisfied parties to seek to delay implementation of the TPM. We consider that any further delay to TPM reform should be avoided, especially where there has already been ample opportunity for participation (and where there are further opportunities).

The checkpoints proposed between Transpower and the Authority are likely to be useful and we support this proposal.

63 NERA *Review of Electricity Authority's transmission pricing review 2019 papers* 2019, at 5.4.
64 Electricity Authority *2019 Issues Paper*, at 6.19.

Proposed implementation timeframes

Clause 12.83 of the Code states that, after considering submissions the Authority must, as soon as reasonably practicable, publish:

(a) the process for the development of the transmission pricing methodology; and
(b) any guidelines that Transpower must follow in developing the transmission pricing methodology.

Meridian considers TPM reform to be urgent and that the Authority should publish a prescriptive process for Transpower to follow in developing a new TPM. While ideally the TPM developed by Transpower and approved by the Authority would commence in 2022, at a minimum Meridian suggests the following process:

- By April 2020 – the Authority should finalise and publish the new Guidelines and immediately request that Transpower submit a proposed TPM.

- By April 2021 – Transpower should develop the proposed TPM, and submit the proposed TPM to the Authority, checking in with the Authority throughout the development of the TPM, for example:
    - within 4 months, provide the Authority with a summary describing the key design choices in its proposed TPM and revise if recommended by the Authority;
    - within a further 5 months, provide the Authority with a draft of the proposed TPM and revise if recommended by the Authority;
    - by a firm deadline of 12 months from the Guidelines being published, present the Authority with its proposed TPM.

- From April 2021 – the Authority should publish and consult on the proposed TPM.

- By October 2021 – the Authority should decide whether to approve the TPM and, if doing so, immediately amend the Code.

- By November 2022 – Transpower should have altered its processes and systems to implement the new TPM. Prices can be published shortly thereafter.

- In April 2023 – Transpower implements the new system and it is operational for the 2023/24 pricing year.

The timeframes proposed above allow Transpower a year for development of a TPM and a further year to alter their systems and processes for implementation. If required, Transpower can bring in additional resources for this task and recover the costs of those resources through an increase in regulated opex and capex. Meridian's experience in this process of reform indicates that all steps of TPM reform will face resistance. Meridian's proposed approach will provide clarity of process and help to reduce the risk of delay and the significant costs that are associated with it.

Part H: Attachments

NERA Report

Orbit Report

Mark-up of the TPM Guidelines

NERA
ECONOMIC CONSULTING

Review of Electricity Authority’s transmission pricing review 2019 papers

Meridian Energy

1 October 2019

Project Team

James Mellsop

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Contents

1. Introduction

1. On 23 July 2019, the Electricity Authority released an issues paper (**"IP"**) and accompanying technical paper (**"TP"**)[1] describing proposed reform to the transmission pricing methodology (**"TPM"**). We have been asked by Meridian Energy to review the IP and TP, as well as the accompanying papers.
2. The crux of the proposed reform is to eliminate the regional coincident peak demand (**"RCPD"**) and high voltage direct current (**"HVDC"**) charges, replacing them with:
    a. Benefit-based charges to recover new grid investments and certain existing grid investments; and
    b. Residual charges to recover the balance of Transpower's maximum allowable revenue (**"MAR"**).
3. We set out our comments in this report.

2. Executive summary

4. There are significant problems with the current TPM, both as it applies to new grid investments and existing grid investments (particularly the HVDC). The current TPM is leading to:
    a. Inefficient load, generation and grid investment;
    b. Underutilisation of the grid;
    c. Over-investment in distributed energy resources; and
    d. Unfairness and durability problems.
5. Replacing the RCPD and HVDC charges with benefit-based and residual charges would address these problems (see section 3 of this report).
6. We are broadly supportive of the proposed design of the benefit-based and residual charges, with some exceptions (see section 4 of our report).
7. Because of the interdependency of the grid and the broader wholesale electricity market, more efficient grid pricing would lead to a more efficient wholesale electricity market. The Authority's cost benefit analysis (**"CBA"**) captures this interdependency and more generally appropriately approaches the quantification.
8. Furthermore, the magnitude of the CBA results is plausible, on the basis of empirical and regulatory estimates of allocative efficiency in industries across economies. See section 5 of our report.

[1] And some further accompanying papers.

3. Problem definition

9. In Table 1 we summarise the Authority's problem definition and provide our comments on it. In summary, we agree with the Authority's problem definition, and we consider that the proposed reform would address the identified problems.

Table 1: Commentary on problem definition

Problem identified by the Authority	NERA comment
Recovery of Transpower's MAR is effectively socialised, meaning that generation and load investment decisions do not fully take into account their impact on grid costs.	A benefit-based charge would result in grid-connected investors taking into account the impact of their generation and load investment decisions on grid investment costs, which would therefore result in investment decisions being more socially efficient.
Socialisation can also lead to beneficiaries advocating for what might be socially inefficient grid investments, and poor grid investment scrutiny by others.	A benefit-based charge should improve participation in, and information available to, the Commerce Commission in respect of its decision-making process about proposed grid investments.
The RCPD charge discourages grid-based electricity use at times when consumers most value it, even though there might be spare grid capacity.	Conceptually this is an allocative inefficiency problem, and the evidence summarised by the Authority suggests it is a material problem. Even though the demand for electricity is inelastic, the Authority does refer to evidence of load responses, and load does have the option of acquiring electricity off-grid, even if this is less efficient. The proposed benefit-based charge and residual charge would raise the required revenue in a materially less distortionary way. The nodal price provides a sufficient signal of transport and congestion costs – the RCPD is not needed for this.
The RCPD charge encourages customers to unnecessarily invest in and operate technologies such as batteries and distributed generation to avoid paying transmission charges, shifting charges to others without necessarily reducing Transpower's costs.	Conceptually this is a productive and dynamic inefficiency problem, as unnecessary investments and costs are incurred. Moreover, the greater charging burden on other grid users would in turn further reduce allocative, productive and dynamic efficiency, in a spiralling fashion.
The HVDC charge distorts generation investment towards the North Island. This may also discourage renewable generation.	It is correct that the HVDC distorts investment – the SIMI charge effectively raises the marginal cost of supplying electricity from the South Island. The Authority provides solid evidence of the materiality of this problem at [2.47-2.49 IP]. Replacement of the HVDC charge by a benefit-based charge would eliminate this distortion.
The current charging regime is not durable, because customers pay for assets they do not benefit from.	A benefit-based charge would be more durable – it would better reflect workably competitive market outcomes and would be regarded as fairer.

4. Our views on the proposal

4.1. Benefit-based charge

10. The basic premise of the Authority's proposal is that the inefficient RCPD and HVDC charges should be discarded and replaced, to the degree possible, with a benefit-based charge - grid costs should be allocated to beneficiaries according to their share of the benefit. As discussed in section 3 above, we agree with the Authority's problem definition. We also consider a benefit-based approach to be an appropriate one (efficient and fair) and in accord with workably competitive market outcomes.

11. The benefit-based charge would be forward-looking and would result in a relatively non-distortionary fixed charge.

12. While the details are to be developed by Transpower, our interpretation of the concept is as follows. Suppose it is calculated that an asset would have four beneficiaries, with beneficiary 1 enjoying 70% of the net benefit, and the other three 10% each. Suppose also that the asset has a cost of $300, to be recovered equally over three years (and ignoring the cost of capital and operating costs, for simplicity). Then beneficiary 1 would face a fixed charge of $70 each year, and beneficiaries 2, 3 and 4 would face a fixed charge of $10 each year, regardless of actual use of the grid (subject to certain exceptions, discussed further below).

13. Those charges would not be affected by actual use of the grid, and therefore grid use behaviour would only reflect the non-sunk costs, as reflected by nodal prices. In contrast, both the RCPD and SIMI charges variabilise the recovery of sunk costs, and inefficiently distort grid use and related investments.

4.2. Treatment of historic investments

14. As well as applying the benefit-based charges to new investments, the Authority's proposal is to also apply them to certain existing assets, specifically the seven listed at [13(b)] of Appendix A to the IP.

15. In our view, the existing charging regime is clearly inefficient in respect of existing (and future) assets, and therefore it would be inappropriate to leave it untouched. The existing regime leads to dynamically inefficient investment off-grid (generation and load), and deterred use of the grid itself. Therefore there are dynamic, productive and allocative efficiency reasons for altering the regime on existing grid assets. While those assets are sunk, how the costs of them are recovered does alter forward-looking behaviour.

16. The Authority's proposal (e.g., as expressed at [B49 IP]) would address these issues, at least in respect of the most important existing grid assets. We note that the option of applying the benefit-based charge only to future assets, and recovering the balance through the residual charge ([B.47 IP]), would also address these issues. However, the other reform option canvassed by the Authority at ([B.48 IP]) would not be appropriate. That option would be to:

    … apply the benefit-based charge only to future grid investments and recover other costs from the parties that currently pay transmission charges, in proportion to their current payments. This could be arranged via an alternative specification of the residual charge (payable by all transmission customers) that was allocated in fixed proportions (determined by fixing the current allocation of RCPD and HVDC charges).

17. This "freeze frame" option would not be appropriate:

    a. It would leave in place a regime for existing assets that is completely at odds with the beneficiaries-pay basis of the reform for post-2019 grid investments. This would be regarded as:

i. Unfair, as some grid assets would be paid for by beneficiaries, while others would not;

ii. Potentially anticompetitive and inefficient (for example, a future South Island generation plant would not contribute to the HVDC, while existing South Island generation plant would); and

iii. Undermining the durability of the TPM regime – we return to this below using the HVDC as an example;

b. Relatedly it would "penalize" those who have not already taken (inefficient) avoidance action - this "freeze frame" option would lock in the (private) benefit to those who have taken inefficient avoidance action (e.g., invested in (socially) inefficient batteries) and deprive others from taking the same steps; and

c. It would not address the existing durability concerns – it would simply continue them.

18. Accordingly, we think the Authority should adopt either its preferred [B.49 IP] option (i.e., applying a benefit-based charge to future assets and the seven specified existing assets) or the option of applying a benefit-based charge to future assets and recovering all other assets via the residual charge [B.47 IP].

19. If the [B.49 IP] option (the Authority's preferred) is adopted, the next question is which pre-2019 assets should be included. The Authority thinks the HVDC should be included in that set and we agree.

20. The HVDC allocation has been controversial for many years. As noted in Appendix B to the Authority's October 2012 Issues Paper, prior to 1996 the costs of the HVDC were allocated 47% to generators and 53% to distributors/direct-connect.[2] As the Authority noted in the 2016 Second Issues Paper:[3]

The current TPM has been in place for almost 8 years. During that time, issues such as HVDC pricing have been extremely controversial and the fundamentals of the current TPM have been under review for most of its existence.

21. Problems with the existing treatment of the HVDC are varied and material – they include:

a. Investment bias, as discussed in the problem definition section of this report;

b. Arbitrariness – there is no economic difference between the HVDC and other grid assets, so a cost recovery distinction makes no sense;

c. Unfairness (due to a misalignment of costs and benefits); and

d. Accordingly lack of durability (and costs associated with lobbying and disputes).

22. Including the HVDC in the Authority's reform proposal would resolve these problems.

4.3. Adaptability

23. At [B.135 IP], the Authority states:

Under the Authority's current proposal, Transpower would determine the share of the benefit-based charge allocated to a transmission customer for an investment at the time the investment is commissioned. Once Transpower has determined this share, it would not change except in exceptional circumstances. This would be the case even if the actual outcome in relation to the benefits obtained by the customer is quite different from the outcome expected at the time the investment was made.

