Response to feedback on the 2019 cost benefit analysis

Revisions to CBA in the 2019 Issues paper
Transmission pricing review

Information paper

April 2020

Executive summary

This information paper sets out the Authority's current thinking on its cost-benefit analysis (CBA) of the transmission pricing methodology (TPM) guidelines it proposed in 2019, having taken into account submissions it received on that proposal.

The Authority has revised its estimates of the benefits and costs of the proposal in the 2019 Issues Paper as a result of these submissions. The revisions are explained in this paper.

Revised net benefits are positive and material

As a result of the revisions, the estimate of the net benefits of the proposal has reduced but remains positive and material – a present value of +$1.3 billion (range of $0.3b-$2.3b) at the median (as the best comparison to the 2019 CBA), or a weighted mean value of +$1.2 billion.

Much of the change is due to revised modelling of:

- investment in utility-scale batteries, using more detailed battery investment and operation rules
- wholesale electricity price formation, using typical offer curves from grid-connected generators by time-of-use, instead of a simpler measure of short-run marginal cost
- investment in new electricity generation, to account for the effect of increased generation on wholesale electricity prices and thus the earnings of new generation investments.

The underlying CBA framework and empirical approach for quantifying costs and benefits of the a TPM based on the proposed guidelines are otherwise largely unchanged.

Sources of quantified benefits from the proposal

Most of the quantified benefits from a TPM based on the proposed guidelines would be due to:

- increased electricity use during peak demand periods (a 1% increase in demand in the near term), when consumers value electricity the most, and
- lower wholesale electricity prices when compared to the baseline.

These effects are caused by more efficient transmission charges under the proposal.

The increase in electricity use during peak demand periods is the result of removing the RCPD charge which, it is generally agreed, is overly high and encourages unnecessary actions and costs to avoid using the grid, even when there is plenty of grid capacity. The proposal would improve the affordability of consuming electricity during peak demand and shoulder periods.

The higher demand, and lower transmission costs on South Island generators from removing the HVDC charge, would bring forward generation investment. This in turn would lead to lower average wholesale electricity prices inclusive of transmission charges compared to the baseline. (Wholesale electricity prices still rise in the model, in line with projections of the cost of thermal fuels and carbon emissions.)

Utility-scale batteries and transmission investments

The proposal would also generate benefits from more efficient investment patterns in utility-scale batteries. However, this effect is much reduced following the revisions made to the CBA modelling to incorporate feedback in submissions on the 2019 CBA.

Investment in batteries or other distributed energy resources will continue – the Authority and others anticipate this to be a growth area. But proposed changes to transmission pricing would remove incentives to inefficiently invest in batteries for the main purpose of avoiding transmission charges and shifting costs to other grid users.

A flow-on effect of the fall in inefficient battery investments is that the estimated cost of transmission investment brought forward under the proposal relative to the baseline is much reduced. In the 2019 CBA, strong growth in battery investment under the baseline repressed peak demand and thus future transmission investment. Without that effect in the CBA model, peak demand and thus transmission investment grows under the baseline, and less additional investment is needed to accommodate the increase in peak demand under the proposal.

Scenarios and sensitivities

In addition to the results for the proposal, we also summarise the quantified CBA results for the following policy scenarios:

- **alternative** to the proposal: a per MWh charge over all trading periods. Under this approach, demand increases during peak periods, but without the re-allocation of the HVDC charge, electricity prices need to rise more than under the proposal to stimulate generation investment. This would likely have a negative impact on consumers
- **future-only**: only the cost of future grid investments would be recovered through the benefit-based charge. Initially a greater share of transmission charges would be recovered through the residual charge from consumers. Demand is suppressed (but so are prices) in the early years, resulting in net benefits that are somewhat less than under the proposal
- **HVDC-only**: alongside the cost of future grid investments, the remaining costs of historical HVDC investments would also be recovered through benefit-based charges. The remaining costs of all other historical investments would be recovered through the residual charge. At the median, this scenario sits in between the proposal and future-only scenario in terms of impact (although after adjusting for the relative probability of some sensitivities it ranks behind the future-only scenario).

Table 1: high level summary of results for different policy scenarios

Scenarios $m present values	Proposal	Alternative	Future-only	HVDC-only
Net benefits (at median)	**1,335**	**-927**	**834**	**1,117**
Net benefits (at mean)	**1,169**	**-760**	**1,130**	**594**

The CBA's quantified results are quite sensitive to assumptions about demand, short-run generation costs and generation investment costs. Changes in these parameters affect the timing of generation investment cycles, which can make considerable differences to the calculated net benefits.

Detailed sensitivity analysis and an exploration of a total surplus measure have therefore been undertaken and show the results are robust to a range of combinations of different assumptions (and to different views about the counting or not of wealth transfers). There are, of course, also unquantified impacts to consider.[1]

The Authority has considered what, if any, impact the revisions to the CBA have on our confidence in the robustness of the estimate of net benefits. The CBA has benefitted from the scrutiny and revision it has received. Overall, the Authority is confident that the revised estimate is a robust and useful input into its decision making.

The Authority's current views on other issues

The Authority is considering, and in this paper addresses, other key concerns raised by some submitters. Table 2 on the next page provides a brief overview of several of these matters.

Cost benefit analysis is an aid to decision-making

A CBA is only an aid to support deliberation and decision-making, alongside a much broader range of factors the Authority has to consider. A quantitative CBA gives a sense of the order of magnitude of benefits or costs that are involved, alongside likely effects that cannot reasonably be quantified.

The analysis of the cost and benefits of a TPM consistent with the proposed guidelines similarly aims to provide a sense of direction and orders of magnitude. It cannot be a precise exercise, and there will always be different views about assumptions and approaches, and opportunities to refine the analysis.

This paper explains how the Authority has taken into account the submissions on its quantitative CBA, and the impact that has had on the CBA's results.

Webinar

This paper is intended to support a webinar on the revised CBA to provide an opportunity for questions and answers.

We note that the TPM review is ongoing and the Authority will take the time we require to consider all issues raised in submissions and at the Q&A session. At this point we intend to make a decision on the proposed TPM guidelines in the second quarter of 2020.

1 See 2019 Issues paper, para 4.174-4.177 and appendix B.

Table 2 Summary of the Authority's current views on several other issues

Submissions on the CBA	Authority's current view
Treats wealth transfers as benefits (e.g., declining prices are a transfer from producers to consumers)	The Authority considers the CBA does not treat transfers as benefits. Lower costs (and so lower prices) are efficiency gains arising from the proposal, and thus are benefits. The proposal does not force lower wholesale electricity prices on producers. They would result from market-driven changes, with producers investing in generation voluntarily. Any rising prices are not treated as transfers from consumers to producers either, but as cost changes.
Omits generation investment costs (i.e., these should be subtracted from the net benefits, just like avoided investment in batteries was added to the benefits)	The costs of generation investments are already captured in market prices. That is, the revenue streams from new generation investments factor in investment costs. Therefore, adding the costs of generation investments to market prices would be double counting. A different approach must be taken in relation to battery investment costs. These costs arise under the baseline because an administratively determined charge incentivises this battery investment. Therefore, the more appropriate way to measure the benefit of avoided battery investment is the change in battery investment costs.
Omits distribution network costs (i.e., increased peak demand may cause a need for more local network investments)	If demand for distribution services expands, then distribution network costs may rise, but these costs will be offset by benefits to consumers that are greater (assuming investments are efficient).
Does not assess the proposal (e.g., does not account for higher prices due to benefit-based charges)	The CBA model does assess the proposal – it allocates interconnection charges to customers: • under the baseline, based on peak demand (as a proxy for the RCPD charge) • under the proposal, based on shares of loss and constraint excess (LCE) and peak demand (as a proxy for a benefit-based charge). Our approach is conservative as it overstates rather than understates the (suppressive) effect of a benefit-based charge on electricity demand.
Does not model relevant baseline (e.g., because the RCPD is obviously too high and distortionary and can be changed without changing the current TPM guidelines)	The existing TPM is the most obvious baseline, as it has resulted from the current guidelines. An operational review of the current TPM could reduce its efficiency costs, but there has been no suggestion of such an extensive operational review being carried out. The 'alternative scenario' could be implemented under current guidelines.

Contents

Tables

Figures

1 Purpose of this paper

1.1 This information paper sets out the Authority's current thinking on its cost-benefit analysis (CBA) of the transmission pricing methodology (TPM) guidelines it proposed in 2019 in light of the submissions it has received.

What this paper is about

1.2 This paper summarises revisions to the CBA of the proposal presented in the 2019 Issues Paper.

1.3 Because the Authority's TPM review is ongoing and its decision on the proposed TPM guidelines has not yet been made, the results ultimately presented in the Authority's decision paper on the TPM guidelines may differ in some respects from the CBA presented here.

1.4 Section 2 presents the key areas of revision and the effects on the estimated benefits and costs of the proposal.

1.5 Sections 3-8 explain the amendments made.

1.6 Section 9 gives an overview of some submissions with which the Authority at this stage does not agree.

A CBA is one input into the Authority's decision-making

1.7 The CBA is only one aid to support the Authority's deliberation and decision-making, with the insights it provides to be considered along with a much broader range of factors.

1.8 A quantified CBA is not a precise exercise – rather it gives a sense of the order of magnitude of benefits or costs that are involved. Where, for ease of communication, point estimates are discussed in this paper, these should be viewed as a reasonable but not definitive point within a wider range of estimates.

1.9 The CBA in the 2019 Issues Paper also described qualitatively several important impacts that have not been able to be quantified, and which continue to be relevant (even if they are not referred to explicitly in this paper). The lack of quantified dollar amounts does not make unquantified impacts less important.

Next steps: a decision on TPM guidelines

1.10 This information paper is to support a webinar by the Authority on the revised CBA to which all submitters on the 2019 Issues Paper are invited to attend, and at which there will be an opportunity for questions and answers.

1.11 The TPM review is ongoing and the Authority will take the time we require to consider all issues raised in submissions we have received and at the Q&A session. At this point we intend to make a decision on the TPM guidelines in the second quarter of 2020.

2 Revised CBA results

A spectrum of views

2.1 Submissions on the 2019 Issues Paper offered a spectrum of views on the CBA. For example, of those submissions commenting in detail on the CBA, views included that:

- the battery impacts were significantly overstated (John Culy Consulting for Trustpower)
- the CBA was fundamentally flawed (HoustonKemp for Trustpower and Axiom Economics for Transpower)
- the CBA started with an irrelevant baseline (the status quo), overstating the benefit of the Authority's proposal (The Lantau Group for the TPM Group)
- the RCPD signal was probably weaker than assumed, and the generation investment modelling and exclusion of distribution costs was problematic (NZIER for the Major Electricity Users' Group)
- the magnitude of the CBA results was plausible, but the modelling of generation investment left questions (NERA for Meridian Energy)
- the conceptual approach to the CBA was logical (Rio Tinto).

