CBA approach, methods and assumptions

TPM decision paper 2020

Technical paper

Information paper

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Market Design

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1 Our overall approach to the Cost Benefit Analysis (CBA)

1.1 The purpose of this paper is to set out:

(a) the approach the Authority has followed in quantifying the proposal's costs and benefits (including revisions after feedback from interested parties on the 2019 Issues Paper)

(b) the main models we have used in the CBA to quantify costs and benefits

(c) the main assumptions we have made when quantifying costs and benefits.

1.2 This paper is an update of the CBA technical paper released with the 2019 Issues Paper. It can be read alongside the information paper and supporting files published by the Authority in April 2020,[1] which set out the Authority's current thinking on the quantitative component of its CBA of the TPM guidelines proposed in 2019, after taking into account submissions received on that proposal.

CBA as an aid to decision-making

1.3 The CBA for the TPM proposal is an aid to support deliberation and decision-making, alongside a much broader range of factors the Authority has to consider. The quantitative component of the CBA gives a sense of the order of magnitude of the quantifiable benefits and costs. These impacts sit alongside effects that cannot reasonably be quantified, and which are not discussed in this technical paper, but which are also relevant and are being considered by the Authority.

1.4 A CBA cannot be a precise exercise. There is imperfect knowledge about the current electricity system, and there are always uncertainties about how the future will unfold. Modelling by its nature seeks to provide a tractable representation (and not a replica) of a complex system. There will always be different views about assumptions made, approaches that could have been taken, and opportunities to refine the analysis.

Aspects of the CBA's design and methodology are novel

1.5 Aspects of the design and methodology of the CBA are novel. This is because the nature of the proposal is novel in a New Zealand context—specifically, the focus on calculating benefits for the purpose of setting transmission charges.

The CBA uses bespoke models as part of a primarily 'bottom up' approach

1.6 To improve the quantitative analysis of the proposal's more novel aspects, we have used bespoke models in the CBA, primarily for our assessment of more efficient grid use and more efficient investment in utility-scale batteries. These bespoke models form part of a primarily 'bottom up' approach to articulating and analysing the mechanisms by which the proposal would lead to incremental gains in economic efficiency. We refer to these bespoke models collectively as the grid use model.

The CBA also uses some 'top down' analysis

1.7 The CBA uses a 'top down' approach to assess quantifiable long-term effects of the proposal on investment by electricity suppliers (generation and transmission) and consumers, scrutiny of grid investment proposals and increased certainty for investment.

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1 Available at https://www.ea.govt.nz/dmsdocument/26659-tpm-response-to-feedback-on-2019-cba.
Supporting programming code, information and analysis is available at https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2020/20200417_TPM_CBAfilesToSupportApr2020InformationPaper.

The CBA largely follows the approach in the CBA working paper

1.8 The CBA continues to largely follow the general approach set out in our 2013 CBA working paper.[2]

Table 1: High-level approach to CBA

Step	Synopsis
Define the problem	Established in chapter 2 of the 2019 Issues Paper—e.g., • poor price signals that result in inefficient consumption and investment • current TPM not durable, resulting in inefficient operation of electricity industry

Select options for addressing the problem that will be assessed	• Current TPM (baseline):
	  o HVDC charge on South Island generation
	  o RCPD charge on load
	  o PDP for up to 15 years, provided bypass alternative is not new generation
	• Proposal:
	  o removal of HVDC and RCPD charges
	  o benefit-based charge, including for seven historical investments
	  o residual charge (gross AMD) for remaining costs
	• Other options:
	  o Alternative: weaken the RCPD signal (see appendix E of the 2019 Issues Paper):
	    ▪ HVDC charge on South Island generation
	    ▪ removal of RCPD charge
	    ▪ a per-MWh charge based on historical MWh, calculated using all trading periods
	  o 'Future-only':
	    ▪ as per proposal, but only future grid investments recovered through benefit-based charges
	    ▪ remaining costs of all historic grid investments recovered through residual charge
	  o 'HVDC-only':
	    ▪ as per proposal, but only future grid investments and remaining HVDC investment costs recovered through benefit-based charge
	    ▪ remaining costs of all existing investments other than HVDC recovered through residual charge
	• All four proposed options would include an extension of the PDP to customers proposing to bypass transmission assets by installing alternative supply, or if their transmission charges exceeded standalone cost

2 Available at https://www.ea.govt.nz/dmsdocument/15683-working-paper-transmission-pricing-methodology-cba.

Step	Synopsis
Specify the baseline to measure costs and benefits against	If no action taken, expected growth in: • demand • costs of distributed generation • costs of demand response • generation costs • transmission investment • grid-connected generation • grid-connected load investment
Identify the effects of the proposed options to address the problem	A ‘bottom-up’ approach to analyse whether a TPM resulting from the proposed guidelines leads to incremental gains in economic efficiency, supplemented by ‘top-down’ analysis that draws on the findings of relevant studies

Assess the effects of the proposed options[3]	Assess relative effects of pricing options on:
	• grid use
	  ○ based on changes to supply costs and prices
	  ○ accounting for interaction between revenue requirements, prices and electricity consumption
	• investment in demand-side and supply-side assets, including transmission assets
	  ○ accounting for differences in timing of options
	• TPM design, implementation and operation costs

Evaluate against decision criteria	Extent to which the proposed options promote the Authority’s statutory objective
Test the sensitivity of the results	Testing the robustness of the results to changes in key assumptions
Document the CBA	Set out the above steps in a clear, concise manner

Source: Electricity Authority

3 This step combines steps 5, 6 and 7 of the 10-step process set out in our 2013 CBA working paper.

Scope of our assessment

We have assessed the five components of the proposed TPM guidelines

1.9 The CBA assesses the costs and benefits of the five components of the proposal shown in Table 2, relative to the current TPM arrangements (the baseline).

Table 2: Components of the proposal that the CBA assesses

Main components of proposed TPM guidelines	
1.	Retain the existing connection charge
2.	Introduce a benefit-based charge, and remove the HVDC and RCPD charges
3.	Introduce a residual charge, based on historical AMD, to recover transmission revenue not collected via other charges (e.g., connection and benefit-based charges)
4.	Extend the PDP— • to (load) transmission customers proposing to bypass existing grid assets by installing generation • to allow customers to apply for a discount based on efficient standalone cost
5.	Place a transitional cap on increases in specified transmission charges

Source: Electricity Authority

1.10 We have not assessed the benefits and costs of the seven additional components of the proposed TPM guidelines, because doing so is unnecessary. They are not mandatory components. Transpower will propose one or more of them for inclusion in the proposed TPM only if doing so would better meet the Authority's statutory objective than not doing so.

1.11 The CBA also assesses the benefits and costs of the three other proposed options summarised in Table 1 (i.e., the alternative, 'future-only' and 'HVDC-only' options). (The 2019 Issues Paper and the Authority's Decision Paper contain a qualitative assessment of a broader range of options.)

We have considered changes in electricity costs, investment and demand

1.12 The CBA, particularly the grid use model, considers changes in electricity costs (prices), investment and demand when a new TPM is introduced. The modelling attempts to hold as many things constant as is reasonable, across assessments of costs and demand under:

(a) the current TPM (the baseline)

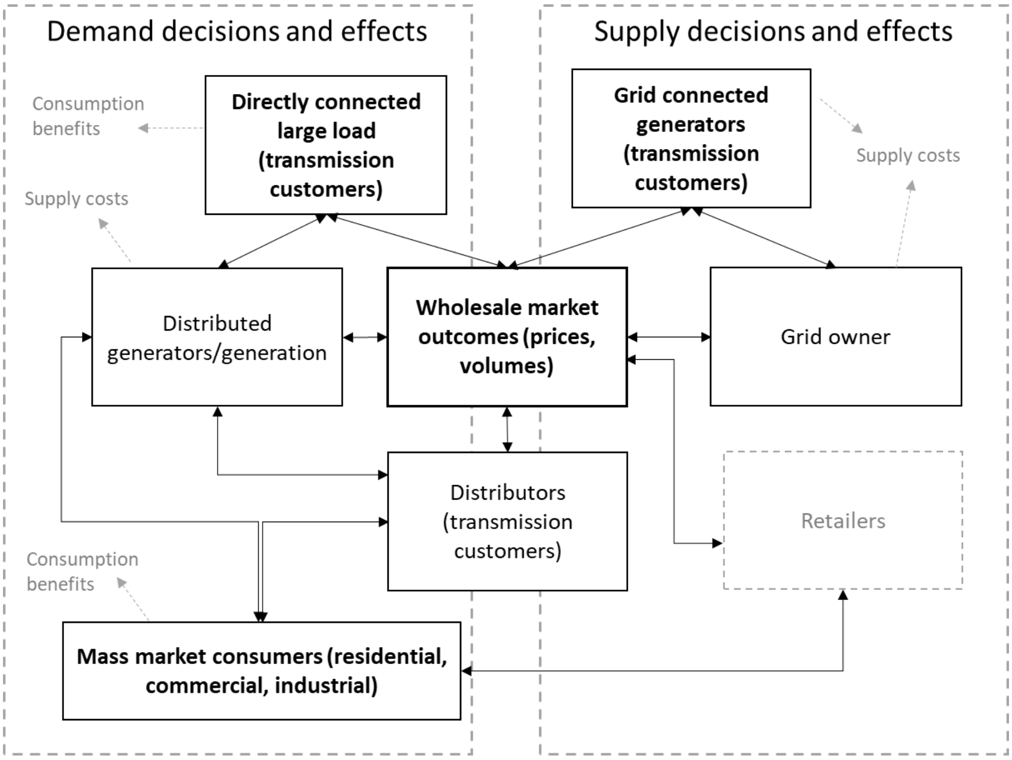
(b) a TPM based on the proposed guidelines

(c) a TPM based on alternative options.

1.13 Electricity costs and demand are projected for the period 2019 to 2049, for the baseline and for each of the four proposed options listed in Table 1. Then results for the five scenarios are compared and consumer welfare changes or cost differences are calculated.

1.14 Figure 1 summarises the scope of our assessment.

Figure 1: Scope of assessment – affected parties



Source: Electricity Authority

We have focussed primarily on those who pay for transmission assets

1.15 Our primary focus is on those that pay for transmission assets—being:

(a) consumers connected to distribution networks or to the transmission network

(b) grid-connected generators.

1.16 Another focus is on distributors, distributed generators, and the grid owner. These parties make operational and investment decisions, either directly or indirectly, in response to the decisions of the parties paying for transmission assets.

1.17 Central to the CBA (in particular, the grid use model) are wholesale market outcomes, such as prices and consumption. We have focussed on wholesale market outcomes because the core economic value of transmission assets stems from the gains from trade reflected in wholesale market outcomes. Transmission enables consumers to access lower cost energy, and generators to receive higher prices, than they otherwise might.

1.18 Our assessment does not directly consider economic effects on retailers or effects on retail prices. The analysis assumes:

(a) wholesale market outcomes, over time, reflect decisions by both retail consumers and wholesale market participants

(b) changes in retailers' transmission-related costs will, over time, be reflected in retail prices.

We have used quantitative analysis as much as practicable

1.19 To the extent practicable, the CBA uses quantitative analysis to assess the TPM proposal's costs and benefits. Table 3 summarises the impacts we have sought to quantify as part of the CBA.

Note, in the quantitative analysis the transitional cap on transmission charges is categorised as a cost—efficiency costs arise from the transitional redistribution—even though following our qualitative assessment that takes into account durability and certainty during the transitional period we consider it to have a net benefit.

Table 3: Components of the proposal that the CBA assesses quantitatively

Benefit categories	Description
More efficient grid use	An efficient increase in the use of electricity at times when use is most highly valued by consumers.
More efficient investment in distributed energy resources	Reductions in inefficient investment in distributed energy resources (e.g., batteries) for the main purpose of avoiding transmission interconnection charges.
Grid investment benefits brought forward	Loss and constraint excess (LCE) reduced sooner due to transmission investment occurring earlier than it would otherwise to cater for increases in peak demand.
More efficient investment by generators and large consumers	More efficient investment by generators and large consumers (as they will take account of the costs of all required grid upgrades when making location decisions).
More efficient grid investment—scrutiny of investment proposals	More efficient grid investment (due to greater scrutiny, and less lobbying for inefficient investments).
Increased certainty for investors	Increased certainty for investors reduces the required return on investment.

Cost categories	Description
TPM development and approval costs	Costs such as policy analysis, modelling and legal fees.
TPM implementation costs	Costs of computer hardware and software, development and testing, changes to business processes, policies and procedures, and user training.
TPM operational costs	Costs of data gathering and management, invoicing and customer liaison.
Grid investment costs brought forward	Requirement for transmission investment to occur earlier than it would otherwise to cater for increases in peak demand.
Load not locating in regions with recent investment in capacity	Distortion from large energy-intensive consumers avoiding investing/locating in a region that already has a benefit-based charge.
Transitional cap on transmission charges	Suppressed demand of customers with transmission charges that are *not* capped.

Source: Electricity Authority

1.21 We have been careful to not double count any benefits and costs that occur for more than one component of the proposal, but which are not additive in nature. That is, we have counted a benefit/cost only once when it occurs for two or more components of the proposal.

Relevant markets and boundaries for the analysis

1.22 The CBA focuses on the extent to which the proposal promotes the Authority's statutory objective, being the extent to which the proposal promotes competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

1.23 The boundaries for the CBA, in terms of costs and benefits assessed, are set by the definition of 'consumer' in the Electricity Industry Act 2010 (Act) and with reference to the Authority's statutory objective. The Act defines "consumer" to mean "any person who is supplied, or applies to be supplied, with electricity other than for resupply". We interpret "electricity industry" to include all parties involved in the electricity industry, including consumers, and not just "industry participants" as defined in section 7 of the Act.[4]

1.24 The CBA does not evaluate effects on industries, markets, or policy objectives outside the electricity industry—so-called secondary market effects. Examples of secondary market effects include:

(a) indirect effects of transmission prices on labour market outcomes, such as wages, in industries outside the electricity industry

(b) demand, costs, and prices in other energy markets, such as gas, unless they are directly relevant to the functioning and efficiency of the electricity market and have an effect on the long-term benefit of electricity consumers

(c) health or environmental policy objectives and outcomes, where such outcomes and objectives are primarily within the mandate of organisations other than the Authority.

1.25 The way these effects manifest themselves is primarily a function of the efficiency of these other markets and the effectiveness of public policy, public institutions and regulation. Therefore, excluding these matters from the CBA avoids counting costs or benefits that are beyond the control of the Authority or electricity industry participants.

1.26 Assumptions also need to be made about the relative importance of, or extent of, the proposal's effect on the efficiency of the electricity industry. That is, in practice, the electricity industry's efficiency is affected by a range of institutions and potential regulatory and market failures. This includes the functions, powers and duties of the Commerce Commission in relation to the electricity industry.

1.27 It is standard practice in a CBA to focus, by default, on the regulatory or market failure at hand and to assume that other parts of the industry are functioning well. Under this approach, all estimated costs and benefits are ascribed to the policy change (or policy) under scrutiny—so long as those impacts occur within the boundary of the analysis (in this case the electricity industry and benefits for consumers).

1.28 Lastly, we have been careful to avoid estimates of effects being implausibly ascribed to changes to the TPM guidelines.

4 The Act's definition of "industry participants" includes generators, retailers, distributors, and industry service providers.

Our main scenario is an updated 'Mixed renewables' scenario from EDGS

1.29 The main scenario under which we have measured costs and benefits is an updated version of the 'Mixed renewables' scenario in the Ministry of Business, Innovation and Employment's (MBIE's) 2016 EDGS. Our main scenario is drawn from the EDGS because:

(a) Transpower must use the EDGS when developing major capital expenditure (capex) proposals

(b) the EDGS went through a public consultation process, during which consumers and industry participants were able to, and did, make submissions and cross-submissions on the draft EDGS.

Table 4: MBIE's EDGS 2016 [5]

	Mixed renewables	High grid	Tiwai off	Global low carbon	Disruptive
Thermal costs	Medium	Low	Medium	High	High
Underlying demand	Medium	High	Low	Medium	Medium
Rankine retirement	2022	2026	2019	2022	2022
Wind capital costs	Medium	Medium	Medium	Low	Medium
Hydro availability	Medium	Low	Medium	Medium	Medium
Solar "uptake"	Medium	Low	Medium	High	Very high
EV "uptake"	Medium	Low	Medium	Medium	Very high
Peak demand	Medium	High	Very low	Medium	Low
Tiwai (MW)	572	572	0	572	572

Source: Ministry of Business, Innovation and Employment

5 The 'High grid' scenario assumes higher GDP and population growth rates leading to higher electricity demand across all sectors—with 1.3% per year growth in grid-connected electricity demand. Higher gas exploration effort results in higher domestic gas supply with a flat wholesale gas price of around $6 / petajoule to 2040.

The 'Global low carbon' scenario assumes a high carbon price and lower cost renewable technology (wind and solar), which leads to more renewable generation build. This scenario assumes:

- high uptake of petrol hybrid vehicles and solar PV systems
- flat electricity demand per household due to energy efficiency measures.

In the 'Disruptive' scenario a reduction in technology costs leads to high uptake of solar PV with batteries and electric vehicles. Both total electricity demand and grid-connected demand increases, as the additional electric vehicle demand is only partially offset by solar generation. Peak and off-peak retail electricity price signals lead to a flattening of electricity demand, with a lower peak demand through battery load shifting and off-peak electric vehicle charging.

In the 'Tiwai off' scenario the Tiwai Point aluminium smelter closes at the start of 2018 and lower GDP growth leads to lower electricity demand across all sectors, averaging 0.4% p.a.

See http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016.

1.30 The 'Mixed renewables' scenario has a mixture of geothermal and wind plant built, starting in the early 2020s. This scenario assumes an average of 1% annual electricity demand growth, reflecting:

(a) moderate gross GDP growth

(b) moderate population growth

(c) views on—

(i) relative technology cost

(ii) expected fuel and carbon prices.

Updates to the 'Mixed renewables' scenario

1.31 In preparing the 2019 CBA we updated the 2016 EDGS 'Mixed renewables' scenario, to reflect key actual and forecast changes in the electricity industry and the New Zealand economy since the 2016 EDGS were finalised.

1.32 We increased the Tiwai Point aluminium smelter's demand by 50 MW, because of the restarting of the fourth potline at the end of 2018.[6] We assumed this additional[7] 50 MW of demand exists until the end of 2022, which is when the smelter's electricity supply agreement with Meridian Energy ends. The 2019 CBA also assumed the Tiwai Point aluminium smelter remains open for the period of our assessment of the proposal's costs and benefits (i.e., until 2049).

1.33 We assumed the retirement of the Rankine units at Huntly will be delayed to the end of 2024. The government's ban on future offshore oil and gas exploration permits may make investment in new baseload thermal generation riskier (because of a concern over the availability and price of gas over the life of the new generation plant). We assumed industry participants will want Genesis Energy to extend the life of the Rankine units until the mid-2020s, while participants assess the economics of new baseload thermal generation relative to other supply options.

1.34 We also added to Transpower's revenue all expenditure forecasts that Transpower had publicly indicated may be necessary over the period covered by the CBA, both base capex and major capex. This included capex not yet approved. We drew this information from:

(a) Transpower's latest (2018) Transmission Planning Report

(b) Transpower's 'Regulatory Control Period 3' (RCP 3) proposal to the Commerce Commission.

1.35 Since we made these input assumptions for the 2019 CBA:

(a) MBIE has released a revised EDGS

(b) new generation investment has been announced and construction, or pre-construction, started[8]

(c) COVID-19 has negatively impacted electricity demand.

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6 On 6 December 2018.

7 Additional relative to the smelter's demand in the 2016 EDGS 'Mixed renewables' scenario.

8 The largest examples being Mercury Energy's 222 MW Turitea windfarm in the Manawatu, Tilt Renewables' 133 MW Waipipi windfarm in south Taranaki, MainPower's 93 MW Mt Cass windfarm in north Canterbury, and Refining NZ's 26.7 MW Marsden Point solar farm.

1.36 Rather than updating the 2019 modelling to reflect these actual and potential changes in the electricity industry and the New Zealand economy, we have instead used sensitivity analyses to assess a range of potential changes in generation costs and underlying drivers of electricity demand growth, for the following reasons.

1.37 The revised 2019 EDGS refreshed some of the 2016 EDGS assumptions and scenarios around electricity demand growth and technology change but did not revisit the detailed analyses underpinning the 2016 EDGS, such as capital costs of potential electricity generation investment projects. Given this, we have continued to rely on the 2016 EDGS.

1.38 The input assumptions in our sensitivity analyses are consistent with the EDGS scenarios as well as scenarios produced by Transpower in its 2018 publication 'Te Mauri Hiko - Energy Futures'.

1.39 We have also chosen this approach because of the material COVID-19 related increase in uncertainty over demand for, and investment in, electricity since the 2019 CBA was prepared. The use of sensitivity analyses helps us to accommodate this uncertainty in the updated CBA.

2 Benefits from more efficient grid use

Factors affecting benefits from more efficient grid use

2.1 In quantifying the proposal's total net benefit from more efficient grid use, under our main scenario,[9] we consider five interrelated effects:

(a) Effect on electricity demand of changes to transmission interconnection charges

(b) Consumer welfare changes due to changes in electricity demand caused by changes in wholesale electricity prices inclusive of transmission interconnection charges

(c) Effects of changes in electricity demand and transmission interconnection charges on investment in grid-connected generation and thereby wholesale energy costs

(d) Effect of changes to transmission interconnection charges on the efficiency of investment in distributed energy resources

(e) Changes in (interconnection) transmission investment costs and benefits.

Effect on electricity demand of changes to transmission interconnection charges

2.2 We used a bespoke model of electricity demand to estimate the responsiveness of distribution-connected consumers and transmission-connected consumers to changes in the price of electricity at grid exit points (GXPs) (i.e., consumers' responsiveness to changes in wholesale electricity prices inclusive of transmission interconnection charges).

2.3 Consumers' responses to changes in wholesale electricity prices inclusive of interconnection charges vary:

(a) between distribution-connected consumers and transmission-connected consumers

(b) between areas of the country.

2.4 This variation reflects fundamental differences in consumers' electricity demand choices. For example, some consumers place a higher value on using electricity during peak demand periods, because they want to use heating when it is cold, or to cook dinner when they get home from work.

2.5 Variations in consumers' responsiveness to wholesale electricity prices inclusive of interconnection charges also reflect:

(a) the availability of local, distributed generation

(b) differences in wholesale energy prices across the transmission network, reflecting the cost of transporting electricity across it.

2.6 Consumers' responsiveness to wholesale electricity prices inclusive of interconnection charges tends to increase if wholesale energy prices are relatively higher. For example, consumers in Northland will tend to be more responsive to wholesale electricity prices inclusive of interconnection charges than consumers in South Canterbury. This is because the wholesale price of energy in Northland is generally 18% higher than the average wholesale energy price nationally, while wholesale energy prices in South Canterbury are on average 5% lower. This price difference reflects the extent to which consumers in Northland rely on more of the transmission network to transport energy to them (thereby facing the cost

9 I.e., the updated EDGS 'Mixed renewables' scenario.

of more energy losses and constraints on this network), compared with consumers in South Canterbury.

2.7 GXPs with a substantial amount of distributed generation can avoid transmission interconnection charges under the current TPM, by reducing their share of demand during peak demand periods.

2.8 For example, Whakamaru has significant distributed generation situated around it, resulting in Whakamaru consumers' electricity offtake from the transmission network being close to zero during periods of peak demand nationally. This reduces overall wholesale energy prices at Whakamaru and tends to reduce the sensitivity of Whakamaru consumers to changes in the price of wholesale electricity inclusive of interconnection charges. A 10% change in wholesale electricity prices inclusive of interconnection charges has a smaller impact if the prices are relatively low to begin with.

2.9 Changes in the incidence of transmission charges translate into changes in prices faced by consumers. Under the current TPM, transmission charges translate into high prices for electricity consumed during periods of peak demand.

2.10 RCPD charges are targeted at the top 100 coincident peak demand periods in each of the four transmission pricing regions. However, we have modelled the RCPD charge to be a charge levied against average MWh consumption during the 1,600 trading periods with the highest MW demand across New Zealand. This choice is based on a cluster analysis of trading periods by transmission pricing region (see also paragraphs 2.143 - 2.144).

2.11 This more diluted price signal is used on the assumption that consumers:

(a) do not know which demand periods will attract coincident peak demand charges, and therefore

(b) treat all peak demand periods as potential candidates for attracting a coincident peak demand charge.

2.12 Our model of electricity demand treats transmission interconnection charges under the proposal as a $ per MWh charge. This means the fixed charges that are anticipated under the proposal are modelled as $ per MWh charges. This is not how Transpower would charge transmission customers for transmission interconnection costs under the proposal. However, the approach we have followed in the CBA ensures that, under the demand modelling, consumers consider the overall cost of electricity when making their consumption decisions.[10] This means we assume consumers decrease / increase their electricity consumption over a period of time if the average cost of electricity consumption over this period rises / falls relative to the cost of other goods and services available to them over the same period.

2.13 To implement this assumption, we must convert lump sum transmission costs into an average cost or price equivalent. We assume consumer time-of-use demand decisions take account of *relative prices* rather than absolute prices. Thus, if the same MWh charge were to apply to all times of use, it would have no effect on shares of consumer spending on electricity by time of use. If the MWh charge were to increase by the same amount across all times of use, this would reduce consumer purchasing power and result in lower overall expenditure on electricity.

[10] That is, consumers consider the cost of electricity consumed over time (e.g., a year), rather than just the cost of electricity consumed at any instant in time.

2.14 In general, during peak demand periods the electricity use of consumers connected to distribution networks is more price sensitive than that of consumers connected to the transmission network. This reflects the fact that the large industrial consumers connected to the grid have already optimised their energy use, to avoid, as far as practicable, consuming electricity when prices are very high. This means the grid-supplied electricity they use during peak periods is generally less avoidable, and thereby less price sensitive than the peak demand of consumers connected to distribution networks.

2.15 Demand on distribution networks also includes automated demand response (ripple control) that generates material demand reductions during peak demand periods.[11] We note that, if such automated demand response occurs every year during peak demand periods, we would not expect to see this demand behaviour showing up in the real world data as demand responding to changes in electricity prices.[12]

Consumer welfare changes

2.16 Impacts on consumer welfare reflect changes in wholesale electricity prices inclusive of interconnection charges. Under the proposal, average prices (expenditure per MWh) are in general expected to:

(a) increase for most consumers in the North Island

(b) decrease for most consumers in the South Island.

Consumer welfare changes are driven by direct and indirect effects

2.17 Consumer welfare changes under the proposal are a combination of two effects:

(a) a **direct effect** on electricity bills, measured by the quantities consumed prior to implementing the proposal multiplied by price changes under the proposal, (i.e., the extent to which consumers' electricity costs would increase or decrease if consumers did not adjust their consumption)

(b) an **indirect effect** on electricity bills from consumers changing their demand—changing how much they consume overall and/or changing how much they consume at different times of use (say from off-peak to peak) in response to:

(i) changes in the relative price of consuming at different times of use

(ii) changes in the overall price of electricity.

2.18 Following a fall in electricity prices, consumers may want to retain their chosen quantity and timing of electricity use from before the price change. This would result in them re-optimising their spending across electricity and the other goods and services they buy. This re-optimisation—the indirect or substitution effect—means their change in economic welfare is different than a direct price change measure might suggest.

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11 In 2016, Scientia Consulting estimated that distributors used 625 MW of demand response to manage peak load (https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TP_TPM_Appendix_G1_Scientia_Gross_Demand_Report_26July2016.pdf).