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[2] The controversy is apparent in subsequent processes. See for example the discussion in Electricity Commission *Transmission pricing methodology: Final decision paper* (7 June 2007) at section 3.4.

[3] At [6.95].

24. The Authority justifies this approach on the basis that it would not "create incentives for grid users to inefficiently avoid transmission charges by altering their use of the grid" ([B.134 IP]). We agree with this justification.

25. The exceptional circumstances the Authority has in mind are listed at [B.135 IP]:

The proposed guidelines allow some exceptions to the general rule that the allocation does not change, notably:

(a) a substantial and sustained change in grid use

(b) the entry or exit of a transmission customer

(c) a transmission customer changing its point of connection

(d) a partial sale of a business

(e) adjustments resulting from reassignment.

26. We comment on each of these below.

4.3.1. Substantial and sustained change in grid use

27. Exception (a) is a mechanism for Transpower to review the benefit-based charge for a high value investment if there has been a "substantial and sustained change in grid use".[4] Like the TPM review itself, this is an example of the balance between regulatory certainty and adaptability, and we agree with the idea of a review mechanism, provided it is carefully designed and used sparingly. Overly frequent reviews would undermine certainty and could affect information revelation incentives at the time of grid investment, and network usage by market participants.[5]

28. However, we are not convinced the proposed design is optimal as there may be ongoing disputes about whether the "substantial and sustained change in grid use" test is met for a particular asset. Instead, we think there is an argument for putting in place a more mechanistic review process, such as a regular (but infrequent) re-running of the model that calculates forward-looking benefits (with inter-review periods long enough to retain the fixity of the charge with respect to throughput, for example, perhaps every five years). This would reduce the scope for lobbying and disputes over whether the threshold is met.

29. The Authority is concerned that "a review process could encourage participants to inefficiently avoid the benefit-based charge, because it would give the parties incentives to alter their behavior to demonstrate that they would benefit less from the investment and so reduce future charges for themselves should a review take place".[6] It is not clear what sort of behavioural alteration the Authority has in mind, but we note that such changes are likely to be costly. For example, if a directly-connected factory materially reduced electricity consumption for a material period (or invested in distributed generation) in order to mimic lower benefits from a grid asset, that reduction would materially reduce the factory's (output and) profits.

30. Similarly, a delay in investment by a customer would have costs.

31. Accordingly, we think the Authority might be overestimating the ability of customers to game benefit reviews. While predictable reviews that reallocate according to benefit would detract

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[4] Draft guideline 26(a).

[5] For example, the broader the option to avoid a grid charge (through increasing the frequency of reviews), the lower the cost to a participant in exaggerating expected benefit from a grid investment.

[6] [B.172 IP].

from the fixity of the charge and give it a use element, this approach should make the TPM more durable.

4.3.2. Entry or exit of a transmission customer

32. Draft guideline 42(a)(i) envisages a process for allocating charges to a new connecting large load or generation customer. We interpret this process to relate to reallocation of charges concerning existing grid assets at the time of the new connection. Given the grid asset is sunk, the Authority's discussion is rightly focused on minimizing customer location and use distortions, and promoting competitive neutrality – see [B.235-236, IP].

33. Customer exit appears to be dealt with under the reassignment provisions, discussed below.

4.3.3. Transmission customer changing its point of connection

34. Draft guideline 42(c) requires the TPM to avoid creating inefficient incentives for large customers to shift their point of connection (e.g., from the grid to a distribution network). While one tool to achieve this is the prudent discount policy, the Authority has in mind that this should be a last resort, and that other mechanisms might be preferable ([B.240 IP]). For example, the Authority refers to Transpower reallocating the charge to the distribution network to which the customer reconnects ([B.239 IP]).

35. While the Authority is not explicit about this, one rationale for using an alternative mechanism to the prudent discount policy is that it might be cost recovery neutral, whereas use of the prudent discount mechanism might raise charges to other grid users.

4.3.4. Partial sale of a business

36. Draft guideline 42(b) requires the TPM to enable Transpower to reallocate charges away from the seller and to the buyer of a connected business in respect of which there has been a partial sale. The Authority explains that this provision is to avoid "an anomalous situation, for example, where the existing customer retained responsibility for all of the transmission charges relating to that part of the business and the new owner paid Transpower nothing" ([B.242 IP]).

37. It is not clear to us why this would be a problem. We might generally assume that the buyer and seller would agree on how to allocate grid charges between them, and we do not really see why Transpower should seek to override whatever contractual arrangement buyer and seller come to.

4.3.5. Reassignment

38. Exception (e) is a mechanism for reassigning costs of a benefit-based investment from the benefit-based charge to the residual charge. It appears this would apply when a grid investment turns out to be a "white elephant" ([B.184 IP]) or when a significant existing customer disconnects from the grid (draft guideline 34(b)(i)).

39. As we understand the Input Methodologies, if a material customer disconnects from the grid and strands an asset, Transpower is still entitled to recover the full value of that asset – in other words, this risk is not allocated to Transpower.[7] Therefore that risk needs to be allocated to one or some combination of the following: (a) the disconnecting customer; (b) the other beneficiaries of the relevant asset; or (c) load through the residual charge. The latter (allocation to load through the residual) is effectively the Authority's reassignment proposal, at least as we understand it. For the reasons we discuss in section 4.5 of this report, we are comfortable with this allocation. However, it is worth considering the implications of not allocating the risk to the disconnecting customer –

[7] The Authority's 2016 Second Issues Paper at [7.157] stated this.

knowledge that there is always an option to exit without cost might affect information revelation incentives during the grid investment approval process.[8]

4.4. Time profile of cost recovery

40. As in the previous process, the Authority wishes grid charges to reflect the Authority's view that service level would be roughly constant over the life of the asset in a workably competitive market (see, e.g., [B.83 and B.85, IP]). To achieve this, the Authority originally proposed to overlay a replacement cost regime on top of the historical cost regime operated by the Commerce Commission.[9] In the subsequent Supplementary Paper, the Authority moved away from the replacement cost regime, and instead suggest an indexed historical cost (**"IHC"**) regime, to apply to both new and existing assets.

41. The Authority is now proposing that the IHC regime would only apply to new assets, not to existing assets. We think retaining the present historical cost approach for existing assets is sensible – as we explained in our 24 February 2017 report, switching to the IHC approach part way through the life of an asset could lead to over-recovery.

42. As also discussed in our 24 February 2017 report, we still have concerns over this IHC approach, even for future assets:

    a. We do not think it is necessarily correct that price will be uniform over time in workably competitive markets; and

    b. It would result in a different time profile of cost recovery to that underlying the Commission's calculation of the MAR, increasing complexity.

4.5. Residual charge

43. The balance of Transpower's allowable revenue would be collected via a residual charge on load customers (distributors and grid-connected industrials). The default allocation would be based on gross anytime maximum demand averaged over at least two years ending prior to 1 July 2019. The Authority states that the intent is to ensure the charge does not affect customers' decision-making, given the charge would be fixed and based off historical behaviour.

44. The Authority proposes that Transpower should adjust the residual allocation where a customer has experienced a substantial change to demand due to factors over which it has no control (draft guideline 41). Draft guideline 42 sets out other proposed adjustment mechanisms to deal with dynamic changes.

45. In our view, it is correct to allocate the residual charge to load only.

46. The grid shares some features of a "two-sided platform". In the "two-sided market" economics literature, a "platform" is an intermediary that allows consumers and suppliers to trade. Two widely accepted elements of a "platform" are the existence of an intermediary that links user

[8] Although noting our understanding that if the disconnecting customer ceases to be a participant under the Code, it may be immune to liability for any of Transpower's revenue requirement in future years.

[9] See [7.39] of the Authority's 2016 Second Issues Paper.

groups, and network externalities.[10] In a platform framework, interactions are triangular in that users interact with each other, and with the platform provider.[11]

47. Setting optimal prices in two-sided markets requires taking into account each user group's own-price elasticity, the strength of the externalities connecting the two groups, and the marginal costs of changes to output on each side.[12] The optimal price for each side of the market depends on a complicated interaction between the network externalities and each side's price elasticity of demand, which can result in one side being charged less than the marginal cost of supply, or even a negative price.

48. In simple terms, the side whose demand is more elastic and that generates externalities over the other side might be subsidised, or at least contribute less to the common costs.

49. The value of the grid to each side (generally) increases as generators and load "join" (connect to the network)[13] – this is the standard (cross-platform or indirect) network externality. The externality is particularly strong from the perspective of load – load benefits from each new generator connecting to the grid, not just because of increased competition (including potential entry), but also because of increased security of supply (for example, due to provision of reserves, generator location or fuel source).

50. Furthermore, it is likely that the demand of load for transmission services is more inelastic than the demand of generation. The demand for transmission services by a load customer is a derived demand – it is ultimately determined by the demand for electricity, which is inelastic.

51. In contrast, the demand by generation for transmission services is regarded as being more elastic.[14] This is reflected in the Authority's TPM problem definition, for example, discouraging investment in South Island grid-connected generation. Consistently, diagrams of wholesale electricity markets are typically drawn with a far flatter supply curve than demand curve – see, for example, the figure below, reproduced from Joskow (2007).[15]

[10] See for example Claire M Weiller and Michael G Pollitt "Platform Markets and Energy Services" (2013) Cambridge Working Papers in Economics 1361; Thomas Eisenmann, Geoffrey Parker and Marshall Van Alstyne "Platform Envelopment" (2011) Harvard Business School Working Paper 07-104; and Jean-Charles Rochet and Jean Tirole "Platform Competition in Two-Sided Markets" (2003) 1(4) Journal of the European Economic Association 990-1029.

[11] Platforms can be monopolies or competitive firms. Examples of platform monopolies in which one side pays zero include the postal network, a yellow pages directory and the only newspaper in a region.

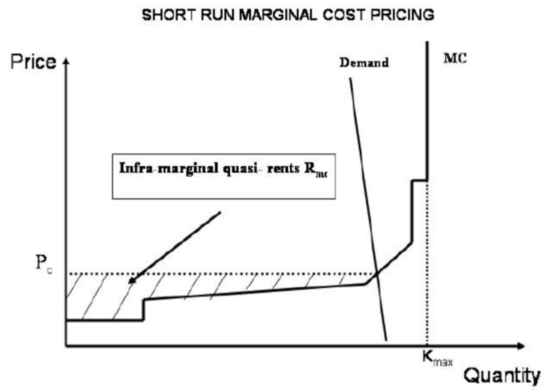
[12] See for example Jean-Charles Rochet and Jean Tirole "Two-sided markets: a progress report" (2006) 37(3) RAND Journal of Economics 645-667; and D Evans and R Schmalensee "The industrial organization of markets with two-sided platforms" (2007) 3(1) Competition Policy International 151-179.

[13] Leaving aside the possibility that new connection leads to congestion.

14 Indeed, European regulations put a cap on the transmission charges that can be recovered from generation. The reason given for this cap lies in the concern that generation might shift inefficiently to regimes with low transmission charges on generation, or at least that such movements are more likely than for consumers.

[15] Paul Joskow "Competitive Electricity Markets and Investment in New Generating Capacity" in Dieter Helm (ed) *The New Energy Paradigm* (Oxford University Press, 2007).