Revision of the CBA

2.2 The Authority remains satisfied with the underlying framework of its CBA and the empirical approach for quantifying costs and benefits. However, having considered the submissions on its 2019 CBA, the Authority has changed some of the modelling.

2.3 The following chapters explain the changes made. Meanwhile, Table 3 shows the revised results against the results that were presented in the 2019 Issues paper. The main changes in the results relate to revised modelling of:

- investment in utility-scale batteries
- wholesale electricity price formation
- investment in new electricity generation.

2.4 The revised results show that most of the proposal's net benefits relative to the baseline are due to:

(a) an increase in electricity use during peak demand periods (by 1% in the near term) when consumers value electricity the most, due to removing the RCPD charge

(b) lower average wholesale electricity prices inclusive of transmission charges compared to the baseline, as higher demand and lower transmission costs on generators (from removing the HVDC charge) bring forward generation investment

(c) less transmission investment brought forward relative to the baseline compared to the 2019 CBA, as reduced battery investment means that peak demand and thus transmission investment continue to grow under the baseline.

2.5 A major difference in the results is that investment in and operation of utility-scale batteries to avoid RCPD charges is very much muted under the baseline compared to the 2019 CBA. This is the result of improvements in the modelling in response to the Culy report in particular. As a result, the proposal's benefit from avoided investment in utility-scale batteries is much reduced.

2.6 Table 3 now separately reports the costs and benefits from transmission investments brought forward. The benefits of transmission investment – reduced transport losses and constraints – were part of the $188m in grid costs brought forward under the 2019 CBA. The $188m was a net figure – $311m grid cost less $123m of benefits from reduced transport costs.

Table 3 Revised benefits and costs of 2019 proposal
$ million in present values

	2019 CBA	Revised CBA	Change
Quantified benefits	**$m**	**$m**	
More efficient grid use	2,579 (81 - 5,678)	1,131 (402 – 2,081)	↓
More efficient investment in batteries	202 (137 - 786)	51 (10 - 54)	↓
Grid investment benefits brought forward		95 (5-129)	
More efficient investment in generation and large load	43 (9 - 112)	40 (8 - 109)	↓
More efficient grid investment (scrutiny of investment proposals)	77 (29 - 125)	49 (9 - 98)	↓
Increased certainty for investors	26 (10 - 48)	31 (11 - 59)	↑
Total quantified benefits	**2,926 (266 - 6,749)**	**1,397 (445 - 2,530)**	↓
Quantified costs	**$m**	**$m**	
TPM development/approval	8 (4 - 12)	8 (4 - 12)	•
TPM implementation costs	9 (4 - 13)	9 (4 - 13)	•
TPM operational costs	9 (5 - 14)	9 (5 - 14)	•
Grid investment brought forward	188 (51 - 324)	35 (-2 - 56)	↓
Load now locating in regions with recent grid investment	1 (0 - 2)	1 (0 - 2)	•
Efficiency costs of price cap	1	1	•
Total quantified costs	**215 (65 - 366)**	**62 (12 - 98)**	↓
Net benefit (benefits less costs)	**2,711 (201 - 6,383)**	**1,335 (433 - 2,432)**	↓

Source: Electricity Authority
Notes: Column totals may not add due to rounding

2.7 We also note we have in the revised CBA results decided to remove the adjustment to the 'more efficient grid use' result in the 2019 CBA. That adjustment took an average of the proposal's 'central scenario' with and without energy price effects.

2.8 The adjustment was made to recognise the sensitivity of results to assumptions about generation investment and the (supply / demand) 'tightness' of the wholesale electricity market, and to account for the possibility that the estimates may contain wealth transfers.

2.9 This adjustment is not needed anymore, because of the revised generation investment modelling. Under the revised decision rule for generation investment, investors consider the suppression of prices once new capacity and offers are added to the market. Generation investment only takes place if new generation is profitable taking that effect into account. The approach also makes it easy to account for generator surplus, making clear there are no wealth transfers.

Other policy scenarios modelled

2.10 We also model three other policy scenarios. We outline the scenarios here. Table 4 summarises the results. The table also introduces a 'weighted mean' measure, made possible by a new approach to sensitivity analysis as discussed in 2.17.

2.11 The table indicates the proposal provides higher quantified net benefits than the other policy scenarios using either the median or weighted mean measure. There are also other benefits to take into account, but which the Authority considers are not able to be credibly quantified.

Alternative to the proposal

2.12 The alternative to a TPM based on the proposed guidelines assumes that the RCPD charge is replaced with a per MWh charge over all trading periods. Some submitters have argued for de-powering the RCPD charge. This is a version of such an approach.

2.13 This design increases electricity use during peak demand periods. But generation investment is not brought forward as under the proposal: without the re-allocation of the HVDC charge, higher wholesale electricity prices are needed (relative to the proposal) to cause investment in South Island generation to satisfy increased electricity demand. As such, wholesale electricity prices rise by more than under the TPM proposal, which would benefit generators, but with a large negative consumer welfare impact.

Proposal 'future-only' scenario

2.14 The future-only scenario would only recover only future grid investments through the proposed benefit-based charge. The remaining costs of the seven historical investments (that would under the proposal be recovered through benefit-based charges) would instead be recovered through the residual charge.

2.15 In this future-only scenario a greater share of transmission charges would be recovered from consumers, and less from generators. This would suppress demand and price dynamics in the initial years compared to the central scenario.

Proposal 'HVDC-only' scenario

2.16 The HVDC-only scenario under the proposal would recover the cost of future investments and the remaining costs of historical HVDC investments through benefit-based charges. All other costs would be recovered through the residual charge. This scenario sits in between the central and future-only scenarios in design and impact.

Table 4 Summary of results for scenarios
$ million in present values

More efficient grid use	Proposal	Alternative	Future-only	HVDC-only
Weighted mean	965	-896	921	396
Mean	973	-808	869	839
Median	**1,131**	**-1,057**	**626**	**900**

At the median	Proposal	Alternative	Future-only	HVDC-only
Net change in consumer welfare	1,131	-1,057	626	900
Inefficient battery investment	51	49	51	51
Invest / scrutiny / certainty benefits	120	-	120	120
Transmission benefits	95	127	107	109
Transmission costs	-35	-36	-43	-35
Other costs	-27	-9	-27	-27
Net benefit	**1,335**	**-927**	**834**	**1,117**

At weighted mean	Proposal	Alternative	Future-only	HVDC-only
Net change in consumer welfare	965	-896	921	377
Inefficient battery investment	49	47	48	49
Invest / scrutiny / certainty benefits	120		120	120
Transmission benefits	93	135	109	112
Transmission costs	-32	-36	-42	-37
Other costs	-27	-9	-27	-27
Net benefit	**1,169**	**-760**	**1,130**	**594**

Ranges	**344 - 2,236**	**-2,019 - 19**	**-85 - 2,098**	**-170 - 2,123**

Note: Ranges based on interquartile grid use results

Sensitivity analysis

2.17 We explored various sensitivities to key aspects of the main CBA model, by:

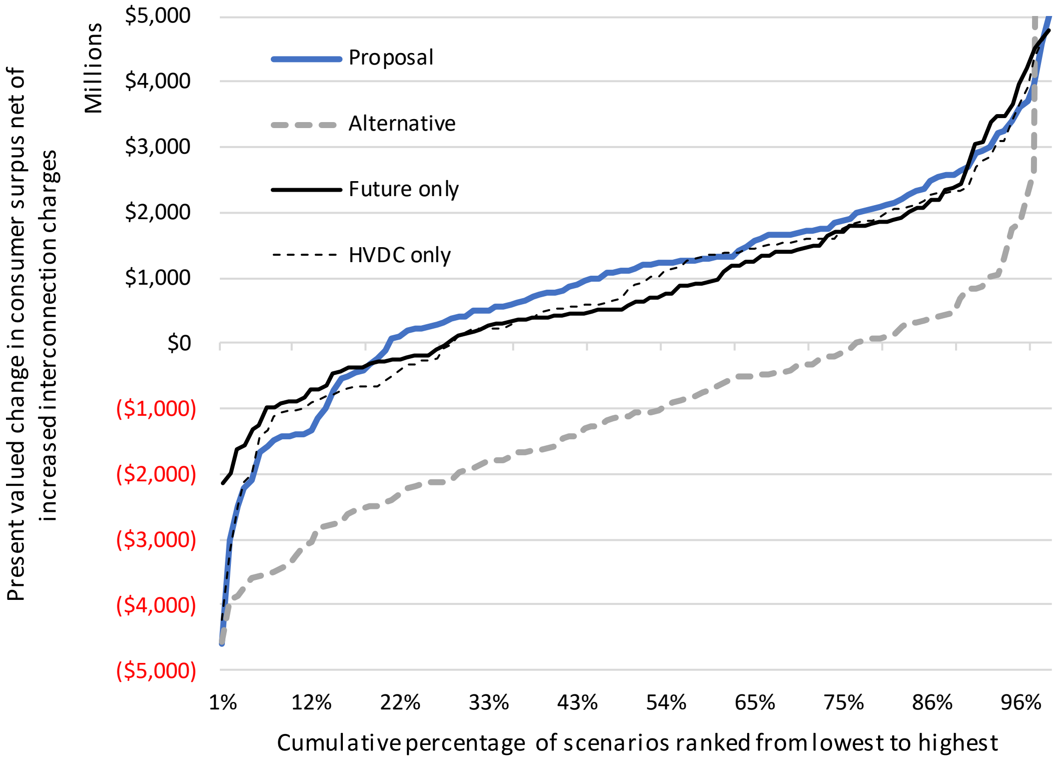
- identifying relevant data that describe the trend and variance for our key parameters
- fitting distributions to these parameters
- testing for dependencies between the parameters and distributions
- using the distributions to assign weights to the results of the sensitivities, based on the probability that different parameter values jointly occur.

2.18 This allowed us to test how sensitive results are to 113 different combinations of parameter values for each of the three scenarios under the proposal and the alternative, recognising that not all combinations of input values are equally likely. Appendix B provides more detail on the approach to weighting the scenarios for estimating the averages and ranges shown in Table 4.