12 Concept Consulting (2020) judged that 15% of demand response from ripple-control is sensitive to the presence of RCPD charges (https://ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published/). However, it is unclear whether any of that 15% is sensitive to marginal changes in energy prices or interconnection prices during peak demand periods.

2.19 Current RCPD charges place a premium on grid use during peak demand periods. This premium is not necessarily correlated with changes to costs of supply. RCPD charges:

(a) are not calculated to reflect region-specific transmission capacity, or lack thereof

(b) rise following increases in transmission capacity

(c) recover overhead costs that are not affected by changes in demand

(d) do not take account of the transport and congestion cost signal already provided in nodal prices.

2.20 Removing the premium on peak demand will benefit consumers by reducing costs associated with demand at times when electricity is particularly valuable to consumers.

2.21 The value to consumers of using electricity at peak is illustrated by the fact that approximately 30% of wholesale electricity market expenditure (energy cost) occurs during the 1,600 trading periods with the highest electricity demand, despite these accounting for only 9% of trading periods.

2.22 To estimate benefits to consumers, we consider:

(a) the value to consumers of using electricity during peak demand periods, based on how much expenditure on wholesale energy occurs during these peak demand periods

(b) the value to consumers of changes to wholesale electricity prices inclusive of interconnection charges, based on the current shares of expenditure on wholesale energy across peak, shoulder and off-peak demand periods.[13]

2.23 We estimate a 50% reduction in wholesale electricity prices inclusive of interconnection charges during peak demand periods would result in an approximate 2% increase in electricity consumption during these peak demand periods (other things being equal). Valued at peak demand's current share of wholesale market expenditure, this change in demand is worth 2% x 30% x $4,000,000,000 = $24,000,000 annually, if we assume fixed annual expenditure.

2.24 In addition, the cost of consuming electricity at the GXP level at peak, irrespective of changes in demand, is on average 50% cheaper. This results in an average annual cost reduction of $600,000,000. To the extent that these cost reductions are offset by an increased cost of consuming in shoulder and off-peak periods, we need to deduct these higher costs of consumption in other periods from the lower cost (benefit) of peak period consumption.

Consumer surplus approach

2.25 We have used a consumer surplus assessment to estimate consumer welfare benefits across all consumers.

2.26 We have also analysed an alternative measure of welfare benefits for distribution-connected demand—the so-called compensating variation. A compensating variation assessment is more complex than the consumer surplus approach. It has the benefits of:

(a) capturing the principle of diminishing marginal utility of consumption

(b) capturing how consumers change the pattern of their total expenditure in response to changes in relative prices.

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13 For example, with a 30% share of current wholesale energy expenditure shares, peak demand is vastly more valuable than demand during shoulder and off-peak demand periods.

2.27 A disadvantage of using the compensating variation approach is that it is based on consumer demand theory and does not necessarily apply to commercial demand.[14]

2.28 As such, the consumer surplus measure is the key input to our central estimate of net benefits. Our estimates of consumer welfare benefits reflect the following conventional economic principles:

(a) revealed preference, which implies that if we observe higher demand for higher-priced products, those products must be preferred to other lower-priced products

(b) optimal decision making, meaning that consumers are assumed to minimise the cost of reaching a given level of welfare.

2.29 The consumer surplus assessment is the standard approach to approximating consumer welfare benefits. It assumes that consumer demand:

(a) is linearly related to prices

(b) does not vary by income level

(c) during peak demand periods does not depend on demand at other times.[15]

2.30 The last of these assumptions does not mean that, if peak demand depends on demand at other times, we cannot use consumer surplus changes to measure welfare changes. Rather, it means that dependence needs to be taken into account before assessing changes in demand and thus changes in consumer surplus.

Effects on investment in grid-connected generation

2.31 Under the proposal we expect increased peak demand from removing the RCPD charge to lead to higher wholesale energy prices and thereby increased investment in generation.

2.32 In addition, changes to interconnection charges levied on generators, such as the removal of the HVDC charge on South Island generation, have the potential to alter the rate of new investment in generation by lowering costs of new investment. This could manifest as either investment in lower cost generation, more rapid investment in generation, or both.

2.33 Having said this, wholesale energy prices under the proposal could be higher or lower than wholesale energy prices under the baseline or the other options modelled. This depends on when the wholesale energy prices are compared against each other over the period of the assessment, and the percentage of total demand that occurs in peak periods (when generation capacity and transmission capacity are most limited) and in off-peak periods.

2.34 Generation investment is a path-dependent process, with investment jointly determined alongside other market characteristics. For example, the exact timing of new generation investments is conditional on the timing of changes in wholesale prices, demand, and generators' operating costs and investment costs. However, the path of wholesale prices, demand and generator's costs is also influenced by generation investment.

14 When we examine welfare benefits using compensating variation, we only apply this calculation to distribution-connected demand. Further, we have discounted welfare changes by the proportion of distribution-connected demand assumed to be exposed (at all) to time-of-use prices. The starting value for this discount is 81%. This is based on the observation that only 19% of retail tariffs (2014-2018) posted on the Powerswitch website had a time-of-use component. We then assume that the share of distribution-connected demand exposed to time-of-use prices rises, non-linearly, to 50% of the market by 2032.

15 These standard assumptions for (quasi-) linear demand are implicit in the original paper that established 'dead-weight loss' triangles as measures of the efficiency costs of market distortions caused by commodity taxes. See Harberger, A. C. (1964) The Measurement of Waste. The American Economic Review, 54(3), 58–76.

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

2.35 The modelling of efficient grid use also covers the cost of generation not locating in regions with recent transmission investment in export capacity.

2.36 An increase in transmission charges (benefit-based charges under the proposal or SIMI charges under the baseline) following such transmission investment would reduce investment in efficient generation plant. This increases wholesale prices and causes consumer demand to be lower.

2.37 These costs are not identified separately in our results, because they are only one part of the generation investment decision. The results from the grid use modelling reflect the net results on nodal energy prices from increased demand (upward pressure on prices), subsequent increases in generation investment (downward pressure on prices), and higher transmission charges potentially impeding investment in the most efficient generation (upward pressure on prices).

Effects on the efficiency of investment in distributed energy resources

2.38 We estimate the proposal would materially improve the efficiency of future investment in distributed energy resources.

2.39 Highly concentrated peak transmission charges could be expected to cause inefficient investment in distributed energy resources under the baseline, done to avoid the peak transmission charges. Economic agents are assumed to invest in distributed energy resources that are:

(a) cheaper than peak electricity prices *inclusive* of interconnection charges, but

(b) more expensive than peak electricity prices *exclusive* of interconnection charges.

2.40 The extent of any such inefficiency depends critically on the relative cost of new technologies. Our assessment suggests that, under the baseline, over the next 20 years the falling cost of new technologies is likely to cause a reasonable amount of inefficient investment in utility-scale batteries that cost more than peak electricity prices exclusive of interconnection charges. This assessment is based on the gains from investing in utility-scale batteries in order to avoid RCPD charges and to arbitrage wholesale energy prices.

2.41 Storage technologies are the most relevant technologies for our assessment. This is because other distributed energy technologies are either already economic, under limited circumstances (such as distributed wind generation), or do not affect peak electricity prices inclusive of interconnection charges, unless storage costs are considered (such as in the case of solar generation).

2.42 Under a regime of peak transmission interconnection charges (i.e., the baseline), investors can use utility-scale batteries to purchase electricity off-peak and sell the electricity into the wholesale market during peak and shoulder periods, while also avoiding transmission charges.

2.43 Under the baseline, this increases transmission prices during RCPD periods, because Transpower's revenue from RCPD charges is recovered over a smaller volume of electricity. The prospect of higher RCPD prices when a party has been able to reduce their exposure to these transmission prices further increases the incentive on other parties to avoid using transmission-supplied electricity during coincident peak demand periods.

2.44 Investment in utility-scale batteries to avoid peak demand charges would have the effect of reducing the need for transmission investment. However, this reduction is economically inefficient to the extent that the investment in utility-scale batteries is occurring only because of RCPD transmission charges[16] and is further accelerated from the ratcheting of RCPD transmission charges.

2.45 It should be noted the CBA only considers the incentive investors would have to invest in utility-scale batteries solely for the purpose of arbitraging energy costs and avoiding peak transmission charges.

Changes in interconnection transmission investment costs and benefits

2.46 Our final step in quantifying the net benefits from more efficient grid use under the proposal, is to assess the effect of changes in the costs and benefits of interconnection transmission investment.

2.47 We treat transmission investment as being determined exogenously.

Key working assumptions about transmission costs

2.48 Our estimates of transmission costs are based on:

(a) Transpower's revenue forecasts in its RCP 3 proposal to the Commerce Commission, which contains forecast revenue for Transpower during RCP 3 (2020/21 to 2024/25) and beyond to 2030 (inclusive)

(b) an assumption that Transpower's revenue would grow after 2030 at the same rate as the growth in base capex that Transpower has forecasted to 2030.

2.49 Our revenue forecast for Transpower assumes:[17]

(a) Transpower's weighted average cost of capital is a constant 6% (real) of Transpower's regulatory asset base (RAB)

(b) all of Transpower's assets are depreciated at a constant 5% per annum

(c) Transpower's operating costs are a constant 6% of Transpower's RAB

(d) the residual charge includes $160 million per annum of revenue for unallocated costs.[18]

2.50 We use these simplified assumptions:

(a) to apportion future transmission expenditure to Transpower's revenue

(b) to determine the rate at which the residual interconnection charges are expected to decline over time under the proposal.

2.51 These assumptions do not match the precise rates used in calculating Transpower's allowable revenue or actual revenue (cashflow). However, simplified assumptions are necessary in our modelling, to limit the complexity of the CBA. Furthermore, the same assumptions are applied under the four proposed options and the baseline. This means the

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16 Noting that nodal prices provide signals of incremental transmission costs that could be efficiently avoided through battery investment. As the International Energy Authority has stated: "A trading arrangement based on LMP [locational marginal pricing] takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments". International Energy Agency, *Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience*, Paris, 2007. http://www.iea.org/publications/freepublications/publication/tackling_investment.pdf

17 Refer to Table 21.

18 Unallocated (overheads and unassignable operating costs) revenue, calculated from average forecast non-network operating expenses and operating expenses for asset management and operations.

assumptions have no significant effect on our measurement of the economic welfare and efficiency effects of the proposal. Table 5 summarises our assumptions about:

(a) growth in interconnection revenue (to recover base capex)

(b) estimated shares of interconnection revenue to recover base capex that would be assigned to load and grid-connected generation under the proposal and the baseline.

Table 5: Forecast interconnection revenue

Growth is annual average growth 2022-2049, demand scenario excluding unapproved major capex

	Component	Value	Growth	Load share	Generation share
2022					
Baseline	AC	620		100%	
	DC	96			100%
	Total	716		87%	13%
Proposal	Benefit-based	218		64%	36%
	Residual	498		100%	
	Total	716		90%	10%
2049					
Baseline	AC	747	0.7%	100%	
	DC	80	-0.7%		100%
	Total	827	0.5%	90%	10%
Proposal	Benefit-based	583	4.1%	91%	9%
	Residual	244	-2.7%	100%	
	Total	827	0.5%	94%	6%

Source: Electricity Authority

Notes: 1. $2018 millions
2. With respect to capex, this forecast includes only proposed forecast base capex
3. Sub-totals may not sum to totals due to rounding

Key working assumptions about the relative benefit of transmission investments

2.52 To assess the costs and benefits of the proposed benefit-based transmission charge, we need to simulate how the benefit-based charge might be allocated. We have assumed that, over the longer term, transmission investment will be driven as much by economic considerations as by reliability considerations—i.e., we assume transmission investment will be split 50:50 between economic investments and reliability investments.

2.53 To model the benefit-based charge in the CBA, we have assigned the benefit of transmission investment to consumers and generators as follows:

(a) The 50% of transmission investment cost ascribed to economic transmission investments is allocated in proportion to each grid user's share of the LCE

(b) The 50% of transmission investment cost ascribed to reliability transmission investments is allocated—

(i) between consumers and generators in proportion to the value of reliability to consumers ($20,000 / MWh)[19] and generators ($200 / MWh)[20] (i.e., 100:1 consumers:generators), and

(ii) amongst distributors and grid-connected consumers in proportion to each party's share of peak demand, and

(iii) amongst grid-connected generators in proportion to each generator's share of peak generation.

2.54 These allocations are simplifications made in order to keep the CBA modelling manageable. That is, we are not suggesting the costs of major transmission investments would actually be allocated in this way if the proposal were to be adopted. The Authority considers it reasonable to adopt this simplifying assumption for the purposes of the CBA.[21]

2.55 The LCE measures the cost of transporting electricity across the transmission network. For consumers, the LCE is the difference between the price paid in a region for electricity and the average price paid nationally to generators for electricity they produce. For generators, the LCE is the difference between the price paid for electricity they produce and the average price paid by consumers, nationally, for electricity they consume.

2.56 Our modelling considers changes in LCE to ensure the proposal's benefits are not overstated by ignoring the effect of higher peak demand on losses and constraints. Peak LCE (transport costs) is modelled as a premium (discount) on national energy prices in areas (or model backbone nodes) where demand exceeds (is below) generation. We assume LCE is, in absolute terms, increasing in proportion to demand growth (see paragraphs 2.178 to 2.190).

2.57 The modelling does not consider other factors that contribute to LCE, such as operational changes to grid constraints. To do so would add considerable complexity to the analysis (raising the need to model power flows and system constraints), when these factors are as likely to be affected by operational decisions not related to changes in the TPM.

2.58 Using the LCE as a measure of some of the benefit consumers and generators receive from transmission investment reflects the economic benefit associated with grid investments reducing losses and mitigating constraints across the grid. Consumers whose costs are higher, and generators whose revenue is lower, than in the absence of the grid investment are assumed to not benefit from it.

2.59 The proposal allows for transmission investment benefits to be calculated on a project-by-project basis and benefit-based charges to be calculated accordingly. However, the above working assumptions allow the CBA to proceed without the need for asset-by-asset analyses of transmission investment benefits.

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19 Being the value for expected unserved energy set out in the grid reliability standards in the Code—refer to clause 4 of Schedule 12.2.

20 This is based on the assumed cost to generators from not being able to sell electricity to consumers.

21 It should not be assumed that Transpower would make a similar assumption for the purpose of determining benefit-based charges. We expect Transpower would use more exacting methods to estimate the benefits of high-value transmission investments.

2.60 We have also applied this working assumption to our estimates of the benefits that consumers and generators receive from the ongoing replacement and refurbishment of grid assets (i.e., base capex).

Potential for changes in the availability of generation in a local area

2.61 The calculation of the benefit of transmission investment considers changes in the availability of local generation (i.e., within one of the 14 areas (grid backbone nodes) in the model—see paragraph 2.78). When local generation is scarce:

(a) benefits of transmission to local consumers increase, because transmission provides access to energy at lower prices

(b) costs of transmission to local generators increase, because transmission increases the supply of generation competing with local generation and lowering local prices.

2.62 We take this into account by considering the frequency with which each of the 14 areas in the model has historically faced situations where local load exceeded local generation (i.e., where the area was a net importer). The model also considers the size of mark-ups over, or discounts under, average generation costs (i.e., transport costs) that typically exist during periods of abundant and scarce local generation.

Table 6: Scarcity of local generation, price mark-ups and discounts

Average mark up (local price over national average). Scarcity measured by net surplus of load over generation (rounded to 2 decimal places).

Backbone node	Probability of scarcity at peak	Mark-up, scarcity	Mark-up, no scarcity
MDN	1.00	1.18	--
OTA	1.00	1.11	--
HLY	0.00	1.16	1.07
TRK	1.00	1.03	0.88
WKM	0.00	1.04	1.04
RDF	0.98	1.04	1.01
SFD	0.20	1.09	1.03
BPE	0.11	1.10	1.04
HAY	1.00	1.08	--
KIK	1.00	1.08	--
ISL	1.00	1.06	--
BEN	0.00	1.13	0.95
ROX	0.00	1.45	0.97
TWI	0.71	1.03	0.88

Source: Electricity Authority

2.63 Table 6 above summarises our assumptions about scarcity of local generation during peak demand periods and transport cost mark-ups (averages across all times of use). This shows the extent to which generation is always scarce during peak demand periods in the north of the country (i.e., at the Otahuhu and Marsden backbone nodes) and never scarce during peak demand periods at the Benmore and Roxburgh backbone nodes.

2.64 This approach to measuring the benefits of transmission assets is consistent with efficient pricing, insofar as the costs of generation and consumption that are reflected in transport charges provide efficient price signals for additional investment in generation or for additional demand. Other things (e.g., fuel costs) being equal:

(a) it is less costly (more efficient) to increase demand where generation is abundant

(b) it is less costly (more efficient) to install generation where demand is abundant, and generation is scarce.

Cost of transmission investment brought forward

2.65 We assume transmission investment under the baseline is efficient (conditional on the baseline growth rate of peak demand). We also assume the long-run level of transmission investment is proportional to peak MW demand.

2.66 We use estimates of the long-run average incremental cost (LRAIC) of transmission to estimate, by transmission pricing region, the cost of transmission investment brought forward under the proposal due to higher peak demand. The cost of transmission investment brought forward under the proposal, by transmission pricing region, is the present-valued difference between growth in peak demand under the proposal multiplied by LRAIC and growth in peak demand under the baseline multiplied by LRAIC.[22]

2.67 Our estimates of LRAIC by transmission pricing region are built up from:

- Transpower's forecast major capex
- Transpower's forecast enhancement and development (E&D) base capex
- Transpower's forecasts of growth in peak demand by transmission pricing region
- judgment to assign forecast capex to transmission pricing regions
- an assumption that incremental operating expenditure is 2.2% of capex.[23]

2.68 Our estimates of LRAIC by transmission pricing region are set out in Table 7. These estimates fall within the range of incremental costs mentioned by Transpower in its 2017 report on "Battery storage in New Zealand".[24]

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22 To be precise, the measure for increased peak demand that is used is the increase in maximum peak demand observed for all model years to date.

23 Based on indicators of incremental investment-related operating expenditure over time. For example, Transpower's core transmission-related operating expenditure was between 2.2% and 2.7% of the closing asset value between 2015 and 2019. Estimating typical incremental investment-related operating expenditure using data over such a short period is somewhat problematic. However, we note that the same ratio for Powerlink in Australia averaged 1.7% between 2008 and 2019. Powerlink is probably the best Australian transmission network to compare Transpower with—long and stringy, with one big city at one end, generation at the other end, and large industrial loads scattered around the transmission network. Acknowledging that the number we use will be somewhat imprecise, we have chosen to use 2.2% as it sits in the middle of the range of 1.7% for Powerlink and the upper end of the observed range for Transpower.

24 Transpower reported a marginal cost range of $30,000 to $80,000 per MW in its 2017 publication "Battery storage in New Zealand". Although the numbers shown in our table are average rather than marginal costs, our average

Table 7: Transmission investment, incremental costs

Present value, 6% discount rate

	NZ	UNI	LNI	USI	LSI
Capital cost increment ($m)	778	383	146	183	65
Cost increment ($m), with incremental opex @ 2.2%	795	391	150	187	66
Demand increment (MW)	948	434	239	313	72
Long-run average incremental cost ($/MW)	838,553	901,854	627,051	598,877	918,900

Source: Electricity Authority

2.69 In calculating the cost of transmission investment brought forward, we use:

(a) forecast E&D base capex, E&D listed capex and major capex included in Transpower's RCP 3 proposal (for commissioning in RCP 3 and beyond)

(b) forecast major capex beyond that in the RCP 3 proposal, using Transpower's Annual Planning Report 2018 as a guide.

2.70 The CBA therefore includes the following major transmission capex:

(a) Waikato and Upper North Island (WUNI) voltage management

(b) South Island reliability—HVDC 2 replacement cables and 1 new cable

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

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

(e) South Island reliability—lower South Island (Clutha - Upper Waitaki)

(f) Transmission capacity north of Bunnythorpe - New Stratford - Whakamaru line

(g) Increase to 400 kV the operating voltage from Whakamaru to Brownhill Road—two additional 220 kV cables from Brownhill Road north into Auckland and substation development at Whakamaru and Brownhill Road

(h) Wairakei Ring upgrade—new double circuit Wairakei - Ohakuri - Atiamuri - Whakamaru line.

2.71 Note we estimate the cost of transmission investment brought forward across the entire interconnected transmission network over the CBA's 30-year assessment period—we do not estimate this cost by specific transmission projects.

Benefit of transmission investment brought forward

2.72 If grid investment is brought forward, due to increased peak demand, then benefits from grid investment will also be brought forward. To calculate the net cost of transmission investment brought forward by the proposal, we deduct, from incremental investment costs, the difference between projected peak LCE under the proposal and projected peak LCE under the baseline.

2.73 As with estimating the cost of transmission investment brought forward, we do not estimate the benefit of bringing forward a single transmission investment or even several specific transmission investments. Instead, we estimate the net benefit of lower projected peak LCE across the entire interconnected transmission network over the CBA's assessment period.

cost estimates imply marginal costs of between $33,800 and $51,900 (based on bringing the average costs forward by one year).

Models for assessing benefits from more efficient grid use

2.74 We have used the following three models to estimate (quantitatively) the net benefits of more efficient grid use:

(a) a model of consumer electricity demand

(b) a model of investment in grid-connected generation

(c) a model of distributed energy resource (utility-scale battery) investment.

2.75 These conceptually distinct models are then combined to form a single overall model.

2.76 We have selected these models:

(a) to strike a balance between:

(i) generality and flexibility—high-level models that reflect a range of scenarios for future market conditions and outcomes under the proposed TPM guidelines, and

(ii) detail—low-level models about existing demand and supply conditions, which can estimate plausible magnitudes of effects

(b) to capture economic dynamics and decisions that are central to transmission pricing and to consumer welfare

(c) to avoid errors and ensure the results can be broken down into intuitive causes and effects.

2.77 The models involve:

(a) taking input data on electricity volumes and prices (of generation and demand) for a given year,[25] then

(b) calculating a new set of prices and demands for the subsequent year, either:

(i) in terms of known forecast information, or

(ii) assumptions about how transmission customers are forming expectations about future electricity prices.

2.78 The models distinguish electricity demand and generation in New Zealand by:

(a) 14 areas (backbone nodes)

(b) electricity demand connected to:

(i) distribution networks

(ii) the transmission network

(c) grid-connected generation, by plant type

(d) time of use across a day (00:00–24:00 hours)

(e) energy source

(f) grid offtake during peaks in electricity demand (the 1,600 trading periods with the highest electricity demand in a calendar year (“the peak demand period”))

(g) electricity demand served by distributed generation, including utility-scale batteries, during the peak demand period

25 Transmission pricing capacity measurement periods (August years).

(h) electricity demand met by grid offtake and distributed generation, including utility-scale batteries, during shoulder demand trading periods (the next 3,075 trading periods with the highest electricity demand in a calendar year, after the 1,600 trading periods with the highest electricity demand ("the shoulder demand period"))[26]

(i) electricity demand met by grid offtake and distributed generation, including utility-scale batteries, during off-peak demand trading periods (the 12,845 trading periods with the lowest electricity demand in a calendar year ("the off-peak demand period"))

(j) grid generation in each of the peak, shoulder and off-peak demand periods.

2.79 The basis for categorising a typical year's 17,520 trading periods in the manner set out above is a cluster analysis of trading periods, by each of the four transmission pricing regions in New Zealand.

2.80 The area breakdown used in the model of electricity demand is based on key points of connection to the grid. We refer to these in this CBA as backbone nodes. Figure 2 presents the location of these backbone nodes and illustrative transmission line connections between them.

2.81 North to south, these backbone nodes are:

(a) Marsden Point in Northland (MDN)

(b) Otahuhu in Auckland (OTA)

(c) Huntly in the Waikato (HLY)

(d) Tarukenga in the Bay of Plenty (TRK)

(e) Whakamaru in the central North Island (WKM)

(f) Stratford in Taranaki (SFD)

(g) Redclyffe in Hawke's Bay (RDF)

(h) Bunnythorpe in the Manawatu (BPE)

(i) Haywards in Wellington (HAY)

(j) Kikiwa in the upper South Island (KIK)

(k) Islington in Canterbury (ISL)

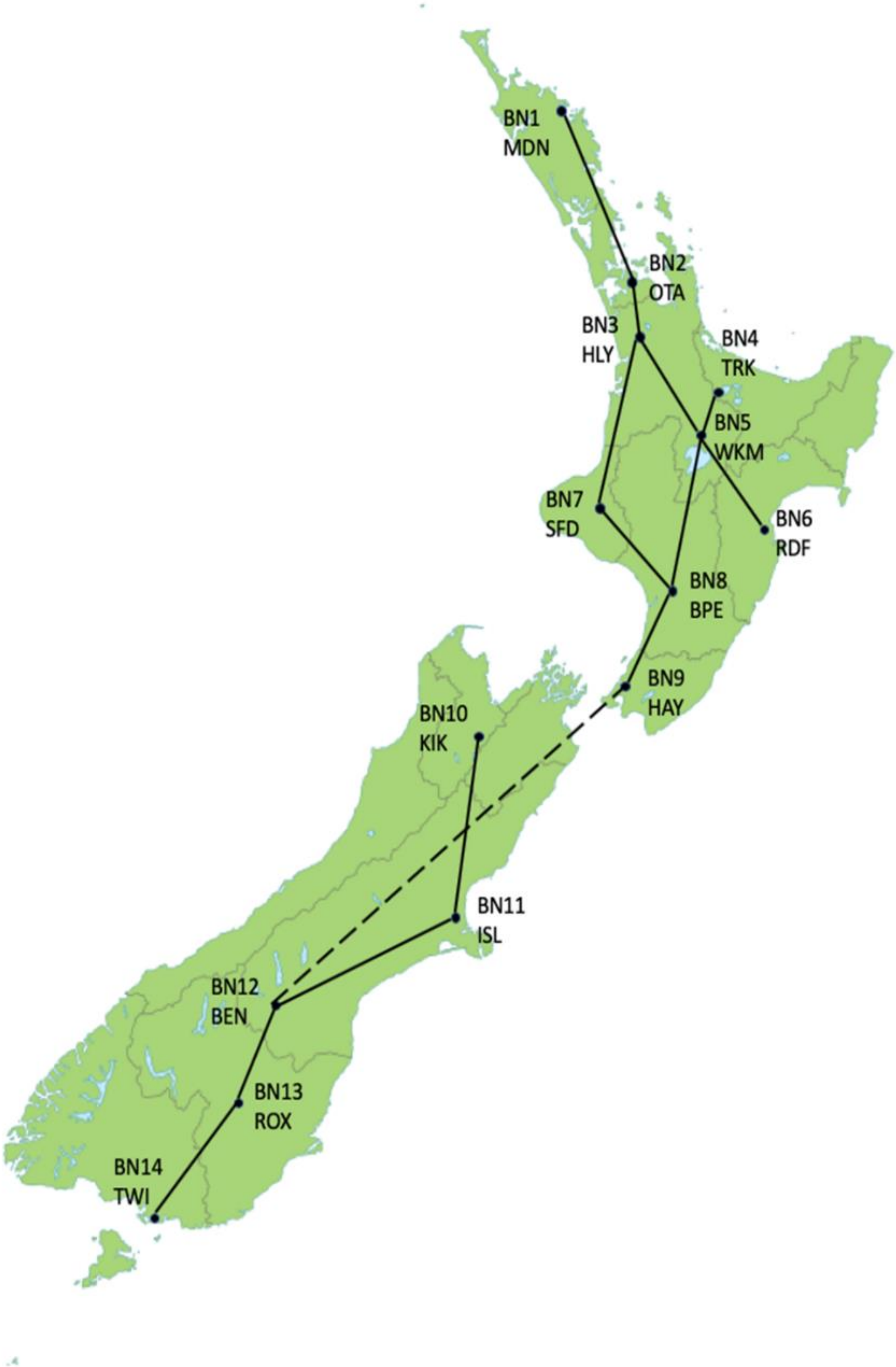
(l) Benmore in South Canterbury (BEN)

(m) Roxburgh in Otago (ROX)

(n) Tiwai in Southland (TWI).