Figure 1: Typical depiction of wholesale market



52. In addition, the impact of capacity limitations and disruption of the grid is likely to be asymmetric. In the case of disruption, it is likely that the value of lost load will significantly exceed the value of lost generation (which would be the margin between the wholesale electricity price and the variable costs of generation), providing an incentive for load to demand more grid reliability investment than would generation.[16]

53. These features suggest that the interconnection elements of the grid should be priced to recover most or all of the costs from the load side. Interestingly, this is the international norm. Table 2 below shows the sharing of transmission network charges across generation and load in a variety of jurisdictions.

Table 2: Global transmission tariffs

Country/jurisdiction	Percentage of transmission charges allocated to generation	Percentage of transmission charges allocated to load
Europe		
Albania	0.0 %	100.0 %
Austria	14.0 %	86.0 %
Belgium	6.0 %	94.0 %
Bosnia and Herzegovina	0.0 %	100.0 %
Bulgaria	0.0 %	100.0 %
Croatia	0.0 %	100.0 %
Cyprus	0.0 %	100.0 %
Czech Republic	0.0 %	100.0 %
Denmark	3.1 %	96.9 %
Estonia	0.0 %	100.0 %
Finland	19.0 %	81.0 %
France	3.0 %	97.0 %
Germany	0.0 %	100.0 %
Great Britain	14.8 %	85.2 %
Greece	0.0 %	100.0 %
Hungary	0.0 %	100.0 %
Iceland	0.0 %	100.0 %
Ireland	25.0 %	75.0 %

[16] The Authority notes at [4.50(b) IP] the lower value of reliability to generators than to load.

Italy	0.0 %	100.0 %
Latvia	0.0 %	100.0 %
Lithuania	0.0 %	100.0 %
Luxembourg	0.0 %	100.0 %
Macedonia	0.0 %	100.0 %
Montenegro	35.2 %	64.8 %
Netherlands	0.0 %	100.0 %
Northern Ireland	25.0 %	75.0 %
Norway	31.0 %	69.0 %
Poland	0.0 %	100.0 %
Portugal	7.9 %	92.1 %
Romania	2.6 %	97.4 %
Serbia	0.0 %	100.0 %
Slovakia	2.6 %	97.4 %
Slovenia	0.0 %	100.0 %
Spain	10.0 %	90.0 %
Sweden	38.0 %	62.0 %
Switzerland	0.0 %	100.0 %
USA		
PJM	0%	100%
New York	0%	100%
California	0%	100%
New England	0%	100%
Texas	0%	100%
Other Regions		
Australia	0%	100%
Chile	80%	20%
Singapore	0%	100%
South Korea	50%	50%

Source: ***European data*** - ENTSO-E, *Overview of transmission tariffs in Europe: Synthesis*, May, 2018, p. 9. Accessed on 23 August, 2019. Available at https://docstore.entsoe.eu/Documents/MC%20documents/TTO_Synthesis_2018.pdf. ***USA and other regions*** – Frontier Economics, *International Transmission Pricing Review – A Report prepared for the New Zealand Electricity Commission*, July, 2009. Accessed on 23 August, 2019. Available at https://www.ea.govt.nz/dmsdocument/2539-report-by-frontier-economics-international-transmission-pricing-review.

54. The Authority also points out that if the residual charge was allocated to generation, it would be passed on to load via higher energy prices anyway ([B.224 IP])). Introductory textbook economics might suggest this is only correct to the extent that short-run marginal cost includes the residual charge. However, in a more dynamic sense, fixed costs have to be recovered through the wholesale market – investment in generation will only occur if investors expect to recover their fixed and variable costs, including any fixed transmission costs. If prices are too low to enable recovery of fixed costs, there would be less investment, and ultimately prices would rise.

55. This is a more general feature of markets – ultimately the demand-side has to pay for all of the costs incurred in producing the goods or services consumed – otherwise no one would invest on the supply-side.

56. Also relevant to final incidence is the relative elasticities of the demand- and supply-sides – as already discussed, the demand-side of the electricity market is more inelastic than the supply-side, suggesting greater and faster incidence on the demand-side.

57. Accordingly, we agree with the Authority's conclusion that the generation side is likely to pass through a residual charge, meaning the load side would pay it anyway.

4.6. Prudent discount policy

58. The proposal includes a prudent discount policy (draft guidelines 46-48), which would reduce the possibility of inefficient grid bypass or disconnection. The prudent discount policy can be thought of as a form of price discrimination (Ramsey pricing), i.e., reducing the charge to particularly price sensitive load.

59. Customers not able to take advantage of the prudent discount policy would still benefit from it, in that any contribution from price sensitive customers would reduce the revenue needing to be recovered from the balance of the customer base. Because Transpower's revenue and investments are regulated, price discrimination of this form is unambiguously efficient.

4.7. The role of nodal pricing

60. We agree with the Authority that nodal prices are sufficient to signal any need for rationing of demand when there is congestion and any need for future grid investment decisions.

4.8. Price cap

61. The proposed cap appears to be primarily a transitional mechanism, i.e., to mitigate any price shocks from the introduction of the new regime.

62. A price cap has the potential to undermine grid price signals, leading to over-use of, and over-investment in,[17] the grid (and consequently under-use of, and under-investment in, substitutes to the grid). However, for the following reasons any such impact is likely to be limited:

    a. The price cap would only apply in respect of charges to load;

    b. The price cap would not apply to any peak charge; and

    c. The price cap would only apply in respect of existing grid assets, not new ones.

[17] In general, a price cap would lead to under-investment. However, in the present situation a muted grid price would encourage customers to support grid investments, against the context of Transpower always receiving its MAR (with any deficit due to a price cap being picked up by the residual).

5. Cost benefit analysis

5.1. Introduction

63. The Authority has carried out a CBA of both its proposed reform and an alternative reform against the status quo counterfactual. We have already described the Authority's proposed reform. The modelled alternative would involve replacing the RCPD charge with a broad-based usage charge ([4.4 IP]).

64. The results of the Authority's CBA are summarised in Table 4 of the IP (page 21), which we replicate in Table 3 below.

Table 3: Summary of the Authority's quantified costs and benefits (millions)

Quantified benefits	Proposal	Alternative
More efficient grid use	$2,579 ($81 - $5,678)	$1,775 ($4 - $4,197)
More efficient investment in batteries	$202 ($137 - $786)	$222 ($137 - $786)
More efficient investment in generation and large load	$43 ($9 - $112)	--
More efficient grid investment – scrutiny of investment proposals	$77 ($29 - $125)	--
Increased certainty for investors	$26 ($10 - $48)	--
Total quantified benefits	**$2,926 ($266 - $6,749)**	**$1,997 ($141 - $4,983)**

Quantified costs	Proposal	Alternative
TPM development / approval	$8 ($4 - $12)	$6 ($3 - $8)
TPM implementation costs	$9 ($4 - $13)	$4 ($2 - $5)
TPM operational costs	$9 ($5 - $14)	$0.3 ($0.2 - $0.5)
Grid investment brought forward	$188 ($51 - $324)	$135 ($6 - $264)
Load not locating in regions with recent grid investment	$1 ($0 - $2)	--
Efficiency costs of price cap	$1	--
Total quantified costs	**$215 ($65 - $366)**	**$144 ($11 - $278)**

Results		
Net (benefits less costs)	**$2,711 ($201 - $6,383)**	**$1,853 ($130 - $4,705)**

Source: Table 4, IP

65. The single largest quantified benefit is "more efficient grid use" ($2.6b out of $2.9b of benefits). Accordingly, we focus our review on this benefit. We then more briefly consider the other material benefits and costs.

5.2. Benefits

5.2.1. More efficient grid use

5.2.1.1. Unpacking of modelling

66. While the proposed reform is limited to pricing of the grid, the Authority's analysis is cognisant of the fact that the grid is part of a broader electricity system. Because the grid is both a complement and a substitute to other parts of the system, how the grid is priced will affect demand, supply, price and quality of other parts of the system.

67. This interdependence is reflected in the Authority's quantification of the "more efficient grid use" benefit. As well as improving the allocative efficiency of grid use (which we will term the "grid price effect"), the TPM reform is also expected to improve the efficiency of the wholesale electricity market, broadly defined, resulting in an "energy price effect".

68. The grid price effect is illustrated by Figures 6 and 7 of the IP, and described more generally on page 35 of the IP, which we have copied and pasted in Figure 2.

Figure 2: Copy of page 35 of Authority's Issues Paper

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

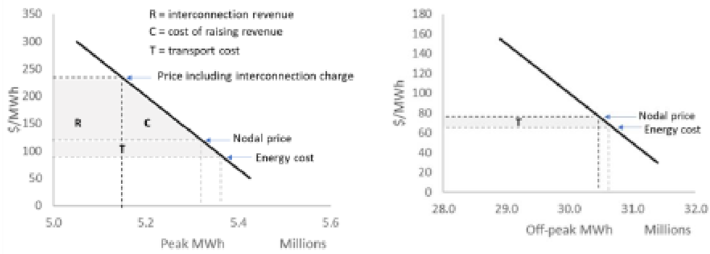
(a) the transport cost (T), ie, the difference between the energy prices paid by consumers at the GXP and those received by generators, for both peak and off-peak periods

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

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

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

Figure 6 Efficiency cost of RCPD charge under the status quo

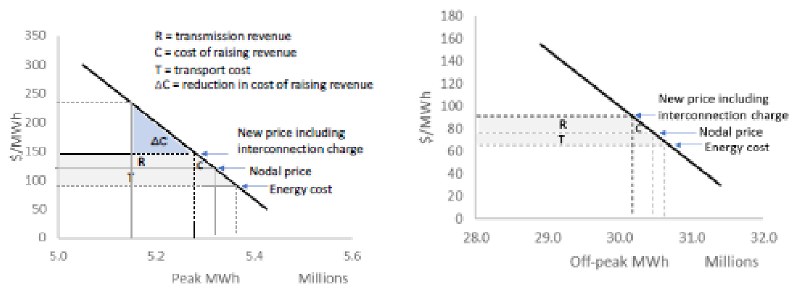


4.82 Figure 7 shows the changes that occur under the proposal. It shows:

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

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

Figure 7 Increased allocative efficiency due to removal of RCPD charge



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

Source: Page 35, IP

69. Under the central scenario, this allocative efficiency is quantified at $50.8m (present value).[18]

70. The energy price effect is explained at [4.94 IP] – with the RCPD gone, demand for grid-connected electricity would increase,[19] raising the wholesale energy price. This in turn would stimulate new generation investment, and ultimately a lower energy price.