2.19 Parameters explored and tested in this way are:

- **short-run generation costs** – changes in prices are an important driver of benefits. Prices in the model are derived from typical annual offer curves measured relative to short-run marginal costs. Producer price index data informs the latter's distribution
- **long-run generation costs** – the model's investment cycles are driven by a link between expected prices and long-run marginal cost. We test sensitivity of results to typical deviations in long-run marginal cost based on a capital goods price index
- **underlying electricity demand growth** – the future rate of demand growth is uncertain; the high grid demand scenarios in Transpower's Te Mauri Hiko publications imply the sector could experience double the rate of growth than we assumed under the central scenario.[2] We tested this with ranges based on fluctuations in gross national income (i.e. people plus purchasing power) large enough to encompass structural changes in demand related to technology
- **utility-scale battery investment costs** – battery investment costs in the CBA are in the bottom quartile of published estimates. We tested with higher battery investment costs and a slower rate of decline in investment costs.

Figure 1 Sensitivity of grid use benefits (consumer surplus)



Note: Top of y-axis is shortened to exclude two extreme values under the Alternative

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2 https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Energy%20Futures%20-%20Te%20Mauri%20Hiko%2011%20June%2718.pdf

https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf

2.20 Figure 1 above presents the results ranked from low to high. It illustrates the results are highly sensitive to changes in parameter values set out above. The figure, to be read with Table 4, shows:

- around 80% of simulations of the proposal show an increase in net consumer surplus, with a median of +$1.13b and weighted mean of +$0.97b.
- the proposal typically has higher benefits than the other scenarios, although the future-only scenario is better at the high and low end of these distributions.

2.21 We also tested the sensitivity of the grid use model results to changes in the following assumptions:

- **implementation date** – the model assumes a start date of 2022. Some submissions prefer a longer implementation. A delay to 2024 would delay the onset of benefits, reducing the net benefit under the TPM proposal 'central' scenario by 30%
- **Huntly closures** – results are not very sensitive to the decommissioning of Huntly generation: the net benefit reduces by 3% if decommissioning does not proceed.

Areas of uncertainty not quantified in the CBA

2.22 The CBA has not examined or sought to quantify several other areas of uncertainty, at least not directly.

2.23 The CBA sensitivities set out above cover material changes in demand and costs arising directly because of a change to the TPM. The CBA simulations do not cover material changes in demand and costs caused by other factors, such as substantial or sharp shocks like the impact of COVID-19 on the New Zealand and global economies, or the demand shock caused should the Tiwai Point aluminium smelter close.

2.24 A significant reduction in economic activity caused by COVID-19 could substantially affect demand and supply dynamics in the electricity market. It is conceivable there could be a substantial and sustained reduction in industrial demand (10% or more). This could also lead to the stranding of some supply-side assets – whether generation or transmission assets.

2.25 We have not examined areas of uncertainty caused by actual or possible external events such as this, because modelling the potential impacts of specific significant external events[3] is outside the scope of a CBA on examining the likely balance of effects of the proposal on consumers. In the case of the current risks from COVID-19, it is also simply too early to make a reasoned assessment of the likely effects over a timeframe relevant to this CBA.

2.26 There is also no strong reason to believe that a significant negative demand shock would change the qualitative conclusions reached in the CBA. Indeed, a substantial negative demand shock would only exacerbate negative effects on consumers of transmission prices that unduly constrain peak demand for electricity under the current TPM. This is because interconnection charges would be recovered over a smaller quantity of peak electricity demand, leading to higher RCPD charges per kWh, leading to further dampening of peak demand and even higher RCPD charges per kWh (a price spiral effect).

3 For example, an assessment of a substantial demand shock requires careful consideration of both supply-side responses. Such analysis ought to be more detailed and more focused on the specifics of the demand shock and ramifications than is required of the analysis in this CBA.

2.27 In addition, negative demand shocks would not negate the benefits from allocating charges on the basis of benefits and encouraging increased scrutiny of transmission investment plans. For example, if the Tiwai aluminium smelter were to close, some transmission investment plans might be deferred, but other plans might be brought forward if, for example, the reduction in load reveals generation export constraints in some parts of the country.

2.28 The range of demand sensitivities modelled cover significant shifts in demand over a long period of time in a more general sense.

Some assumptions in the CBA have been overtaken by time

2.29 This paper explains how we have changed aspects of the 2019 CBA in response to feedback from stakeholders and how these revisions impact the costs and benefits identified in 2019. The aim of these revisions has not included updating the underlying data or assumptions for new information we have become aware of by means other than reviewing submissions.

2.30 This does mean that various assumptions in the 2019 analysis may now appear out of date. For example, the COVID-19 has just resulted in the announced closure of the fourth potline at the Tiwai Point aluminium smelter. Another example is the Commerce Commission's reset of Transpower's regulatory revenue allowance for Transpower's regulatory control period (RCP) 3. This has resulted in Transpower's maximum allowable revenue falling by approximately 6%. There will be a number of other examples.

2.31 The sensitivity analysis discussed above provide a sufficient range of possible circumstances to cover the potential effects of such other changes in assumptions.

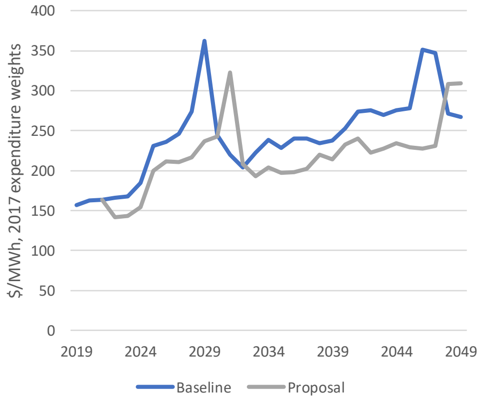
Consumer benefits from more efficient grid use sensitive to assumptions

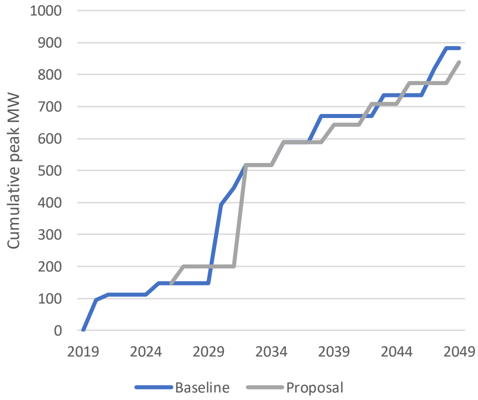
2.32 The diagram below illustrates the path dependence and sensitivity of 'grid use benefits' to factors that affect the speed and magnitude of supply response, using high and low generation cost scenarios (+/-10% shift in assumed fuel, capital and operating costs).

$/MWh incl. interconnection costs | **Generation Investment (cum. peak MW)**

Proposal's central scenario

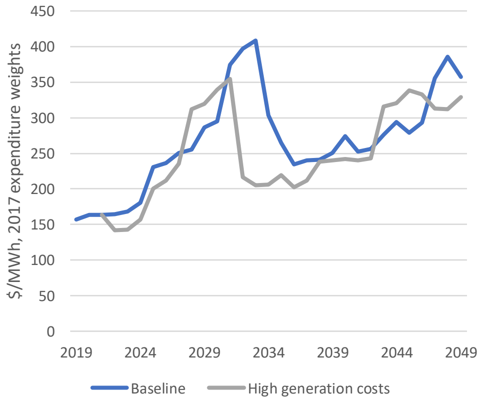
Rising gas prices and assumed closure of Huntly capacity creates a price spike in late 2020s. Higher demand due to the proposal brings forward generation investment, dampening prices.

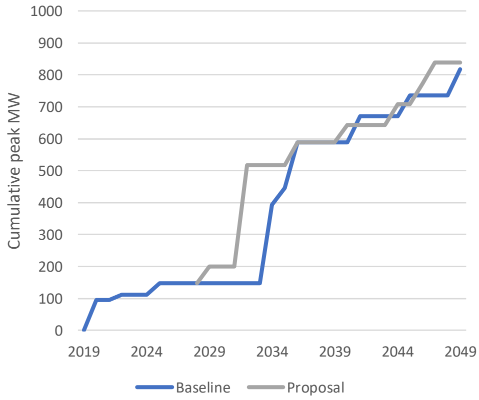




High generation costs scenario

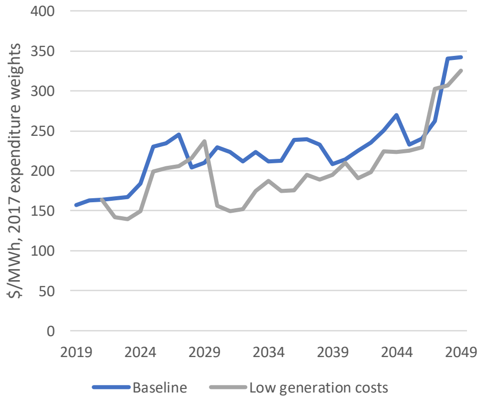
Prices rise higher before they stimulate investment, so consumers face higher prices, longer. Proposal increases demand, bringing forward investment. Lower prices benefit consumers.

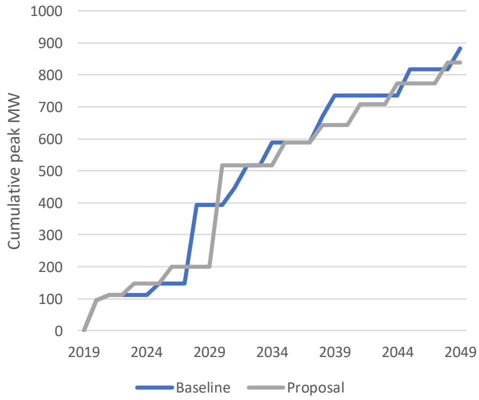




Low generation costs scenario

Prices do not need to rise as much to stimulate investment. This benefits consumers too. Low generation costs create similar dynamics as under the central scenario, but sooner.





Further tests of the robustness of the CBA results

2.33 The CBA results are sensitive to the timing of generation investment cycles, which can make a difference to the calculated net benefit.