26 When ranking trading periods, we give the same ranking to trading periods with the same MWh. The maximum number of trading periods included in peak demand periods for one region is 1,641, while for shoulder trading periods it is 3,260.

Figure 2: Simplified 14 backbone node grid



Source: Electricity Authority

Model 1: Demand model

2.82 The demand model and its associated parameter estimates play a crucial role in the CBA, because consumption/demand is the key determinant of consumer welfare.

2.83 Furthermore, as the CBA is assessing changes in the incidence of prices, the results are highly sensitive to assumptions about:

(a) the relative responsiveness of electricity demand to changes in electricity prices during the peak demand and off-peak demand periods, and

(b) the relative responsiveness of different consumers (or regions) to changes in electricity prices.

2.84 This is why there is the need to establish a well-specified (logically consistent) and robustly estimated model of demand response.

2.85 The demand model needs to account for:

(a) economic limits on the amount by which electricity demand can increase (aggregate income constraints)

(b) substitution of electricity demand, across time periods and between energy sources

(c) non-constant price responsiveness (elasticities that vary with price levels and changes in aggregate income levels over time)

(d) potential effects on consumers if wholesale electricity prices rise when transmission prices decline.

Form of demand model

2.86 The demand model is an expenditure system—specifically an 'almost ideal demand system'.[27] This form of model and variants of this form of model have been widely used in New Zealand and elsewhere for analysing welfare effects of price changes.[28]

2.87 This form of model accounts for the allocation of demand over different goods (or time periods) and for different types of consumers.

2.88 Useful properties of this form of model include that:

(a) demand is limited by prices and available expenditure (income constraints), and changes in demand are limited by adding-up constraints, such that if expenditure on one product increases, expenditure on other products must fall

(b) cross-price elasticities can be calculated, such as changes in demand for off-peak energy when peak energy prices increase (highly relevant for analysis of transmission prices that may cause load shifting between peak, shoulder and off-peak demand periods).

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27 Deaton, A., & Muellbauer, J. (1980). An Almost Ideal Demand System. The American Economic Review, 70(3), 312–326. The model used to estimate the parameters is, ultimately and for simplicity, the linear approximation to the almost ideal demand system.

28 See for example, Filippini, M. (1995). Swiss Residential Demand for Electricity by Time-of-Use: An Application of the Almost Ideal Demand System. The Energy Journal, 16(1), 27–39 for a previous use for analysing time of use electricity demand; Creedy, J. (2004) 'The effects of an increase in petrol excise tax: the case of New Zealand households', National Institute Economic Review, 188, April, 70–79, for an application of a linear expenditure system; Gomez-Lobo, A. (1996). 'The welfare consequences of tariff rebalancing in the domestic gas market'. Fiscal Studies, 17(4), 49–65 for an application using the quadratic almost ideal demand system.

2.89 In the description that follows, the term “consumers” covers both businesses and households. The model presented below is typically associated with households or individuals. However, the foundations for the model are also found in models of production. That is, the almost ideal demand system is derived from a specific expenditure function that defines the minimum expenditure needed to meet a given level of welfare. This is analogous to a firm’s cost minimisation problem for a given level of output.

2.90 Consumers are assumed to choose when to consume or what to consume based on a log expenditure function:

$$\ln \mathrm{e}(p_t, U_t) = \alpha_0 + \sum_{i=1}^{4} \alpha_i \ln p_{it} + \frac{1}{2}\sum_{i=1}^{4}\sum_{j=1}^{4} \gamma_{ij} \ln p_{it} \ln p_{jt} + U\beta_0 \prod_{i=1}^{4} p_{it}^{\beta_i} \quad \text{Equation 1}$$

Where:

(a) e is expenditure

(b) p_{it} is price of product i at time t (in our application there are 4 products)

(c) U is some unobserved level of utility or welfare

(d) the α_i parameters represent consumer preferences and marginal budget shares of expenditure in the absence of relative price differences

(e) the γ_{ij} terms determine the effects of relative prices of products on expenditure for each of the i products

(f) the β terms determine income effects and are positive for goods that are luxuries and negative for normal goods.

2.91 Demand functions, derived from the expenditure function, are:

$$x_{it}(p_{it}, m_t) = \frac{m_t}{pi}\left(\alpha_i + \sum_j \gamma_{ij} \ln p_{jt} + \beta_i \ln\left(\frac{m}{P_t}\right)\right) \quad \text{Equation 2}$$

Where m is income and P is a price index:

$$\ln P = \alpha_0 + \sum_{i=1}^{4} \alpha_i \ln p_{it} + \frac{1}{2}\sum_{i=1}^{4}\sum_{j=1}^{4} \gamma_{ij} \ln p_{it} \ln p_{jt} \quad \text{Equation 3}$$

2.92 In our application, the price index is replaced by a Laspeyres price index (the linearised almost ideal form of model).

2.93 The expenditure share (s_{it}) form of the demand function is:

$$s_i = \alpha_i + \sum_j \gamma_{ij} \ln p_{jt} + \beta_i \ln\left(\frac{m}{P_t}\right) \quad \text{Equation 4}$$

2.94 A key assumption in our use of this model is that demand for energy is determined after determining demand for other products.[29] Thus, there are two stages in the demand system.

First stage of demand modelling: consuming energy vs other goods

2.95 In the first stage of the demand modelling, consumers choose between consuming energy and consuming other goods.

2.96 For the first stage modelling, aggregate energy demand is differentiated by:

(a) the demand of consumers directly connected to the transmission network (nationally)

29 This is a simplification. An alternative approach would be to include estimates of aggregate expenditure on all other, non-energy, products.

(b) the demand of consumers connected to a distribution network, by network reporting region.

2.97 These are the lowest levels of aggregation for which total activity, or income and expenditure, proxies can be obtained. These proxies are needed to estimate the two components of the demand model.

2.98 For consumers connected to a distribution network, we model demand by region on a per-ICP basis (x_{rt}), assuming that aggregate demand rises proportionally with population (N_t) and income (M_{rt}), and declines proportionally with higher average electricity prices (p_{rt}). This yields total regional demand for distribution-connected consumers (X_{rt}):

$$X_{rt} = x_{rt}(p_t, M_{rt}).N_t \qquad \text{Equation 5}$$

2.99 In practice, we simply model changes in demand according to population growth (on a one-for-one basis) and income growth (also on a one-for-one basis), using estimated income elasticities of demand that are constant for all regions (η_{rt}). That is:

$$X_{rt} = \left(\frac{N_{rt}}{N_{rt-1}} + \eta_t \frac{M_{rt}}{M_{rt-1}} - 1\right).\left(X_{rt-1} + \dot{X}(\Delta p_t)\right) \qquad \text{Equation 6}$$

Where the term $\dot{X}(\Delta p_t)$ denotes the change in demand in response to prices.

2.100 The aggregate price elasticities of demand are ‘plugged’ directly into the second stage (time of use) demand model. Combining aggregate and product-specific demand elasticities allows for aggregate demand to be a result of product-specific prices and demand decisions—as these are ultimately what create overall average prices. Indeed, this endogeneity between observed prices and expenditure weights (demand choices) is why the almost ideal demand system has such a convoluted price index term.

2.101 Population growth used in the modelling is based on Statistics New Zealand population growth projections. Incomes are modelled using an assumed national average growth rate, with regional variations based on observed historical deviations from national trend income growth.

2.102 For consumers directly connected to the transmission network, we assume that demand grows according to regional income growth and in line with the same income elasticities as distribution-connected consumers (i.e., as for distribution-connected demand, but without the term reflecting population growth). This is a simplification employed to avoid having to forecast demand for output and input costs of large industry. The absence of the population growth parameter means that large industry is a declining share of electricity demand and, implicitly, of economic output, roughly in line with empirical trends.

2.103 Aggregate price elasticities of demand for transmission-connected consumers are based on a translog cost function that follows the same general approach as for the time-of-use model. A single (average) elasticity is used for all industry due to difficulties differentiating between quite different demand characteristics of firms in the same industry (such as distinguishing steel and aluminium demand in the basic metals industry).

Second stage of demand modelling: grid-connected vs distributed generation

2.104 In the second stage of the demand modelling, consumers choose between consuming:

(a) grid-exported electricity, measured in MWh

(b) electricity from distributed generation, measured in MWh.

2.105 In the second stage modelling, demand is differentiated by time of use. This is to reflect that electricity consumed at different times is a distinct product. We use three periods of demand:

(a) peak

(b) shoulder (near peaks)

(c) off-peak.

2.106 We have used statistical data reduction analysis (clustering and factor analysis) to determine the time periods to include in each of the three demand periods. We have supplemented this analysis with expert judgment about optimal cut-off times for defining the three demand periods.

2.107 The peak demand period comprises 1,600 trading periods, which is a substantially larger number of trading periods than Transpower uses to calculate interconnection charges. We have done this to capture consumer responses to expected electricity prices, with these responses reflecting the uncertainty of peak transmission charge periods, which are determined after the fact.

Calculating elasticities

2.108 Once the parameters of the demand system have been estimated, elasticities from the model can be calculated directly from parameters, as follows

(a) Simple (Marshallian) demand elasticities:

$$e_{ij} \begin{cases} -1 + \frac{\gamma_{ij}}{s_i} - \beta_i s_{j0}, i = j \\ \frac{\gamma_{ij}}{w_i} - \beta_i s_{j0}, i \neq j \end{cases} \qquad \text{Equation 7}$$

(b) Expenditure elasticity:

$$\eta_i = 1 + \frac{\beta_i}{s_i} \qquad \text{Equation 8}$$

2.109 These demand elasticities are used to drive demand in the model. We do not model demand directly, using all the estimated parameters, as this would drive consumers towards unrealistically similar consumption patterns. This is an issue because we are analysing demand over long periods of time.

2.110 Changes in consumer welfare are measured by changes in consumer surplus (ΔCS_t), calculated as:

$$\Delta CS_t = \sum_{i=1}^{4}\left(-x_{it0}(p_{it1} - p_{it0}) - \frac{1}{2}(x_{it1} - x_{it0})(p_{it1} - p_{it0})\right) \qquad \text{Equation 9}$$

2.111 With parameter estimates, the effect of price changes on consumer welfare can also be evaluated by the change in total expenditure required to achieve the same level of utility before the price change (so-called "compensating variation"). This can be calculated, for an individual consumer type and assuming no income effects, as follows:

$$\ln \mathrm{e}(p_{t1}, U_t) - \ln \mathrm{e}(p_{t1}, U_t) = \sum_{i=1}^{4} \alpha_i (\ln p_{it1} - \ln p_{it0}) + \frac{1}{2}\sum_{i=1}^{4}\sum_{j=1}^{4} \gamma_{ij} (\ln p_{it1} - \ln p_{it0}) . (\ln p_{jt1} - \ln p_{jt0}) \qquad \text{Equation 10}$$

Where the price subscripts 0,1 indicate prices before and after a price change respectively.

2.112 In expenditure share form we approximate the compensating variation (cv) as a percentage of pre-price change expenditure, with:

$$cv_{tp} = \sum_{i=1}^{4} s_{0_{it}}(\ln p_{it1} - \ln p_{it0}) + \frac{1}{2}\sum_{i=1}^{4}\sum_{j=1}^{4} h_{ij}(\ln p_{it1} - \ln p_{jt0}).(\ln p_{jt1} - \ln p_{jt0})$$

Equation 11

Empirical analysis to establish demand model parameters

2.113 Parameters for the first and second stages of the demand modelling are estimated separately:

(a) for the first stage, aggregate annual demand for electricity is analysed

(b) for the second stage, electricity demand by time of use is analysed.

2.114 Transmission-connected and distribution-connected demands are also analysed separately.

2.115 Similar, but not identical, empirical models are used to estimate time-of-use parameters for distribution-connected demand and transmission-connected demand.

2.116 The demand model for transmission-connected load is similar to the demand model for distribution-connected load, insofar as it is an expenditure model. However, it is an expenditure model derived from theoretical cost minimising behaviour of a profit maximising producer, while the demand model for distribution-connected load is derived from theoretical cost minimising behaviour of a utility maximising consumer.

2.117 The model used to analyse aggregate transmission-connected demand also differs from the model used to analyse distribution-connected demand insofar as transmission-connected demand is estimated using industry-level data that does not distinguish between industrial loads connected to the transmission network and to distribution networks.

Aggregate, first stage, model of industrial demand

2.118 The model of industrial demand is a translog cost model. This model is akin to a complete demand system, because it estimates shares of expenditure devoted to all inputs to production, given relative prices for these inputs. The translog cost function is derived from translog production functions, which are widely used in productivity analyses.

2.119 Here the demands (for energy inputs) that are being analysed are not exclusively transmission-connected demands, but rather industrial demands. This is due to an absence of data on transmission-connected consumers' input demands and output.

2.120 The model that is estimated is a system of equations expressing the shares of expenditure (s) on inputs to production as a function of the prices (p) of those inputs:

$$s_k = \beta_k + \delta_{kk}p_k + \delta_{kl}p_l + \delta_{ke}p_e + \delta_{kn}p_n + \delta_{ki}p_i \quad \text{Equation 12}$$
$$s_l = \beta_l + \delta_{lk}p_k + \delta_{ll}p_l + \delta_{ke}p_e + \delta_{kn}p_n + \delta_{ki}p_i \quad \text{Equation 13}$$
$$s_e = \beta_e + \delta_{ek}p_k + \delta_{el}p_l + \delta_{ee}p_e + \delta_{en}p_n + \delta_{ei}p_i \quad \text{Equation 14}$$
$$s_n = \beta_n + \delta_{nk}p_k + \delta_{nl}p_l + \delta_{ne}p_e + \delta_{nn}p_n + \delta_{ni}p_i \quad \text{Equation 15}$$
$$s_i = \beta_i + \delta_{ik}p_k + \delta_{il}p_l + \delta_{ie}p_e + \delta_{in}p_n + \delta_{ii}p_i \quad \text{Equation 16}$$

Where:

(a) the inputs are:

(i) capital (k)

(ii) labour (l)

(iii) electricity (e)

(iv) non-electricity energy products (n)

(v) other intermediate goods (i)

(b) the β terms are constants

(c) the δ terms are coefficients (derivatives) on prices and they vary by product.

2.121 In estimating the model, we impose restrictions on the coefficients to ensure:

(a) expenditure shares sum to 1 (requiring that the β coefficients sum to 1)

(b) cross-price coefficients are symmetric (e.g., $\delta_{kl} = \delta_{lk}$).

2.122 This is achieved by transforming prices into relative prices compared to the price of intermediates (dividing each equation by p_i).

2.123 The model is estimated using the seemingly unrelated regressions method with the intermediates equation (s_i) dropped from the system to avoid singularity. The coefficients for the intermediates equation can be recovered using the adding-up constraints.

2.124 Data used for estimating this model has been sourced from:

(a) MBIE's energy statistics, for data on:

(i) annual energy volumes by industry (from energy balance tables)

(ii) annual average prices by fuel by industry, where available otherwise average industry-level prices have been used

(b) Statistics New Zealand's National Accounts, for data on:

(i) expenditure on intermediates

(ii) economy-wide inflation (GDP deflator)

(iii) compensation of employees, by industry

(iv) nominal capital stocks

(c) Statistics New Zealand's sources for statistics on employment by industry:

(i) productivity statistics, indices of labour input by industry

(ii) Quarterly Employment Survey (QES) data on fulltime equivalents (FTEs) per job

(iii) Linked Employer-Employee Dataset (LEED) data on employment by industry.

2.125 The data spans the years 1990 to 2016.

2.126 The industry breakdown in the MBIE data is less detailed than the data available in Statistics New Zealand's National Accounts. Industry data is aggregated, from National Accounts industries to energy data industries, using shares of input weights.

Results

2.127 The model is fitted for each industry in the data. A sample of model results is summarised in Table 8, for data aggregated to all industries.

2.128 To use these coefficients for the purposes of the TPM modelling, we calculate average price elasticities of input demands.

2.129 For example, the electricity own price (η_{ee}) elasticity and cross price (η_{ek}) elasticity for substitution between capital and electricity are calculated as follows:

$$\eta_{ee} = \delta_{ee} + s_e(s_e - 1) \qquad \text{Equation 17}$$

$$\eta_{ek} = \eta_{ke} = s_e + \frac{\delta_{ke}}{s_k} \qquad \text{Equation 18}$$

Where s_e is the share of costs, as defined earlier along with the parameters (δ).

2.130 Table 9 provides a summary of estimated elasticities evaluated at the mean values for expenditure shares and prices for each industry. All industries, except mining, exhibit small negative price elasticities of demand. The result for mining—that demand for electricity increases when electricity prices increase—could be due to the close relationship between demand for output from mining and energy prices, including electricity prices. Mining includes fuel for electricity generation and has output prices that rise with prices for energy commodities.

2.131 The cross-price or substitution elasticities indicate that electricity is in many cases a complement to other sources of energy. This means an increase in the price of electricity reduces demand for both electricity and other sources of energy. In the case of the aggregate 'All' industry model, this value is -2.455, such that a 1% increase in electricity prices is associated with a 2.5% reduction in demand for other energy products.

Table 8: Cost function coefficient estimates

Dependent variables are input cost shares across all industries

Input	Coefficient	Standard error	T statistic	P value
Constants:				
Capital (β_k)	0.242	0.0020	118.84	0.000
Labour (β_l)	0.251	0.0022	115.98	0.000
Electricity (β_e)	0.008	0.0021	3.79	0.000
Non-electricity energy (β_n)	0.004	0.0021	1.71	0.090
Price coefficients:				
Capital (δ_kk)	0.098	0.0112	8.81	0.000
Capital-Labour (δ_kl)	0.007	0.0080	0.94	0.352
Capital-Electricity (δ_ke)	0.025	0.0128	1.95	0.054
Capital-Non-electricity (δ_kn)	0.018	0.0090	2.04	0.044
Labour (δ_ll)	0.085	0.0111	7.66	0.000
Labour-Electricity (δ_le)	0.000	0.0116	-0.02	0.984
Labour-Non-electricity(δ_ln)	-0.027	0.0107	-2.55	0.012
Electricity (δ_ee)	-0.010	0.0233	-0.41	0.682
Electricity-Non-Electricity (δ_en)	-0.026	0.0127	-2.07	0.041
Non-electricity energy (δ_nn)	0.019	0.0147	1.32	0.189

Source: Electricity Authority

Table 9: Industry input price elasticities

Industry	s_e	Electricity (η_{ee})	Electricity-Non-electricity (η_{en})	Electricity-Capital (η_{ek})	Capital-Labour (η_{kl})
All	0.013	-0.022	-2.455	0.114	0.269
Agriculture	0.014	-0.030	3.644	0.001	0.116
Chemicals	0.019	-0.024	0.112	-0.041	0.293
Construction	0.012	-0.018	0.110	0.023	0.193
Commercial	0.013	-0.033	-2.223	0.133	0.081
Food products	0.018	-0.012	-0.291	0.005	0.373
Mechanical products	0.018	-0.012	0.091	0.022	0.204
Metal products	0.020	-0.001	-3.119	0.142	0.184
Mining	0.016	0.013	4.297	-0.400	0.192
Non-metallic minerals	0.020	-0.024	-0.389	0.012	0.380
Other	0.018	-0.082	-1.513	0.303	0.322
Textiles	0.016	-0.014	-0.875	0.042	0.253
Wood products	0.018	-0.007	-1.100	0.084	0.336

Source: Electricity Authority

Aggregate first stage model of distribution-connected demand

2.132 The model of aggregate distribution-connected demand is a dynamic panel model.[30] The model is:

$$x_{rt} = \alpha_r + \beta_p p_{rt} + \beta_l x_{rt-1} + \beta_e e_{rt} + \beta_h h_t + \beta_d d_{rt} + \beta_i d_{rt} . p_{rt} \quad \text{Equation 19}$$

2.133 This model estimates annual grid export demand per ICP by networking reporting region (x_{rt}).

Where r is the subscript for regions and t is the time or year subscript), accounting for:

(a) regional differences in average levels of demand (so-called fixed effects, α_r)

(b) wholesale prices, by region and year, inclusive of interconnection charges (p_{rt})

30 Similar methods and models were used in Filippini, M. (2011). Short- and long-run time-of-use price elasticities in Swiss residential electricity demand. *Energy Policy*, 39(10), 5811–5817. https://doi.org/10.1016/j.enpol.2011.06.002

(c) delayed adjustments to price changes (lagged demand x_{rt-1})

(d) employee earnings per ICP (e_{rt}), as a proxy for income, by region

(e) average national heating degree days in each year (h_t)

(f) observed annual maximum distributed generation per ICP (d_{rt})

(g) interactions between prices and observed annual maximum distributed generation ($d_{rt}.p_{rt}$), to account for potential reductions in a region's exposure to wholesale prices and transmission charges when distributed generation is available.

2.134 The price and earnings variables in the model are real values deflated by national price indices. The price, earnings, and demand variables are transformed by natural logarithms and the heating degree day variable is a ratio of heating degree days to the average over 37 years.

2.135 The results of the model estimation (the β parameters and model fit statistics) are summarised in Table 10—in the column 'Final'. Other variations on the model that were also estimated are shown in columns A to I. These other models tested other combinations of predictive variables—including distribution prices. The final model and model A included regional fixed effects. The other models shown included both regional fixed effects and time-specific (year-specific) fixed effects. Model E also considered retail as a predictor of demand, rather than wholesale prices inclusive of transmission interconnection charges.

2.136 The final model was chosen on the basis that it was both the model that best explained the data, while using the fewest explanatory variables to explain demand patterns (highest adjusted R-squared).

2.137 The coefficients in the final model all have intuitively reasonable values with:

(a) a 10% increase in prices predicted to reduce demand by 1.1% (coefficient of -0.11) in the short term

(b) a 10% increase in income (earnings) predicted to increase demand by 1.1% (coefficient of 0.11)

(c) a 10% increase in distributed generation capacity reducing grid demand per ICP by 1.6%—the coefficient of -311 needs to be interpreted considering average MW per ICP of 0.0005, such that a 10% increase is an increase of 0.05 kW per ICP

(d) a 10% increase in heating degree days increasing aggregate annual grid demand by 0.1%—notably a 10% increase is not a rare event, with the standard deviation of the heating degree day index equal to 0.65

(e) an increase in distributed generation has the effect of muting the effects of prices on annual grid demand (as indicated by the positive coefficient on the interaction term).

Table 10: Dynamic panel models

Dependent variable: annual MWh consumption per ICP by network reporting region

Variable	Values	**Final**	A	B	C	D	E	F	G	H	I
Wholesale price (natural logarithm)	Coefficient	**-0.110**	-0.105	-0.31	-0.29	-0.21		-0.22	-0.22	-0.31	-0.23
	Std error	**0.04**	0.05	0.09	0.09	0.08		0.08	0.08	0.09	0.08
	p-value	**0.01**	0.02	0.00	0.00	0.01		0.01	0.01	0.00	0.01
Earnings per ICP	Coefficient	**0.11**	0.14	0.44	0.44	0.40	0.38	0.41	0.41	0.44	0.43
	Std error	**0.11**	0.13	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	p-value	**0.30**	0.26	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00
Prior year consumption	Coefficient	**0.85**	0.85	0.85	0.85	0.85	0.84	0.85	0.85	0.85	0.85
	Std error	**0.04**	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	p-value	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum observed DG output, per ICP	Coefficient	**-311.02**	-310.66	-401.07	-386.62		-47.15			-401.07	36.93
	Std error	**236.09**	236.39	236.21	237.06		214.96			236.21	28.21
	p-value	**0.19**	0.19	0.09	0.10		0.83			0.09	0.19
Interaction between DG and price	Coefficient	**75.788**	76.210	100.292	97.082		19.852			100.292	
	Std error	**53.63**	53.70	53.70	53.89		48.67			53.70	
	p-value	**0.16**	0.16	0.06	0.07		0.68			0.06	
Index of heating degree days, nationally	Coefficient	**0.01**	0.01								
	Std error	**0.01**	0.01								
	p-value	**0.22**	0.39								
Retail distribution charges (per kWh, natural logarithm)	Coefficient		-0.05		0.12	0.14					
	Std error		0.11		0.15	0.16					
	p-value		0.63		0.43	0.37					
Retail charges (per kWh natural logarithm)	Coefficient						0.38				
	Std error						0.30				
	p-value						0.20				
Implied long run elasticity		**-0.74**	-0.71	-2.06	-1.90	-1.40	0.00	-1.55	-1.55	-2.06	-1.52
	R-squared	**0.633**	0.634	0.637	0.637	0.632	0.630	0.637	0.630	0.631	0.625
	Adj R-squared	**0.58**	0.58	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.56
	F-statistic	**88.11**	75.37	104.77	87.30	129.02	171.05	104.77	171.05	128.41	99.84

Source: Electricity Authority

2.138 Table 11 provides a summary of the data used in the first stage model of distribution-connected demand. This data provides important context for interpreting model coefficients.

Table 11: Dynamic panel model data, descriptive statistics
Annual data, 2010–2017, for 39 network reporting regions

	Mean	Standard deviation
MWh consumption per ICP	2.8	0.52
Wholesale price (natural logarithm)	4.4	0.29
Earnings per ICP (natural logarithm)	10.3	0.57
Maximum observed DG output, per ICP	0.0005	0.0007
Index of heating degree days, nationally	-0.4	0.65
Retail distribution charges (per kWh, natural logarithm)	2.2	0.22
Retail charges (per kWh natural logarithm)	3.2	0.12

Source: Electricity Authority

Demand by time of use

2.139 Data used for estimating demand by time of use is:

(a) annual wholesale demand

(b) demand-weighted wholesale market prices by network reporting region.

2.140 The data is derived from:

(a) final prices by trading period and point of connection

(b) metered grid offtake by trading period and point of connection

(c) reconciled demand by trading period and point of connection.

2.141 In addition to this core data, additional explanatory variables are added, as outlined in paragraph 2.147 below.

2.142 Transmission charges are included in the data, by calculating regional coincident peaks and applying the interconnection charges ($/kW per year) published in Transpower's pricing disclosures. These charges are assigned to the relevant capacity measurement period (August year), rather than pricing year in which charges are applied. This accounts for consumers responding to expected/prospective charges, rather than current charges—because current charges are unaffected by current demand decisions.

2.143 Times of use are calculated by ranking trading periods by coincident volume (MW) of demand in a transmission pricing region with:

(a) the peak being the top 1,600 trading periods

(b) the shoulder being the next 3,075 trading periods

(c) off-peak being the remaining 12,845 trading periods.

2.144 As noted above, this split is based on a cluster analysis of trading periods, by transmission pricing region. The cluster analysis identified six clusters of demand. Our interest is in peak demand, given its impacts on transmission system capacity and costs. Therefore, we chose to take the first two clusters as the peak demand period and shoulder demand period, and to combine the subsequent clusters into a single off-peak demand period.

2.145 We constructed a single set of trading periods for each time of use, using the average number of trading periods for each time of use over a 10-year period[31] across all pricing regions. This was so that we had a single, system-wide definition of peak, shoulder and off-peak demands. However, the actual dates and times (trading periods) that are used to calculate time-of-use volumes differ by transmission pricing region and year.