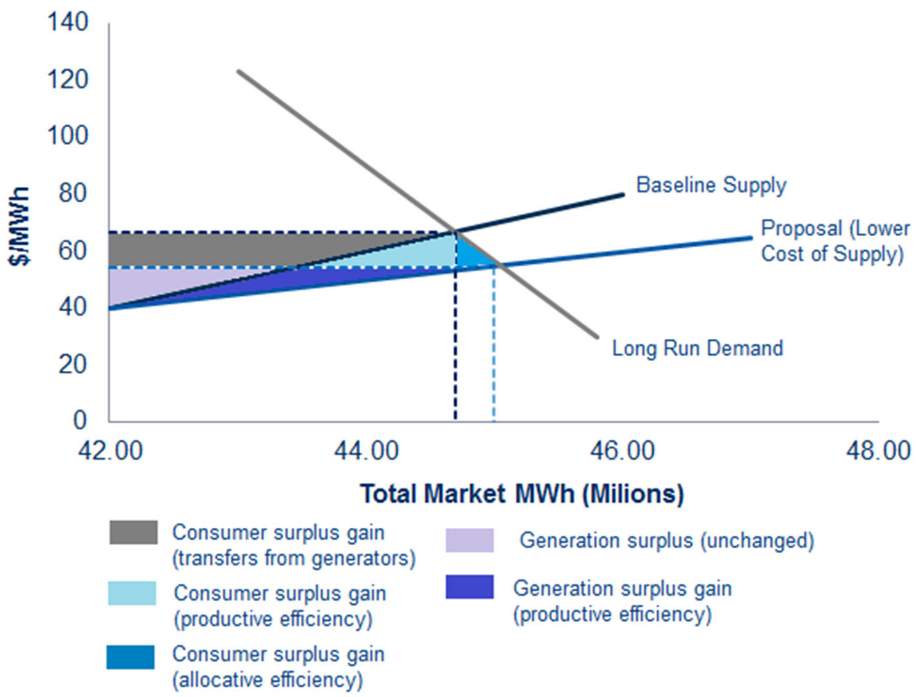
[18] Cell F8, tab "Summary grid use model" https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Summary

[19] And presumably demand for off-grid-connected electricity would decrease.

71. Accordingly, the Authority has in mind that TPM reform would lead to electricity demand switching to more efficient grid-connected generation and away from less efficient distributed energy resources.[20] This would increase consumer surplus. Some of the increase in consumer surplus would be a transfer from existing generation plant. However, because the Authority considers this transfer to be difficult to disentangle from the efficiency gains, the Authority instead scales the calculated benefit down by 50%.

72. During its 10 September 2019 CBA workshop, the Authority presented an illustrative diagram of these changes.[21] We replicate that diagram below, with some additional annotations.

Figure 2: Long run energy price effect



73. It can be seen that the efficiency gains are a combination of allocative (dark blue triangle) and productive efficiency (light blue and dark purple triangles). The consumer surplus benefit also includes the grey shaded trapezoid.

74. Because the Authority's focus is on changes in consumer surplus, it has presumably not included as a benefit of the proposed reform any increase in generator (producer) surplus, even if this is genuinely new surplus.

75. Under the central scenario, the consumer surplus benefit of the energy price effect is quantified at $4,370.3m (present value).[22]

76. The Authority considers that the energy price effect should be taken into account, but is also conscious that it:

[20] That is, distributed energy resources inefficiently incentivised by the above cost RCPD.

[21] Right-hand panel diagram of slide 14.

[22] Cell E8, tab "Summary grid use model" https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Summary

a. Includes transfers that are difficult to disentangle from the efficiency effects ([4.63 and 4.99, IP]); and

b. Is based on forecasts of wholesale energy prices that "are quite sensitive to assumptions about generation investment behavior …" ([4.60, IP], and see also [4.99, IP]).

77. Accordingly, the Authority takes the average of the grid price and energy price effects (i.e., multiplies each by 0.5, before summing them). In effect the Authority is finding that:

a. Just taking the grid price effect of \$50.8m would be too extreme, as it would ignore the energy price effect; and

b. Taking the full energy price effect of \$4,370.3m would be too extreme for the practical reasons noted above.

78. Accordingly, the Authority treats these two points as ends of a range and takes the mid-point between the two. If anything, we think this is probably conservative. At a conceptual level, it is appropriate to consider the broader electricity market benefits that TPM reform would bring (i.e., the energy price effect), and the only reason to discount these is for the more practical reasons noted above.

79. So, to this point the central scenario more efficient grid use benefit is equal to:

$$\frac{(\$50.8m + \$4370.3m)}{2} = \$2210.55m$$

80. The Authority than adds \$368.2m to this, resulting in the (approximately) \$2,579m that appears in Table 4 of the IP.[23] This \$368.2m represents the present value of the transfer from load to generation due to the removal of the SIMI and reallocation of some HVDC charges to load. Because this is a transfer and the Authority prefers to assess only efficiencies (to the extent possible), this sum is added back in order to quantify the benefit.

81. As noted, the reason the energy price would be lower (on the Authority's theory) is that TPM reform would stimulate earlier generation investment. At [4.162 IP], the Authority states the CBA does not include any costs for generation investment brought forward because:

… the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.

82. In excluding this cost from the CBA, the Authority treats it differently from other costs such as the saving in battery costs and the increased cost relating to grid investments brought forward (see sections [5.2.2] and [5.3] below). We think it would be useful for the Authority to explain this distinction further.

5.2.1.2. NERA cross-check

83. The \$2.6b (which is a present value) calculated by the Authority equates to approximately 1.6% of the present value[24] of the sum of Transpower's expected revenue and expected wholesale electricity market revenue over the next 30 years (\$160.6b).[25]

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[23] See cell F4, tab "Summary table with ranges", https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Summary.

[24] Using a discount rate of 6%.

[25] The Transpower present value revenue number was calculated using the Transpower's revenue data series taken as an input to the Authority's modelling. Electricity Authority, *forecast_revenue*, 28 August, 2019. Accessed 13 September, 2019. https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/201907

84. An efficiency gain of this relative magnitude seems quite plausible. Consider the following analyses of allocative efficiency effects:

   a. Diewert and Lawrence find the deadweight loss (allocative inefficiency) of raising labour tax in New Zealand was about 18% of the revenue raised in 1991;[26]

   b. There are numerous studies of the size of what is sometimes referred to as "Harberger's triangle", i.e., the deadweight loss (allocative inefficiency) arising from market power in an industry. These estimates range from approximately 2.9 to 27% of revenue;[27] and

   c. When assessing merger authorization applications, the Commerce Commission estimates the allocative inefficiency from post-merger prices increases. For example, in the *Cavalier Wool Holdings/New Zealand Wool Services International* authorisation decision,[28] allocative inefficiency (due to expected merger-induced price rises) was estimated to be in the range of $0.53m to $3.6m per annum, which amounted to approximately 1% to 5% of total industry revenue.[29] In previous (confidential) merger work we have found similar orders of magnitude for allocative inefficiencies as a percentage of total revenue.

85. None of these studies are directly on point, but they do suggest that the $2.6b efficiency gain seems to be quite plausible. This is particularly the case given the $2.6b consists of productive as well as allocative efficiency gains.

5.2.2. More efficient investment in distributed energy resources

86. The Authority states at [4.106, IP]:

> *This benefits (sic) stems from avoiding investment in [distributed energy resources] (particularly network-scale batteries) that would otherwise be inefficiently brought forward under the current TPM arrangements.*

87. This benefit is quantified by comparing the present value of battery costs under the reform scenario and under the counterfactual, with the difference being $202m. This methodology seems appropriate.

23_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Grid%20use%20model/Data.

For the wholesale electricity market, we have used the latest estimate from the International Energy Agency (IEA) 2017 New Zealand Review that groups the revenue of the five biggest generators (NZ$10,116m), and assumed the amount will remain constant during the next 30 years. IEA, *Energy Policies of IEA Countries – New Zealand 2017 Review*, 2017, p. 64. This is likely to be very conservative.

[26] Diewert, W E and D A Lawrence (1995) "The Excess Burden of Taxation in New Zealand", *Agenda*, 2(1), 27-34.

[27] Yoon (2004) looks at welfare loss due to monopolies in Korea and finds this to be 4.03%-7.56% of annual gross value of shipments. Yoon, S., 2004. "Welfare losses due to monopoly: Korea's case", *Journal of Policy Modeling*, 26(8-9), pp.945-957. Masson & Shaanan (1984) measure the average deadweight loss triangle from market power across 37 industries in the US and find this is 2.9% of the value of shipments. Mason R.T and J Shaanan, 1984, "Social Costs of Oligopoly and the Value of Competition", *The Economic Journal*, 94(375), pp.520-535. van Dijks & Bergeijk (1997) look at 12 sectors in the Dutch economy to estimate Harberger dead weight loss of imperfect competition and find that this is 15% of turnover. van Dijks, M.A. and Van Bergeijk, P.A., 1997. "Resource misallocation and mark-up ratios: an alternative estimation technique for Harberger triangles", *Economics Letters*, 54(2), pp.165-167. Daskin (1991) calculates the deadweight loss in the US manufacturing sector to be between 6-10% of value of shipments if assuming inelastic demand, and up to 27% if assuming elastic demand. Daskin, A.J., 1991. "Deadweight loss in oligopoly: a new approach", *Southern Economic Journal*, 58(1), pp.171-185.

[28] [2015] NZCC 31.

[29] Table 7 (at paragraph [626]) of [2015] NZCC 31 reports the annual allocative efficiency range. At [650] the Commission notes the annual industry revenue is in the range of $60m to $80m. We calculate allocative efficiency as a percentage of industry revenue based on revenue in the midpoint of this range ($70m).

5.2.3. HVDC

88. We have already discussed the transfer aspect of the HVDC under the CBA.
89. Regarding the benefits of HVDC reform, at [4.108 IP] the Authority states:

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

90. A large component of the more efficient grid use quantified benefit (i.e., the $2.6b) is due to lower energy prices (i.e., the energy price effect discussed above). These energy prices are modelled based on generation investment forecasts over the time period of the model. The Authority is picking up the undistorted North Island/South Island generation investment decisions (under the proposal) in the generation investment forecasts that underlie this. The more efficient generation profile would flow into lower energy prices.
91. This interpretation is implied by [4.109 IP], where the Authority notes:

 These benefits are not reported as a separate figure as it is difficult, if not impossible, to completely disentangle the effects of the distortion from the HVDC charge on generation investment.

5.2.4. More efficient investment in generation and large load

92. As generation and load investors would face the full impacts of their decisions on grid costs, grid investment should be delayed under the reform versus under the counterfactual. The Authority has quantified the present value benefits as being $43m. At a high level, the Authority's methodology looks appropriate. The Authority has attempted to estimate the sensitivity of load and generation investment to higher grid prices, and how this would affect grid investment.

5.2.5. More efficient grid investment due to scrutiny of proposed investment

93. The approach taken by the Authority to quantifying this benefit is similar to that taken by the Commerce Commission in merger authorisation analysis. When quantifying the detrimental effect of a merger (i.e., less competitive pressure) on productive efficiency, the Commission applies a scalar to pre-merger variable costs. For example, in the *Cavalier Wool* case the Commission applied 0% and 1%.
94. The Authority assumes the improved scrutiny incentives arising from a beneficiaries-pay approach would "lead to a productivity gain in the long-run costs of transmission investment" ([4.130 IP]), and applies different scalars depending on the investment category ([4.131 IP]). The scalar is lower for categories reviewed by the Commission.
95. We think the Authority's quantification approach for this benefit is practical and reasonable.

5.2.6. Increased certainty for investors

96. As we have already discussed, the current TPM is not durable:
    a. The HVDC is not being properly allocated to its beneficiaries and causes investment distortion; and
    b. The RCPD is resulting in costly distortionary, evasive behavior.
97. This lack of durability is likely to be raising the cost of capital and therefore retarding efficient investment in the sector. As already noted, the proposed reform would address these issues.
98. The Authority correctly adopts a real options approach to quantifying this benefit:

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

99. This is the same framework we adopted in section 8.5 of our 26 July 2016 report.

100. The Authority quantifies this benefit as $26m. The Authority's approach is complicated, and is set out at [3.37-3.59, TP]. At its heart are certain parameters representing:

a. The change in uncertainty arising from the TPM reform proposal; and

b. The responsiveness of demand and supply to uncertainty. For example, based on literature the Authority assumes that a doubling of policy uncertainty reduces investment by 8.7% (Table 28, TP).