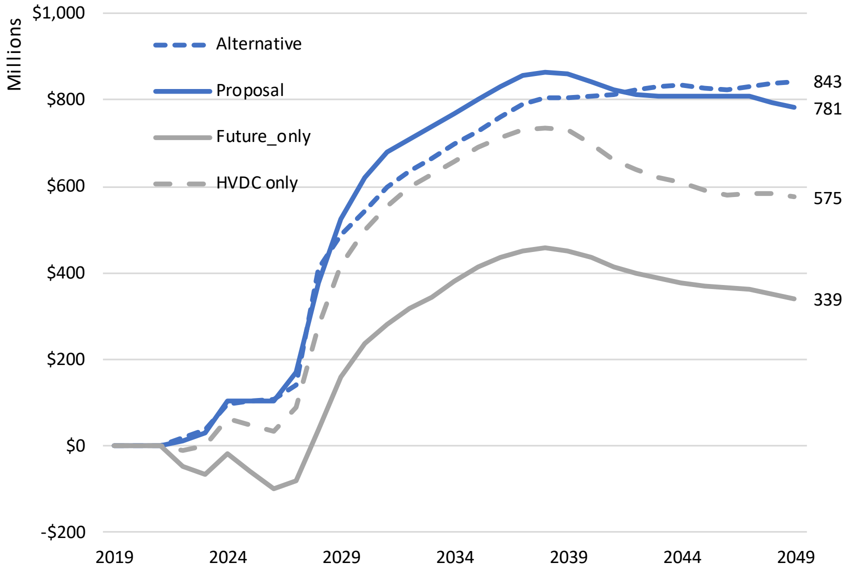
2.34 This sensitivity reflects the following dynamic: as demand increases, so do wholesale electricity prices. This increases generators' earnings and thereby their producer surplus.[4] Costs rise for consumers, reducing their consumer surplus. As wholesale electricity prices rise above the long run marginal cost of new generation, this new generation enters the wholesale market, and the additional capacity reduces wholesale prices. This in turn increases consumer surplus and reduces producer surplus.

2.35 This example also illustrates that choices of the timeframe over which to calculate net benefits may have a material effect on net benefits, as these are sensitive to discounting and end-point effects.

2.36 We therefore examined total market surplus to test whether timing differences are unduly influencing assessed net benefits. Total market surplus is the total of changes in producer surplus (i.e. earnings or revenue above costs) and changes in consumer surplus. This measure of welfare nets out a substantial amount of timing effects.[5] The role of total surplus in our analysis is discussed further at paragraph 5.10.

2.37 Figure 2 presents the assessment of total surplus changes for the different scenarios, to test for sensitivity of the CBA results to timing issues. The proposal is superior in total surplus terms to 'future-only' and HVDC-only scenarios. It tracks the alternative scenario closely, with the proposal being higher on average across 111 of 113 sensitivities. (The remaining two sensitivities are large outliers that drive the total surplus measure higher; and notably in terms of consumer surplus changes, 75% of sensitivities are negative under the alternative as explained at paragraph 2.13.)

Figure 2 Cumulative change in (mean) total surplus $m



4 The increase in generators' earnings from the price rise exceeds the fall in earnings from lower electricity consumption due to higher wholesale electricity prices.

5 This measure does not net out timing effects from external factors such as assumptions about rising fuel costs, which are assumed to rise in steps rather than gradually (e.g. the 2016 EDGS assumed that gas prices rise 26% between 2022 and 2026, exclusive of emissions costs).

3 Investment in utility-scale batteries

Feedback

3.1 Concerns have been raised that the scale of utility-scale battery investment modelled under the baseline was excessive, because the modelling:

(a) was "not determined by reference to a model of optimal decision-making in response to economic inputs"[6]

(b) assumed constant marginal profitability of battery investment while profitability is likely to decline as battery investment increases[7]

(c) used assumptions about battery operation (frequency of charge and discharge cycles) that were not based on hourly demand profiles[8]

(d) did not consider constraints on load shifting to avoid peak demand charges (the risk of creating new demand peaks)[9]

(e) did not include costs of connecting batteries to distribution networks[10]

(f) assumed a constant rate of decline in the capital cost of batteries, while the rate of decline is more likely to diminish over time[11]

(g) assumed that both battery costs and the costs of the non-battery components of utility-scale battery installations would decline over time at the same rate[12]

(h) excluded benefits from battery investment beyond price arbitrage and peak demand charge avoidance.[13]

Response

3.2 The Authority agrees the battery investment modelling used for its 2019 CBA did not account for constraints on load shifting and was not based on detailed modelling of battery operation by time of use. It also used a stylised, rather than an optimising, investment rule.

3.3 The Authority has therefore revised the battery investment model, with reference to John Culy Consulting's report for Trustpower and updated it in light of published estimates of utility-scale battery investment costs to:

(a) remove charging of batteries during the 1,600 trading periods that constitute the peak demand periods in the CBA's grid use model

(b) reflect a declining return on avoiding the RCPD charge as more batteries are used

(c) update the cost of battery investment in 2019 from $800k / MW to $1m / MW, using up-to-date assessments and meta-analyses

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6 HoustonKemp, for Trustpower, p. 54.

7 HoustonKemp, for Trustpower, pp. 54-55., John Culy Consulting, for Trustpower, p. 4., The Lantau Group, for the TPM Group, pp. 34-35., Orion, p. 5.

8 John Culy Consulting, for Trustpower, p. 4., Network Waitaki pp. 31-32.

9 John Culy Consulting, for Trustpower, p. 4.

10 Orion, p. 4.

11 John Culy Consulting, for Trustpower, p. 16 (footnote ii).

12 John Culy Consulting, for Trustpower, p. 16 (footnote ii).

13 Energy Trusts of New Zealand p. 4.

(d) adopt a slower rate of decline in battery costs out to 2050 (from a constant 7% per annum to a rate of decline that starts at 11% but declines to 2% per annum)

(e) base investment on the optimal MW of batteries installed, given marginal profitability and marginal costs, with expected earnings:

(i) based on detailed modelling of optimal daily battery charging and discharging given three years of data on wholesale electricity demand, wholesale electricity prices, and transmission interconnection charges

(ii) accounting for the effects on wholesale electricity prices of increased demand due to battery charging and increased supply from battery discharging.

3.4 See Appendix A for more detail on the modelling of investment in utility-scale batteries.

Effect

3.5 The revisions have reduced the benefits from avoided investment in utility-scale batteries. The main changes relative to the 2019 Issues Paper are:

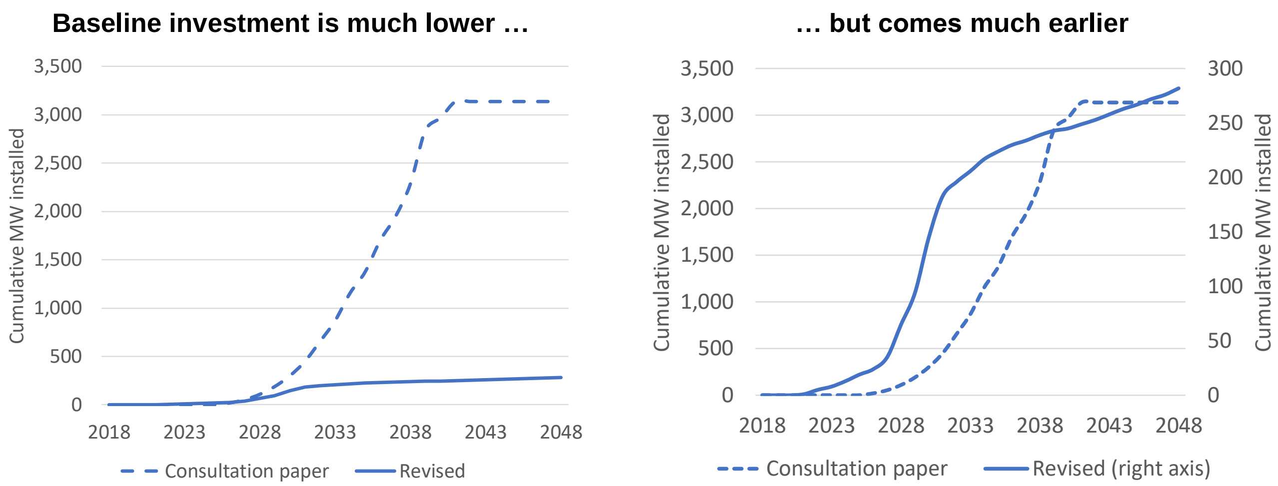
(a) batteries become economic sooner, with the first MW of battery investment occurring in 2022 in the baseline, compared to 2027 in the 2019 CBA

(b) the total investment in batteries is substantially smaller (see Figure 3):

(i) under the revised results for the baseline, a maximum of 280 MW of batteries are installed, compared with 3,000 MW in the 2019 CBA

(ii) under the revised results for the proposal, a maximum of 4 MW of batteries are installed, compared with a maximum of 914 MW in the 2019 CBA.

Figure 3 Changes to battery investment results (MW of capacity)



3.6 This result continues to highlight that the removal of the RCPD charge under the proposal eliminates the incentive to invest in utility-scale batteries for the sole purpose of transmission charge avoidance.

3.7 As the proposal does not affect or consider investments in batteries that participants make for reasons other than avoiding RCPD charges, the modelling or results presented here do not necessarily reflect the overall amount of future battery investment.

4 Formation of wholesale electricity prices

Feedback

4.1 Submitters questioned whether:

(a) modelled wholesale electricity prices adequately accounted for supply risks and all costs factored into wholesale market offers, such as the scarcity value of water[14]

(b) increased volatility in wholesale electricity prices was factored into generation investment decisions[15]

(c) the use of caps and floors on wholesale electricity prices undermined the robustness of the CBA results.[16]

Response

4.2 The Authority agrees with submitters that the wholesale electricity price formation module of the grid use model warranted revision. Wholesale electricity price formation was assumed to be a function of short-run marginal costs of generation. This affected estimates of the profitability of generation investment and (given also the investment rule used) notional floors and caps on wholesale electricity prices had to be used to prevent very high or very low modelled prices.

4.3 The Authority has amended its model so that formation of wholesale electricity prices is now based on the intersection of demand by time-of-use and typical annual offer curves based on offers from grid-connected generators for the 3 years 2015-2017 (thereby also accounting for the value of water). Offer curves are measured relative to short-run marginal costs, so the curves shift up or down as short-run marginal costs change over time. There is now no need to use floors and ceilings.

4.4 Consumers' price expectations (at each of the model's backbone nodes and by consumer type and time of use) have also been revised. Rather than being backward-looking, an adaptive expectations process takes account of the past two years' wholesale electricity prices inclusive of transmission charges and the current year's expected wholesale electricity prices.

4.5 The grid use model now also has a final pricing step where a year's final wholesale electricity prices inclusive of transmission charges, by modelled times of use, are set after all demand and all generation investment decisions have been determined. The earlier version reported prices based on consumers' expectations of wholesale electricity prices inclusive of transmission charges.

Effect

4.6 In the revised results, average wholesale electricity prices inclusive of transmission charges (weighted by 2017 expenditure shares by time of use and region) are projected to rise in line with the cost of thermal fuels and greenhouse gas emissions.[17] This effect was smaller in the 2019 Issues Paper, because larger amounts of generation investment suppressed wholesale electricity price increases.

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14 Electric Power Optimisation Centre p. 4.