2.146 In addition to these three times of use, which are treated as separate products, a fourth category of demand is defined. This is consumption of energy produced off-grid—referred to here as distributed generation. This is calculated by taking the difference between reconciled load by GXP and metered grid export at a GXP.[32] Thus, four times of use are defined:

(a) peak grid demand

(b) peak distributed generation demand

(c) shoulder demand

(d) off-peak demand.

2.147 The time of use model is

$$w_i = \alpha_i + \alpha_{ri} + \delta_{si} \ln S_{si} + \sum_{j=1}^{N} \gamma_j \ln p_{ij} + \beta_i \ln \frac{X}{P} \qquad \text{Equation 20}$$

Where:

(a) w_i is the share of spending at times of use ($i = \{peak, peak\ distributed\ generation, shoulder, off\ peak\}$)

(b) α_i and α_{ri} are national and region-specific averages (constants)

(c) the p_{ij} terms are the price of consuming during each time of use

(d) $\frac{X}{P}$ is total expenditure deflated by a price index on consumption across all four times of use

(e) the term S_{si} represents exogenous demand 'shifters':

(i) an index of hydro storage relative to historical means, with schemes weighted by storage capacity

(ii) an index of national heating degree days, relative to historical averages

(iii) observed annual maximum distributed generation (MW) in any year

31 2010 to 2017 years ended in the month of August.

32 During initial analysis, the data also included measures of consumption of energy produced off-grid during shoulder and off-peak periods (i.e., we considered six categories of demand). However, the presence of very small numbers and many zeros had a significant negative effect on the fit of models on all six categories of demand. Given our primary interest in peak demand, we determined that the results would be more reliable and more useful if off-grid generation was only included for the peak demand period.

(iv) a dummy (binary) variable indicating whether a network reporting area includes New Zealand Aluminium Smelters—used only when estimating the expenditure system for large industrial load

(v) regional labour market earnings (linked employer-employee data from Statistics New Zealand)—used only in the model of distribution-connected demand

(vi) average residential distribution prices (from MBIE's Quarterly Survey of Domestic Electricity Prices, QSDEP)—used only in the model of distribution-connected demand.

2.148 The data is for 2010 to 2017 years ended in the month August (transmission pricing capacity measurement years), by network reporting region divided into two types of consumers:

(a) distribution network connections

(b) load connected directly to the transmission network—for the purposes of our analysis, this includes large industrial loads that are connected to the transmission network at a GXP, via a distributor.

2.149 Separate models are fitted for the distribution-connected and transmission-connected consumer types.

2.150 The model that is estimated is a linear approximation to the "almost ideal demand system" (LA–AIDs). In practice, this means the price index (P) used to deflate total expenditure is a Laspeyres price index, with price changes evaluated relative to shares of expenditure in a base year (w_{0i}):

$$P_t = \sum_{i=1}^{4} w_{i0} \left(\frac{\ln p_{it}}{\ln p_{0t}}\right) \qquad \text{Equation 21}$$

2.151 Estimation of the model requires also adding restrictions to parameter values, based on economic theory. Adding-up constraints (i.e., all expenditure is spent) are enforced automatically by:

(a) estimating the share equations as a system, and

(b) dropping one share equation (also necessary to avoid singularity) during the estimation, and

(c) then inferring parameter values for the share equation that is omitted.

2.152 Table 12 summarises estimated parameters for the LA–AIDs model of demand, by time of use, for:

(a) the model of distribution-connected demand

(b) the model of transmission-connected demand.

2.153 The parameters in Table 12 determine the average elasticities of demand for electricity at the four times of use.

Table 12: LA-AIDS time-of-use parameter values

Coefficient	Time of use	Distribution-connected	Transmission-connected
α	Peak	-0.067	0.081
α	DG peak	0.073	0.004
α	Shoulder	0.307	0.238
α	Off-peak	0.687	0.677
β_1	Peak	0.003	-0.003
β_2	DG peak	-0.009	0.000
β_3	Shoulder	-0.002	-0.002
β_4	Off-peak	0.008	0.004
γ_{11}	Peak, Peak	0.152	0.201
γ_{12}	Peak, Peak DG	0.009	-0.004
γ_{13}	Peak, Shoulder	-0.038	-0.052
γ_{14}	Peak, Off-peak	-0.123	-0.145
γ_{21}	DG peak, Peak	0.009	-0.004
γ_{22}	DG peak, DG peak	0.010	0.008
γ_{23}	DG peak, Shoulder	-0.018	-0.005
γ_{24}	DG peak, Off-peak	-0.001	0.001
γ_{31}	Shoulder, Peak	-0.038	-0.047
γ_{32}	Shoulder, DG peak	-0.018	-0.006
γ_{33}	Shoulder, Shoulder	0.155	0.165
γ_{34}	Shoulder, Off-peak	-0.099	-0.112
γ_{41}	Off-peak, Peak	-0.123	-0.150
γ_{42}	Off-peak, DG peak	-0.001	0.002
γ_{43}	Off-peak, Shoulder	-0.099	-0.109
γ_{44}	Off-peak	0.224	0.256

Source: Electricity Authority

2.154 Table 13 and Table 14 contain examples of these elasticities. Actual elasticities vary by time-of-use expenditure shares. The examples in Table 13 and Table 14 are based on average historical expenditure shares.

Table 13: Demand elasticities for distribution-connected demand
Evaluated at the average expenditure share 2010-2017

Price	Quantity			
	Peak	Distributed generation peak	Shoulder	Off-peak
Peak	**-0.49**	0.03	-0.13	-0.43
Distributed generation peak	0.61	**-0.40**	-0.88	0.21
Shoulder	-0.18	-0.09	**-0.23**	-0.49
Off-peak	-0.26	0.00	-0.21	**-0.55**
Expenditure	1.011	0.467	0.991	1.016

Source: Electricity Authority

Table 14: Demand elasticities for direct-connected industrial demand
Evaluated at the average expenditure share 2010-2017

Price	Quantity			
	Peak	Distributed generation peak	Shoulder	Off-peak
Peak	**-0.13**	-1.08	-0.29	-0.25
Distributed generation peak	-0.02	**1.33**	-0.03	0.00
Shoulder	-0.20	-1.93	**-0.08**	-0.19
Off-peak	-0.64	0.70	-0.60	**-0.57**
Expenditure	0.988	0.980	0.991	1.007

Source: Electricity Authority

Implementation of estimated parameter values

2.155 The aggregate demand and time-of-use models are combined, in two steps, to create a single model of changes in demand in response to changes in electricity prices and relative prices.

2.156 In the first step, parameters estimated from the time-of-use expenditure models are used to determine price elasticities that are conditional, in any given period, on existing expenditure shares by time of use.

2.157 These elasticities are calculated using the formulae above, giving a (4 by 4) matrix of elasticities that describes the changes in demand across all times of use, in response to a change in prices of any, or all, of the other prices for each time of use.

2.158 On its own, this matrix of time-of-use elasticities does not fully account for changes in demand in response to increases or decreases in average electricity prices inclusive of transmission interconnection charges. To account for this, the matrix of time-of-use elasticities is multiplied by the aggregate elasticities estimated in the dynamic panel and industrial cost function models. The time-of-use elasticities (e_{ij}) are multiplied by the aggregate demand elasticities ($\bar{e}$) to obtain time-of-use elasticities in terms of effects on total demand for electricity (e_{ij}^{*}):

$$e_{ij}^{*} = |\bar{e}|. e_{ij} \qquad \text{Equation 22}$$

2.159 For the model of transmission-connected demand, the aggregate price elasticity chosen is the all-industry value (-0.02). Though industry-specific elasticities were estimated, using these elasticities is problematic in practice. This is because the geographic areas in our modelling are relatively highly aggregated (14 representative grid nodes) and include a range of different industries in some nodes. Rather than make assumptions about which industry elasticity to apply, we have used the same general industrial elasticity.

2.160 When time-of-use elasticities are calculated, the demand shifters are ignored. In the case of hydrological conditions and heating degree days, this is equivalent to assuming average hydrology and average temperatures.

2.161 In the case of distributed generation capacity, our modelling scenarios involve investment in utility-scale batteries, with distinct impacts on demand at other times of use reflecting the fact that utility-scale batteries change the timing of demand for electricity from non-battery/traditional generation. Thus, the estimated coefficients that dictate impacts of distributed generation capacity on demand are replaced by technical parameters calculated in our analysis of utility-scale battery costs and typical operational characteristics.

Prices

2.162 The demand model considers prices for grid-supplied electricity (prices at the GXP or grid injection point) comprising:

(a) national average generation prices

(b) transport costs (nodal price differences due to losses and constraints)

(c) transmission charges.

Generation prices

2.163 We use a simplified wholesale market dispatch model to produce generation prices. The purpose of the model is:

(a) to allow for feedback effects between demand growth and generation prices

(b) to provide a basis for assessing generation investment decisions.

2.164 In this model generation plant is 'dispatched' according to merit order (ranking) of generation plant offers. Prices are calculated, for each of the model's four times of use, by observing the price in the aggregate (market) offer curve that aligns with the amount of generation (MW) required to serve demand. The price for each time of use is the expected average annual price for that time of use.

2.165 The shape of generation plant offer curves is fixed at historical averages, by modelled time of use, over a three-year period from 2014 to 2017.[33] Actual averages of existing generation plant offers are used to model future offers from existing generation plant. Offer curves for new generation investments are based on offer curves of comparable existing generation plant.

2.166 The offer curves that are used in the model reflect actual market offers with five quantity-price pairs for offers (or bands).

2.167 For new investments in wind generation, average MWh of generation is based on an assumed 39.4% capacity factor (output relative to capacity) and this value is assumed to apply to off-peak demand periods. Output is assumed to be 6.9% lower during peak periods (a capacity factor of 32.5%) and 4.6% lower during shoulder periods (a capacity factor of 34.8%). These capacity factors are based on observed wind generation output by time of use over 2007-2018.

2.168 The dispatch model includes an adjustment factor to account for diversity of demand and offers. That is, the sum of average MW offered by generation plant, individually, will understate the average aggregate market MW offered, due to a positive correlation between capacity offered by individual generation plant, by trading period.

2.169 Input data for the dispatch model includes data used in the Generation Expansion Model in MBIE's EDGS. This includes data (estimates and actuals) on generation plant—

(a) nameplate capacity

(b) typical annual GWh

(c) contribution to peak

(d) short-run marginal cost

(i) fuel costs

(ii) heat rates

(iii) variable operating and maintenance costs

(iv) other variable costs (such as gas transmission costs).

2.170 The EDGS includes forecasts of fuel costs including emissions prices. We use the forecasts from the 2016 EDGS 'Mixed renewables' scenario and update these forecasts to account for actual data since the 2016 EDGS was completed.

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[33] 1 September 2014 to 31 August 2017.

2.171 Generation offer curves are shifted up or down as short-run marginal costs change, thus capturing the effects of changes to operating costs (e.g., from increases in gas prices and emissions prices).

2.172 The generation plant in the model is limited to grid-connected generation. However, dispatch volumes for shoulder and off-peak periods are adjusted in the dispatch model, for the purposes of price determination, to account for distributed generation that contributes to supply during these periods.

2.173 Generator earnings are calculated as part of the dispatch process. Earnings are the surplus of generator revenue (market price multiplied by dispatched quantities) less short-run operating costs (short-run marginal costs multiplied by dispatched quantities). This provides a measure of market surplus attributable to producers (producer surplus), excluding fixed costs (where fixed costs include capital rental costs).

Transport costs

2.174 Transport costs are modelled as a function of:

(a) average historical price differences at each backbone node from average national generation prices (LCE)

(b) growth in demand, which is assumed to increase price differentials.

2.175 Three types of transport costs are considered:

(a) average LCE during all trading periods

(b) average LCE during periods of local resource scarcity (when demand exceeds generation at the backbone node)

(c) average LCE during periods of local resource abundance (when generation exceeds demand at the backbone node)

2.176 This ensures the model takes account of:

(a) nodes having periods with positive transport costs and periods with negative transport costs (net generation or net load), and thus

(b) the extent to which backbone nodes, and generators and consumers, are beneficiaries of the transmission network.

2.177 Transport costs are also differentiated across peak, shoulder and off-peak periods.

2.178 For reasons of tractability the demand model does not adjust transport costs in response to transmission investment. As a result, transport costs increase whenever demand increases and do not decline unless demand declines. The effects of transmission investment on transport costs are analysed outside the demand model. (See the section above on the effect of changes in transmission investment costs and benefits on more efficient grid use—starting at paragraph 2.48.)

2.179 We estimated a model summarising the effects of an increase in demand on transport cost (LCE) mark-ups over generation costs (prices received by generators). The conceptual basis for the model is that energy losses and constraints are an increasing function of demand. Empirically, the relationship is expected to be conditional on:

(a) year-specific differences in grid configuration and assets

(b) node-specific differences in load management

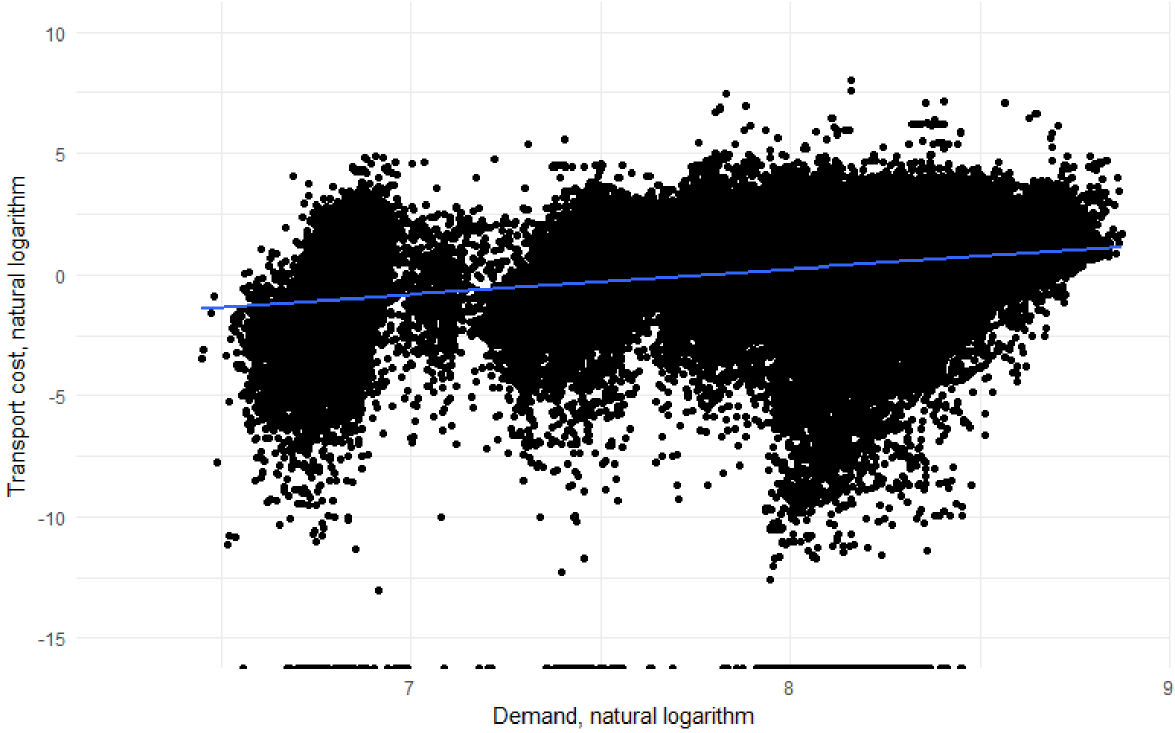
(c) capacity utilisation of the HVDC being constrained

(d) availability and cost of generation

(e) availability of distributed generation.

2.180 Without conditioning on other factors, data shows a positive relationship between demand and transport costs over time. However, the relationship is not strong (see Figure 3).

Figure 3: Relationship between demand and transport costs
Observations by backbone node and trading period, 2007–2018



Source: Electricity Authority

2.181 The model that is estimated is:

$$l_{it} = \alpha_i + \delta_t + x_{it} + g_{it} + u_t + p_{it} + d_{it} \qquad \text{Equation 23}$$

2.182 Where

(a) l is LCE by back-bone node and trading period (indices i, t respectively) per MWh

(b) α_i and δ_t are locational (back-bone node) and year-specific fixed effects (means)

(c) x_{it} is metered grid exports (demand)

(d) g_{it} is generation

(e) u_{it} is utilisation of the HVDC (flows relative to maximum capacity)

(f) p_{it} is price received by generators

(g) d_{it} is distributed generation.

2.183 All variables are transformed by natural logarithms.

2.184 Two variants of the model are estimated:

(a) one for periods and locations where transport costs are positive and generation at a node is scarce (load exceeds generation)

(b) one for periods and locations where transport costs are negative and generation is not scarce (generation exceeds load).

2.185 In the model of negative transport costs, the LCE value is the absolute value.

2.186 The model results, shown in Table 15 and Table 16, indicate that the elasticity of transport costs with respect to an increase in demand are 0.13 for situations of positive transport costs and -0.05 for situations of negative transport costs.

Table 15: Model of transport costs

Dependent variable is natural logarithm of LCE per MWh

Term	Coefficient	Standard error	T statistic	P value
Intercept	-0.35	0.0206	-16.9	0.000
BPE	-0.97	0.0087	-110.5	0.000
HAY	-1.63	0.0105	-155.1	0.000
HLY	-0.18	0.0091	-19.9	0.000
ISL	-0.44	0.0103	-43.1	0.000
KIK	-0.40	0.0097	-41.4	0.000
MDN	-0.01	0.0099	-1.5	0.143
OTA	-0.30	0.0116	-26.1	0.000
RDF	-0.87	0.0099	-88.1	0.000
ROX	0.19	0.0086	21.7	0.000
SFD	-0.84	0.0086	-97.2	0.000
TRK	-0.63	0.0092	-68.5	0.000
TWI	0.27	0.0097	27.9	0.000
WKM	0.02	0.0101	1.5	0.127
2010	-0.17	0.0095	-18.1	0.000
2011	-0.17	0.0095	-18.1	0.000
2012	0.25	0.0100	25.1	0.000
2013	-0.09	0.0096	-9.0	0.000
2014	-0.41	0.0096	-42.8	0.000
2015	-0.65	0.0096	-68.1	0.000
2016	-0.41	0.0096	-42.9	0.000
2017	-0.19	0.0097	-19.4	0.000
x	0.13	0.0027	48.1	0.000
g	-0.20	0.0019	-106.0	0.000
u	0.34	0.0014	252.8	0.000
p	0.73	0.0019	383.9	0.000
d	-0.0004	0.0001	-3.8	0.000

Source: Electricity Authority

Table 16: Model of negative transport costs
Dependent variable is natural logarithm of absolute value of LCE per MWh

Term	Coefficient	Standard error	T statistic	P value
Intercept	-2.29	0.02	-97.26	0.00
BPE	-0.67	0.01	-83.36	0.00
HAY	-0.78	0.01	-79.77	0.00
HLY	-0.29	0.01	-35.85	0.00
ISL	0.20	0.01	18.68	0.00
KIK	0.35	0.01	30.07	0.00
MDN	-0.20	0.01	-14.09	0.00
OTA	-0.06	0.01	-5.61	0.00
RDF	0.15	0.01	16.31	0.00
ROX	0.31	0.01	50.18	0.00
SFD	-0.47	0.01	-67.62	0.00
TRK	0.01	0.01	0.88	0.38
TWI	0.39	0.01	52.46	0.00
WKM	-0.30	0.01	-35.65	0.00
2010	-0.19	0.01	-17.86	0.00
2011	-0.20	0.01	-18.79	0.00
2012	0.40	0.01	36.41	0.00
2013	-0.01	0.01	-1.13	0.26
2014	-0.34	0.01	-31.04	0.00
2015	-0.54	0.01	-49.63	0.00
2016	-0.38	0.01	-34.64	0.00
2017	-0.15	0.01	-13.80	0.00
x	-0.05	0.00	-20.71	0.00
g	0.16	0.00	64.28	0.00
u	0.19	0.00	134.62	0.00
p	0.80	0.00	377.21	0.00
d	0.00	0.00	-27.12	0.00

Source: Electricity Authority

Transmission charges

2.187 Transpower's forecast revenue comprises:

(a) Transpower's base capex

(b) Transpower's listed projects[34]

(c) Transpower's approved major expenditure.

2.188 The demand model implements five methods for recovering transmission interconnection revenue (inclusive of overheads but excluding connection charges, which are not included anywhere in the model):

(a) benefit-based charges on load and generation

(b) RCPD charges on load

(c) SIMI charges on South Island generation

(d) MWh charges on load

(e) fixed-like (residual) charges on load—based on AMD measured at some point in history.

2.189 Benefit-based charges are allocated (without ad-hoc project-specific adjustment), according to:

(a) an initial externally determined share of charges, if any

(b) shares of LCE as a measure of economic benefits, for new base capex or major capex, with generation shares of LCE discounted by two-thirds to account for operating costs

(c) share of average peak MWh (demand plus generation) in the previous 3 years as a proxy for reliability benefits, with benefits to generation discounted by 99% to reflect the relative values of lost revenue and lost load (assumed to be $200 versus $20,000, as discussed above in paragraph 2.53).

2.190 The default benefit-based allocation is economic benefits.

2.191 RCPD charges are modelled as:

(a) a charge per MWh during peak periods under the baseline

(b) a charge per MWh during all trading periods under the alternative proposal.

2.192 SIMI charges are based on shares of the previous five years' average generation for South Island generators (grid-connected generators only).

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34 As part of each process for setting Transpower's price-quality path for a regulatory control period, the Commerce Commission publishes a list of base capex projects that:

(a) Transpower expects to commission during the regulatory control period, and

(b) must follow the same process for approval as a major capex project.

Transpower may submit a proposal to the Commerce Commission, seeking approval for one or more of these 'listed projects', up to 22 months prior to the end of the regulatory control period within which the project is commissioned. The approved funding for the listed project is added to Transpower's base capex allowance as part of the yearly updates to Transpower's allowed revenue. See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-listed-projects.

2.193 The allocation of fixed-like AMD charges was modelled as a one-off allocation based on initial shares of peak demand (MWh) averaged over a five-year period.[35] The charges are then modelled as MWh charges applied evenly across each of the model's four times of use. This is done to ensure that consumers in the demand model 'perceive' the charges—although this does cause bias in the model's results, in terms of overstating the deadweight loss associated with the AMD charge, by overstating the AMD charge's (dampening) impact on demand. We are comfortable with this negative bias in our modelling of the proposal as it is consistent with being conservative in our estimation of the proposal's benefits.

Price expectations

2.194 In the demand model consumers are assumed to choose their demand for electricity based on their expectations of wholesale energy prices and transmission interconnection prices (i.e., electricity prices inclusive of transmission interconnection charges).

2.195 In the model we assume consumers' expectations of wholesale energy prices are based on the average of:

(a) the prior two periods' wholesale market prices, and

(b) the dispatch price calculated from the prior year's wholesale market offer curves and national demand, by time of use, where national demand is equal to the prior year's national demand multiplied by the prior year's demand growth rate.

2.196 We use an average to account for the fact that energy prices can be volatile and mean-reverting (a high price last period is likely to be followed by a downward correction in the next period).

2.197 Consumers' expectations of transmission interconnection prices are based on their most recent transmission interconnection charges, combined with information about future growth in these charges based on forecast transmission revenue (in the case of interconnection charges that change over time).

2.198 In the case of coincident peak demand charges, consumers do not know for certain what their charges will end up being, as these are only determined after all consumers have made their consumption decisions (in the model and in practice). Ex-post balancing is undertaken to ensure that all transmission revenue is recovered (as happens in practice). However, consumers will not perceive their actual transmission interconnection price until the next year when they recalibrate their expectations.

Model 2: Generation investment model

2.199 Generation investment is modelled using the schedule of potential generation investments in the 2016 EDGS and selecting the lowest cost investments, subject to expected average revenue in the first year of a new generation investment being equal to or larger than annualised long-run marginal generation costs plus expected interconnection charges.

[35] The 2019 Issues Paper suggested the allocator should be based on at least 2 years' of data. The Authority is considering adopting an allocator based on four years. The difference between a residual allocator based on four or five years does not make a material difference to CBA results.

2.200 Expected average revenue in the first year of a new generation investment is based on adding the new investment's offer curves to the previous year's wholesale market offer curves and calculating nodal prices based on the previous year's demand.

2.201 This simplified model of investment decision-making, which has investors requiring an immediate positive return on their investment, is consistent with investors ignoring the possibility that wholesale energy prices will rise in the future. We consider it reasonable to assume investors would take this approach, on the grounds that the future is inherently uncertain—for example, the investment's profitability might be undermined by wholesale prices declining, by negative demand growth shocks, or by technology shocks.

2.202 Expected interconnection charges are based on the previous year's average interconnection charge ($/MWh) at the node where the new generation investment is occurring.

2.203 The following ad-hoc adjustments made in the 2019 CBA are retained:

(a) the commissioning of a gas peaker in 2020 at Junction Road, near New Plymouth

(b) the decommissioning of 500 MW of thermal plant at the end of 2024 (the Rankine units at Huntly) and 50 MW of thermal plant at the end of 2028 (the open cycle gas turbine at Huntly).[36]

2.204 However, as noted in section 1, we have not made further ad-hoc adjustments for generation currently under (pre-) construction—preferring instead to rely on sensitivity analyses to account for the effect of this new generation on the four proposed options' benefits and costs relative to the baseline.

Model 3: Model of investment in distributed energy resources (batteries)

2.205 We have modelled investment in distributed generation or other distributed energy resources, using the specific example of investment in utility-scale batteries. For the purposes of the modelling, we treat these investments as demand-side investments.

2.206 Decisions to invest in utility-scale batteries are based on a model of the optimal amount of battery capacity in a transmission pricing region. The optimal amount of battery capacity is found by equating marginal present-valued earnings (revenue less variable operating costs) with marginal present-valued capital costs (inclusive of fixed operating costs).

2.207 Earnings on utility-scale battery investment are assumed to be a declining function of the amount of battery capacity installed (i.e., decreasing marginal returns) and an increasing function of peak demand charges.

2.208 A simulation model is used to estimate earnings from utility-scale battery investment by transmission pricing region. It takes a fixed amount of battery investment (in MW) and uses a linear programme to find the timing and scale of battery charging and discharging that maximises earnings. By running multiple simulations, varying the amount of battery

36 The 2016 EDGS 'Mixed renewables' scenario had the 500 MW of thermal generation at Huntly being decommissioned at the end of 2022 and the further 50 MW of thermal generation at Huntly being decommissioned at the end of 2026.

investment (MW) in each simulation, the model produces a data set that describes the relationship between:

(a) earnings from battery investment, and

(b) the scale of battery investment and peak demand charges.

2.209 Earnings calculated using the simulation model are then adjusted to account for the potential effects of battery operation on wholesale energy prices by trading period. That is, as battery investment increases and load curves are flattened, we would expect energy price arbitrage opportunities to diminish as high prices fall and low prices rise. To capture this effect, we assume that a 1% change in grid energy demand causes a 2% change in prices.[37]

2.210 Earnings functions are then constructed. The natural logarithm of average earnings (e_z) per MW (x) by pricing zone (z) from the simulation model results is expressed as a polynomial of the natural logarithm of the amount (MW) of utility-scale batteries installed and the interconnection rate (ic):

$$e_z = \exp(c_{z1} + c_{z2}\log(x) + c_{z3}\log(x)^2 + c_{z4}\log(x)^3 + c_{z5}\log(x)^4 + c_{z6}\log(x)^5 + c_{z7}.ic) \qquad \text{Equation 24}$$

2.211 The coefficients (c_{zi}) are estimated using ordinary least squares with year fixed effects.

2.212 Costs of investing in utility-scale batteries are similarly characterised by a polynomial. Costs in dollars per MW (c) are expressed as a function of the year (y) of investment:

$$c_y = c_1 + c_2 y + c_3 y^2 + c_4 y^3 + c_5 y^4 \qquad \text{Equation 25}$$

2.213 The linear programming model used to simulate earnings is adapted from Davies et al (2019).[38] The linear programming model determines optimal battery operation cycles (charging and discharging).