101. While we have not carefully worked through the Authority's modelling, we think the broad framework is an appropriate one, and draws on the literature. We also note that the quantified benefit is materially lower than our estimate during the last round, which we considered to be conservative.

102. The following text is from our 26 July 2016 report:

One principled[30] *way to represent this is to apply an adjustment $k \geq 0$ to a risky, irreversible investment decision. If I is the irreversible amount of investment and NPV the net present value of the consequent cash flows, the rule is invest if $NPV > (1+k)I$, where k increases with the idiosyncratic risk or variance of potential outcomes, and kI is the value of the option to delay implementing the project. We can ask the effect of increased risk, or variance, on k, and so on the hurdle rate that firms use for investment decisions. The key is that the hurdle rate for irreversible decisions includes the option to wait, which is higher the higher is volatility.*

Of course some abstraction in implementation would be required, but it may be possible to calculate a k from price volatility and changes in k from potential adjustments in the volatility due to changes in regulatory certainty.

Even more tractably (but less rigorously), we could take a plausible range of increments to the hurdle rate, and then multiply those increments by average annual investment in generation and load assets, to give a feel for the magnitude of the social cost. For example, suppose the increment is 1%. We do not have any data on average annual load investment, but Meridian has provided us with estimates of industry-wide generation investment since 1997. The average annual generation investment between 1997 and 2014 (in 2014 dollars) was $474m. Multiplying this by 1% results in $4.74m. If we assume this figure would be repeated every 20 years as per the base OGW model,[31] *the present value would be $50.24m.*

This number provides a feel for the social cost of regulatory uncertainty, as it provides a proxy for the social value of deterred investments.

Survey evidence of US firms in Jagannathan et al (2015)[32] *finds that firms use hurdle rates on average almost twice their WACC. The firms responding to this survey had an average WACC of 8% compared to an average hurdle rate of 15%.*

We are not arguing that the regulatory uncertainty in this context would double the WACC. However, this evidence does suggest that a 1% premium is not an unreasonable assumption to use for present purposes.

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30 R K Dixit and R S Pindyck *Investment under Uncertainty* (Princeton University Press, 1994) at ch 6.

31 And using the OGW discount rate of 8%.

32 Ravi Jagannathan, David A Matsa, Iwan Meier and Vefa Tarhan "Why Do Firms Use High Discount Rates?" (2015); available online at SSRN: http://ssrn.com/abstract=2412250.

103. If we were to repeat this analysis assuming the annual generation investment is still $474m and the increment 1%, but using a 30-year period instead of a 20-year one, the present value would be $57.63m.

5.3. Costs

104. The only material cost is the cost of grid investment brought forward as peak demand increases due to the elimination of the RCPD. The Authority assumes that transmission investment is proportional to peak MW demand. Because the Authority's models forecast change in peak MW demand, they can also forecast the transmission investment brought forward. This is then costed.

105. The mid-point of the cost range is $188m (present value).

5.4. Effect of bringing reform forward

106. We have been asked by Meridian to calculate the impact of bringing the proposed TPM reform forward by one or two years.

107. The Authority's CBA assumes the reform commences in 2022 and quantifies the benefits and detriments (in 2019 present value terms) from 2022 to 2049.

108. We know the profile of the modelled consumer surplus gains (energy price effect) at each of the modelled 14 nodes over the period 2022-2049, which sum to the $4,370.3m.[33] The net benefit of $2,711m (Table 4, IP) is 0.62 of this (2,711/4,370.3 = 0.62).

109. We then transform the consumer surplus gains (energy price effect) profile by bringing it forward by one year. In terms of the net present value calculation, instead of supposing a three-year window (between 2022 and 2019), as the Authority does in its calculations, we use a two-year window (between 2021 and 2019).

110. This turns the $4,370.3m into $4,632.47 (2019 present value). Multiplying this by 0.62 gives $2,873.91. Then subtracting $2,711m results in $163m – this would be an approximation of the benefit in bringing reform forward by one year.

111. If the reform was brought forward by two years, the increase in net benefits would be $335.11m.

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[33] See columns BA and CA. Electricity Authority, *cs_results*, 28 August, 2019. Accessed 25 September, 2019. https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Grid%20use%20model/Output/All_major_capex.

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Transmission Pricing Methodology: Review of Schedule 1 modelled beneficiaries of existing transmission assets

Prepared for Meridian Energy by Orbit Systems Ltd

30 September 2019

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Andrew Coyle - Principal

About Orbit

Orbit Systems is a majority New Zealand owned Operations Research and Information Technology consulting company. We supply solutions for complex business problems worldwide, by providing advice and analysis, with a strong focus on delivering on-going value through organisational processes and information systems.

With over 30 years' experience both in New Zealand and overseas, Orbit Systems staff have worked on a wide variety of projects across many sectors including the electricity industry. The company has a number of high-profile international clients, including some of the largest companies in the world, such as Proctor & Gamble, Nestlé and Kraft.

Orbit has a thorough knowledge of the wholesale electricity markets and systems from the perspective of all participants. We provide advice and analysis, custom build energy sector models, and have been used in our expert capacity to review and audit other third-party produced systems.

Orbit staff have extensive experience in many different energy segments, from constructing and utilizing models for managing hydro reservoirs, storage valuations, release guidelines and spill analysis, evaluation of competitor capabilities and positions, forecasting future consumption, future prices, revenues, and risk positions, and the economic evaluation of new energy projects.

Orbit has also worked in the creation of Long, Mid and Short-term electricity price forecasts in many countries including Russia, New Zealand, Australia, America, Korea, Singapore and the Philippines, using a variety of in house and third-party price forecasting models such as PLEXOS and SDDP. We have experience building and utilizing transmission nodal pricing methods and preparing risk evaluation and reporting methodologies, along with developing and implementing a market clearing engine for various electricity markets.

Transmission pricing methodology: Review of Schedule 1

The Electricity Authority (the Authority) has proposed a benefit-based approach to allocating transmission costs. This means transmission customers who benefit from specific grid investments would pay for them. The Authority proposes two new charges to replace the current regional coincident peak demand (RCPD) charge and the high voltage direct current (HVDC) charge:

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

The Authority has published a draft of the Transmission Pricing Methodology (TPM) Guidelines including Schedule 1, which is the Authority's calculation of the relative benefits to different parties of seven major existing transmission investments.

Meridian asked us to assess the modelling methodology used by the Authority to produce Schedule 1. Schedule 1 was created by running the vSPD model with and without each of the seven transmission investments to calculate changes in the price and quantity of energy at various nodes and therefore the beneficiaries of each of that investment.

Meridian requested that we test a range of key input assumptions and that we re-run the Authority's modelling using vSPD and published GDX files.

In particular, Meridian sought a better understanding of:

- the assumptions made in respect of offers in the factual and counter factual scenarios;
- the effect of running the model over different time periods;
- the way that net benefits are assessed and the way any dis-benefits are treated;
- the modelling of the NIGUP and UNI Reactive Support investments together rather than individually; and
- the way security and reliability benefits are accounted for.

Orbit has re-run the vSPD model to confirm the Authority's calculations in Schedule 1 and to test their sensitivity to various key assumptions including those identified by Meridian.

In more detail, the benefit modelling process includes the following steps:

1. Take the existing factual case based on the market solves for the last 4 years.
2. Create a counterfactual case without the particular transmission investment.
3. Solve the counterfactual to maximise the sum of producer and consumer surplus, and determine prices, load cost and generation revenue.
4. Calculate the annual positive net benefit for relevant parties, for generators and load separately: for all generators, sum each node's total annual generation benefit; and for load, sum the total annual load benefit (net of distributed generation). If the generation and/or load benefit is negative then it gets zeroed before they are combined into the net total (i.e. dis-benefits are ignored).
5. Determine the proportion attributable to each customer by averaging the annual figure across the 4-year period.

We re-ran the model for the HVDC case and tested a range of the Authority's input assumptions for Schedule 1. For other assets we scrutinised the Authority's data and results.

We found that the Authority's assumptions are reasonable. That includes but is not limited to assumptions about the VPO and modelling time periods for the HVDC.

Overall we have concluded that:

- The assumptions were clear and the results reproducible.
- We have not identified any issues of concern.
- The input and modelling assumptions made by the Authority appear reasonable.

Orbit's finding is that the Authority's methodology is robust and objective – resulting in a market-like way to identify the beneficiaries of each pre-2019 asset.

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Appendix A Proposed TPM guidelines

Policy objectives

The Electricity Authority (the **Authority**) has reviewed the guidelines which Transpower is required by the Electricity Industry Participation Code 2010 (the **Code**) to follow in developing a proposed transmission pricing methodology (**proposed TPM**) (the **Guidelines**).

Having undertaken this review, the Authority considers that, in order to allow Transpower to recover up to its forecast maximum allowable revenue in any year and to better meet the Authority's statutory objective, the proposed TPM should contain the following components:

(a) a connection charge;

(b) a benefit-based charge;

(c) a residual charge;

(d) a prudent discount policy;

(e) a transitional cap on transmission charges; and

(f) ~~seven~~ additional components which are to be implemented if they better achieve the Authority's objective.

Connection charge

The purpose of the connection charge is to charge each designated transmission customer to recover the cost of the assets that connect it to the interconnected grid.

Benefit-based charge

The purpose of the benefit-based charge is to recover the costs of new and certain existing investments in the interconnected grid (including investments in transmission alternatives). The charge is to be allocated between designated transmission customers in accordance with the estimated positive net private benefits that each transmission customer is expected to receive from the investment (or a proxy for these benefits). The positive net private benefit of the transmission customer includes the positive net private benefit of any parties that are connected to the interconnected grid through the transmission customer.

Residual charge

The purpose of the residual charge is to provide a mechanism to ensure that Transpower is able to recover up to its forecast maximum allowable revenue in any year in a way which does not affect designated transmission customers' decision-making.

Prudent discount policy

The purpose of the prudent discount policy is to allow Transpower to discount the transmission charges of a designated transmission customer who otherwise would find it viable to inefficiently bypass the grid (including inefficiently disconnecting from the grid in favour of alternative supply).

Transitional ~~C~~cap on transmission charges

The purpose of the transitional cap on certain transmission charges is to minimise price shock by limiting the total increase in transmission charges relating to the existing interconnected grid that each load customer faces ~~relative to the charges that the customer actually pays for the existing interconnected grid in the 2019/20 pricing year. The cap applies only as long as it is effective in limiting a designated transmission customer's transmission charges subject to the price cap as set out in clause 49~~.

Additional components

[DRAFTING NOTE: Meridian's submission is that the Authority defers consideration of (a), (b), (c), (f) and (g). Meridian opposes the inclusion of component (e). If these submissions are accepted, the drafting of this policy objective should be amended accordingly.]

Transpower ~~would~~ must include each additional component in the TPM if doing so would better achieve the Authority's statutory objective. Implementation of these additional components must be deferred if their implementation may compromise or delay development and implementation of the main components.

(a) Staged commissioning. The purpose of this component is to allow Transpower to adjust how it recovers the cost of an investment that is commissioned in stages, so the charges better reflect the positive net private benefits it provides.

(b) Assets that in substance provide connection services. The purpose of this component is to ensure that if a connection asset that continues in substance to provide principally connection services is reclassified as an investment in the interconnected grid, it is still charged for as a connection asset.