15 Independent Electricity Generators Association p. 3., Flick Electric Co pp. 7-8.

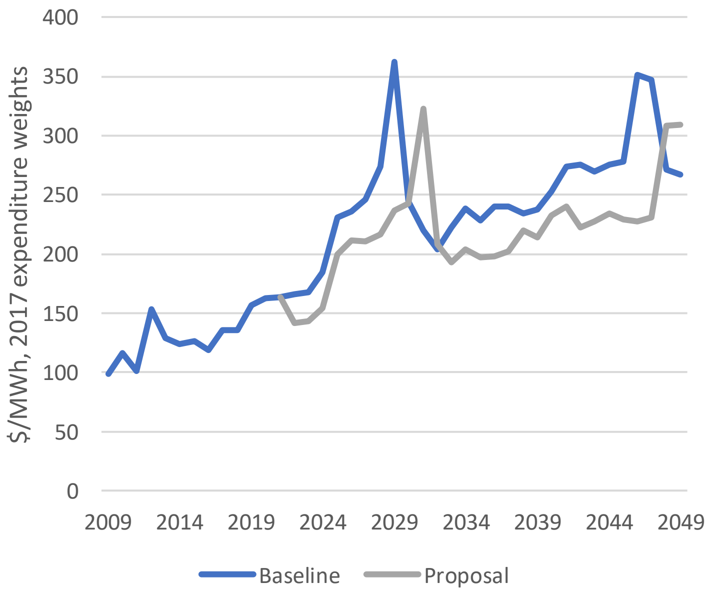
16 Axiom Economics, for Transpower, pp. 162-164.

17 The baseline wholesale prices align with long-term price levels in 2019 BusinessNZ Energy Council scenarios. https://bec2060.shinyapps.io/BEC2060/

4.7 The revised methodology based on offer curves allows for higher wholesale electricity prices inclusive of transmission charges in situations of generation scarcity. Spikes in wholesale electricity prices in the mid-to-late 2020s reflect decommissioning of Huntly capacity – 500 MW in 2024 and 50 MW in 2028.

4.8 The difference in wholesale electricity prices inclusive of transmission charges between the proposal and the baseline reflects generation investment occurring more quickly under the proposal. For example, under the proposal, a hydro station is commissioned in Marlborough in 2027, but under the baseline it would not be commissioned until 2031.

Figure 4 Average wholesale electricity prices incl. interconnection charges



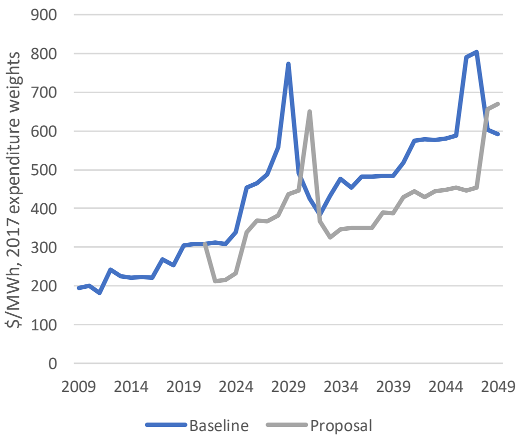
4.9 The cumulative effect of decommissioning Huntly capacity causes a price spike in 2029 under the baseline, but under the proposal it does not occur until 2031 and is not as high.

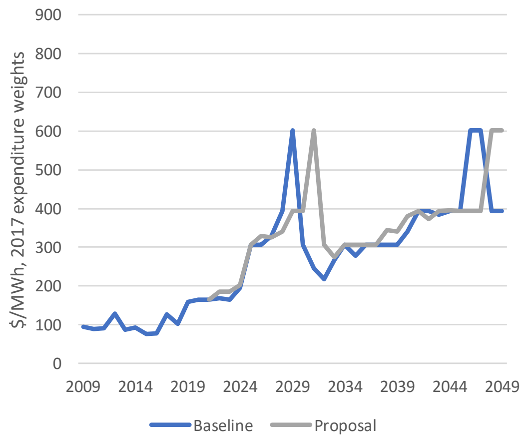
4.10 In the 2019 Issues Paper, large numbers of batteries caused much higher average wholesale electricity prices inclusive of transmission charges under the baseline in later years compared to the proposal. This effect is no longer apparent because battery investment is substantially reduced.

Figure 5 Annual wholesale electricity prices

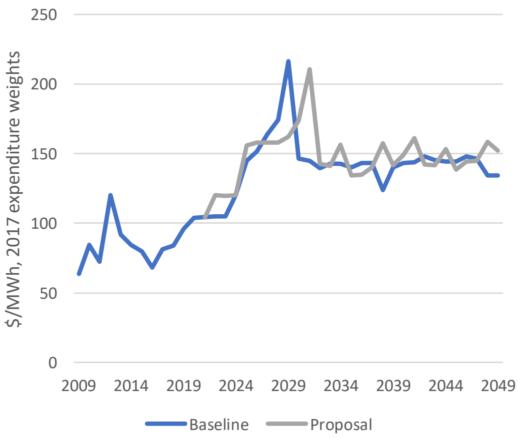
Inclusive of interconnection charges | **Exclusive of interconnection charges**

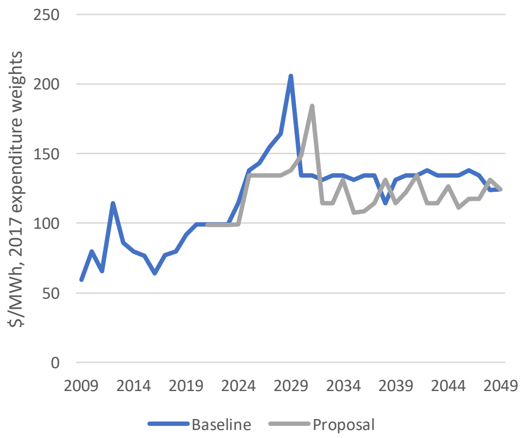
Peak



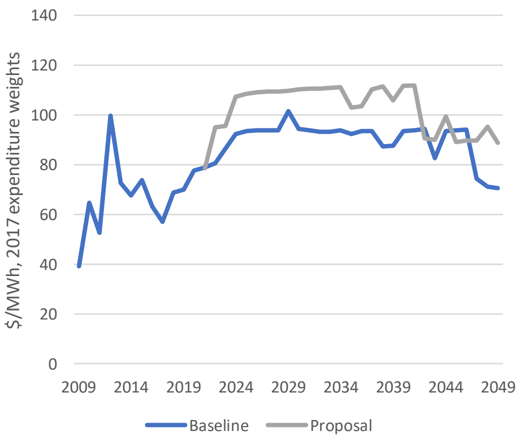


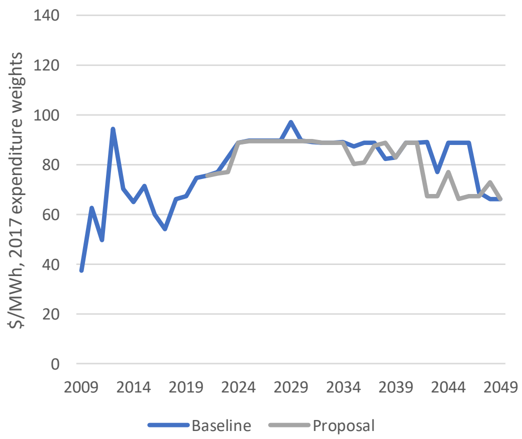
Shoulder





Off-peak





5 Investment in new electricity generation

Feedback

5.1 Submissions raised a number of concerns that the approach to modelling new generation investment in the 2019 Issues Paper led to "…what appear to be odd outcomes. It would be preferable to use more sophisticated investment decision-making rules."[18]

5.2 Outcomes produced by the model that raised concerns were that:

(a) generation investment occurs while wholesale electricity prices are falling[19]

(b) increased electricity demand causes lower wholesale electricity prices[20]

(c) generation investment occurs despite inadequate revenue to recover the costs of new generation investments[21]

(d) there is inadequate accounting for suppression of wholesale electricity prices caused by generation investment.[22]

Response

5.3 The Authority agrees that the decision rule used in the grid use model could be more nuanced. It did not adequately account for the effect of new generation investment in suppressing wholesale electricity prices. Some generation investments were modelled as taking place when it was unclear whether these investments would be profitable.

5.4 The grid use model assumed generation investment would occur if earnings in the first year of investment (expected wholesale revenue less short-run marginal costs and interconnection costs) at least recovered long-run marginal costs. Expected revenue was based on wholesale electricity prices in the year prior to investment. This did not account for the effect of increased generation on wholesale electricity prices.

5.5 The decision rule included a constraint on the maximum number of generation investments that occurred in a single year, to moderate the potential for large reductions in wholesale electricity prices from large multi-generation plant investments. However, this constraint was an assumption.

5.6 Under the revised decision rule, earnings on new generation investments are based on the price investors would receive once their capacity and offers are added to the market.

5.7 This amendment removes the need for assumptions about the number of generation investments that would occur in a single year. Instead, a sequential decision rule is used, where multiple generation investments in a single year can only occur if all investments are profitable after accounting for the collective effect of these investments on suppressing wholesale electricity prices.

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18 NERA Economic Consulting, for Meridian Energy, cross-submission p. 4.

19 Axiom Economics, for Transpower, p. 86. ENA p. 12., HoustonKemp, for Trustpower, pp. 55-62. Oji Fibre Solutions p. 4., Electra p. 6., Mercury p. 8. Mercury cross-submission pp. 3-4,

20 Axiom Economics, for Transpower, p. 86. HoustonKemp, for Trustpower, pp. 55-62.

21 Axiom Economics, for Transpower, p. 80. HoustonKemp, for Trustpower, pp. 55-62. Northpower p. 9. Independent Electricity Generators Association p. 4.

22 HoustonKemp, for Trustpower, pp. 55-59.

Effect

5.8 The revised generation investment rule in the grid use model results in less generation investment compared to the results in the 2019 Issues Paper (which had 1–1.5 GW of generation investment). In the revised results, generation investment totals 838 MW under the proposal and 885 MW under the baseline.