2.214 Optimal operation is simulated, for each transmission pricing region, over each trading period between 1 September 2014 and 31 August 2017. The simulation model optimises hourly operation on a daily basis, with links between days created by tracking the amount of energy stored in batteries at the end of each day. Energy prices and demand are exogenous and are based on actual wholesale electricity market demand and prices by trading period. Interconnection charges are based on calculating RCPD charges using 100 trading periods and revenue requirements.

2.215 The main adaptation of the model in Davies et al (2019) is to restrict battery operation to account for the effects that charging and discharging of batteries has on regional coincident peak demands and transmission interconnection prices. This includes the following adjustment to account for uncertainty in predicting RCPD periods:

- upper bound on **charging** is held at zero where forecast regional grid export is within 2% of minimum observed RCPD, to represent load forecasting errors

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37 This assumption is informed by a simple linear regression of the natural logarithm of prices on a 3rd order polynomial of demand by trading period between 2010 and 2017 with year fixed effects. The fitted values from that model show the average percentage change in prices is twice the percentage change in demand.

38 Davies, D.M., Verde, M.G., Mnyshenko, O., Chen, Y.R., Rajeev, R., Meng, Y.S., Elliott, G., 2019. Combined economic and technological evaluation of battery energy storage for grid applications. Nature Energy 4, 42. https://doi.org/10.1038/s41560-018-0290-1

- upper bound on **discharging** is held at zero where forecast regional grid export is a peak period and within 2% of minimum RCPD.

2.216 To determine the optimal scale of battery investment, there are also:

- upper bounds on charging per trading period equal to the difference between forecast minimum RCPD and forecast regional grid export, assuming perfect knowledge
- upper bounds on discharging during peak demand periods equal to the difference between forecast regional grid export and forecast minimum RCPD, assuming perfect knowledge.

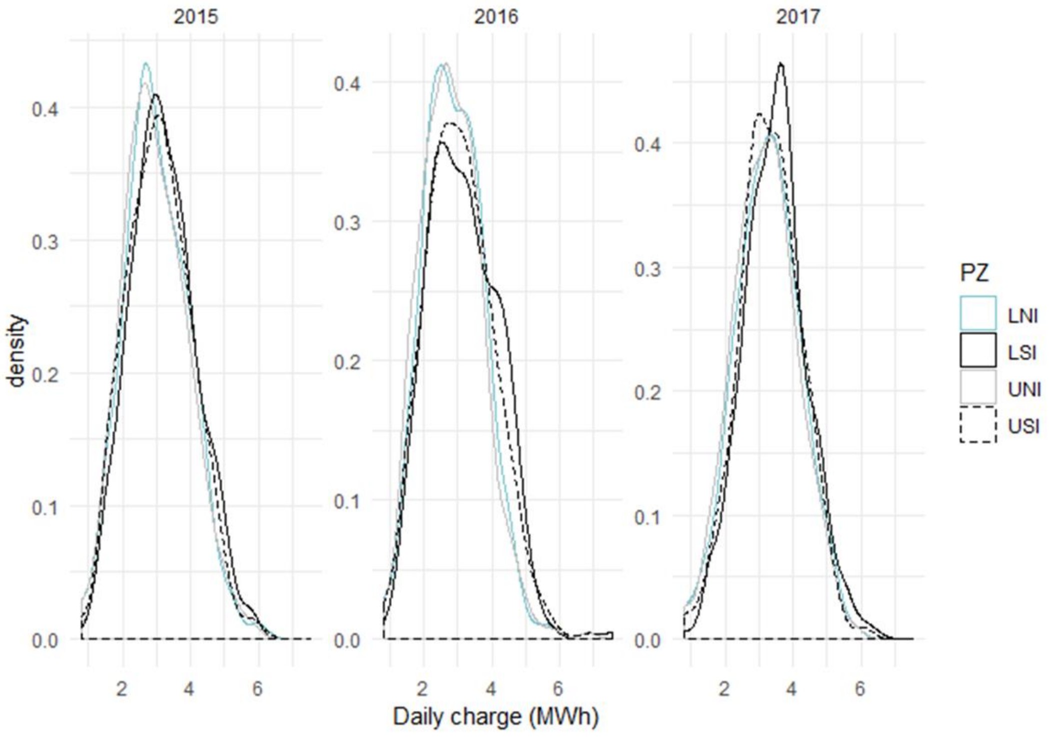
2.217 The simulation model (and our analysis of battery costs) assumes that:

- batteries have a maximum operating range of 10% to 90% of maximum capacity (a state of charge of between 0.1 and 0.9 of capacity)
- all batteries have an energy-to-power ratio of 1 (a 1 MW / 1 MWh battery)
- energy losses of 10% occur during battery operation.

2.218 The simulation model shows significant variation, within a year, of daily battery cycling. Figure 4 shows the distribution of daily charging in MWh for a 1 MWh battery with unit energy to power ratio and operating limits of 10%–90% of battery charge. Average daily discharge is 2.8 MWh per day and average daily charge is 3.1 MWh per day (the difference being losses).

Figure 4: Modelled battery cycles, baseline

PZ is transmission pricing region: Upper North Island (UNI), Lower North Island (LNI), Upper South Island (USI), Lower South Island (LSI)



Source: Electricity Authority

2.219 Battery profitability is highest at low levels of total investment (see Table 17). Battery profitability is constrained, as the amount of batteries increases, because of:

- a narrowing of differences across wholesale energy prices (high prices fall and low prices rise)[39]
- fewer opportunities to flatten load, to avoid peak demand charges.

2.220 Batteries are substantially more profitable with RCPD charges than without RCPD charges and earnings are highest in areas with the peakiest load.

Table 17: Modelled average annual earnings per MW invested ($)40

	Without RCPD charge, by pricing zone				With RCPD charge, by pricing zone			
MW	**UNI**	**LNI**	**USI**	**LSI**	**UNI**	**LNI**	**USI**	**LSI**
1	26,756	25,175	24,455	22,224	53,827	64,211	39,317	20,832
5	26,513	24,968	24,169	21,997	51,721	62,371	35,575	20,378
10	26,210	24,710	23,813	21,713	50,007	59,654	32,415	19,891
20	25,604	24,193	23,099	21,144	46,752	55,645	28,217	18,975
50	23,785	22,644	20,960	19,438	39,785	45,567	23,193	16,917
100	20,754	20,061	17,394	16,595	32,491	35,538	18,290	14,123
200	14,692	14,895	10,262	10,909	23,109	24,537	10,901	9,916
300	8,629	9,729	3,130	5,223	15,144	16,222	5,428	7,184
400	2,567	4,564	-4,002	-463	8,110	9,669	1,428	5,064
500	-3,495	-602	-11,105	-6,149	2,125	4,414	-1,383	3,333

39 The modelling assumes a price elasticity of supply of 2—a 1% change in demand is assumed to change wholesale energy prices by 2%. This assumption was informed by analysis of correlations between changes in demand and changes in wholesale energy prices.

40 Numbers in this table include losses due to ex-post price adjustment. Daily cycle optimisation does not permit losses.

2.221 The simulation model is also used to provide estimates of the net effects of utility-scale battery operation on grid-level demand, by time of use. This is done by noting time of use (being the grid use model's four times of use) prior to the simulation of battery operation and then calculating changes in demand by time of use.[41] This calculation indicates that, in the presence of RCPD charges, one MW of batteries causes, on average:

- 100 MWh reduction in peak grid demand
- 100 MWh increase in peak non-grid demand
- 22 MWh reduction in shoulder demand
- 222 MWh increase in off-peak demand.[42]

2.222 These numbers reflect changes in traded volumes of energy and amount to a 199 MWh net change in the amount of energy traded. The change in final consumption demand is zero. There is a net increase in grid supply/demand of 99 MWh, reflecting energy lost during battery charging and discharging.

2.223 As noted above, the battery investment model is focussed on optimal investment by transmission pricing region. We have used each backbone node's historical average share of grid demand in the transmission pricing region in which the backbone node is located to determine each backbone node's share of utility-scale battery investment.

2.224 Battery investment cost assumptions reflect recent international research reports and analyses of current and expected battery costs.[43] Figure 5 summarises the central projection for battery investment costs (present-valued costs per MW).

2.225 Our assumed costs include upfront capital and connection costs and the present value of ongoing operating and maintenance costs (fixed at 2.5% of capital costs).

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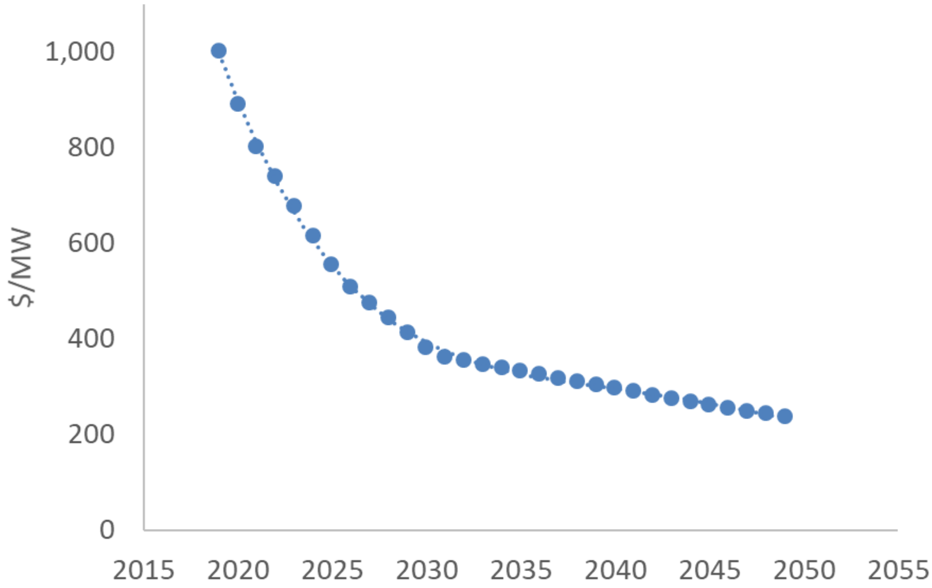
41 The effects of battery operation on grid-level demand are subject to index number problems in the sense that the effects of battery operation on demand by time of use depends on whether the change in demand is measured with reference to demand before or demand after batteries are introduced.

42 These are net numbers—the net of charging which increases grid demand and discharging which reduces grid demand.

43 See Schmidt, O., Melchior, S., Hawkes, A., Staffell, I., 2019. Projecting the Future Levelized Cost of Electricity Storage Technologies. Joule 3, 81–100. Refer also National Renewable Energy Laboratory, 2019 Annual Technology Baseline and Cole, W. and Frazier, A. W., National Renewable Energy Laboratory, June 2019, Cost Projections for Utility-Scale Battery Storage.

Figure 5: Battery investment cost assumption

Present value cost ($/MW) for a 1 MW battery with energy to power ratio of 1 (1 MWh battery)



Source: Electricity Authority

Assessing the other options

2.226 The grid use model projects electricity demand and costs (prices) for the period 2019 to 2049, for each of the four proposed options and the baseline. Results for the five are then compared, and consumer welfare changes or cost differences are calculated.

The alternative option

2.227 We modelled the alternative option using the same methodological steps and models as for the proposal and the proposal's 'future-only' and 'HVDC-only' options. However, under the alternative option, transmission revenue is recovered using the same charges as in the baseline, but with RCPD charges modelled as a charge per MWh during all trading periods.

The proposal's future-only option

2.228 We estimated the costs and benefits of a 'future-only' version of the proposal. Under this scenario, benefit-based charges would be applied only to future grid investment. The costs of all grid investment up to 2019 would be recovered via the residual charge.

2.229 This scenario was straightforward to model. We moved the revenue requirements for the seven major investments that we propose be covered by a benefit-based charge into the residual and assessed the changes in consumer welfare compared to the proposal.

The proposal's HVDC-only option

2.230 We estimated the costs and benefits of an 'HVDC-only' version of the proposal. Under this scenario, benefit-based charges would be applied only to future grid investment and to revenue from existing HVDC assets. Other costs of grid investment up to 2019 would be recovered via the residual charge. This scenario was also straightforward to model, being a variation on the proposal and the proposal's future-only option.

Assessing the proposed changes to the PDP

2.231 The PDP allows for a reduction in a transmission customer's interconnection charges if the transmission customer can show it would be privately beneficial to disconnect from the grid, but that this would be inefficient because it would result in costs being shifted to other consumers, thereby increasing costs overall.

2.232 The proposed changes to the PDP are to extend access to a prudent discount to—

(a) transmission-connected consumers that would disconnect from the grid in favour of alternative supply

(b) transmission customers whose transmission charges exceed the efficient standalone cost of supplying the customer with the transmission services it receives.

Extending the PDP to disconnection in favour of alternative supply

2.233 The proposed extension of the PDP to include cases of disconnection in favour of alternative supply (generation), would increase the likelihood that consumers could avoid the cost of increased transmission charges from a transmission customer disconnecting (by receiving a prudent discount, the transmission customer would not disconnect).

2.234 To estimate the cost to consumers of a transmission customer disconnecting from the grid, we have used the following inputs:

(a) average interconnection revenue of $132,698 per MW between 2022 and 2049

(b) an assumed flat load profile (i.e., 1 MW equalling 8,760 MWh of demand)

(c) costs being reallocated under the proposal to all remaining demand in proportion to estimated transmission charges

(d) the demand model's assessed welfare consequences of consumers facing an increase in charges to recover the transmission revenue no longer paid by the disconnecting transmission customer.

2.235 The cost to consumers is the compensation required to ensure consumers are no worse off following the increase in transmission charges. So, for a 1 MW disconnection, which causes an average increase in transmission charges of 0.02%, the cost to consumers is $137,494. This is fractionally higher than the amount of revenue reallocated to transmission customers.

Extending the PDP to cap transmission charges at efficient standalone cost

2.236 The proposed extension of the PDP to cap transmission charges at the efficient standalone cost of supplying a transmission customer's transmission services is subtly different from extending the PDP to include cases of disconnection in favour of alternative supply.

2.237 This second proposed extension of the PDP deals with the situation where transmission charges are above standalone costs, but there are barriers to the transmission customer exercising the option to bypass the grid by building its own transmission assets. The supplementary consultation paper gave the example of consent never being granted for construction of a duplicate transmission link through pristine wilderness. This situation risks the customer being overcharged, causing it to inefficiently close.

2.238 Another example is the situation where:

(a) a grid-connected load can build its own transmission (or distribution) assets in order to be supplied by a grid-connected generator for a cost less than its transmission charges, but

(b) the load customer expects Transpower to transfer the load's charges to the grid-connected generator in the expectation those charges will be passed to the load.[44]

2.239 To assess whether this second proposed extension to the PDP has a net benefit, we apply a case-study approach. Our rationale for a case study approach is that:

(a) the second proposed extension to the PDP would apply to only a very narrow range of situations—generally not distributors nor most direct-connect consumers. As such, we assume Transpower would receive just three applications under this proposed extension over the CBA's 30-year assessment period.

(b) if a prudent discount application under this extension were successful, the extension would be net beneficial so long as Transpower's costs of assessing the prudent discount application was less than the difference between the standalone cost and the applicant's transmission charges. This is because a successful application would mean an inefficient disconnection was avoided, resulting in net benefits.

(c) The framework and approach we apply to the case study of the example in paragraph 2.238 can be applied, with a little modification, to a case study of the example in paragraph 2.237.

Case study

2.240 In relation to a grid-connected consumer, if a prudent discount is not granted and the consumer disconnects due to plant closure, then this will carry a cost that is equal to the consumer's willingness to pay a lower rate of transmission charges. Standard economic benchmarks (for subsidy-free prices) show that if this lower rate of charges is equal to standalone costs, then reducing the consumer's transmission charges to that lower level is efficient.

2.241 We assume the capital cost of the alternative supply project reflects the grid-connected consumer's willingness to pay for transmission services—the capital cost represents the private benefit to the consumer of remaining in business and is essentially a reservation transmission price, above which the consumer's demand would fall to zero. That is, the alternative supply project is used as a benchmark for determining the efficient level of transmission pricing, such that if the consumer remains grid-connected at that price, then the decision to provide a prudent discount can be considered efficient.

2.242 We assess the cost of a prudent discount under the proposed extension to be:

(a) the loss in consumer surplus that would result from shifting <u>some</u> of the grid-connected consumer's interconnection charges to other consumers[45]

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[44] The proposed guidelines require that a TPM must avoid creating inefficient incentives for a large consumer of generator to shift their point of connection.

[45] When we applied this to our case study this equated to an estimated 0.3% of the present value of the sum of the grid-connected consumer's transmission charges reallocated to other consumers, using the demand model for assessing benefits from more efficient grid use.

(b) the loss and constraint excess costs associated with the grid-connected consumer's demand remaining on the grid, assessed as:

   (i) the percentage change in the pro-rata average national MW of demand (MWh/8,760) multiplied by the parameter in the grid use model that describes the estimated percentage change in LCE per percentage change in MW of demand

   (ii) multiplied by an assumed annual average LCE cost of $102,000,000

(c) the costs Transpower incurs assessing the prudent discount application.

2.243 The benefit of a prudent discount under the proposed extension would be:

(a) avoiding the loss in consumer surplus that would result from shifting <u>all</u> of the grid-connected consumer's interconnection charges to other consumers

(b) avoiding the economic cost associated with the grid-connected consumer disconnecting due to closure, which equals:

   (i) the capital cost of the alternative supply option (see above)

   (ii) conservatively, a 50% discount on the cost in (i) to reflect a 50% probability that the consumer would continue to operate if the prudent discount was available to the consumer at a cost equivalent to the consumer's standalone cost of supply. Equivalently, this is a 50% probability that the plant would close even with transmission charges no larger than the standalone cost. This reflects uncertainty about the extent to which transmission charges would cause the plant to close.

2.244 The results are sensitive to the amount of transmission charges that would be shifted from the grid-connected consumer to other consumers. Therefore we also considered the application of the proposed transitional cap on transmission charges when estimated the net benefit of this extension.

Assessing the proposed transitional cap on transmission charges

2.245 The proposal includes a transitional cap on the amount that transmission charges[46] could increase as a direct result of introducing a new TPM consistent with the guidelines:

(a) limit the percentage increase in each distributor's transmission charges to no more than 3.5% of an estimate of the total electricity bill of all consumers supplied (directly and indirectly) from the distributor's network—

   (i) relative to estimated bills in the 2019/2020 pricing year, which is equivalent to the charges based on the 2017/18 measurement year

   (ii) after adjusting for inflation

   (iii) after adjusting for demand growth

(b) limit the percentage increase in each grid-connected consumer's transmission charges to no more than 3.5% of an estimate of the total electricity bill of the direct consumer—

46 Transmission charges subject to the cap are benefit-based charges in respect of the Schedule 1 investments and the residual charge.

(i) relative to estimated bills in the 2019/2020 pricing year, which is equivalent to the charges based on the 2017/18 measurement year

(ii) after adjusting for inflation

(iii) after adjusting for demand growth for the first 5 years of the new TPM, increasing by 2% in each year from 5 years after the 2019/2020 pricing year.

2.246 We have used the results from the demand modelling to calculate the changes in transmission customers' transmission charges (in $ / MWh) as a result of the proposal.

2.247 We have then estimated the increase in the total electricity bill of all distribution-connected consumers and transmission-connected consumers.

2.248 We have assumed the percentage of a final bill that (interconnection) transmission charges comprise is the same for all distribution-connected consumers at a backbone node. The percentage we have used is the percentage that transmission charges represent, on average, in residential consumers' final bills.

2.249 This is a necessary simplifying assumption because we do not know the transmission charge percentage for commercial and industrial consumers on distribution networks. We only have data on the transmission charge percentage for residential bills, from MBIE's QSDEP data.

2.250 Note that the percentage varies between backbone nodes because of differences in the transmission charge component across QSDEP areas.

2.251 The effect of this assumption is to understate how much revenue would need to be reallocated via transmission charges for distribution-connected customers. This is because residential consumers have the lowest shares of transmission charges in their final bills.

2.252 For transmission-connected consumers, we base our calculations of the final total bill on average energy and transmission costs (connection and interconnection charges) at the backbone node. These averages will hide some variation where there are multiple transmission-connected consumers supplied via the same backbone node.

2.253 Following our initial allocation, we perform a one-off reallocation of the interconnection revenue left over because of the price cap, to load and generation in areas (backbone nodes) that are below the price cap in proportion to their shares of revenue paid.

2.254 We assume the economic effect from the surcharge on generators is minimal and therefore need not be quantified. This is for the following reasons:

(a) the operational effects of the surcharge are nil, because the surcharge is assumed to be a fixed charge, which has no effect on the short-run marginal cost of generation (i.e., on fuel and other operating costs)

(b) the present value amount of the surcharge on generators is very small in the context of generation revenue over 30 years.

2.255 The last step is to estimate the welfare effects of the price cap on consumers:

(a) by running the revised transmission charges through the demand model, and

(b) observing the welfare effects of the price changes brought about by the price cap, measured by changes in consumer surplus.

2.256 The only consumers for which the price cap applies are:

(a) distribution-connected consumers supplied via the Whakamaru backbone node

(b) transmission-connected consumers supplied via the Otahuhu backbone node.

2.257 However, the modelling of the price cap is based on averages across transmission customers at a backbone node. So, there may be some transmission customers supplied electricity via other backbone nodes who will, in practice, also benefit from the price cap. For other consumers, the price cap causes transmission charges to be higher than they otherwise would be during the transitional period while the price cap applies.

Other key assumptions in modelling more efficient grid use

2.258 We have made a number of key assumptions in our modelling of more efficient grid use. Key assumptions not set out earlier in this section are set out below.

Population growth assumptions

2.259 Population growth parameters used in the CBA are from medium population projections produced by Statistics New Zealand, aggregated to backbone nodes. Other scenarios (low and high) can also be used by setting parameters in the model. These parameter assumptions translate directly into growth in numbers of ICPs. Table 18 sets out our assumptions for the low and high population growth rate scenarios.

Table 18: Population growth rate scenarios

Backbone node	Medium	Low	High
MDN	0.4%	-0.1%	0.9%
OTA	1.3%	0.8%	1.6%
HLY	0.7%	0.2%	1.1%
TRK	0.6%	0.0%	1.0%
WKM	0.2%	-0.3%	0.6%
RDF	0.2%	-0.4%	0.7%
SFD	0.2%	-0.4%	0.7%
BPE	0.2%	-0.3%	0.7%
HAY	0.4%	-0.1%	0.8%
KIK	0.3%	-0.3%	0.7%
ISL	0.8%	0.2%	1.3%
BEN	0.5%	0.0%	0.9%
ROX	-0.3%	-0.8%	0.3%
TWI	0.0%	-0.6%	0.5%

Source: Electricity Authority

Income growth assumptions

2.260 Our default assumption is that national per capita income growth (real) is 1% per annum, from which we derive income growth parameters by backbone node using the factors set out in Table 19.

Table 19: Assumed income growth by area, relative to national rate

Backbone node	Value
MDN	0.998
OTA	0.999
HLY	1.002
TRK	1.000
WKM	1.010
RDF	0.999
SFD	0.999
BPE	0.997
HAY	1.000
KIK	0.998
ISL	1.005
BEN	1.006
ROX	0.998
TWI	0.996

Source: Electricity Authority

Other key assumptions or parameters

2.261 Table 20 contains other key assumptions used in the CBA that are not stated elsewhere in this document.

Table 20: Other key assumptions or parameters in modelling of efficient grid use

Assumption / Parameter	Value
vSPD is used to estimate benefits to transmission customers of transmission investments $20 million and over[47]	Not applicable
Demand-based charge and residual charge typically incorporated in retail tariffs as a fixed charge, not as a variable charge, at least for larger consumers[48]	Not applicable
AMD behind each GXP, including GXPs for consumers directly connected to the transmission network: (a) includes embedded generation directly connected to the local network (b) excludes generation indirectly connected to the local network (i.e., behind a consumer's meter)	Not applicable
Benefits of transmission investment included in a benefit-based charge are calculated using metered electricity offtake at each GXP in the relevant area, but Transpower is permitted to calculate the benefits with load behind each GXP grossed up by embedded generation directly connected to the local network.[49]	Not applicable
Social discount rate (real)	6%
Residual share of interconnection charges when a TPM based on the proposed guidelines is introduced	0.7273
Initial share of benefit-based charges:	
Generation, backbone node BEN	0.1358
Generation, backbone node BPE	0.0111
Generation, backbone node HAY	0.0011
Generation, backbone node HLY	0.0074
Generation, backbone node ISL	0.0053
Generation, backbone node KIK	0.0015
Generation, backbone node RDF	0.0000
Generation, backbone node ROX	0.0000
Generation, backbone node SFD	0.0002

47 This assumption aligns with the high complexity scenario in PWC's July 2016 report to Transpower setting out a TPM change impact assessment (refer to page 20 of Appendix D of Transpower's submission on the 2016 Issues Paper).

48 We do not expect this assumption to hold fully in reality across all classes of consumer, in part because regulation currently limits the use of fixed charges. However, we consider that a workably competitive retail market means it is reasonable to expect that retailers would be unwilling to accept the price risk associated with converting all fixed transmission charges into variable charges.

49 Generation indirectly connected to the local network (i.e., behind a consumer's meter) is not included in the grossing up of load.

Assumption / Parameter	Value
Generation, backbone node TRK	0.0757
Generation, backbone node TWI	0.0090
Generation, backbone node WKM	0.0032
Mass market, backbone node BEN	0.0844
Mass market, backbone node BPE	0.0562
Mass market, backbone node HAY	0.0114
Mass market, backbone node HLY	0.0136
Mass market, backbone node ISL	0.0399
Mass market, backbone node KIK	0.0323
Mass market, backbone node MDN	0.0586
Mass market, backbone node OTA	0.0113
Mass market, backbone node RDF	0.0348
Mass market, backbone node ROX	0.2702
Mass market, backbone node SFD	0.0139
Mass market, backbone node TRK	0.0091
Mass market, backbone node TWI	0.0112
Mass market, backbone node WKM	0.0107
Large industrials, backbone node BPE	0.0091
Large industrials, backbone node HLY	0.0005
Large industrials, backbone node ISL	0.0021
Large industrials, backbone node OTA	0.0022
Large industrials, backbone node RDF	0.0010
Large industrials, backbone node SFD	0.0161
Large industrials, backbone node TRK	0.0032
Large industrials, backbone node TWI	0.0006

Source: Electricity Authority

Key sensitivities analysed in modelling of more efficient grid use

2.262 We have undertaken a sensitivity analysis on key input assumptions that can significantly affect the results of our modelling of benefits from more efficient grid use.

2.263 The results of the grid use model are sensitive to the timing and size of changes in underlying costs of, and demand for, electricity. To account for this, the CBA considers the range of results produced by the grid use model for different policy options, through variations to the model's input assumptions about future:

- **short-run costs** of operating electricity generation
- **long-run costs** of investing in electricity generation
- **underlying electricity demand growth** driven by growth in population and incomes
- **battery investment costs**, for utility-scale batteries.