(c) Charges for connection assets. The purpose of this component is to allocate connection charges in substantially the same way as benefit-based charges.

(d) Transitional peak charge. The purpose of this component is to efficiently influence grid use at peak times for a limited transitional period, if nodal prices are not adequate to meet this objective.

~~(e) Extension of benefit based charge. The purpose of this component is to allow Transpower to extend the benefit based charge to further pre-2019 investments.~~

~~(f)~~(e) Opex. The purpose of this component is to attribute opex to the investment or asset that it is spent on without recourse to proxies.

~~(g)~~(f) kvar charge. The purpose of this component is to allow Transpower to impose a charge on reactive power.

General matters

1. In developing the **TPM** ~~in accordance~~consistent with these **Guidelines**, Transpower must~~, as far as reasonably practicable~~:

   (a) set charges in a way that reflects:

   ~~(b)~~ (i) the cost of providing designated transmission customers with:

      A. new investment in the grid;

      B. access to the parts of the grid relevant to them; and

      C. use of the grid to transport energy;

   (ii) the **positive net private benefits** those designated transmission customers derive from ~~those things~~the matters referred to at (A) to (C) above;

   (b) balance the economic benefits and costs of precision of the **TPM** with the economic benefits and costs of practical considerations including:

   (i) robustness;

(ii) simplicity;

(iii) certainty, including through limiting the need for Transpower to exercise a discretion; and

(iv) costs associated with developing, administering and complying with the **TPM**;

(c) avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;

(d) avoid creating incentives for distributed generators to seek avoided cost of transmission payments, except to the extent that the payments reflect a saving in the costs of transmission (not just a saving in **transmission charges** to the relevant distributor);

(e) avoid discriminating between designated transmission customers, except to the extent necessary to achieve the Authority's statutory objective; and

(f) allow Transpower to recover its **forecast MAR**, should it wish to do so.

~~2. Transpower may propose a **TPM** which differs in its details from the particular requirements in the **Guidelines**, if it considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the **Guidelines** in their entirety.~~

~~3. All subsequent provisions in these **Guidelines** are to be interpreted and applied subject to clauses 1 and 2 above.~~

~~4.~~2. In developing the **TPM**, Transpower must prepare an outline of Transpower's reasons for proposing the particular methods and assumptions it has adopted~~included~~ in the **TPM**, to be provided to the Authority along with the **TPM**. ~~This outline must include details of:~~

~~(a) where, under clause 2, Transpower proposes a **TPM** which differs in its details from the particular requirements of the Guidelines, how the **TPM** differs from the **Guidelines** and Transpower's reasons for proposing a **TPM** which differs from the **Guidelines**, including why it considers that its proposed **TPM** better meets the Authority's statutory objective; and~~

~~(b) where Transpower has made an assumption in developing the **TPM**, the assumption made and Transpower's reasons for making that assumption.~~

~~5.~~3. The **TPM** must include requirements for Transpower to conduct consultation or allow rights of challenge to proposed charges under the TPM or their inputs. For the avoidance of doubt, this clause does not require Transpower to consult on a proposed TPM submitted to the Authority under clasuses 12.88 or 12.90 of the Code. ~~on:~~

~~(a) the proposed **benefit-based charge** and its allocation between designated transmission customers for each proposed **high-value benefit-based investment**;~~

~~(b) the proposed allocation of the **residual charge**;~~

~~(c) important parameters used to calculate those charges and allocations;~~

~~(d) any proposed material changes to those charges or allocations (in which case consultation must extend to whether such changes are warranted by a change in circumstances); and~~

~~(e) any assumptions made in calculating those charges, allocations or material changes to those charges or allocations,~~

~~with parties who have a material financial interest in the charges. Where Transpower can demonstrate that such parties have already been consulted on the above (whether by Transpower or any other party), it need not repeat that consultation for the purposes of this clause.~~

~~6.~~4. The **TPM** must include a requirement for Transpower to provide each designated transmission customer with information regarding how its **transmission charges** have been calculated, including the basis on which its **benefit-based charge** and **residual charge** have been set. The basis on which the **residual charge** has been set includes the extent to which the **residual charge** comprises unallocated **opex** and the extent to which it comprises costs which have been reallocated to the **residual charge** as a result of **benefit-based investments** having been subject to **reassignment**. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to verify the accuracy of Transpower's calculations of its **transmission charges**.

~~7.~~5. The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, or incentives on, a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, or incentives on any parties directly or indirectly electrically connected to that designated transmission customer.

~~8.~~6. The **TPM** must provide for the treatment of a transmission alternative to be consistent with the treatment the investment which the transmission alternative seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, for the cost of transmission alternatives to be allocated to the designated transmission customers that benefit from them in proportion to the relative level of benefit that each customer receives.

Main components

~~9.~~7. The **TPM** must include:

1. a charge for **connection assets**;
2. a **benefit-based charge**;
3. a **residual charge**;
4. a prudent discount policy; and
5. a transitional cap on specified **transmission charges**.

The total recovered by Transpower under these components may not exceed Transpower's **forecast MAR**.

Main component 1: connection charge

~~10.~~8. The **TPM** must provide for the costs of **connection assets** to be recovered from those designated transmission customers that are connected to them.

~~11.~~9. The **TPM** must include a definition of deep connection, which must be applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent reasonably practicable.

Main component 2: benefit-based charge

Benefit-based charge must apply to benefit-based investments

~~12.~~10. The **TPM** must include a **benefit-based charge** for each **benefit-based investment**.

~~13.~~11. A **benefit-based investment** means:

(a) any **post-2019** investments in the **interconnected grid**, including any transmission alternatives;

(b) the following **pre-2019** investments in the **interconnected grid:**

(i) the Bunnythorpe-Haywards Reconductoring Project

(ii) investments in and associated with the HVDC link

(iii) the Lower South Island Renewables Project;

(iv) the Lower South Island Reliability Project;

(v) the North Island Grid Upgrade (NIGU) Project;

(vi) the Upper North Island Dynamic Reactive Support Project; and

(vii) the Wairakei Ring Project;

(c) **upgrading expenditure** as provided for in clauses 28 to 30 below; and

(d) **pre-2019** investments in the **interconnected grid** identified by means of a method established under clauses 1 and 1 below**.**

Benefit-based charges must recover the covered cost of benefit-based investments

~~14.~~12. The **benefit-based charge** for a **benefit-based investment** must recover, over the **benefit-based investment's remaining life**, the present value of the **covered cost** of that **benefit-based investment**, which comprises:

(a) the capital cost of the **benefit-based investment**, based on:

(i) for **post-2019 benefit-based investments**, the **value of commissioned assets** forming part of that **benefit-based investment**;

(ii) for **pre-2019 benefit-based investments**, the depreciated value of the assets comprising the **benefit-based investment** as recorded in the **regulatory asset base** at the date the **benefit-based charge** is first applied to the **benefit-based investment**;

(b) a return on capital for the **benefit-based investment**, based on its capital cost as allowed for under paragraph (a) and **WACC**;

(c) an amount of forecast **opex** reasonably attributable to the benefit-based investment based on an allocation of the **opex** allowance for the **pricing year** as set by the Commerce Commission in the **IPP**; and

(d) any other costs attributable to that **benefit-based investment**.

Recovery of the covered cost of a benefit-based investment over time

~~15.~~13. The **TPM** must provide for the **annual benefit-based charges** for each **post-2019 benefit-based investment** to be calculated:

(a) using the following method:

(i) the expected **benefit-based charge** for the **benefit-based investment** is divided into equal annual amounts over the **benefit-based investment's remaining life**; and

(ii) the annual amounts determined under subclause (a)(i) are adjusted for inflation over the **benefit-based investment's remaining life** using an index determined by Transpower; or

[DRAFTING NOTE: Meridian's submission favours using a "depreciated historic cost" method when setting an annual benefit-based charge, i.e. the same method used for the annual recovery of capital components under Transpower's individual price-quality path determined by the Commerce Commission. If Meridian's submission is accepted the drafting of these clauses will need to be amended accordingly.]

(b) according to an alternative method, where that alternative method:

(i) would better meet the Authority's statutory objective than the method described in paragraph (a); and

(ii) would still recover the **covered cost** of that **benefit-based investment**.

~~16.~~14. The **TPM** must provide that Transpower's recovery of the capital components for each **pre-2019 benefit-based investment** for a **pricing year** under the **TPM** must be the same as the forecast depreciation and forecast capital charge in that **pricing year** for the assets of that **benefit-based investment** under the **IPP***.*

~~17.~~15. The **TPM** must allow Transpower to adjust future **annual benefit-based charges** for a **benefit-based investment** if, in Transpower's reasonable assessment, there has been, or will be, a material change to any of the expected future:

(a) **WACC**;

(b) **opex** attributable to the **benefit-based investment**;

(c) **remaining life** of the **benefit-based investment**; or

(d) any other costs attributable to the **benefit-based investment**.

The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**.

Damage to a benefit-based investment

~~18.~~16. The **TPM** must allow Transpower to adjust or end future **annual benefit-based charges** for a **benefit-based investment** where an asset or assets forming part of that **benefit-based investment** are destroyed or substantially damaged.

Allocating annual benefit-based charges among customers

~~19.~~17. The **TPM** must include one or more standard methods for allocating **annual benefit-based charges**.

~~20.~~18. The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.

~~21.~~19. The **TPM** must provide:

(a) that Transpower must use a standard method to allocate the **annual benefit-based charges** for **high-value post-2019 benefit-based investments**;

(b) that Transpower must use Schedule 1 to allocate the **annual benefit-based charges** for the **benefit-based investments** included in Schedule 1;

(c) where these **Guidelines** provide for an adjustment to the Schedule 1 allocations, a method for making that adjustment. That method must be a standard method, simple method or combination of both; and

(d) that Transpower must use a standard method, simple method or combination of both to allocate the **annual benefit-based charges** for any other **benefit-based investments**.

~~22.~~20. A standard method:

(a) must allocate the **annual benefit-based charge** for a **benefit-based investment** between the designated transmission customers expected to benefit from the **benefit-based investment** in proportion to their expected **positive net private benefit** from the **benefit-based investment** over its **remaining life**;

(b) where necessary, may determine expected **positive net private benefits** using one or more reasonable proxies. Such proxies must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to each designated transmission customer who receives a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had expected **net private benefits** been used to calculate the allocation.

~~23.~~21. A simple method:

(a) must be capable of being implemented at a lower cost to participants, including Transpower, than the standard method(s). Cost includes administrative burdens on participants but does not include increases in resulting **transmission charges**;

(b) must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to the designated transmission customers who receive a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had the standard method been applied. However, Transpower is not required to apply the standard method solely for the purpose of making this assessment; and

(c) may exempt designated transmission customers who do not receive a major **positive net private benefit** from a **benefit-based investment** from receiving an allocation of the **annual benefit-based charges** for the **benefit-based investment**.

~~24.~~22. The **TPM** must provide that, ~~save for benefits and costs included at Transpower's discretion, ~~the treatment of benefits and costs used to calculate **net private benefits**, to the extent applicable, in respect of **post-2019 benefit-based investments** under each standard method and each simple method must be consistent with, though not necessarily identical to, the treatment of the relevant **electricity market benefit or cost elements** under the test used by the Commerce Commission in its approval of the **post-2019 benefit-based investment**, unless Transpower considers there has been a material change since that test was applied.

~~25.~~23. The **TPM** must provide that, once a designated transmission customer's share of the **annual benefit-based charge** has been allocated, that share will not change, save where these **Guidelines** permit otherwise.