5.9 Although accelerated generation investment under the proposal is a key driver of benefits, there are periods where generation investment is higher under the baseline. See Table 5 and Figure 6. This reflects:

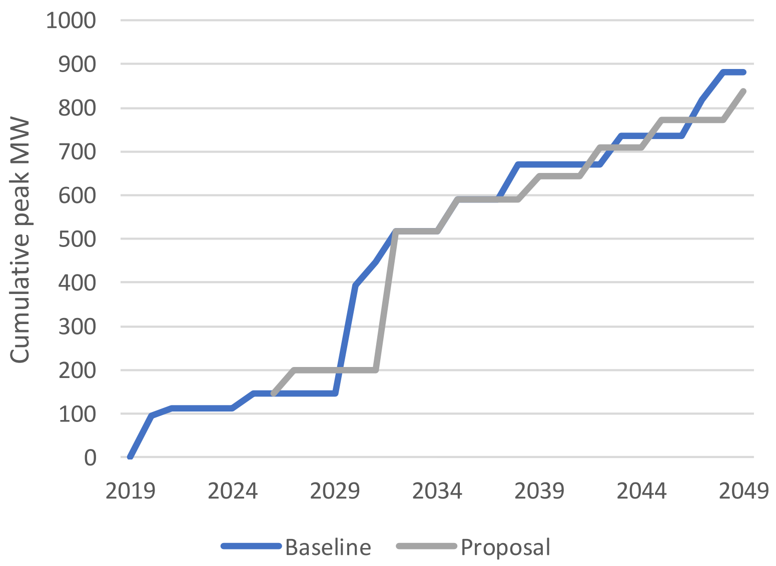
(a) higher electricity demand under the baseline, for the purpose of charging batteries (because of losses during battery charging and discharging), and

(b) the prior investment under the proposal moderating wholesale electricity prices and delaying the need for further new generation investment.

Table 5 Modelled commissioning of generation investment

Node	Fuel	MW	Cost ($m)	Baseline	Proposal	Impact of proposal
SFD	Gas	95	104	2020	2020	
BEN	Hydro	17	41	2021	2021	
BEN	Hydro	35	113	2025	2025	
BEN	Hydro	247	1,059	2030	2032	Later
KIK	Hydro	53	292	2031	2027	Sooner
ISL	Hydro	70	292	2032	2032	
RDF	Wind	73	593	2035	2035	
BPE	Wind	81	684	2038		Not under proposal
TWI	Wind	53	433		2039	New
HAY	Wind	65	548	2043	2042	Sooner
BPE	Wind	81	685	2047		Not under proposal
HAY	Wind	65	548	2048	2045	Sooner
HAY	Wind	65	548		2049	New

Figure 6 Generation investment, cumulative peak MW



Generator surplus

5.10 A submitter noted the Authority omitted from its calculation of grid use benefits any increase in generator surplus that was genuinely new producer surplus, presumably because “the Authority’s focus is on changes in consumer surplus”.[23] This was despite such generator efficiency gains arguably representing a gain for society (through cheaper generation being used under the proposal than under the baseline).[24]

5.11 There is some debate over the meaning and value of producer surplus in long-run economic analysis. Practically speaking, some generator surplus (above short-run costs) is needed to attract new generation investment and to keep existing generating assets in useful operation. That is, all activities have an opportunity cost and investors will allocate their resources to something other than electricity generation assets if they are not achieving a reasonable return. But, beyond this, the meaning of producer surplus in long-run analysis is ambiguous, or at least is not a settled part of economics.

5.12 The Authority pursues improvements in the electricity market for the long-term benefit of consumers. These are likely served by regulatory or market settings that are conducive to entry by innovative suppliers and conducive to efficient investment.[25]

5.13 By contrast, settings that cause prices to fall so consumers are better off in the short run but that undermine profitability and the incentive to invest would not be for the long-term benefit of consumers. That is because such a situation can result in under-investment, reduced competition, higher prices and/or reduced quality of product/service over the long-term.

5.14 As such, the Authority agrees the effect of a policy change on producer surplus (or profits) is a relevant consideration. The revised generation investment rule in the grid use model enables the Authority to estimate generator surplus in a transparent manner. This in turn has enabled us to assess the total economic surplus associated with increased demand and subsequent generation investment in the wholesale electricity market under the proposal. We discuss our assessment at paragraph 2.33 above.

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23 NERA Economic Consulting, for Meridian Energy, p. 15.

24 NERA Economic Consulting, for Meridian Energy, cross-submission p. 6.

25 Refer to Appendix A of the Authority’s interpretation of its statutory objective, available at: https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011.

6 Cost of transmission investments brought forward

Feedback

6.1 Submissions on the 2019 Issues Paper included the following feedback on the estimates of grid investment brought forward:

- costs may be underestimated by an arbitrary averaging of costs across scenarios[26]
- incremental costs of grid investments could be higher than average costs.[27]

Response

6.2 High and low scenarios were averaged because the Authority considered that the method used to estimate the incremental costs of transmission was very conservative and significantly over-estimated the cost of transmission investment brought forward.

6.3 The source of the over-estimated costs was the combined effect of:

- treating Transpower's forecast transmission revenue per MW of peak demand[28] as being that necessary to maintain an optimal transmission investment path under the baseline
- multiplying this per MW value by the difference between anytime peak demand under the proposal and anytime peak demand under the baseline
- not adjusting the baseline forecast transmission revenue requirement for the significant reduction in peak demand due to large amounts of battery investment.

6.4 The Authority agrees the method for estimating additional transmission investment costs should be improved. The revised approach:

- is based on the estimated amount of transmission necessary to meet incremental demand per year in each of the four transmission pricing regions
- links our estimate of enhancement and development (E&D) transmission expenditure for 2035-2050 to major capital projects over this period.

Effect

6.5 The revised CBA now shows much less transmission investment needs to be brought forward to meet additional peak demand under the proposal. This is because, compared to the 2019 CBA, substantially reduced battery investment modelled as occurring under the baseline means peak electricity demand under the baseline continues to grow at a level that is closer to the level under the TPM proposal.

6.6 The cost of transmission investment brought forward is valued at $35 million. Offsetting this cost is the bringing forward of reduced transport costs (losses and constraints) from the additional grid investment. These lower transport costs are valued at $95 million.[29]

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26 Axiom Economics, for Transpower, pp. 164-165., ENA, p. 12. HoustonKemp, for Trustpower, pp. 50-51.

27 Tauhara North No. 2 Trust p. 4.

28 Peak demand over the years, starting in 2008.

29 This reduction in transport costs was also present in the 2019 Issues Paper, but it was obscured by the method used to estimate the incremental grid investment cost.

7 Benefits from increased scrutiny

Feedback

7.1 In terms of the estimate of benefits from increased scrutiny of transmission investments, feedback included that:

- it was unclear how increased scrutiny of proposed transmission investments could give rise to further savings[30]
- the estimate is based on only a single observation, so is not reliable.[31]
- it would be more likely that there would be increased litigation on every transmission investment proposal, increasing costs[32]
- reduced expenditure could involve costs or foregone benefits (fewer services, lower reliability or increased future expenditure)[33]
- participants may not have the skills or resources to submit a more efficient alternative investment proposal to the Commerce Commission.[34]

The Authority's current view

7.2 The Authority is of the view it is likely that increased scrutiny would further improve the efficiency of decisions. This view is based on its observations from the Commerce Commission's regulation of Transpower's expenditure over the past 10-15 years and the administrative settlement between Transpower and the Commission in May 2008.

7.3 The stakes for participants to get the right decision, by scrutinising proposals and revealing good information on the value to them, increase if participants face benefit-based charges.

7.4 The Authority agrees it would be desirable to have more than one observation to inform its choice of assumptions in its modelling. We consider a 1% - 4% productivity improvement is reasonable, but to ensure the quantitative estimate is conservative, the assumed productivity factors have been scaled down (see Table 6).

Table 6 Greater stakeholder scrutiny and input

Productivity improvement on:	Value
Major capex <u>reviewed</u> by the Commerce Commission	3% (was 4%)
Transpower's E&D base capex <u>not reviewed</u> by the Commerce Commission when approving RCP proposal (assumed share 30%)	3% (was 4%)
Transpower's E&D base capex <u>reviewed</u> by the Commerce Commission when approving RCP proposal (assumed share 70%)	1.5% (was 2%)
15% of Transpower's R&R base capex	1.5% (was 2%)
On R&R base capex not recovered via connection charges and on R&R base capex (assumed 15%) that could be recovered by deeper connection charges	0.5% (was 1%)

30 HoustonKemp, for Trustpower, pp. 71-72.

31 Axiom Economics, for Transpower, p. 102. HoustonKemp, for Trustpower, pp. 70-71. Northpower pp. 16-17. Mercury cross-submission p. 5.

32 Northpower p. 16. Electra p. 7.

33 HoustonKemp, for Trustpower, p. 71. Axiom Economics, for Transpower, pp. 102-103. Northpower p. 17

34 Fonterra p. 4.

7.5 The Authority also agrees it would be prudent to factor in some additional litigation costs under the proposal, reflecting the greater financial consequences for beneficiaries of a transmission investment. We have allowed for an additional six legal challenges to major capex investment decisions over the period of the CBA.[35]

7.6 Conceptually, the Authority agrees that increased scrutiny could lead to reduced transmission expenditure which then may result in inefficiently fewer services, lower reliability or increased future expenditure. We considered this possibility when estimating the potential benefits from increased grid scrutiny.

7.7 Our assessment was, and remains, that the reduced expenditure on which we based our productivity gain assumptions has not resulted in these things happening to date. The reasons for changes to Transpower's enhancement and development (E&D) base capex following the Commerce Commission's review of Transpower's regulatory control period (RCP) 2 proposal included: the deferral of need, use of non-transmission alternatives, and fewer 'economic projects' than anticipated.

7.8 The Authority's estimates do not rely on customers having knowledge or resources to submit alternative investment proposals to the Commerce Commission. Our proposal is based on the logic that customers have a stronger incentive to participate in the process for the proposed transmission investment if they face the costs of the investment. More information about their needs or concerns will identify the most efficient way forward.

7.9 It is anticipated that consumers use interest groups, such as consumer or industry representative bodies, for cost-effective engagement with these processes. Nevertheless, the reduction in our assumed productivity factors set out above was in part motivated by a consideration of an additional cost associated with stakeholders employing resources to scrutinise Transpower's investments.

Effect

7.10 The central estimate and range around the impact of greater scrutiny have been reduced.

7.11 The Authority considers this to be a very conservative quantification of the benefits of improved scrutiny. If there is insufficient scrutiny of large, long-lived projects this can lead to costly decisions without commensurate benefits.

7.12 The current TPM spreads the costs of investments across all customers, regardless of where they live, so that those who benefit from an investment are to a large extent subsidised by the rest of the country. This opens the door for investments where it is unclear the benefits are greater than their cost.

7.13 In 2019 the Authority proposed not to recover the remaining costs of the North Auckland and Northland Grid Upgrade, Otahuhu GIS, and Upper South Island Reactive Support through its proposed benefit-based charge for this reason, so that approximately $37m per year of charges would be included in the residual charge instead.

7.14 In this way benefit-based charging will guard against local consumers lobbying for costly investments, such as undergrounding of transmission lines, unless they are willing to pay the additional costs (See case study, 2019 Issues paper p12).

[35] Spaced evenly across the 30 years. Based on experience, we assume the cost would be approximately $1.5m across the Commerce Commission, Transpower, three main appellants, and 15 parties joining the legal challenge.