2.264 We weight the results of different simulations as it is important to avoid treating highly unlikely results the same as more likely results. As such, our approach involves:

- specifying ranges for the model's key input assumptions
- simulating model results for each of the following policy scenarios:
  - the baseline
  - the proposal
  - the 'future only' option
  - the 'HVDC only' option
  - the alternative option
- weighting the model results by the relative likelihood of combinations of input assumptions.

The approach is similar to, but simpler than, Monte Carlo analysis

2.265 This approach has similarities to Monte Carlo analysis, a widely used modelling method where a model is simulated thousands of times, with input assumptions drawn randomly from pre-defined probability distributions. Results obtained from Monte Carlo analysis can be thought of as providing a probability distribution over outcomes.

2.266 Applying Monte Carlo analysis to each of the policy scenarios listed above is impractical, primarily because of the amount of data generated. In particular, a simulation for each policy scenario produces 500 MB of data, and 1,000 simulations of a policy scenario (which would take one week to complete) would produce 500 GB of results.

2.267 Instead, we took the approach of fitting probability distributions to the input assumptions and then assessing the **relative** likelihood of combinations of input assumption values, as if these values have been drawn randomly. Weighting the grid use model's results by the relative likelihood of each of the model's input assumptions provides a simpler means of reflecting a probability distribution over the model's results.

Ranges of input assumptions

2.268 We carried out model simulations using 112 different combinations of input assumptions in addition to the input assumptions for the 'central scenario' of the proposal. These 112 simulations were chosen to capture a reasonable range of possible input assumption values, while also limiting the number of simulations for practical reasons.

2.269 The ranges of input assumption values we have used are as follows:

- electricity generation short-run cost multipliers: 0.800, 0.850, 0.900, 0.925, 0.950, 0.975, 1.025, 1.050, 1.075, 1.100, 1.150, 1.200
- electricity generation long-run cost multipliers: 0.900, 0.925, 0.950, 0.975, 1.025, 1.050, 1.075, 1.100
- utility-scale battery cost multipliers: 0.90, 1.10, 1.20, 1.30[50]
- electricity demand growth shifters: -0.01, -0.005, 0.005, 0.01.

2.270 The above values provide for 28 simulations with individual changes to input assumptions. In addition, there are 84 simulations that take combinations of alternative input assumptions, for a total of 112 simulations with varying input assumptions in addition to the initial central scenario.[51]

2.271 Each change to input assumptions is implemented as a single change applied over all future periods. That is, a short-run cost multiplier of 1.100 raises generators' operating costs and wholesale market offers in all future years by 10%. So, if the proposal's 'central' scenario assumes an emissions price of $\$50/tCO_2e$ in 2030, then the multiplier increases emissions prices to $\$55/tCO_2e$ for generators that face these prices.

2.272 The demand growth shifter is applied as an addition to growth rates for national per capita income and number of ICPs (a proxy for population). In the proposal's 'central' scenario these growth rates are both 1% per annum, with a combined growth in underlying demand growth (excluding price effects) of 2% per year. A value of 0.01 for the demand growth shifter raises growth in both per capita incomes and ICPs by 1% per year—equating to underlying demand growth of 4% per annum. A value of -0.01 implies no underlying demand growth.

2.273 Though the demand growth assumption is implemented as a shock to incomes and ICPs, it could equally be thought of as a shock to the intensity of electricity use or to the breadth of electricity use, holding costs and prices constant.

2.274 An assumption of 4% annual growth in underlying demand drivers leads to a doubling of demand over a 30-year period—other things being equal.[52] This compares to:

- a range for increased demand of 18% to 78% over 33 years in MBIE's 2019 refresh of its 2016 EDGS[53]
- a projected 68% increase in demand (within a range of 31% to 87%) by 2050 in Transpower's 2020 publication *Whakamana i Te Mauri Hiko: Empowering our Energy Future*.[54]

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50 As noted earlier, battery investment costs applied in the CBA's central scenario are in the bottom quartile of published estimates. Hence, sensitivities for utility-scale battery costs seek to cover more of the upper range.

51 The number of combinations chosen is a subset of 1,920 possible unique combinations for the ranges of values. The subset has been chosen to provide a reasonable range of combinations of input assumptions, focusing on less extreme input assumptions.

52 Annual growth in incomes of 2% translates to a 0.22% increase in demand given an estimated income elasticity of 0.11. This value, combined with an assumption of 2% growth in ICPs, yields growth in demand for electricity of 2.22%—assuming nothing else changes, such as prices and costs.

53 https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios

54 https://www.transpower.co.nz/about-us/transmission-tomorrow/whakamana-i-te-mauri-hiko-empowering-our-energy-future

2.275 That said, all else is not equal in the sense that the proposal's 'central' scenario assumes non-trivial increases in electricity supply costs, due to rising gas prices and emissions prices. As a result, applying the high demand input assumptions in the proposal's 'central' scenario would result in an approximate 20% increase in electricity demand over 30 years.

Probabilities for input assumptions

2.276 We specified probability distributions for our input assumptions based on:

- identifying long-term historical data series that reflect our input assumptions
- deflating any price indices by economy-wide inflation (Statistics New Zealand's GDP deflator)
- de-meaning these series
- fitting distributions to de-meaned data based on graphical analysis and comparison of the fit of the data to commonly used probability distributions[55]
- analysing correlations between the series, to determine whether or not the probability distributions should be treated as independent probabilities.

Short-run generation costs

2.277 We modelled variations in short-run generation costs using data on input costs from Statistics New Zealand's Producer Price Index for inputs into the electricity and gas supply industries.

2.278 MBIE data on inflation-adjusted wholesale gas prices was also considered as a source of data on short-run generation costs. We decided not to use this data because:

- it excludes non-fuel short-run generation costs, and
- gas prices exhibit significant structural changes not reflected in broader price indices.

2.279 The probability distribution with the best fit to the data was a log-normal distribution with a log mean of -0.007 and a log standard deviation of 0.117. This distribution has a long right-hand tail, meaning that higher values are more likely than lower values. This is shown in Figure 6. The data in the plot are typical rates of increase after de-trending the data (deducting the average growth rate).

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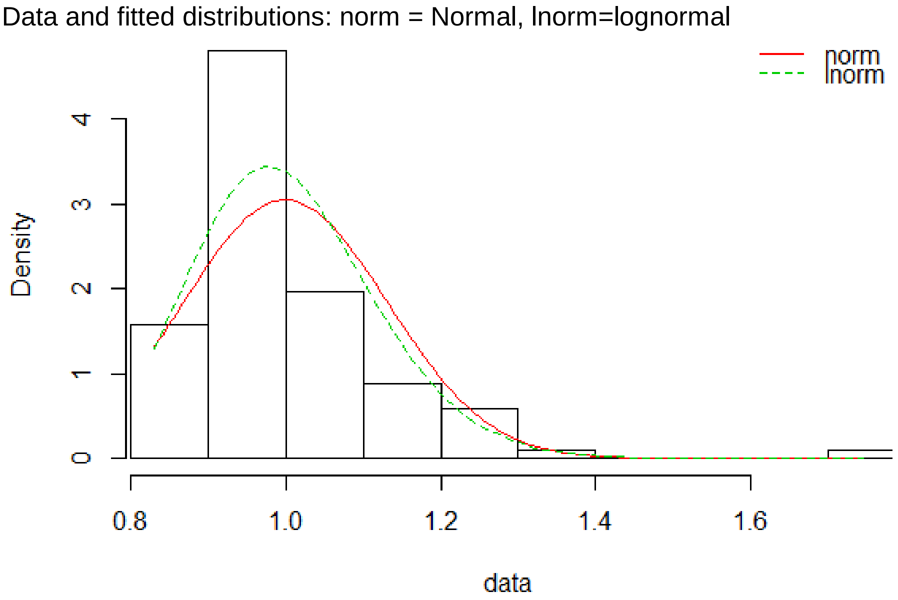
[55] For example: normal, uniform, exponential, logistic, beta, lognormal and gamma. Utility-scale battery costs are an exception, as there is no obvious candidate data series for fitting distributions. Accordingly, battery investment cost assumptions are assumed to be equally likely (uniformly distributed).

Figure 6: Distribution of changes in short-run costs



Long-run generation costs

2.280 We modelled variations in long-run generation costs using data on capital costs from Statistics New Zealand's Capital Goods Price Index (CGPI) for all capital goods.

2.281 Other capital goods price indices that we considered were:

- civil construction
- plant, machinery and equipment
- engines and turbines
- electric motors, transformers and generators
- electricity distribution and control apparatus
- an average of civil construction and plant, machinery and equipment indices.

2.282 There are strengths and weakness in using any of these series to characterise long-run generation investment costs.

2.283 No single index can capture all relevant investment costs for electricity generation. This is because some generation investment projects are dominated by civil construction costs (e.g., a large-scale hydro generation project), while other projects are dominated by plant machinery and equipment costs (e.g., an investment in a thermal peaking plant).

2.284 Furthermore, costs for plant, machinery and equipment have been declining steadily over the past 15 years (-20% between 2004 and 2019) relative to general inflation in the economy, while civil construction costs have been rising (+15% between 2004 and 2019). As such, a decision to use either one of these indices over the other would significantly affect the assessed rate of increase in generation investment costs.

2.285 We chose the CGPI for all capital goods, over any particular sub-group of costs, as it:

- captures other capital costs (such as buildings) of some relevance to generation investment

- is closely correlated with an average of civil construction and plant, machinery and equipment costs—so choosing the most general measure of costs does not shift the assessment of growth in costs in any material way.

2.286 The distribution with the best fit for variations in the CGPI cost series was a normal distribution with a mean of 1 and a standard deviation of 0.026.

Underlying demand growth

2.287 We have used growth in Gross National Income (GNI) to depict variations in underlying demand growth. This is an obvious candidate because it reflects the combination of population growth and per capita income growth.

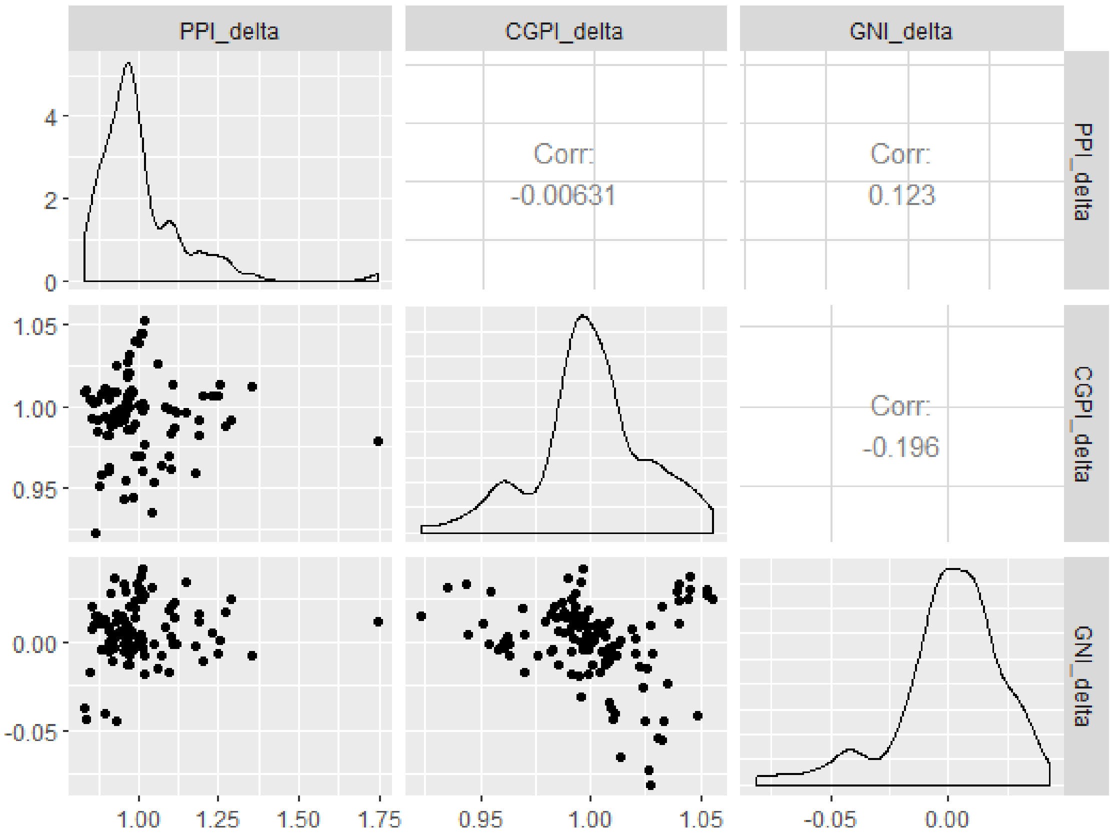
2.288 The distribution with the best fit for this data is a normal distribution, with a mean of 0 and a standard deviation of 0.011.

Distributions assumed to be independent

2.289 We have assumed the probability distributions chosen to depict variations in input assumptions are independent of one another.

2.290 This assumption is based on the observation that variations in the underlying data series (i.e., deviations from average growth rates) are not strongly correlated. This can be seen in Figure 7 below, which shows that the largest correlation is only -0.196—between deviations in GNI ('GNI_delta') and deviations in the CGPI.

Figure 7: Correlations between data used for input assumption probabilities



Using probability distributions to weight model results

2.291 The grid use model's results have been weighted using the distributions described above, by assessing the **relative** likelihood of a combination of the 28 input assumption values above (plus the input assumption values used in the proposal's 'central' scenario) as if these values have been drawn randomly.[56]

2.292 For example, in our set of simulated results the input assumption value for short-run generation costs under the proposal's 'central' scenario (a multiplier of 1) has a 0.11 probability of occurring relative to the other values in our list. Likewise, the input assumption values for long-run generation costs, utility-scale battery costs and demand growth under the proposal's 'central' scenario have 0.39, 0.20 and 0.24 probabilities of occurring relative to the other values in our list. Thus, using this approach, the notional probability of the input assumption values for the proposal's 'central' scenario occurring is 0.0021 (0.11 x 0.39 x 0.20 x 0.24). This notional probability provides a weight to be placed on the grid use model's result for the proposal's 'central' scenario (the central simulation (np_s)).

2.293 The actual weight applied to the result of a simulation of the grid use model (w_s), when summarising the model's results, is the simulation's notional probability divided by the sum of the notional probabilities of all other simulations of the grid use model, i.e., $w_s = np_s / \sum_s np_s$.

[56] The input assumption values for the proposal's 'central' scenario are that the short-run and long-run cost and battery cost multipliers are equal to 1 and the deviation in underlying demand growth is equal to 0.

3 Benefits from more efficient investment by generators and large consumers

We have used a top-down assessment

3.1 Our estimate of the potential net benefit from the proposal leading to more efficient investment by generators and (large) consumers is based on a top-down assessment.

3.2 We define more efficient load and generation investment as private consumption decisions, over time, that minimise social costs of transmission investment.

3.3 Our focus is on consumption decisions because, from the perspective of a top-down assessment of costs and benefits, growth in consumption is not readily distinguishable from investment decisions by consumers and generators. Furthermore, we measure the costs and benefits of load and generation investment through effects on electricity consumption/demand.

3.4 This top-down assessment looks at a different aspect of consumer and generator investment decisions than does the assessment of more efficient grid use. Here, we are assessing the extent of any net benefit from a generator or consumer in a region being incentivised under the proposal to not make an investment/consumption decision that will necessitate transmission investment:

(a) in that region, or

(b) between that region and other regions.

The basic framework is an externality framework

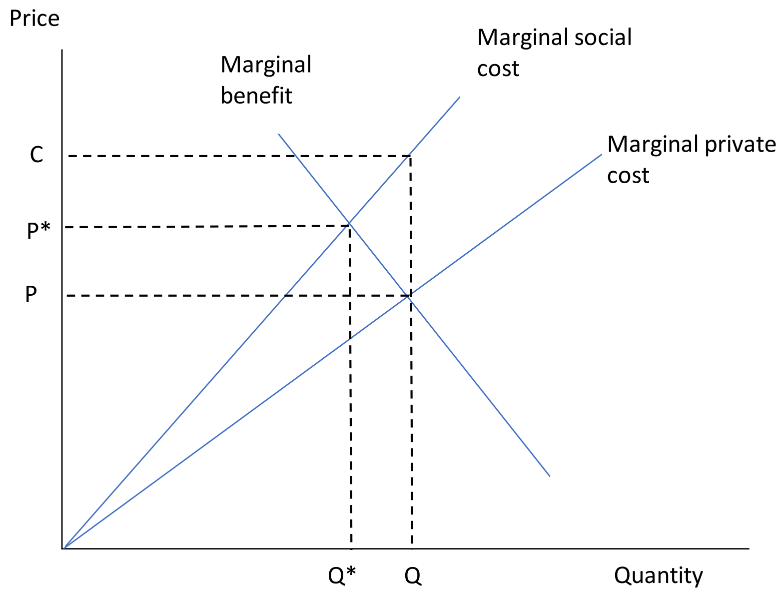
3.5 The basic framework is an externality framework: when marginal private costs of demand are lower than marginal social costs, electricity demand will exceed the level that is economically efficient for society. This is depicted in Figure 8, where the efficient price and quantity combination is P*,Q* but the market equilibrium is P,Q because consumers do not face marginal social costs of consumption. Marginal social costs incurred are C x Q.

3.6 Figure 8 depicts demand in a region that imports electricity under a regime where the costs of transmission are recovered from consumers in the importing region and consumers outside the importing region (the exporting region in a simple two region model).

3.7 Figure 9 provides an alternative representation of Figure 8, reflecting the dynamics of transmission investment. Levels of consumer demand are a function of nodal energy prices (P_e) and expectations of transmission charges under the status quo ($E[P_t]$) and with a benefit-based charge ($E[P^*_t]$). The diagram is a static snapshot of dynamic decisions. The dashed vertical lines reflect capacity limits on peak MW of demand due to fixed capacity (MW). Demand growth is lower when consumers in an importing region face a benefit-based charge. As a result, transmission capacity expansion (Q-Q*) is deferred. At the same time, growth in demand is expected to be higher in the exporting region because expectations of transmission charges will be lower.

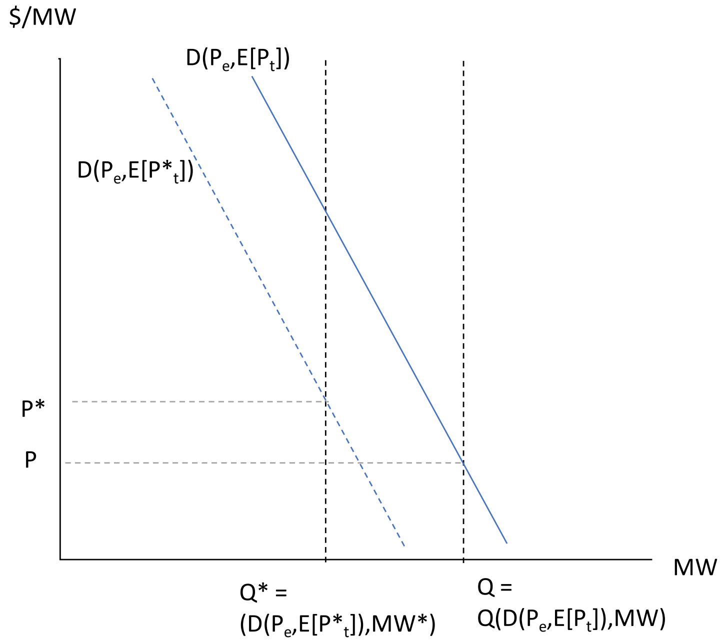
3.8 These fundamentals apply to both generation and demand decisions, however formulae for analysing demand differ from those for generation.

Figure 8: Excess demand with prices that do not reflect marginal social costs



Source: Electricity Authority

Figure 9: Efficient investment deferral, in an importing region



Source: Electricity Authority

Assessing transmission investment efficiency benefits arising from more efficient investment and consumption decisions by consumers

3.9 Our assessment framework for analysing benefits of more efficient demand investment (and consumption) decisions consists of determining:

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

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

(c) incremental costs of transmission investment.

3.10 To implement this framework, we further assume that long-run (efficient) transmission investment is, in real and current value terms, a constant function of peak demand growth. This implies that, over a multi-decade time period (from time 0 to time T), the current value of total transmission costs (TC) is simply a reflection of the change in aggregate peak demand (Q) and long-run unit/incremental costs (c) of transmission investment:

$$TC = (Q_T - Q_0).c \qquad \text{Equation 26}$$

3.11 This view of transmission costs is consistent with efficient, cost minimising, transmission investment decisions assuming constant productivity.

3.12 In addition, we make an assumption about the share of incremental transmission investment costs that are due to demand growth rather than to growth in generation independent of demand. Here, for expositional purposes, we refer to this as the share of transmission investment undertaken for reasons of reliability (s_r).

3.13 The current value of the benefit (B_c) of transmission investment deferral can then be measured as the proportional reduction in aggregate peak demand multiplied by expected aggregate peak demand and the expected incremental cost of reliability transmission investments:

$$B_c = -\frac{\Delta Q_T}{Q_T}.Q_T.c.s_r \qquad \text{Equation 27}$$

3.14 The welfare consequences of efficient transmission investment deferral will depend on the current status of transmission capacity. That is, whether investment deferral is likely to occur soon, or in the distant future.

3.15 Timing of transmission investment deferral can be measured, as a first approximation, by:

(a) forecast transmission E&D expenditure (c_t), which can be expected to be lower when transmission capacity is less constrained and higher when transmission capacity is more constrained, and

(b) forecast trend growth in peak demand.

3.16 When combined with discounting to account for social rate of time preference (δ) the formula for the present-valued benefits of transmission investment deferral is then:

$$B = \frac{\sum_t -\frac{\Delta Q_T}{Q_T}Q_t.c_t.s_r.\delta^t}{T} \qquad \text{Equation 28}$$

3.17 The percentage reduction in demand that is expected to occur with benefit-based charges can be calibrated using examples (a case study) and/or assumed long-run price elasticities of demand—elasticities that reflect demand investment decisions as well as short-run demand consumption decisions.[57]

3.18 If long-run elasticities were to be used, case studies would still be needed to determine potential changes in expected transmission charges. Case studies could be drawn from project-specific transmission investment analyses used in the modelling of more efficient grid use. For example, transmission prices and demand associated with the WUNI project could be compared to transmission prices and demand when benefit-based charges exist but when unapproved major capex, including the WUNI project, are not included in the model.[58]

3.19 If a long-run elasticity (η) is used and prices are calculated directly, by scenario, assumptions would need to be made about the typical amounts of demand affected by benefit-based charges. This is for the purpose of determining expected transmission price changes associated with benefit-based charges.

3.20 For example:

$$B = \frac{\left(-\sum_t \eta \frac{\Delta P}{P} Q_t . c_t . s_r . \delta^t\right)}{\mathrm{T}} \qquad \text{Equation 29}$$

$$\frac{\Delta P}{P} = \left(\frac{\frac{I(1+w+\rho+o)}{Y} . \frac{1}{Q_A}}{\frac{I(1+w+\rho+o)}{Y} . \frac{1}{Q_t}} - 1\right) . s_T = \left(\frac{Q_t}{Q_A} - 1\right) . s_T \qquad \text{Equation 30}$$

3.21 In this, a typical transmission investment (I in Equation 30) creates a benefit-based charge proportional to the rate of return on (w), and the rate of return of (i.e., depreciation of) (ρ), the investment, plus an operating expenditure (opex) allowance (o assumed here to be proportionate to the investment), in equal increments over the number of years (Y) that the capital costs are being recovered.

3.22 The annual cost is spread over the estimated typical demand of beneficiaries (Q_A), as opposed to being spread over total demand (Q_t). The reference price (denominator) for measuring the percentage change in demand is assumed to have the same energy (nodal) prices in both cases, so that we are isolating the effect on demand of the move to a benefit-based charge for recovering transmission investment costs. However, the demand elasticity is assumed here to be an elasticity with respect to wholesale electricity prices, inclusive of transmission interconnection charges. So, the price change needs to be adjusted to reflect the share of wholesale electricity prices that relates to recovery of the costs of transmission investment (s_T).

3.23 Note that the effect of the benefit-based charge on demand is evaluated at its maximum value in terms of deferral, occurring immediately before the transmission investment occurs, when expected benefit-based charges are largest.

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57 Consideration should also be given to adjusting long-run elasticities using actual transmission cost data, to account for the possibility that demand response based on expectations about transmission prices may differ from demand response based on actual/observed transmission prices. This difference in demand response would be the result of uncertainty associated with future transmission prices compared with actual/observed transmission prices.

58 Comparing effects under two scenarios that both exclude peak (RCPD) charges is necessary for separating allocatively efficient increases in demand, under the proposal, from effects on the efficiency of transmission investment over time.

3.24 To calculate the estimated transmission investment benefits due to more efficient demand investment (and consumption) decisions by consumers, we have used:

(a) long-run price elasticities of demand, and

(b) assumptions about the scope and incidence of benefit-based charges over the period of the CBA (i.e., 2019 – 2049), rather than modelled results.

3.25 This approach is more transparent than calculating estimated transmission investment efficiency benefits, using changes in demand taken from the model of demand used in estimating the net benefit of more efficient grid use. This sort of transparency is important for top-down analyses, which rely heavily on assumptions, because it enables the effects of assumptions to be interrogated easily.

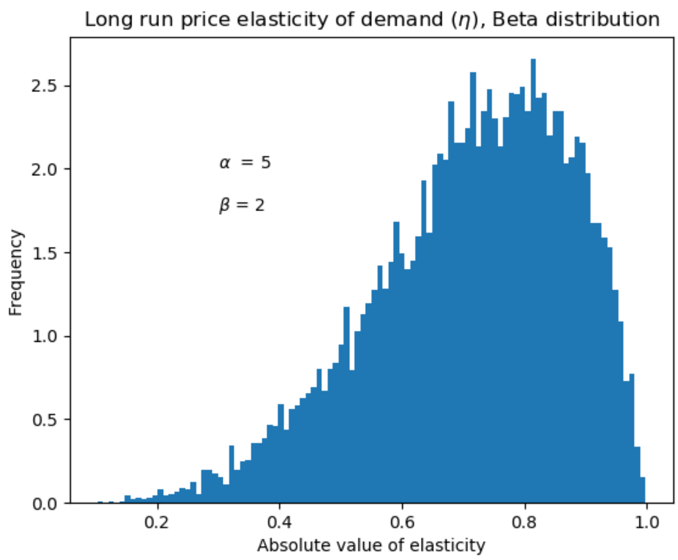
Parameters used

3.26 Table 21 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to more efficient investment and consumption decisions by (large) consumers.

3.27 We have applied a Monte Carlo analysis to some parameter values, to generate a distribution for the values. Figure 10 gives an example of the distribution generated for the long-run elasticity of demand parameter value.

3.28 The distributions chosen for parameter values reflect our knowledge of the parameter values. Where we have strong prior knowledge of a parameter value, uncertainty is expressed with a normal distribution. Where we have weaker prior knowledge about the correct central value for a parameter, we use the parameters of a beta distribution to specify reasonably large variances. We also use the beta distribution to specify skewed distributions. Where we have very weak prior knowledge about the central value of a parameter, we use a uniform distribution. Where reasonable, we have erred on the side of caution, by selecting parameter values that understate benefits and overstate costs.