~~26.~~24. The **TPM** must provide:

(a) that Transpower may review the allocation of future **annual benefit-based charges** for a **high-value benefit-based investment** if Transpower considers there has been, or expects that there will be, a substantial and sustained change in grid use affecting the **net private benefits** derived by one or more designated transmission customers from the **benefit-based investment**;

(b) that a substantial change in grid use will only have occurred where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges;

(c) a method for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment**; and

(d) a method/s for adjusting allocations in the event that there has been a substantial and sustained change in grid use.

[DRAFTING NOTE: Meridian's submission supports a regular mechanical review as well as the consolidation and clarification of guidelines on the various adjustment mechanisms. If this submission in accepted, the clause above should be amended to give effect to that submission.]

Implementation timeframe for the benefit-based charge

[DRAFTING NOTE: This section could be a stand-alone implementation section rather than part of the "Main component 2: benefit-based charge" section. Clause 27 should provide for deferment of additional components if their implementation may compromise or delay development and implementation of any main component.]

~~27.~~25. The **TPM** must provide for the **benefit-based charge** to apply to **high-value post-2019 benefit-based investments** and **pre-2019 benefit-based investments** to which Schedule 1 applies from the commencement of the **TPM** or the date on which the investment is **commissioned** (whichever is later).

~~28.~~26. The **TPM** must provide for **benefit-based charges** for **low-value post-2019 benefit-based investments** to be phased in as soon as is reasonably practicable after the **benefit-based charge** has been applied to the **high-value benefit-based investments** listed in clause 25 and no later than five years after the commencement of the **TPM**.

~~29.~~27. The **TPM** must provide that the implementation of **additional components**, other than a transitional **peak charge**, must be deferred if their implementation may compromise or delay development and ~~necessary in order to expedite the~~ implementation of the **benefit-based charge** for **high-value benefit-based investments**.

Upgrading expenditure

~~30.~~28. **Upgrading expenditure**, in relation to existing **benefit-based investments**, means expenditure that results in an extension to the existing **benefit-based investment's remaining life** or otherwise increases the benefits that **benefit-based investment** is expected to provide.

~~31.~~29. The **TPM** must provide that, where Transpower undertakes **upgrading expenditure**, that **upgrading expenditure** must be recovered using the method prescribed in these **Guidelines** for recovering the **covered cost** of a **post-2019 benefit-based investment** having a capital cost equal to the cost of the **upgrading expenditure**.

~~32.~~30. Subject to clause 29, in recovering **upgrading expenditure** on existing **benefit-based investments**, Transpower may:

(a) treat the **upgrading expenditure** as a new **benefit-based investment**; or

(b) adjust as appropriate the value of the **benefit-based investment**, its **remaining life**, its estimated benefits and the calculation and allocation of the **annual benefit-based charge** for it, in order to reflect the changes caused by the **upgrading expenditure**. An adjustment under this paragraph may alter the **covered cost** and allocation for the overall **benefit-based investment** (comprising the initial **benefit-based investment** and the **upgrading expenditure**). However, such an adjustment is not to alter the requirement to recover the **covered cost** of the initial **benefit-based investment** or the calculation of **net private benefits** for the initial **benefit-based investment**.

Reassignment

[DRAFTING NOTE: Meridian's submission supports a regular mechanical review as well as the consolidation and clarification of guidelines on the various adjustment mechanisms. If this submission in accepted, these reassignment clauses should be amended to give effect to that submission.]

~~33.~~31. The **TPM** must provide for a party to make an application to Transpower for **reassignment** of charges:

(a) where that party has a direct or indirect financial interest in the **annual benefit-based charge** for that **benefit-based investment**;

(b) where the **benefit-based investment** had an initial value of $5 million or more (with this threshold to be adjusted for inflation); and

(c) whether or not the **benefit-based investment** has previously been subject to **reassignment**.

~~34.~~32. The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if Transpower considers that the circumstances which led to the **reassignment** are likely to be sustained and:

(a) for a **pre-2019 benefit-based investment**, the investment's value following **reassignment** would be less than 80% of its current value;

(b) for a **post-2019 benefit-based investment**:

(i) where the disconnection of a single party causes the **benefit-based investment's** value following **reassignment** to be less than 80% of its current value; or

(ii) the **benefit-based investment** has been **commissioned** or otherwise been in operation for the period of time specified in the **TPM** for the purpose of this subclause and its value following **reassignment** is now less than 80% of its current value.

~~35.~~33. In setting a period of time for which a **post-2019 benefit-based investment** must have been **commissioned** in order for it to be eligible for **reassignment**, the **TPM** must provide for that period to be sufficiently long that the prospect of **reassignment** will likely have a negligible impact on the characteristics of the **post-2019 benefit-based investment** that designated transmission customers are incentivised to seek.

~~36.~~34. The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the revision to forecast future demand for **transmission lines services** which gave rise to the **reassignment**.

~~37.~~35. The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist, it must reverse the **reassignment** (that is, restore the value of the **benefit-based investment** to the value that would have applied if the **reassignment** had not taken place) or adjust the level of the **reassignment**, as is appropriate.

~~38.~~36. The **TPM** must provide that, where Transpower determines to carry out **reassignment** with respect to a **benefit-based investment** or reverse a **reassignment**, it must:

(a) modify the **annual benefit-based charge** for that investment to take into account the change in the **benefit-based investment's** value;

(b) adjust the allocation of the **annual benefit-based charge** to designated transmission customers to the extent necessary to take into account the change in forecast future demand for **transmission lines services** which led to the **reassignment** or reversal of the **reassignment**; and

(c) adjust the **residual charge** as necessary to take into account the changes to the **annual benefit-based charge**.

Main component 3: residual charge

~~39.~~37. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers to the extent that they are load to recover any remaining **forecast MAR** not recovered through other **transmission charges**.

~~40.~~38. The **TPM** must provide for the **residual charge** to be allocated:

(a) in proportion to each designated transmission customer's historical anytime maximum demand, which is to be calculated using data supplied by the reconciliation manager and by:

(i) taking, in a **pricing year**, the highest value for any trading period which represents the sum of:

A. the highest net quantity of electricity flow from the grid at the designated transmission customer's grid exit point; and

B. Transpower's estimate of any concurrent generation by distributed generators or behind-the-meter generation that is indirectly connected to the grid through the designated transmission customer; and

(ii) taking the average of that value over at least two years ending prior to either 1 July 2019 or the date 10 years prior to the date on which the **residual charge** is to be assessed, whichever is the later; or

(b) by an alternative method of allocating the charge to designated transmission customers to the extent that they are load, should Transpower consider that the alternative method would better meet the Authority's statutory objective than the method set out in paragraph (a) above.

~~41.~~39. The **TPM** must provide that, in initially allocating the **residual charge** under clause 38, Transpower may adjust the allocation where necessary to accommodate circumstances in which a designated transmission customer has experienced a substantial change in demand due to factors beyond their control or influence. For the purposes of this clause, a substantial change in demand is to be assessed relative to the designated transmission customer's remaining demand.

[DRAFTING NOTE: Meridian's submission supports a regular mechanical review as well as the consolidation and clarification of guidelines on the various adjustment mechanisms. If this submission in accepted, clauses 39 to 42 above and below should be amended to give effect to that submission.]

Provisions relating to adjustments

~~42.~~40. The **TPM** must:

(a) provide for a process for allocating **benefit-based charges** and **residual charges** in respect of:

(i) new **large consumers or generators**;

(ii) existing **large consumers or generators** who establish a new plant or generating unit or increase (where that increase is substantial and sustained) an existing plant's electricity use or an existing generating unit's generation, where that plant or generating unit is directly or indirectly connected to the grid;

(b) provide that, where a designated transmission customer sells part of its business, Transpower may allocate the designated transmission customer's charges between the original and new owners; and

(c) avoid creating inefficient incentives for a **large consumer or generator** to shift their point of connection (beyond the ability to do so in the prudent discount policy). The prudent discount policy may apply to circumstances where a **large consumer or generator** is considering shifting their point of connection, but the **TPM** must include additional provisions to avoid creating such incentives.

The charges may need to be scaled back

~~43.~~41. The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year**:

(a) applying the other provisions of the TPM would result in Transpower recovering more than its **forecast MAR**; or

(b) Transpower wishes to recover less than its **forecast MAR**.

~~44.~~42. The **TPM** must provide that~~, where clause 43(a) applies,~~ charges are to be scaled back in the following order:

(a) the **residual charge**;

(b) the **annual benefit-based charge** for **pre-2019 benefit-based investments**; then

(c) the **annual benefit-based charge** for **post-2019 benefit-based investments**.

~~45. The **TPM** must provide that, where clause 43(b) applies, Transpower may first scale back the **annual benefit-based charge** for a **benefit-based investment**. However, such a scaling back of the **annual benefit-based charge** must not result in an increase to the **residual charge**.~~

Main component 4: prudent discount policy

~~46.~~43. The **TPM** must provide for a prudent discount policy that encourages designated transmission customers not to inefficiently bypass the grid, including encouraging **load customers** not to inefficiently disconnect from the grid in favour of alternative supply.

~~47.~~44. The prudent discount must be available where a designated transmission customer can establish that:

(a) it would be technically and operationally feasible, and commercially beneficial, for the designated transmission customer to undertake the relevant action described in clause 43; and

(b) the relevant action would be inefficient to implement given Transpower's economic costs of providing the designated transmission customer with access to the **interconnected grid** and the economic costs incurred by the designated transmission customer if it proceeded with the relevant action described in clause 43.

~~48.~~45. The prudent discount must apply for the **remaining life** of the relevant investment, unless Transpower and the party receiving the prudent discount agree to a different period.

Main component 5: transitional ~~C~~cap on transmission charges

[DRAFTING NOTE: Meridian does not support a price cap but submits that, to the extent it is retained, it may be sufficient for the Guidelines to set out the purpose, rate and broad nature of the cap, and to leave Transpower to develop the detailed mechanisms.]

~~49.~~46. Subject to clause 50, the **TPM** must provide for a transitional price cap on each **load customer's** total **transmission charges** excluding:

(a) any **connection charge**;

(b) any **peak charge**;

(c) any kvar charge;

(d) any charge attributable to investments commissioned or otherwise entering into operation after the end of the 2019/20 **pricing year**;

~~(e) any **benefit-based charge** in respect of any **pre-2019 benefit-based investment** identified by means of a method established under clauses 62 and 63;~~

~~(f)~~(e) any increase in the **residual charge** due to a **reassignment** of a **benefit-based investment**;

~~(g)~~(f) any increase in a designated transmission customer's allocation of the **annual benefit-based charge** for a **benefit-based investment** due to a reallocation under clause 24; and

~~(h)~~(g) the application of clause 40.