8 Benefits from increased investor certainty

Feedback

8.1 Three submitters said the Authority's estimate of the benefits of increased investor certainty did not rest on any evidentiary basis.[36] One submitter considered the 'benefits from increased certainty' calculations were a 'random number generator', because calculations relied on an assumed base level of 100.[37]

8.2 One submitter pointed out the Authority had made an algebraic error in its workings, which caused it to incorrectly express its formula for the equilibrium price and for the effect of uncertainty on price.

Response

8.3 The Authority agrees there is no strong evidence as to the right number that should be used to express existing effects of uncertainty in the New Zealand electricity market. However, it does not then follow that this effect should be left unquantified.

8.4 The model had been calibrated with information from a study of policy uncertainty and its effects on electricity distributors in the United Kingdom. This helps to provide a sense of the potential scale (order of magnitude) of potential effects. This is also buttressed by evidence from other markets.

8.5 The Authority agrees there was an algebraic error in the workings. The price effects of changes in uncertainty should be zero when uncertainty is assumed to have the same effect on demand and on supply. Correcting the calculation increases the estimated benefit from increased investor certainty.

8.6 The benchmark value of 100 used to express current uncertainty could, in principle, be calibrated to any number greater than zero, but it does have an interpretation that limits the reasonableness of a chosen number. For example:

- a value of 100 would imply that the market is currently 0.5% (236,000 MWh) smaller than it would be if there was no TPM-related uncertainty. This reflects a reduction in investment of $4.4 million per year
- a value of 1 would imply that the market is 0.005% smaller than it would be without any TPM-related uncertainty and the related amount of investment is a reduction of $44,000 per year
- a value of 200 would imply that the market is currently 1% (473,000 MWh) smaller than it would be if there was no TPM-related uncertainty. This reflects a reduction in investment of $8.7 million per year.

8.7 Furthermore, there are alternative methods for calculating the effects of uncertainty, which do not require setting the initial level of uncertainty in the market. These methods – fundamentally the same as those in the existing CBA – also result in benefits that are similar to, but larger than, the value of benefits presented in the existing CBA.

Effect

8.8 The central estimate and ranges have been increased accordingly.

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36 Northpower p. 20. HoustonKemp, for Trustpower, pp. 72-74. Axiom Economics, for Transpower, pp. 103-105.

37 Axiom Economics, for Transpower, p. 104.

9 Current views on some other matters raised

CBA does not count transfers as benefits

Feedback

9.1 Several submissions asserted the CBA is invalid because it counts wealth transfers from producers to consumers as benefits.[38] These transfers are thought to arise as a result of declining prices which benefit consumers at the cost of generators. Axiom Economics (p.91) claimed the CBA framework is inconsistent because it treats changes in wholesale electricity prices as benefits but changes in interconnection charges as transfers.

The Authority's current view

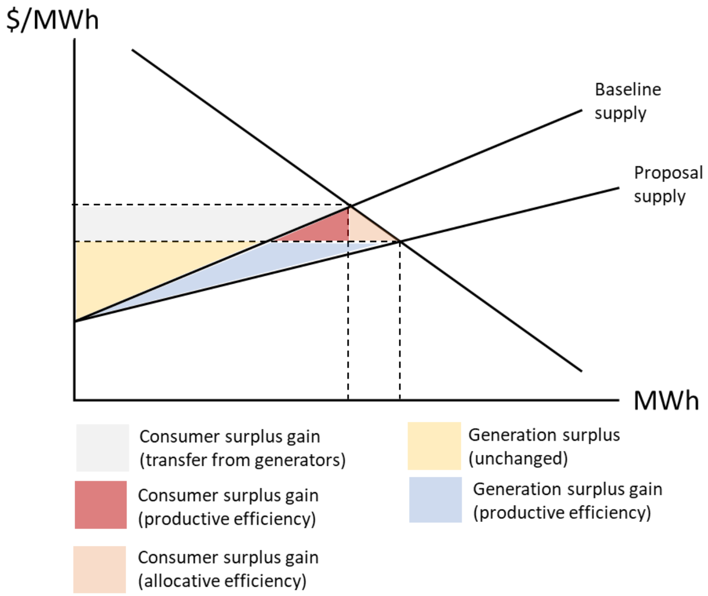
9.2 The Authority considers the CBA does not treat transfers as benefits. Lower costs (and so lower wholesale electricity prices) are from efficiency gains, which are benefits.

9.3 If new generation investment lowers wholesale electricity prices, then consumers will likely benefit from lower prices and higher consumption. Of course, existing suppliers may lose profits and market share, but that is not a cost but an efficiency gain that should be counted as a benefit. Note, we do not count increases in wholesale electricity prices as transfers from consumers to producers, but as cost changes.

9.4 The proposal does not force lower wholesale electricity prices on producers. Lower prices result from market-driven changes, with producers investing voluntarily. Rising wholesale electricity prices bring forward generation investment, in turn reducing wholesale prices. The net impact on wholesale electricity prices over time determines whether the overall effect is positive or negative.

A diagram presented by NERA for Meridian (p.15) and based on one shown at the Authority's September 2019 CBA workshop illustrates the effects the CBA is capturing.[39]

Figure 7 Long run energy price effect



38 Axiom Economics, for Transpower, p. 80., HoustonKemp, for Trustpower, pp. 43-46., ENA p. 13., Vector pp. 15-16., Northpower pp. 9-10., The Lantau Group, for the TPM Group, cross-submission p. 31.

39 NERA Economic Consulting, for Meridian Energy, p15 and cross submission p5

9.5 NERA disagrees with some submissions suggesting the Authority counts transfers as benefits. The figure shows a change in investment changes the long run supply curve, leading to a mixture of efficiency gains and changes in allocation of surplus (i.e. gains from trade). The key point of this diagram is to illustrate how efficiency gains result in lower prices and benefits to consumers.

9.6 The Authority agrees the CBA did not necessarily discuss or decompose the implied effects of changes in prices on the profitability of new generation investment; and the combination of low wholesale electricity prices and increased generation investment raised legitimate questions about transfers. However, these questions do not arise under the amended generation investment rule.

9.7 On a related point, the Authority also considers that it is not correct to say the CBA framework is inconsistent because it treats changes in wholesale electricity prices as a cost or benefit but changes in interconnection charges as transfers. The starting point of virtually all welfare analysis on revenue recovery or tax collection is that the revenue will be used to provide valuable services – here transmission services. Costs only arise from how taxes are collected.

9.8 Under the proposal, consumers will on average pay higher interconnection charges. As total transmission charges would not change, all else constant, the higher average interconnection charges paid by consumers is not an extra resource cost and should not be treated as a welfare cost, but as a transfer from consumers to generators. Therefore, to understand the net efficiency effects of the proposal, the transfer – the increase in interconnection revenue recovered from consumers – must be netted off (or else a total surplus measure of welfare changes used which automatically nets out these transfers).

The CBA captures generation investment costs

Feedback

9.9 Submitters raised a concern that the CBA model omits generation investment costs, and that these should be subtracted from the net benefits (just like avoided investment in batteries was added to the benefits).[40]

The Authority's current view

9.10 The Authority considers that generation investment costs are captured in wholesale electricity market prices.

9.11 There are two mutually exclusive ways to measure costs of supply. One is to measure changes in investment costs. The other is to measure changes in the costs of supply as measured by output prices and quantities (i.e. revenue).

9.12 In principle, these two measures produce the same result, on average. There are good reasons for the Authority's approach. This is because results can differ in practice, depending on how final investment costs or prices are treated. For example, if a large generation investment occurs towards the end of the CBA period, any value attached to the investment at the end of the period needs to be deducted from the investment cost. CBAs can be quite sensitive to such adjustments, although using a long timeframe can substantially reduce this sensitivity because of discounting.

9.13 Similarly, when supply costs are measured by prices, these costs will rise and fall due to investment cycles (i.e. prices will tend to rise and then fall after large investments are made). In the 2019 CBA, this effect was quite pronounced, with large generation investments causing wholesale electricity prices to fall for long periods even though demand growth would be expected to cause prices to increase in future. This can make the CBA results sensitive to the scale and timing of generation investment.

9.14 An alternative approach is to use changes in the long-run marginal costs of generation—i.e. the average long-run per MWh cost of the next cheapest (or most recent) generation investment. This does not eliminate the sensitivity of CBA results to the timing of investments, but it does eliminate sensitivity to the effects of investment cycles on prices. However, investment cycles are an important measure of market efficiency. Further, capital or fuel costs say nothing about value, unlike output prices which reflect consumer willingness-to-pay or value. Hence, our preference for using the output price measure.

9.15 The CBA uses a different approach in the case of avoided costs of battery investment. The reason is that the reduction in battery investment under the proposal, relative to the baseline, reflects the removal of a non-market price (the RCPD charge) that incentivises battery investment in the baseline. Because the RCPD charge is not a market-determined price, it is inappropriate to rely on market prices when measuring the benefit of avoided battery investment. Instead, this benefit should be measured based on the change in battery investment costs.

[40] Axiom Economics, for Transpower, pp. 95-97. HoustonKemp, for Trustpower, pp. 46-50. The Lantau Group, for the TPM Group, pp. 33-34 and cross-submission p. 19 (footnote 22). ENA p. 8. Northpower p. 10 11. Tauhara North No. 2 Trust p. 4. Vector p. 15. Mercury cross-submission p. 4

Appropriate not to account for extra distribution network costs

Feedback

9.16 Several submissions consider the CBA should include the cost of distribution network investment that would be needed to support increases in forecast peak demand under the proposal.[41]

9.17 Costs on distribution networks from increased peak demand were estimated in one submission to equal to $27m - $81m[42] and $106m - $428m in another.[43]

The Authority's current view

9.18 The estimated increase in peak demand under the proposal might bring forward additional distribution network investments, but this is not a given, because the estimated increase in peak demand is small (1%). There may be localised capacity issues, however distributors' load factors in general do not indicate a pressing issue[44] noting that distributors have other options available for efficient cost management (such as introducing more efficient distribution pricing or continued use of ripple control). This is why it is important that distribution price reform continues at pace.

9.19 The Authority also considers that if additional distribution network investment were needed, then the additional costs would likely be offset by increased benefits to consumers (unless the investments are inefficient).

9.20 When submissions cite the costs of additional network investments to be made due to the removal of inefficient price signals, these should also recognise the benefits to consumers from local network expansion – benefits that can be valued separately based on the substantial difference between wholesale prices at the point of connection and delivered electricity prices at the ICP. These benefits are in addition to those already captured by the analysis, which stops at the point of grid connection.

9.21 If demand for distribution services expands due to removal of inefficient price signals, then supply costs will increase but the cost increase will be offset by increased benefits to consumers.