Figure 10: Long-run price elasticity of demand



Source: Electricity Authority

Table 21: Parameters for transmission investment efficiency benefits due to more efficient investment and consumption decisions by consumers

Parameter	Value	Source / Comment
Long-run unit/incremental costs of transmission investment	Average of $1.16m (real, $2018)	Based on average expenditure of $81.3m (real, $2018), and average demand growth (incremental MW) of 0.9% p.a. Refer: a. RCP 3 proposal, base capex E&D and major capex projects under development b. Transpower forecast peak demand (P90) used to inform investment planning (plus an assumed diversity factor of 1.28). Values beyond Transpower's forecast horizon have been forecast using: a. average expenditure per additional MW 2022-2034 b. average demand growth rate from the TPM CBA grid use model. Actual expenditure is expected to deviate from project-specific marginal costs because investment tends to proceed for additional reasons (such as reliability investments) beyond simply matching grid capacity to demand growth on a one-for-one basis. The use of projected expenditure as a cost basis helps to take account of variable timing in transmission investment in the near term.
Average transmission revenue per MWh	$19	Revenue per MWh is from Transpower's RCP 3 forecast of HVAC revenue divided by Transpower's RCP 3 forecast of demand, extrapolated with forecast demand from the modelling of efficient grid use.
Share of transmission investment undertaken for reasons of reliability (being the share of incremental transmission investment costs that are due to demand growth rather than to growth in generation independent of demand)	50% Monte Carlo analysis: Beta (alpha=2, beta=2)	Percentage from modelling of efficient use of the grid.

Parameter	Value	Source / Comment
Long-run price elasticities of demand, and transmission costs (variable i.e., E&D) as shares of wholesale electricity prices including interconnection charges	-0.74 elasticity Monte Carlo analysis: Beta (alpha=5, beta=2) 0.84% transmission costs share of prices Monte Carlo analysis: Normal (mu=0.0084, sigma=0.0005)	Elasticity from aggregate demand elasticity for consumers connected to distribution networks. Transmission share of costs based on: a. Transpower forecast E&D and forecast revenue b. MBIE EDGS 'Mixed renewables' forecast demand and forecast wholesale energy prices c. Average transmission revenue per MWh.
Forecast trend growth in peak demand with benefit-based charge and without a coincident peak demand charge	2,051 MW increase in grid peak demand for 2019-2049 (0.84% p.a. compound annual growth rate)	From modelling of efficient use of the grid.
Required rate of return on transmission investments	6% (real)	Average (to nearest percent) of Transpower's rate of return over the period 2016-2030 inclusive. Taken from Transpower's pricing disclosures and Transpower's RCP 3 revenue model.
Depreciation on transmission investments	5%	Average (to nearest percent) of Transpower's observed implied depreciation, as publicly reported in Transpower's RAB (historically). Taken from Transpower's pricing disclosures and Transpower's RCP 3 revenue model, across all the RAB.
Opex allowance on transmission investments	6%	Average (to nearest percent) of Transpower's observed opex as publicly reported over the period 2016-2030 inclusive. Taken from Transpower's pricing disclosures and Transpower's RCP 3 revenue model.
Years over which transmission investment capital costs are recovered	38 years	38 years provided by Transpower. The majority of capital costs is recovered over the first approximately 16 years of this period, because straight line depreciation is in nominal terms.

Parameter	Value	Source / Comment
Quantity of demand over which the benefit-based charge for a demand-driven transmission investment is expected to be recovered (on average)	2,464 MW Monte Carlo analysis, modelled as share of peak demand, with the share distributed: Beta (alpha=2, beta=4)	Refer Transmission Planning Report 2018 and Transpower's RCP 3 proposal. Taking weighted average of the following two arithmetic averages: a) The arithmetic average of the 2033 peak grid demand in regions expected to be the predominant beneficiaries of demand-driven E&D capex[59] by Transpower. 2033 demand used because 2033 is the mid-point year for the analysis period of 2019-2049. b) The arithmetic average demand of the main expected beneficiaries of E&D base capex over RCP 2 and RCP 3 (i.e., 2015-2025). This is used as a proxy for the arithmetic average demand of the main expected beneficiaries of E&D base capex over the analysis period.

Source: Electricity Authority

Assessing transmission investment efficiency benefits arising from more efficient investment by generators

3.29 Calculation of benefits from more efficient generation investment can be calculated using a similar formula to the one used for demand, but with:

(a) demand replaced by generation investment (MW)

(b) specific identification of areas where increases in generation are likely to create a need for investment in injection and export transmission capacity (export of generation, from a generator's perspective, as opposed to export of energy to load from the grid)—denoted with a subscript x (MW_x)

(c) reliability shares of spending replaced by, for example, economic shares of investment spending (s_e).

3.30 The formula is:

$$B = \frac{\sum_t -\frac{\Delta MW_{X,T}}{MW_{X,T}} MW_{X,t}.c_t.s_e.\delta^t}{T} \qquad \text{Equation 31}$$

3.31 As for the demand analysis, this equation could be parameterised, in terms of generation investment location decisions, using project-specific transmission investment analyses used in the modelling of more efficient grid use. Alternatively, this analysis could be undertaken using estimates of long-run marginal generation investment costs inclusive of transmission charges—so analysed independently of TPM effects on demand growth and hence demand for generation investment.

3.32 We have used estimates of long-run marginal generation investment costs, because this will be the most transparent method. This is consistent with our approach to assessing

59 I.e., major capex and E&D base capex.

transmission investment efficiency benefits arising from more efficient investment and consumption decisions by consumers.

Parameters used

3.33 Table 22 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to more efficient investment decisions by generators. We have applied a Monte Carlo analysis to some parameter values.

Table 22: Parameters for transmission investment efficiency benefits due to more efficient investment decisions by generators

Parameter	Value	Source / Comment
Forecast generation investment in areas likely to be export constrained (areas of large net generation surplus), without a benefit-based charge and without the distortion of SIMI charges or coincident peak demand charges	Per EDGS, as amended for modelling of efficient use of the grid Monte Carlo analysis: Normal (mu=4500, sigma=500)	Note this is a conservative approach. There may be intra-regional transmission efficiency benefits, which are not captured here.
Expected percentage change in generation investment in areas likely to be export constrained, with a benefit-based charge	0.5% Monte Carlo analysis: Uniform (-0.03, 0)	From modelling of efficient use of the grid. The average difference in generation investment in export constrained regions under the central scenario in the modelling of the proposal’s impact on efficient use of the grid is 0.5% lower than under the alternative proposal. The alternative proposal is used here instead of the baseline in order to avoid comparing generation investment under an RCPD regime, which has a totally different effect on total demand. A uniform distribution over values between 0 and -3% is adopted, reflecting that we do not have strong priors as to the ‘right’ value.

Source: Electricity Authority

Benefits from greater scrutiny of proposed grid investments

3.34 An anticipated benefit of the proposal is a reduction in transmission investment costs, from beneficiaries of transmission investments having a greater incentive:

(a) to more closely scrutinise proposed transmission investments and provide information that enables lower cost (or deferred) transmission investments or transmission investment alternatives, or

(b) to not propose inefficient transmission investments.

3.35 We have modelled (a) as a productivity gain in the long-run cost of transmission investment (the c_t term discussed above). In relation to (b), we have modelled the undergrounding of transmission lines in Auckland, as a case study.

Parameters used

3.36 Table 23 contains the parameter values we have used in our top-down assessment of transmission investment efficiency benefits due to greater scrutiny of proposed grid investments by beneficiaries. The productivity factor improvement values are a little lower than in the 2019 CBA, reflecting our desire to ensure the CBA is conservative in its estimates of the proposal's benefits.

Table 23: Parameters for transmission investment efficiency benefits due to greater scrutiny of proposed grid investments by beneficiaries

Parameter	Value	Source / Comment
Greater stakeholder scrutiny and input into transmission investments	3% productivity factor improvement over Transpower's major capex reviewed by the Commerce Commission Sensitivities: 1% and 5%.	The Authority considers 3% to be reasonable. In support of this view are: • the 4.4% reduction in Transpower's E&D base capex for RCP 2 that came from the Commerce Commission's scrutiny of the projects in Transpower's submission on the draft RCP 2 determination • the Commerce Commission's 1.25%, 2.5% and 5% downward adjustments on annual Transpower expenditure not regulated by the Electricity Commission in the 5–10 years preceding RCP 2.[60] We expect that greater stakeholder engagement and information provision in major capex investment decisions would deliver a similar efficiency benefit, over and above any efficiency benefit from the Commerce Commission's review of a major capex proposal.
Greater stakeholder scrutiny and input into transmission investments	3% productivity factor improvement over Transpower's E&D base capex not reviewed by the Commerce Commission when approving Transpower's RCP proposal. Assume 30% of E&D base capex is not reviewed by the Commerce Commission. Sensitivities:	The Authority considers 3% to be reasonable. In support of this view are: • the 4.4% reduction in Transpower's E&D base capex for RCP 2 that came from the Commerce Commission's scrutiny of the projects in Transpower's submission on the draft RCP 2 determination • the Commerce Commission's 1.25%, 2.5% and 5% downward adjustments on annual Transpower expenditure not regulated by the Electricity Commission in the 5–10 years preceding RCP 2. Based on RCP 2 E&D base capex.

60 The Electricity Commission regulated Transpower's major E&D capex, while the Commerce Commission regulated Transpower's R&R expenditure, E&D expenditure, and operational IT-related expenditure.

Parameter	Value	Source / Comment
	1% and 5%.	
Greater stakeholder scrutiny and input into transmission investments	1.5% productivity factor improvement over all of Transpower's E&D base capex that was reviewed by the Commerce Commission when approving Transpower's RCP proposal. Assume 70% of E&D base capex is reviewed by the Commerce Commission. Sensitivities: 0.5% and 2.5%.	Mid-point between lower bound productivity factor improvement (0%) and estimated productivity factor improvement from greater stakeholder scrutiny of E&D base capex not reviewed by the Commerce Commission. Based on RCP 2 E&D base capex.
Greater stakeholder scrutiny and input into transmission investments	1.5% productivity factor improvement over 15% of Transpower's R&R base capex. Sensitivities: 0.5% and 2.5%.	We consider it reasonable to expect stakeholders would be more likely to promote efficiency gains for R&R base capex that could be covered by deeper connection charges (e.g., interconnection transformer capacity, AC substation busbar refurbishments and security upgrades). We estimate approximately 15% of R&R base capex falls in this category. This estimate uses as a proxy for such assets 50% of base capex on AC substations, ACS buildings & grounds, and Secondary assets. Refer to base capex over RCP 1–5 per Transpower's RCP 3 proposal. Consistent with E&D base capex, a 1.5% productivity factor improvement is used over R&R base capex reviewed by the Commerce Commission. We assume no R&R base capex has a 3% productivity factor improvement applied. During a regulatory control period, it is very rare for a new transmission project to be added to the list of projects for which R&R base capex has been approved by the Commerce Commission. This is because R&R base capex relates to the upkeep of existing transmission assets based on known condition assessment and asset life cycle strategies. This contrasts with E&D base capex, which is more uncertain when approved by the Commerce Commission, because it is typically demand-driven, and demand forecasts are inherently uncertain over the medium to longer term.

Parameter	Value	Source / Comment
Greater stakeholder scrutiny and input into transmission investments	0.5% productivity factor improvement over R&R base capex that is not: • recovered via connection charges • the 15% of R&R base capex that could be covered by deeper connection charges. Sensitivities: 0% and 1.5%.	One third of estimated productivity factor improvement from greater stakeholder scrutiny of R&R base capex reviewed by the Commerce Commission. We have applied a 0.5% productivity factor improvement because stakeholders are unlikely to be able to promote efficiency gains to the same extent for R&R base capex that is not recovered via connection charges or which could be covered by deeper connection charges. Examples include tower painting (which accounted for \$238m of R&R base capex in the RCP 3 proposal), transmission tower foundation refurbishments, and improving the seismic performance of HVDC buildings. We estimate approximately 15% of R&R base capex is recovered via connection charges. This estimate relies on connection charges recovering 50% of base capex on AC substations, ACS buildings & grounds, and Secondary assets. Refer to base capex over RCP 1–5 per Transpower's RCP 3 proposal.
Less likelihood of inefficient investments being proposed Case study: Undergrounding of all urban transmission lines in Auckland	Change in probability of undergrounding all urban transmission lines in Auckland proceeding in absence of a benefit-based charge: 25% Sensitivities: 0% change in probability 50% change in probability	NB: We are only concerned about the probability of economically inefficient investment in the undergrounding of all of Auckland's urban transmission lines occurring in the absence of the proposal. We assume that if the undergrounding of all of Auckland's urban transmission lines occurs with the proposal in effect, then this undergrounding is economically efficient. So, if we assume there is a 5% probability of undergrounding occurring with the proposal in effect, and a 30% probability in the absence of the proposal, then the probability of economically inefficient investment in undergrounding is 25%.
Less likelihood of inefficient investments being proposed Case study: Undergrounding of all urban transmission lines in Auckland	Should inefficient undergrounding proceed, assume this occurs over the period 2035-2045.	Refer to "Powering Auckland's Future"—Transpower's strategy to support Auckland's growth and blueprint for further work. Transpower's blueprint for further work in Auckland includes undergrounding new 220 kV lines between 2030 and 2050 (Brownhill Road to Otahuhu (as part of the NIGU) and Pakuranga to Albany).

Source: Electricity Authority

Benefits from increased policy certainty for investors

3.37 Compared with the baseline, we expect the proposal would be less likely to be subject to successful challenge and change or reversal, whether on grounds of inefficiency or unreasonableness. We consider that this would reduce the cost of investing (i.e., reduce the return needed to trigger an investment) in both demand-side and supply-side assets.

3.38 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.[61]

3.39 Analysing these effects requires:

(a) specifying the impact on uncertainty (size of shock) of a TPM based on the proposed guidelines

(b) specifying marginal effects of uncertainty on investment costs.

3.40 One simplified (reduced form) framework for assessing these effects is to analyse long-run supply and demand in terms of a static equilibrium (possibly the most simplified approach). For example, assume that long-run electricity demand is a linear function of prices (P), incomes (M) and a measure of policy uncertainty (U),[62] and supply is a linear function of prices and policy uncertainty.

$$Q_d = \alpha_d + \beta_d P + \delta_d U_d + \gamma M \qquad \text{Equation 32}$$

$$Q_s = \alpha_s + \beta_s P + \delta_s U_s \qquad \text{Equation 33}$$

3.41 Given an estimate of the incremental effects of policy uncertainty on investment, measured in terms of, for example, peak supply and peak demand, we can estimate effects on quantities supplied. Assuming prices do not change, the benefits of increased policy certainty would be equal to the change in total surplus from the increase in quantities:

$$\Delta TS = \frac{P\delta_s \Delta U_s + (\bar{P} - P)\delta_d \Delta U_d}{2} \qquad \text{Equation 34}$$

Where $\bar{P}$ is the price at which demand is equal to 0.

3.42 Prices may change too, depending on the responsiveness of demand and supply to changes in policy uncertainty.

3.43 With demand equal to supply, the long run equilibrium price level is:

$$P = \frac{\alpha_d - \alpha_s + \delta_s U_s - \delta_d U_d + \gamma M}{(\beta_s - \beta_d)} \qquad \text{Equation 35}$$

3.44 If we assume that sources of policy uncertainty are identical between demand and supply, then the effect of a change in policy uncertainty on prices is zero:

$$\frac{\partial P}{\partial U} = \frac{\delta_s}{\beta} + \frac{\delta_d}{\beta} = \frac{\delta_s - \delta_d}{\beta} = 0 \qquad \text{Equation 36}$$

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61 A considerable amount of research has been carried out into real options effects over the past quarter century. This research has mostly been theoretical, but it has also been validated in empirical case studies of investment (e.g., Kellogg, R. (2014). The Effect of Uncertainty on Investment: Evidence from Texas Oil Drilling. *The American Economic Review*, 104(6), 1698–1734.)

62 Note that no distinction is made between risk (knowable) and uncertainty (unknowable). Consideration of this difference is, however, relevant when it comes to parameter estimates.

3.45 The parameters that need calibrating are:

(a) the long-run response of supply to prices (β_s)

(b) the long-run response of demand to prices (β_d)

(c) the responsiveness of demand and supply to changes in policy uncertainty (δ_d and δ_s)

(d) a measure of the effects of a change in policy uncertainty on investment

(e) a measure of the expected unit change in policy uncertainty.

3.46 A total surplus measure of benefits from increased policy certainty is:

$$\Delta TS = \frac{1}{2}((P'Q' - PQ) + ((\bar{P} - P')Q' - (\bar{P} - P)Q)) \quad \text{Equation 37}$$

Where new prices and quantities, with increased policy certainty, are P' and Q' and $\bar{P}$ is the notional price at which demand is equal to zero, calculated based on:

$$\bar{P} = \frac{Q(P=0)}{-\beta_d} \quad \text{Equation 38}$$

$$Q(P = 0) = Q^* - \beta_d . P^* \quad \text{Equation 39}$$

3.47 We have drawn on several international sources/experiences when considering possible effects of policy uncertainty on investment.

3.48 Research from the United States quantifies, empirically, links between policy uncertainty, reversals and reduced investment:

(a) Fabrizio (2013) found that in the United States policies aimed at increasing investment in renewable electricity generation (Renewable Portfolio Standards) had no effect in states that had reversed earlier measures to restructure the electricity industry.[63] States with more stable policy environments experienced an increase in investment in renewable electricity generation.

(b) Ford (2018) found that a reversal of regulatory settings in the telecommunications industry in the United States in the 2010s—raising the prospect of increased regulatory controls—caused a 20% decline in investment in internet services.[64]

(c) Gulen and Ion (2016) use an index of policy uncertainty throughout the economy to estimate effects of uncertainty on economy-wide investment and find that “a doubling in the level of policy uncertainty is associated with an average decrease in quarterly investment rates of approximately 8.7% relative to the average investment rate in the sample” (p 525).[65] They also find that the dampening effect of uncertainty on investment is highest in industries where investments are typically irreversible.

63 Fabrizio, K. R. (2013). The Effect of Regulatory Uncertainty on Investment: Evidence from Renewable Energy Generation. The Journal of Law, Economics, and Organization, 29(4), 765–798.

64 Ford, G. S. (2018). Regulation and investment in the U.S. telecommunications industry. Applied Economics, 50(56), 6073–6084.

65 Gulen, H., & Ion, M. (2016). Policy Uncertainty and Corporate Investment. The Review of Financial Studies, 29(3), 523–564. https://doi.org/10.1093/rfs/hhv050

3.49 These findings are supported locally by researchers at the Reserve Bank of New Zealand who found a negative relationship between uncertainty and macroeconomic measures of economic activity including investment.[66]

3.50 From the United Kingdom, Buckland and Fraser (2001) found that market risk values ('betas') for electricity distributors showed significant variation in response to policy uncertainty.[67] A policy announcement that induced uncertainty was shown to increase systematic asset risks (beta) by 40% to 60% for five months after the announcement.

3.51 Other research into the effects of policy uncertainty tends to be more theoretical,[68] or related to developments in developing countries.[69] Historically, developing countries have faced fundamentally different (greater) issues in respect to policy uncertainty, due to weaker institutions.

3.52 Given that empirical research focusses on investment effects of uncertainty, estimates of the responsiveness of demand and supply to changes in policy uncertainty (δ_d and δ_s) need to translate investment effects into effects on demand and supply. To calibrate the effect of a change in policy uncertainty on investment and then on output, we make use of typical (average) relationships between the capital stock and output (dY/dK) and typical rates of investment as a share of the capital stock (I/K).

$$dI = dU \frac{dI}{dU}\, Y \frac{dY}{dK} \frac{I}{K} \qquad \text{Equation 40}$$

3.53 We then consider the average effects on output of a present-valued change in investment (dI_{PV}):

$$\delta = \frac{dQ}{dU} = \left(dI_{PV}\, \frac{dY}{dI}\right) . \frac{1}{P} \qquad \text{Equation 41}$$

3.54 If we assume linear demands, values for supply and demand response parameters can be calibrated using demand elasticities (η_d) or supply elasticities and assumptions about average market prices (P^*) and quantities (Q^*)—for example:

$$\beta_d = \frac{\eta_d}{\frac{P^*}{Q^*}} \qquad \text{Equation 42}$$

Parameters used

3.55 Table 24 contains the parameter values we used in our top-down assessment of transmission investment efficiency benefits due to increased certainty for investors. We have applied a Monte Carlo analysis to some parameter values.

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

67 Buckland, R., & Fraser, P. (2001). Political and Regulatory Risk: Beta Sensitivity in U.K. Electricity Distribution. *Journal of Regulatory Economics*, 19(1), 21.

68 E.g., Pástor, Ľ., & Veronesi, P. (2013). Political uncertainty and risk premia. Journal of Financial Economics, 110(3), 520–545. https://doi.org/10.1016/j.jfineco.2013.08.007. Although the authors do test their theoretical model this testing is rather limited.

69 Rodrik, D. (1991). Policy uncertainty and private investment in developing countries. *Journal of Development Economics*, 36(2), 229–242. https://doi.org/10.1016/0304-3878(91)90034-S

Table 24: Parameters for transmission investment efficiency benefits due to reduced uncertainty for investors

Parameter	Value	Source / Comment
Forecast trend growth in electricity prices with current level of policy uncertainty	EDGS 'Mixed renewables', 0.9% p.a. (2018-2050) implying long run average price of $109/MWh (in 2050) Monte Carlo analysis conducted by varying price growth rates: Normal (mu=0.00906, sigma=0.005)	Select the value that minimises benefits from the proposal (to err on the side of not overstating proposal benefits) selecting from: a) MBIE EDGS long-run price indicator ('Mixed renewables') b) modelling of efficient use of the grid c) the ICCC's recent assessment of an LRMC for generation of $113 / MWh, under a 100% renewables scenario.
Long-run response of demand to prices	-0.74 elasticity Monte Carlo analysis: Beta (alpha=5, beta=2)	As above, long-run price elasticity of demand estimated during preparation of CBA demand model. This elasticity is appropriate as long as the estimated price changes being evaluated are not large (and are within the range, say one standard deviation, of the sorts of price changes observed in the data used to estimate the elasticities—otherwise they could imply infeasibly large demand changes).
Long-run response of supply to prices	1 Monte Carlo analysis: Normal (mu=1, sigma=0.25)	Assume that supply is perfectly elastic over the long run.
Factor representing responsiveness of investment to change in policy uncertainty	A doubling of policy uncertainty reduces investment by 8.7% (elasticity of investment response to change in uncertainty = 0.087/2) Monte Carlo analysis: Normal (mu=0.0435, sigma=0.01)	Refer to Gulen, H., & Ion, M. (2016). Policy Uncertainty and Corporate Investment. The Review of Financial Studies, 29(3), 523–564.
Factor representing expected change in uncertainty	Uncertainty assumed to be proportional to the frequency of political events. Assume 10 yearly political uncertainty events become 11 yearly political uncertainty events. Monte Carlo analysis for percentage change in frequency of events: Normal (mu=0.09, sigma=0.03)	For motivation refer to Buckland, R., & Fraser, P. (2001). Political and Regulatory Risk: Beta Sensitivity in U.K. Electricity Distribution*. Journal of Regulatory Economics, 19(1), 21.

Parameter	Value	Source / Comment
Average forecast demand (MWh)	47,015,448 Monte Carlo analysis conducted by varying demand growth rates: Normal (mu=0.009, sigma=0.005)	Geometric average of forecast MWh demand in MBIE EDGS 'Mixed renewables' scenario 2019-2049
Effect of investment on demand and supply	0.05475 Monte Carlo analysis: Normal (mu=0.05, sigma=0.01)	Assess the ultimate effect of an increase in investment on an increase in output. Value-based ratio of investment to capital stock (excluding property) multiplied by the ratio of output to the capital stock—national accounts averages 1987-2017.

Source: Electricity Authority

4 Costs of load or generation not locating in regions with recent investment in transmission capacity

Cost of load not locating in regions with recent investment in transmission capacity

4.1 Once a transmission investment is sunk, a benefit-based charge may continue to deter demand growth, as new demand investment gravitates to areas with lower benefit-based charges. This could lead to displacement of demand investment from the region where the benefit-based charge applies.[70]

4.2 Notably, the displaced demand need not be a consumer moving their demand from a region with a benefit-based charge. Rather, it could be a consumer increasing their demand in a region without a benefit-based charge, while a consumer in a region with a benefit-based charge delays increasing their demand.

4.3 Displacement of demand investment would be inefficient if the decision to invest in load in a location with lower benefit-based charges brings forward transmission investment in that location at a speed and scale that exceeds any incremental effects on the need for new transmission investment in the area with higher current benefit-based charges.[71]

4.4 Costs from displaced demand investment can be calculated using the same formula as for calculating benefits from more efficient demand investment (Equation 29), with adjustments to reflect the fact that:

(a) electricity prices are only one part of a decision to choose a location for new investment, with other factors including:

(i) local amenities

(ii) local prices for, and availability of, inputs (e.g., land, raw materials, and human capital)

(iii) local demand

(iv) transport costs

(b) other things being equal, demand is likely to gravitate to areas that are least constrained, in terms of transmission capacity, because energy prices will be lowest in these locations.

4.5 As such, costs of displaced demand would need to be adjusted by parameters reflecting:

(a) the amount of forestalled demand that is displaced to another region (D, where $0 < D < 1$), and

(b) the extent to which demand displaced to another region by a benefit-based charge reduces the time lag (L) (i.e., brings forward) before investment is needed to relieve transmission congestion in the other region (L, where $0 < L < 1$).

4.6 If the costs are also calculated using a long-run demand elasticity (η), the cost would be:

$$C = \frac{\sum_t \eta \frac{\Delta P}{P} Q_t . D . L . c_t . s_r . \delta^t}{T} \qquad \text{Equation 43}$$

[70] Any net reduction in demand is an unavoidable cost of revenue recovery and something taken into account in our estimates of changes in allocative efficiency.

[71] In addition, it could also be inefficient even if it does not bring forward transmission investment—simply by driving the consumer into a more costly pattern of demand-side investment.

4.7 The displacement parameter could be reasoned using a model (i.e., equation) of its own, based on conventional models of firm location decisions, or drawing on empirical research into locational decisions of firms.[72] Historically, large electricity-intensive loads have tended to locate near raw materials in New Zealand, though this may reflect a mixture of economic fundamentals and past pricing methodologies.

4.8 We have not adopted this approach because we believe identification problems would be considerable, relative to our preferred and simpler approach set out in Table 25. A considerable majority of large electricity intensive manufacturing plants (major direct-connect consumers) were established decades ago when energy and network access pricing differed substantially from the sorts of methodologies and markets used today.

Parameters used

4.9 Table 25 contains the parameter values we used in our top-down assessment of costs due to load not locating in regions with recent investment in transmission capacity. We have applied a Monte Carlo analysis to some parameter values.

Table 25: Parameters for assessment of costs due to load not locating in regions with recent investment in transmission capacity

Parameter	Value	Source / Comment
Discount factor (where 0 < D < 1) representing expected amount of forestalled load locating in another region due to a benefit-based charge	0.5 (Monte Carlo analysis: Beta (alpha=2, beta=2) Sensitivities: a) Very low D value(s) (e.g., D=0, D=0.05, D=0.1) b) Higher D value(s) (e.g., D=0.75)	We consider it is reasonable to expect that, over the long run, a benefit-based charge would displace some forestalled demand. 0.5 chosen as a very conservative estimate, consistent with the CBA being conservative (the higher the “D” value, the more forestalled demand that is displaced to another region, thereby increasing the likelihood of inefficient transmission investment being required in the other region).
The change in the present value multiplier due to bringing forward transmission investment to relieve congestion caused by a change in demand	0.03 (Monte Carlo analysis: Beta (alpha=2, beta=60)	Central estimate based on investment brought forward, from 10 years hence to 9 years hence. Assume demand-driven transmission investment in other region not needed for at least 10 years, because displaced demand would not locate in a region where transmission investment was likely to occur in the short to medium term. Discount rate of 6% used in calculating the change in the present value multiplier.