~~50.~~47. Subject to clause 50, in setting a price cap, the **TPM** must provide for:

~~(i)~~(a) any increase in a distributor's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than the amount resulting from the following formula:

B x (0.035 + CPI + L)

where:

B is Transpower's estimate of the total electricity bill for all consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 **pricing year** (expressed in dollars), calculated as:

$$B = C + P*V$$

and where

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the distributor's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

C is the distributor's total line charge revenue for the 2019/20 **pricing year** excluding GST from Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012;

P is the volume weighted average of wholesale energy prices at the distributor's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in \$/MWh and excluding GST, with weights being the gross load as determined by the reconciliation manager; and

V is the distributor's total gross load for the 2019/20 **pricing year**, expressed in MWh, as determined by the reconciliation manager;

~~(j)~~(b) any increase in a direct consumer's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than:

B x (0.035 + 0.02 x Y + CPI + L)

where:

B is Transpower's estimate of the total electricity bill of that direct consumer in the 2019/20 **pricing year** (expressed in dollars), calculated as;

B = T + P*V

and where

Y is the greater of zero and of the number of **pricing years** which have elapsed since the 2019/20 **pricing year** minus 5;

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the direct consumer's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

T is what the direct consumer's total **transmission charge** (including any **connection charge**) is or would have been under the existing **TPM** in the 2019/20 **pricing year**, excluding GST;

P is the volume weighted average of wholesale energy prices at the direct consumer's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST; and

V is the total direct consumer's load in the 2019/20 **pricing year** in MWh, such information to be obtained from the reconciliation manager; and

~~(k)~~(c) the price cap to be permanently removed for a particular **load customer** if, in any **pricing year** after the **pricing year** in which **benefit-based charges** are first applied to **low-value post-2019 benefit-based investments**, the cap does not have the effect of reducing the **load customer's transmission charges** subject to the price cap as set out in clause 49.

~~51.~~48. To the extent that the price cap results in a reduction in **transmission charges** for one or more **load customers**, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the **benefit-based charge** for the investments listed in clause 13(b) and the **residual charge** for each designated transmission customer.

~~52.~~49. The surcharge on the **benefit-based charge** and the **residual charge** for a designated transmission customer is to be reduced if necessary and to the extent necessary to ensure that its **transmission charges** subject to the price cap as set out in clause 49 meet the condition in clause 50.

~~53.~~50. The price cap provisions must not prevent Transpower from recovering its **forecast MAR**.

Additional components

[DRAFTING NOTE: Meridian's submission is that the Authority defers consideration of (a), (b), (c), (f) and (g). Meridian opposes the inclusion of component (e). If these submissions are accepted, this section should be amended accordingly.]

~~54.~~51. To the extent that clause 27 of the guidelines does not apply and require deferment of additional components, ~~T~~the **TPM** must incorporate each of the following **additional components**, where including that component would~~, in Transpower's reasonable opinion,~~ better meet the Authority's statutory objective than not including that **additional component**:

(a) staged commissioning, as described in clause 52;

(b) charges for assets principally providing connection services, as described in clause 53;

(c) charges for connection assets, as described in clause 54;

(d) a transitional peak charge, as described in clauses 55 to 58;

~~(e) including additional pre-2019 investments in the benefit-based charge, as described in clauses 62 and 63;~~

~~(f)~~(e) charging for **opex**, as described in clause 59; and

~~(g)~~(f) a kvar charge, as described in clause 60.

Additional component A: staged commissioning

~~55.~~52. This component must provide a method for Transpower, at its discretion, to adjust the time profile and allocation of charges over a **benefit-based investment's remaining life** where an investment is **commissioned** in stages so that it sometimes meets the definition of a **connection asset**, in order to best reflect the benefits provided while it is a connection investment relative to the benefits provided after it has become an investment in the **interconnected grid**. The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**, less any **connection charges** already paid.

Additional component B: charges for assets principally providing connection services

~~56.~~53. This component must provide a method to ensure that charges that apply to assets that provide connection services are not affected by connecting those assets to other assets, if they continue to provide principally the services of a **connection asset**, notwithstanding that they do not meet the formal definition of a **connection asset**.

Additional component C: charges for connection assets

~~57.~~54. This component must provide for the method for determining the annual amount to be recovered for each new **connection asset** to align with the method for determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 8 and 9.

Additional component D: transitional peak charge

~~58.~~55. This component must provide a method for determining, in respect of the transitional **peak charge**:

(a) the initial level of the charge;

(b) the designated transmission customers or geographic areas to, or the circumstances in, which it applies; and

(c) how the charge is to be allocated between designated transmission customers.

The transitional **peak charge** may only apply in respect of those geographic areas, circuits or other circumstances which, in Transpower's reasonable opinion, would experience congestion without a transitional **peak charge**.

~~59.~~56. If Transpower determines to include a transitional **peak charge** in the **TPM**, it must include in its outline required under clause 2 of these **Guidelines**, an explanation as to why it considers that grid demand will not be adequately controlled by the other prices including nodal pricing.

~~60.~~57. If the **TPM** includes a transitional **peak charge**:

(a) the transitional **peak charge** must be progressively phased out, such phase-out to commence no later than one year after the transitional **peak charge** is first imposed;

(b) the phase-out of the transitional **peak charge** must result in it being phased out completely within five years of the **TPM** entering into effect. Transpower may, during this phase-out period, temporarily pause the phase-out or increase the transitional **peak charge**, including by reinstating a transitional **peak charge** which has already been phased out, where doing so would~~, in Transpower's reasonable opinion,~~ better meet the Authority's statutory objective, provided that the phase-out is still completed within the five year period unless Transpower has obtained the Authority's approval under paragraph (d) below to extend that period;

(c) the **TPM** must include the process for phasing out the transitional **peak charge**, including specifying the maximum transitional **peak charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **peak charge**; and

(d) the **TPM** must include provision for Transpower to apply to the Authority during the phase-out period, to deviate from the maximum transitional **peak charge** that may be levied in any year, the time limit on or duration of the phase-out period. Transpower must provide to the Authority such information as the Authority requires to determine an application under this paragraph.

~~61.~~58. Notwithstanding anything in clause 57 above, after the phase-out period has ended, Transpower may propose to reinstate or introduce a new transitional **peak charge** as part of a review under clause 12.85 of the **Code**. In proposing a reinstated or new transitional **peak charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal.

~~*Additional Component E: Including additional pre-2019 investments in the benefit-based charge*~~

~~62. This component must include a method for extending the definition of **benefit-based investment** to other **pre-2019 benefit-based investments** in the **interconnected grid** and related services, including transmission alternatives, that contribute to Transpower's **forecast MAR**.~~

~~63. If the **TPM** includes such a method, it:~~

~~(a) must specify a method for allocating the **annual benefit-based charges** for the **benefit-based investments** between designated transmission customers. The method must be a simple method as described in clause 23;~~

~~(b) must provide for the **benefit-based charge** for such **benefit-based investments** to be capped at the present value of the aggregate **positive net private benefits** expected to be derived by designated transmission customers from the **benefit-based investment** over its **remaining life**; and~~

~~(c) may include transitional provisions which phase in the relevant charges.~~

Additional component F: charging for opex

~~64.~~59. This component must include a method for allocating **opex** expended in relation to **connection assets** and assets in a **benefit-based investment** to the designated transmission customers paying charges in relation to that asset or investment. The method must not use a proxy or generalised rule for allocation.

Additional component G: kvar charge

~~65.~~60. This component must include a method for imposing a kvar charge on reactive power.

Interpretation

~~66.~~61. In these **Guidelines**, unless the context otherwise requires it:

2019 Issues Paper means the issues paper prepared by the Authority under clause 12.81 of the **Code** and published by the Authority on [**date**] 2019.

additional component means one of the components required by clause 0 of these **Guidelines** to be included in the **proposed TPM** where Transpower considers that including that component will better meet the Authority's statutory objective than not including it.

annual benefit-based charge means the amount of the **benefit-based charge** to be recovered in respect of a particular **benefit-based investment** in any one **pricing year**.

asset refurbishment has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

asset replacement has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

benefit-based charge means the charge as described in clause 10.

benefit-based investment has the meaning given to it in clause 11.

Code means the Electricity Industry Participation Code 2010, as amended from time to time.

commissioned has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

connection assets means the assets owned by Transpower used to connect a designated transmission customer to the grid**,** and may have a more precise definition in the **transmission pricing methodology** as amended from time to time.

connection charge means the charge described in clauses 8 and 9.

covered cost, in relation to a~~n~~ **benefit-based investment**, has the meaning given to it in clause 12.

electricity market benefit or cost element has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2, as amended from time to time.

forecast MAR means, for a **pricing year**, Transpower's forecast maximum allowable revenue as set by the Commerce Commission in the **IPP**, as amended from time to time. The **IPP** for the **pricing year** commencing 1 April 2010 is the *Transpower Individual Price-Quality Path Determination 2020.*

generation customer means a designated transmission customer that is a generator.

Guidelines means these guidelines.

high-value, in respect of a **benefit-based investment**, means a **benefit-based investment** that, at the time it was first **commissioned** exceeded the "base capex threshold" as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time, whether or not the investment would otherwise meet the test for "major capex".

interconnected grid means the grid including the HVDC link but excluding **connection assets.**

IPP means Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act 1986 from time to time. At the date of these **Guidelines** the relevant determination is the *Transpower Individual Price-Quality Path Determination 2015.*

large consumer or generator means an actual or potential user of **transmission lines services** (whether as load or generation) which could reasonably contemplate shifting its point of connection.

load customer means a designated transmission customer that is a distributor or direct consumer.

low-value means, in respect of a **benefit-based investment**, a **benefit-based investment** which does not meet the definition for a **high-value benefit-based investment.**

net private benefit means, for a designated transmission customer:

(a) the value of the private benefits which are consistent with **electricity market benefit or cost elements** that arise from the **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**; less

(b) the value of the private costs which are consistent with **electricity market benefit or cost elements** (but excluding the cost of the **benefit-based investment** itself) that arise from that **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**,

provided that Transpower may, at its discretion, include as part of the calculation the value of other benefits or costs where those benefits or costs are substantial and result from the **benefit-based investment.**

opex means "operating cost" as defined in the Commerce Commission's *Transpower Input Methodologies Determination 2010*, as amended from time to time.

peak charge means a charge, over and above nodal prices and the other **transmission charges** provided for in these **Guidelines**, imposed to influence peak demand for use of the grid.

positive net private benefit means for a designated transmission customer:

(a) the **net private benefit** if it is positive; or

(b) zero if it is not

post-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is first **commissioned** after the publication of the **2019 Issues Paper** (including any part of a **pre-2019 benefit-based investment** to the extent that it is **commissioned** after this date) and which at the relevant time of **commissioning** constitutes base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pre-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is **commissioned** on or before the date of publication of the **2019 Issues Paper** and which at the relevant time of **commissioning** would have constituted base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pricing year has the meaning given to it in the **IPP.**

reassignment means a reassignment of charges from the **benefit-based charge** to the **residual charge** due to a reduction in the value of an asset for the purposes of the **benefit-based charge**, and **reassignments** and **reassigned** have equivalent meanings.

regulatory asset base means, for a **pricing year**, the asset base used to determine **forecast MAR** for the **pricing year.**

remaining life means, for a **benefit-based investment**, the **benefit-based investment's** expected economic life at the time the relevant clause of the **TPM** applies.

residual charge means the charge as described in clause 37.

TPM means the transmission pricing methodology.

transmission lines services has the meaning given to it in the **IPP.**

transmission charges means the charges provided for by the **TPM**, as amended from time to time.

upgrading expenditure has the meaning given to it in clause 28.

value of commissioned assets has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

WACC means, for a **pricing year**, the pre-tax nominal weighted average cost of capital used to determine **forecast MAR** for the **pricing year.**

~~67.~~62. In these **Guidelines**, unless the context requires otherwise, any other term that is defined in Part 1 of the **Code**, and used but not defined in these **Guidelines**, has the same meaning as in Part 1 of the **Code**. Terms defined in Part 1 of the **Code** are underlined in these **Guidelines**.