Source: Electricity Authority

[72] For a reasonably recent summary see: Arauzo-Carod, J.-M., Liviano-Solis, D., & Manjón-Antolín, M. (2010). Empirical Studies in Industrial Location: An Assessment of Their Methods and Results*. *Journal of Regional Science*, 50(3), 685–711. https://doi.org/10.1111/j.1467-9787.2009.00625.x

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

4.10 We have assessed the cost of generation not locating in regions with recent investment in transmission capacity as part of our assessment of the benefits of more efficient grid use. This cost reduces the net benefit associated with lower energy prices from generation investment.

Cost of grid investment brought forward

4.11 We have assessed the cost of grid investment brought forward as part of our assessment of the benefits of more efficient grid use.

5 Costs of developing, implementing and operating a new TPM

Conservative approach to reflect high level of uncertainty

5.1 Quantifying the costs of developing, implementing and operating a new TPM consistent with new guidelines is subject to uncertainty over:

(a) the TPM development and implementation process that is to be adopted (which had not been determined at the time of developing and finalising the CBA)

(b) the course of future events and decisions that are inherently unknowable now.

5.2 Against this background we have adopted a conservative approach to estimating the development, implementation and operating costs under different options. This is to counteract the well-known phenomenon of optimism bias in CBAs.

5.3 We emphasise that the discussion in this section should not be seen as a rigorous exercise in budgeting TPM development, implementation and operating costs. Instead, the estimates should be considered in the context of testing whether benefits under each of the four options are likely to exceed the costs. This section should therefore not be regarded as seeking to confirm specific budgets for funding approval purposes.

5.4 Our estimate of the costs in this section should be regarded as conservative, that is, likely to be excessive. There are likely to be opportunities to reduce or otherwise manage TPM development, implementation and operating costs through effective governance and management.

We have drawn cost information from Transpower's 2016 submission

5.5 Transpower will incur most of the costs associated with developing, implementing and operating a revised TPM.

5.6 In preparing the CBA for the 2019 Issues Paper, we drew upon the cost information that Transpower provided to the Authority in its submission on the 2016 Issues Paper.[73] This was because there were sufficient commonalities in the 2016 and 2019 proposals to conclude that the considerations and costs in Transpower's 2016 submission could usefully inform our 2019 estimates.

5.7 After considering submissions, we believe this remains the case. We received no critique of our estimated development, implementation and operating costs under the proposal and alternative proposal.

5.8 In its submission on the 2016 Issues Paper, Transpower set out estimates of its cost to develop, implement and administer a TPM under three scenarios:

(a) *High complexity scenario*: implementing the full scope of the TPM guidelines proposed in the 2016 Issues Paper

(b) *Medium complexity scenario*: using simpler assessment and accounting procedures than under the high complexity scenario

(c) *Lower complexity scenario*: using alternative approaches to the 2016 proposal in areas where there is a high impact on Transpower's business.

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73 Available on our website, at https://www.ea.govt.nz/dmsdocument/21135-transpower.

Using cost information from the high and lower complexity scenarios

5.9 We have used Transpower's cost estimate under the high complexity scenario as our starting point for estimating the cost Transpower would incur to develop, implement and operate a new TPM under the proposal and the future-only and HVDC-only options.

5.10 We consider the development, implementation and operating costs would be similar under the proposal and the future-only and HVDC-only options—differences between these options may decrease costs in some respects but increase them in others.

5.11 Although the proposal differs from the proposal in the 2016 Issues Paper, we consider Transpower's overall effort to develop, implement and administer a TPM would likely be similar under both proposals. Compared with the proposal in the 2016 Issues Paper, the current proposal requires Transpower to expend:

(a) more effort in some areas (e.g., Transpower must seek to more specifically allocate overhead and unallocated expenses to grid investments whose cost is recovered via the benefit-based charge)

(b) less effort in other areas (e.g., the Authority would provide the benefit-based charge allocators for seven historical assets).

5.12 We have used Transpower's cost estimate under the lower complexity scenario as our starting point for estimating the cost Transpower would incur to develop, implement and operate a new TPM under the alternative option. The alternative option consists of:

(a) the existing connection charge

(b) the HVDC SIMI charge

(c) an interconnection charge levied on all load, with the charge levied in proportion to shares of historical MWh (in place of the current RCPD charge)

(d) a PDP that provides for a transmission customer to receive a discount on its transmission charges if:

(i) it has a private incentive to bypass the grid resulting in an inefficient outcome for all consumers

(ii) a load customer might inefficiently disconnect in favour of alternative supply

(iii) its transmission charges exceed the efficient standalone cost of the transmission services it receives.

5.13 We consider the lower complexity scenario most closely resembles this, albeit that the alternative option is on balance likely to be simpler to develop, implement and operate than this lower complexity scenario. The key differences appear to be that the low complexity scenario includes:

(a) a benefit-based charge, based on including Transpower's entire asset register in the benefit-based charge and allocating costs to benefitting transmission customers using a generalised approach

(b) an LRMC charge and locational pricing for generators

(c) the current PDP.[74]

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[74] Transpower's medium complexity scenario did not extend the existing PDP options. Therefore, we have assumed Transpower's lower complexity scenario also does not extend the existing PDP options. See p 27 of Appendix D of Transpower's submission on the 2016 Issues Paper.

Sensitivity-testing of estimates of net costs

5.14 We have applied a sensitivity of +/- 50% to our estimates of TPM development, implementation and operating costs.

5.15 We note this is consistent with the approach Transpower and PWC adopted in 2016. Transpower noted the difficulty in estimating the size of the TPM development, implementation and ongoing tasks, with this difficulty stemming from the discretion inherent in the then-proposed TPM guidelines.[75] PWC noted the cost estimate was indicative and might vary by +/- 50%.[76]

Costs of TPM development

Transpower, the Authority, and stakeholders would incur costs

5.16 We believe Transpower, stakeholders, and ourselves would incur costs in the development and approval of all four options considered here:

- Transpower would incur costs developing a proposed TPM
- the Authority would incur costs reviewing, approving and determining to incorporate Transpower's proposed TPM into the Code, particularly in relation to our Code obligations to consult
- stakeholders participating in Transpower's TPM development process and/or in our TPM process would incur costs participating in Transpower's and the Authority's processes.

Assumed development and approval process

5.17 It follows that the design of the process for developing and approving a TPM is fundamental to estimating the costs of developing and approving the TPM. Chapter 6 of the 2019 Issues Paper described a proposed process for Transpower to develop, and seek approval of, a revised TPM. For the purpose of updating the 2019 CBA, we assume a similar process would be followed.

We have adjusted Transpower's 2016 development cost estimate

5.18 Transpower's July 2016 TPM development cost estimate was based on Transpower preparing a TPM that comprised all the components of the TPM guidelines proposed in the 2016 Issues Paper.[77]

5.19 As discussed in chapter 4 of the 2019 Issues Paper, we are not assessing the costs and benefits of the additional components of the proposal in this CBA. This is because Transpower can only propose one or more of the additional components to the Authority for inclusion in the TPM if doing so would have a net benefit. So, an analysis of benefits and costs will be prepared for each component should Transpower propose it to the Authority.

5.20 Therefore, we must revise Transpower's estimated TPM development cost to exclude some of the costs Transpower estimated it would incur when incorporating into a proposed TPM the additional components shown in Table 26. We must exclude only some of the costs, rather than all the costs. This is because the current proposal requires Transpower to determine whether each additional component is practicable and

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75 See p 27 of Transpower's submission on the 2016 Issues Paper.

76 See p 6 of Appendix D of Transpower's submission on the 2016 Issues Paper.

77 See pp 47-48 and pp 53-54 of Appendix D of Transpower's submission on the 2016 Issues Paper.

consistent with clause 12.89 of the Code. We expect Transpower would, when doing this, incur a large percentage of the cost associated with incorporating into a proposed TPM the additional components shown in Table 26.

5.21 We have further revised Transpower's estimated TPM development cost under Transpower's lower complexity scenario, when estimating the cost of developing a proposed TPM under the alternative proposal. This is to:

(a) remove the cost of developing a benefit-based charge

(b) include the cost of developing—

(i) a MWh residual charge

(ii) the proposed PDP.

5.22 We expect the net effect would be to reduce Transpower's TPM development cost relative to under the proposal. This is because we expect the benefit-based charge in Transpower's lower complexity scenario would be more complex to develop than, a MWh residual charge plus the change to the PDP under the alternative proposal.[78]

Table 26: Additional components costed in Transpower's July 2016 submission

Component proposed to be included in TPM	March 2016 Guideline section	Transpower project 'Trigger ID'[79]
Define assets subject to staged commissioning as connection assets while they meet the definition of a connection asset	43a	AC02
Develop a methodology for ensuring charges for connection assets are not affected by a person other than Transpower connecting to Transpower's assets	43b	AC03
Develop a methodology to allocate maintenance costs according to actual cost, not a proxy allocator	43c	AC04
Develop a LRMC charge, but only if the charge is necessary to promote efficient investment in the grid	43d, 45	AC05
Develop a kvar charge, but if a kvar charge is included Transpower must specify the circumstances and regions in which it would apply	43e, 46	AC06

Source: Transpower

5.23 To aid us in preparing our estimates, we corresponded with Transpower in 2019 over the evaluation underpinning the $4.3 million TPM development cost estimate in Appendix D of Transpower's submission on the 2016 Issues Paper. Transpower said its view was

78 Specifically:

a) we estimate the cost of developing a simplified benefit-based charge represents approximately 50% of Transpower's low complexity TPM development cost (i.e., $1.3 million)

b) we estimate the cost of developing a MWh residual charge and the proposed PDP would be approximately 33% of Transpower's low complexity TPM development cost (i.e., $0.85 million)

c) we assume Transpower fulltime equivalents are reduced proportionally across Transpower's resources (i.e., across internal SMEs, regulatory & pricing, external support, and legal resources).

79 See pp 47-48 of Appendix D of Transpower's submission on the 2016 Issues Paper.

that we should use the cost information in Appendix D of its submission as the best information available.

5.24 Transpower's July 2016 cost estimate was prepared on the basis that Transpower would develop a TPM under the then-proposed TPM guidelines over a 12-month period.[80] Subsequently, Transpower revised its timeframe for developing a TPM to be 18 months.[81] Amongst other things, this was to enable Transpower to engage with stakeholders on high-level TPM design options and detailed TPM design options.

5.25 Our estimate of Transpower's TPM development cost allows for almost 7.5 people to be working fulltime for 18 months to develop a TPM. We consider this should be more than enough, based on our experience:

(a) developing and consulting on the 2019 Issues Paper, including:

(i) modelling benefit-based charges for seven major pre-2019 grid investments

(ii) modelling the expected impacts on consumers from adopting a TPM developed in accordance with the proposal in the 2019 Issues Paper

(iii) comprehensively assessing the expected costs and benefits of a TPM developed in accordance with the proposal in the 2019 Issues Paper

(b) consulting on the 2016 Issues Paper and supplementary paper and considering submissions and cross-submissions on these papers.

Estimating the Authority's costs in relation to TPM development

5.26 The 2019 Issues Paper assumed the Authority would take six to nine months to complete the process set out in clauses 12.91 to 12.94 of the Code, based on:

(a) two to three months to prepare the necessary material to accompany the proposed TPM when we consult

(b) a reasonable amount of time for consultation on the proposed TPM

(c) a reasonable amount of time to consider submissions on the proposed TPM and to go through the approval processes for incorporating a new TPM in the Code.

5.27 We estimate the Authority's resourcing for the TPM development process over that period would involve:

(a) four FTEs under the proposal (or the future-only and HVDC-only options)

(b) three FTEs under the alternative option.

5.28 We would use a combination of internal and external resources.

5.29 Our estimate is based on the anticipated TPM development process set out in chapter 6 of the 2019 Issues Paper, and our experience with both the TPM review to date and the 2015 TPM operational review.

Estimating stakeholders' costs in relation to TPM development

5.30 Industry and consumer stakeholders showed significant interest in the 2016 Issues Paper and the 2016 supplementary consultation paper. We received 727 submissions

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80 See p 28 of Transpower's July 2016 submission and Appendix D of Transpower's July 2016 submission.

81 See Figure 4 on p 30 of Transpower's submission on the supplementary TPM guidelines consultation paper we published in late 2016.

on these papers.[82] Submissions ranged in size from short e-mails and pro forma submissions to documents that were hundreds of pages in length.

5.31 The 2019 Issues Paper and supplementary consultation paper also received much interest, with 133 submissions and cross-submissions.[83] However, if we decide to revise the TPM guidelines, we expect less stakeholder interest in the Authority's consultation on Transpower's proposed TPM than the consultation on the TPM guidelines. This is because we expect many stakeholders may view the development of a TPM as a detailed exercise implementing a policy already consulted on.

5.32 For the purposes of this CBA, we have used an estimate of 100 stakeholders, on average, making submissions on each consultation undertaken during the TPM development process. While this figure is substantially lower than the number of submissions received in 2016, it is reasonably similar to the number of submissions received on the 2019 Issues Paper, on the 2012 Issues Paper, and on our 2015 consultation paper setting out options for the TPM.

5.33 We have categorised, into five levels, our estimates of submitters' costs preparing submissions on consultation papers published during the TPM development process. Table 27 shows this cost categorisation. These categories of estimated costs are based on the type of analysis contained in the submissions we have received on TPM consultation papers since 2011. Please note, each cost category includes submitters' incremental internal costs (e.g., incremental administrative, analytical and legal costs).

Table 27: Incremental cost incurred by submitters during TPM development

Cost category	Cost estimate	Basis for cost categorisation
Very high cost	$125,000	Submissions include reports or other input from at least three or four subject matter experts
High cost	$70,000	Submissions include reports or other input from two subject matter experts
Medium cost	$30,000	Submissions include a report or other input from one subject matter expert
Low cost	$2,500	Submission with no expert report attached
Negligible cost	$0	Simple e-mail or social media post

Source: Electricity Authority

5.34 Based on the submissions we have received on TPM consultations since 2011, we estimate the cost of 300[84] submissions during the TPM development process would be approximately $1,500,000, as shown in Table 28.

82 508 submissions on the 2016 Issues Paper and 219 submissions on the supplementary consultation paper published in late 2016.

83 93 submissions and 18 cross-submissions on the 2019 Issues Paper and 22 submissions on the supplementary consultation paper published at the beginning of 2020.

84 Assuming Transpower undertakes two rounds of engagement during the TPM development process and we consult once during the process.

Table 28: Estimate of incremental cost of submissions during TPM development

Cost category	Cost estimate per submission	No. of submissions	Cost
Very high cost	$125,000	2	$250,000
High cost	$70,000	10	$700,000
Medium cost	$30,000	10	$300,000
Low cost	$2,500	100	$250,000
Negligible cost	$0	178	$0
Total		300	$1,500,000

Source: Electricity Authority

5.35 We note this estimate assumes:

(a) a continuation of the same amount of sharing of expert resources by submitters as we have seen since 2011

(b) Transpower undertakes two rounds of formal/structured engagement with stakeholders during the TPM development process

(c) Transpower does not establish a TPM working group to assist Transpower in the detailed design of the proposed TPM.

5.36 We applied this estimate to a proposed TPM under all four options.

Legal challenge costs

5.37 We expect legal challenges may well occur during the development and/or implementation of a revised TPM. This is because of the significant amount of money being reallocated under each of the TPM guidelines options being considered by the Authority.

5.38 To be conservative, we have allowed for a legal challenge during the TPM development process and during the implementation of the TPM. We assume the cost of any such legal challenges would be the same for a TPM developed under each option.

5.39 We estimate the cost of any such legal challenges would be approximately $1.5 million across the Authority, Transpower, three main appellants, and 15 parties joining the legal challenge. This estimate is based on our experience with legal challenges to several of our decisions over the years.

Costs of TPM implementation

Transpower would incur implementation-related costs

5.40 Transpower would incur costs changing its processes, procedures and IT systems related to implementing a new TPM.

We have adjusted Transpower's 2016 implementation cost estimate

5.41 As with Transpower's TPM development costs, Transpower and PWC estimated Transpower's TPM implementation costs based on Transpower preparing a TPM comprising all components of the TPM guidelines proposed in the 2016 Issues Paper.

5.42 Therefore, we must revise Transpower's estimated TPM implementation costs, to exclude our estimate[85] of the costs relating to the components shown in Table 26.

5.43 We must also revise Transpower's estimated TPM implementation costs to exclude the cost of determining the charges for the seven major pre-2019 grid investments proposed to be subject to the benefit-based charge according to allocators developed by the Authority.

5.44 We estimate approximately one third of Transpower's estimated cost to implement a TPM under the proposal in the 2016 Issues Paper[86] was attributable to:

(a) the additional components in the TPM guidelines proposed in the 2016 Issues Paper

(b) determining the charges for 11 major grid investments we proposed be subject to the benefit-based charge.

5.45 This estimate is based on our experience:

(a) modelling benefit-based charges for seven major pre-2019 grid investments

(b) modelling the expected impacts on consumers from adopting a TPM developed in accordance with the proposal in the 2019 Issues Paper.

The Authority does not expect to incur implementation-related costs

5.46 We have assumed that we would face negligible incremental costs associated with Transpower implementing a revised TPM.

Transmission customers would incur implementation-related costs under the proposal and its two variants, but not the alternative option

5.47 We expect transmission customers would incur some costs associated with implementing a revised TPM under the proposal and the future-only and HVDC-only options. At a minimum these would relate to:

(a) time and effort spent understanding the basis for the revised transmission charges

(b) updating processes and procedures.

5.48 We expect transmission customers would face negligible incremental costs associated with implementing a TPM developed under the alternative option. This is because such a TPM is relatively simple, and like the current TPM.

Implementation costs under the proposal

5.49 Transpower has noted there are no substantial changes to the process for invoicing transmission charges, although several explanatory additions would be needed for the new TPM charges on invoices and other transmission customer-facing material.[87]

5.50 On this basis, we believe transmission customers would face relatively minor costs implementing a new TPM consistent with the proposal or the future-only and HVDC-only options. We expect these costs would relate primarily to:

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85 Noting that at the time of developing these estimates we were unable to obtain Transpower's 2016 estimate of the cost of these components as an input to this.

86 I.e., the high complexity scenario in Appendix D of Transpower's submission on the 2016 Issues Paper.

87 See p 21 of Appendix D of Transpower's submission on the 2016 Issues Paper.

(a) understanding and validating the revised transmission charges, particularly the benefit-based charge, when these were introduced

(b) updating policies and/or procedures.

5.51 We estimate the incremental resourcing required by a transmission customer to undertake these activities would be approximately four weeks of an analyst's (or equivalent) time. This is an average figure—it would be higher for some transmission customers and lower for others.

5.52 Using an average salary of $100,000 for an analyst (or equivalent), the incremental cost faced by each transmission customer to undertake the activities above would be approximately $7,700. This sums to approximately $370,000 across Transpower's 48 transmission customers.

5.53 Some transmission customers may need to make IT system changes (e.g., distributors incorporating the changed structure of the transmission charges into their invoices to retailers and direct-billed consumers). The "set and forget" nature of the benefit-based charge means we do not expect transmission customers would need to build relatively complex IT systems to verify their transmission charges.

5.54 We have allowed for approximately half (15) of New Zealand's distributors to incur some IT system change costs, with the average of this cost being $20,000. This gives a total incremental cost of $300,000.

5.55 We may be conservative with our incremental cost estimate. Currently, distributors receive a monthly invoice for transmission services, which they allocate across their customers in a variety of ways. Rather than half of distributors, most distributors might require no change to their IT systems to accommodate monthly invoices calculated using a different TPM. This would be because the distributors' allocation of transmission costs to their customers would not change.

Legal challenge costs

5.56 As set out in the discussion on TPM development costs, we are allowing for a legal challenge to occur during the implementation of a TPM under each of the four proposed options.

5.57 We estimate this legal challenge will cost approximately $1.5 million across the Authority, Transpower, three main appellants, and 15 parties joining the legal challenge.

Costs of TPM operation

Transpower would incur costs administering the TPM

5.58 We expect Transpower would face higher ongoing costs under the proposal and the future-only and HVDC-only options, than under the current TPM. This is because of the more complex nature of a TPM consistent with the proposed guidelines.

5.59 On balance, we expect Transpower would face slightly higher ongoing costs administering a TPM under the alternative proposal than under the current TPM. This is because of the proposed change to the PDP.

Transpower's ongoing TPM administration costs under the proposal and its options

5.60 As with Transpower's TPM development and implementation costs, Transpower and PWC estimated Transpower's ongoing TPM administration costs based on Transpower preparing a TPM comprising all components of the TPM guidelines proposed in the 2016 Issues Paper.

5.61 Therefore, under the proposal and the future-only and HVDC-only options, we revise Transpower's estimated ongoing TPM administration costs to exclude our estimate[88] of the costs relating to the components shown in Table 26.

5.62 We estimate approximately one quarter of the effort in Transpower's 2016 cost estimates for administering a TPM under the TPM guidelines proposed in the 2016 Issues Paper[89] was attributable to the additional components in the proposed TPM guidelines.

5.63 The benefit-based charge would add complexity to Transpower's pricing and finance team's TPM-related work, and to the amount of liaison, and possibly consultation, Transpower undertakes with transmission customers. The introduction of a transitional congestion charge would also materially add to Transpower's work—this component replaces the 2016 costing of LRMC charge in Table 26). We may be too conservative estimating a 25% reduction in Transpower's ongoing administration costs from removing the additional components shown in Table 26. A one third reduction may be more accurate. However, in keeping with the conservative nature of this CBA, we have used a 25% reduction.

Transpower's ongoing TPM administration costs under the alternative option

5.64 We expect Transpower's incremental ongoing costs would be relatively minor under the alternative option.

5.65 We expect that replacing the RCPD residual charge with a MWh residual charge may result in an incremental cost in the first year of operation. This would relate to time and effort spent explaining to transmission customers the basis for the revised transmission charge. Thereafter, we expect the MWh charge would place no incremental ongoing cost on Transpower compared to the RCPD charge. This is because the MWh charge would be no more complex than the RCPD charge (and is likely to be simpler to administer).

5.66 We expect the expanded scope of the proposed PDP would mean an incremental ongoing cost for Transpower over the current PDP, because of the increased probability of a transmission customer seeking a PDP. We are unsure whether this cost would be larger in the first year of operation than in subsequent years. The first year of operation would see time and effort spent explaining to transmission customers the basis for the revised PDP. Subsequent years would be more likely to see applications for a PDP, as transmission customers assess their circumstances.

5.67 We estimate that Transpower's incremental ongoing cost under the alternative proposal would be approximately half a fulltime resource in the first year of operation, dropping to between one quarter and one third of a fulltime resource thereafter. We expect applications for a prudent discount would remain a relatively rare occurrence under the revised PDP—we have allowed for 13 over 30 years, with:

(a) 10 relating to uneconomic bypass of existing transmission assets, and

(b) three relating to a customer's transmission charges exceeding the standalone cost of the transmission services the customer receives.

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88 Noting we have been unable to obtain Transpower's 2016 estimate, as an input to this.

89 As per the above footnote.

5.68 Our estimate of Transpower's incremental ongoing resourcing assumes, on average:

(a) once every three years Transpower assesses a PDP application relating to uneconomic bypass of existing transmission assets

(b) three Transpower staff work fulltime for a little under 2.5 months assessing each PDP application relating to uneconomic bypass of existing transmission assets

(c) once every 10 years Transpower assesses a PDP application relating to a customer's transmission charges exceeding the efficient standalone cost of the transmission services the customer receives

(d) four Transpower staff work fulltime for three months assessing each PDP application relating to a customer's transmission charges exceeding the efficient standalone cost of the transmission services the customer receives.

The Authority does not expect to incur additional ongoing costs

5.69 The Authority has assumed that once a revised TPM has been implemented, either under the proposed TPM guidelines or under the current TPM guidelines, it would have the same ongoing operational costs as under the current TPM.

Transmission customers would incur some ongoing costs under the proposal and its options, but not under the alternative option

5.70 We expect some transmission customers would periodically face incremental costs under the proposal and the future-only and HVDC-only options. These would stem from optimising the value of a transmission investment with an initial value of at least $5 million (inflation adjusted).

5.71 We expect transmission customers would be unlikely to face ongoing incremental costs under the alternative proposal. This is because a TPM developed under the alternative is likely to be similar to the current TPM.

Reassignment

5.72 Under the reassignment provisions in the current proposal, a party may ask Transpower to reduce the value of a transmission investment with a book value of at least $5 million, provided certain conditions are met.

5.73 We believe this process would result in incremental costs over the current TPM. This is because the current TPM guidelines contain no equivalent reassignment provisions.

5.74 For the purposes of this CBA, we have assumed each transmission customer will engage in this process (either by asking Transpower to reduce the value of a transmission asset or by making a submission on a proposed reassignment) once during the 30-year period over which the CBA is being undertaken. For simplicity, we have assumed this occurs:

(a) for a third of transmission customers at year 10

(b) for a third of transmission customers at year 20

(c) for a third of transmission customers at year 30.[90]

5.75 We estimate:

90 We believe this simplified approach is reasonable because of the conditions that must be met for a party to ask Transpower to optimise the value of a transmission investment.

(a) a transmission customer asking Transpower for reassignment will, on average, incur a cost of approximately $100,000 (2018 dollars) providing the necessary prima facie evidence to Transpower[91]

(b) a transmission customer making a submission to Transpower as part of the reassignment process will incur a cost of approximately $10,000 (2018 dollars)[92]

(c) the number of transmission customers increases by three every 10 years, from the current 48 transmission customers.

Substantial change in circumstances

5.76 Under the current proposal, the TPM must provide for Transpower to adjust the allocation of the benefit-based charge for a high value investment, if there has been a substantial change in circumstances. This provision is intended to be invoked rarely, and only if some event causes a widespread, substantial change in the pattern of grid use.

5.77 We have considered whether this requirement imposes an incremental cost over the current TPM. We have concluded it does not.

5.78 In reaching this conclusion we have considered:

(a) whether an operational review by Transpower, or a targeted TPM review by the Authority[93] would occur under the baseline or alternative proposal if:

(i) there had been a substantial and sustained change in grid use, and

(ii) the actual circumstances (such as demand and generation outcomes) were outside the range of scenarios contemplated at the time the relevant charges were established

(b) whether an operational review / targeted TPM review under (a) would occur as often under the baseline or alternative proposal as under the proposal and future-only and HVDC-only options.

5.79 In relation to paragraph 5.78(a), examples of the TPM being reviewed under the baseline or alternative option because of a substantial and sustained change in grid use, include:

(a) proposing the introduction of a kvar charge as a result of transmission customers changing their demand for reactive power from the grid over time

(b) reviewing the approach to recovering the interconnection charge:

(i) because the demand for grid capacity has become peakier over time (e.g., because of a higher percentage of solar generation without storage)

(ii) because of significant changes in the demand for grid capacity across regions over time.

5.80 In relation to paragraph 5.78(b), we anticipate reviews triggered by a substantial change in circumstances under the proposal would be infrequent—perhaps 1–3 times during the 30 year period of the CBA. We believe it is reasonable to expect that, under the baseline

91 We assume this cost is incurred by two transmission customers at year 10, by two transmission customers at year 20, and by two transmission customers at year 30.

92 We assume this cost is incurred by 15 transmission customers at year 10, by 16 transmission customers at year 20, and by 17 transmission customers at year 30.

93 Under clause 12.86 of the Code.

or alternative proposal, there would also be 1–3 instances of examples such as those in paragraph 5.79 occurring during the 30 year period of the CBA.

5.81 Therefore, we consider it appropriate to not estimate incremental costs for the substantial change in circumstances component of the proposal.