9.22 This point is illustrated in the diagram below. This diagram depicts final peak demand for electricity, inclusive of distribution charges, and the effects of a transmission charge per MW of peak electricity demand.

9.23 The charge, because it is linked to quantities consumed, suppresses demand and creates a deadweight loss from unserved demand – the shaded triangle. When the charge is removed (with revenues to be recovered in a different, less distorting manner), demand increases, and the deadweight loss is eliminated.

9.24 The mechanics of price and demand adjustment are complicated by distribution networks having fixed capacity in the short-run. In the above paragraph it was assumed

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41 Axiom Economics, for Transpower, pp. 94-95. HoustonKemp, for Trustpower, pp. 46-50. NZIER, for MEUG, p. 8. Northpower p. 10. Vector p. 15. Electra p. 7. Energy Trusts of New Zealand p. 8. ENA p. 8, and cross-submission p. 2. Mercury cross-submission p. 4. Ecotricity et al cross-submission, p. 3. The Distribution Group p. 17.

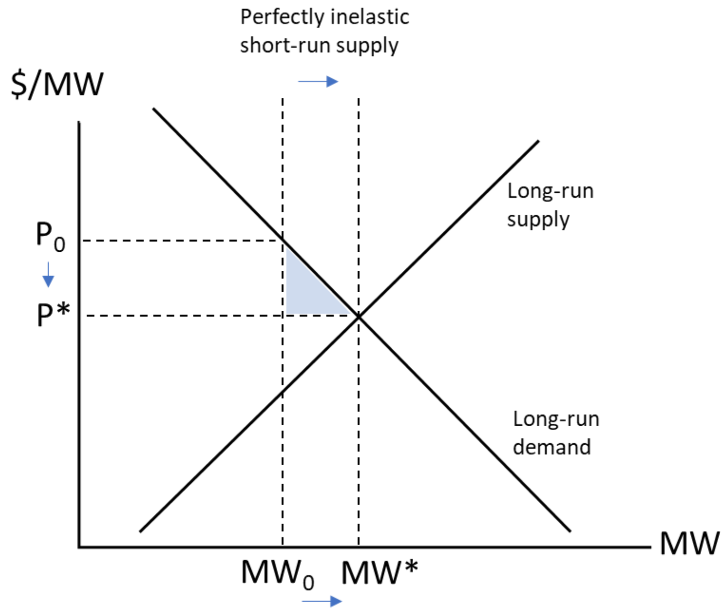
42 Axiom Economics, for Transpower, p. 95.

43 HoustonKemp, for Trustpower, p. 50.

44 See, for example, load factors (peak demand /installed transformer capacity) reported by distributor at pp 84-85 of Counties Power's Asset Management Plan at https://www.countiespower.com/vdb/document/130

that network capacity was MW*. But if network capacity was MW^0 then price P_0 is consistent with demand being constrained to short-run capacity. As such, demand can only increase if there is an incremental expansion of fixed capacity (i.e. the short-run perfectly inelastic supply curves). This gives rise to a net benefit from expansion of both supply and demand.

Figure 8 If costs increase then so do benefits



9.25 Increased distribution costs, from increased peak demand, would not create net economic costs unless there are significant regulatory or market failures that prevent efficient adjustment of distribution networks to higher levels of demand.

9.26 The Authority's view does assume that distribution pricing is efficient (in that consumers face the cost of distribution services). If distribution pricing is not efficient, it is possible that the current inefficient transmission charge acts like a correcting tax, and that without it there could be inefficient investment in distribution networks.

9.27 However, the transmission charge may be over- or under-correcting for inefficient distribution price signals. The CBA takes the middle road – assuming no net under- or over-correction of distribution price signals via the current transmission charge.

9.28 The decision to exclude distribution costs and benefits and to analyse costs and benefits at the point of grid connection was also influenced by empirical considerations. There is no readily available time-of-use consumption data by ICP. Time-of-use is a critical issue in assessing the effects of transmission pricing in New Zealand. Demand varies by time, the value of electricity varies by time-of-use, transmission prices vary by time-of-use, and costs of network services vary by time-of-use.

The CBA model does use the appropriate baseline

Feedback

9.29 Some submissions contend that the CBA does not appropriately model the relevant baseline, because the RCPD charge is obviously too high[45] and distorts investment decisions[46] and can be changed within the current TPM guidelines.

9.30 Related concerns are that the baseline used did not encompass variations on current transmission charging, such as increasing the number of trading periods used to calculate the RCPD interconnection charge (as has been suggested by a number of submissions), or options in Transpower's 2016-17 operational review of transmission pricing.[47]

The Authority's current view

9.31 By convention, a CBA involves establishing a single quantified baseline against which alternative arrangements can be considered (though there may be circumstances that warrant a departure from this practice). The existing TPM is the most obvious baseline to use, as it has resulted from implementing the current guidelines, and because in this case the Authority considers there are no alternatives which have a reasonable prospect of occurring.

9.32 It is of course possible that Transpower could adapt the TPM to reduce the strength of the RCPD signal. However, this has not happened to any significant degree since this pricing methodology was introduced 12 years ago. Operational amendments to the TPM have been relatively minor, given the scale of changes to RCPD signals over the past 12 years. Between 2008 and 2015 the strength of the RCPD price signal rose by over 50% despite a substantial reduction in the economic cost of using the grid following a period of substantial grid investment.

9.33 The proposed TPM guidelines are intended to address the problem of an overly high RCPD charge, but also other fundamental problems with the current TPM. The Authority considers it appropriate (and consistent with its statutory objective) to consider the costs and benefits of solutions that also address these other problems.

9.34 However, the CBA does include an option (the alternative to the proposal), which increases the number of trading periods used to calculate the interconnection charge – from 100 trading periods to all 17,520 trading periods a year. This option could be implemented under the current TPM guidelines.

9.35 Many of the distortions that are created by the RCPD charge would continue irrespective of operational amendments – such as the RCPD charge being negatively correlated, over time with the economic costs of using the grid, and not correlated, except very weakly, with benefits of using the grid. These distortions are minimised if the RCPD charge is levied on all trading periods. Hence why this is being considered as the alternative to the proposal in the CBA. The CBA indicates this option is clearly inferior to the proposal.

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45 The Lantau Group, for the TPM Group, p. 3.

46 Professor Bunn, for Vector, p. 10.

47 Tauhara North No 2 Trust p. 3.

The CBA does assess the Authority's proposal

Feedback

9.36 Submissions also argue the CBA does not assess the Authority's proposal, because:

- it does not account for higher prices due to benefit-based charges[48]
- optimism bias has caused the Authority to ignore the effects of 'shadow prices' (from benefit-based charges) when using the grid use model[49]
- insufficient attention is paid to effects of benefit-based charges[50]
- the grid use model would predict the same outcome and produce largely the same benefit estimate for any alternative approach comprised solely of fixed charges.[51]

The Authority's current view

9.37 The Authority considers that the CBA does adequately take account of the effect of benefit-based charges as:

- the grid use model includes transport costs (LCE) that rise as grid demand increases relative to local supply, and these costs reflect the shadow prices of congestion and losses. Relieving these costs is a benefit from new grid investments
- under the baseline, interconnection costs are allocated to consumers in accordance with shares of peak demand (a proxy for RCPD). For a TPM based on the proposed guidelines, interconnection costs are allocated in accordance with shares of LCE (a proxy for benefits from economic investments) and shares of peak demand (a proxy for benefits from reliability investments)
- in preference to adding significant additional complexity to the grid use model, a top-down analysis of generation and load investment decisions was used to assess the high-level effects of benefit-based charges on discrete investment decisions
- rather than understate the effect of benefit-based charges on consumer demand, the grid use model tends to overstate this effect because benefits from reduced LCE are only used in assessing the proposal's effect on transmission investment.

9.38 The Authority's current view is that there is no issue with the CBA measuring the costs and benefits of recovering transmission interconnection revenue through less-distortive (fixed-like) charges. That these effects are common to a TPM based on the proposed guidelines as well as other possible TPMs does not diminish the value of assessing these effects in the case of the proposed TPM guidelines.

48 HoustonKemp, for Trustpower, pp. 65-67.

49 Axiom Economics, for Transpower, pp. 139-140

50 Professor Bunn, for Vector, p. 10.

51 Axiom Economics, for Transpower, pp. 99-100., Northpower p. 12., Entrust p.4.

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Papers are available at www.ea.govt.nz[52]

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NERA, 1 October 2019, *Review of Electricity Authority's transmission pricing review 2019 papers*, appendix to Meridian Energy Submission Transmission Pricing Review: 2019 Issues Paper

NERA, 31 October 2019, *2019 transmission pricing review – a review of certain economic reports*, appendix to Meridian Energy cross-submission on Transmission Pricing Review: 2019 Issues Paper

NZIER, 1 October 2019, *TPM 2019 Cost benefit analysis, Initial review,* appendix to Major Electricity Users' Group: Consultation paper- Transmission Pricing review

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Rio Tinto, October 2019, *Cross-submission on the submissions to the 2019 issues paper Transmission pricing review: consultation paper*

The Lantau Group, October 2019, *Review of Transmission Pricing Guidelines Issues Paper 2019*, appendix to TPM Group, Response to Electricity Authority's 2019 Issues Paper on Transmission Pricing Methodology

52 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

Appendix A Revised battery modelling

A.1 The revised battery modelling calculates expected earnings per MW of battery investment with and without peak demand charges, based on a model of optimal dispatch calculated using 2017-2019 wholesale electricity market demand and price data by trading period.

A.2 Charging and discharging is determined using linear programming to find optimal dispatch to maximise revenue. Revenue is obtained by arbitraging wholesale electricity prices inclusive of transmission charges.

A.3 The methods are adapted from models used in Davies et al (2019).[53] The main adaptation is to restrict battery operation to account for the effects from charging and discharging of batteries on regional coincident peak demands and transmission prices. This includes an 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
- upper bound on **discharging** is held at zero where forecast regional grid export is a peak period and within 2% of minimum RCPD.

A.4 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.

A.5 The modelling is applied by transmission pricing region. This can be considered the same as assuming a single battery owner-operator per pricing region.

A.6 The model shows significant variation, within a year, of daily battery cycling. Figure 9 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).

A.7 Battery profitability is highest at low levels of total investment (see Table 7 below). Battery profitability is constrained, as the amount of batteries increases, because of:

- a narrowing of differences across wholesale electricity prices (high prices fall and low prices rise)[54]
- fewer opportunities to flatten load, to avoid peak demand charges.

A.8 Batteries are substantially more profitable with RCPD charges than without RCPD charges. Earnings are highest in areas with the peakiest load.

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53 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

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

Figure 9 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)

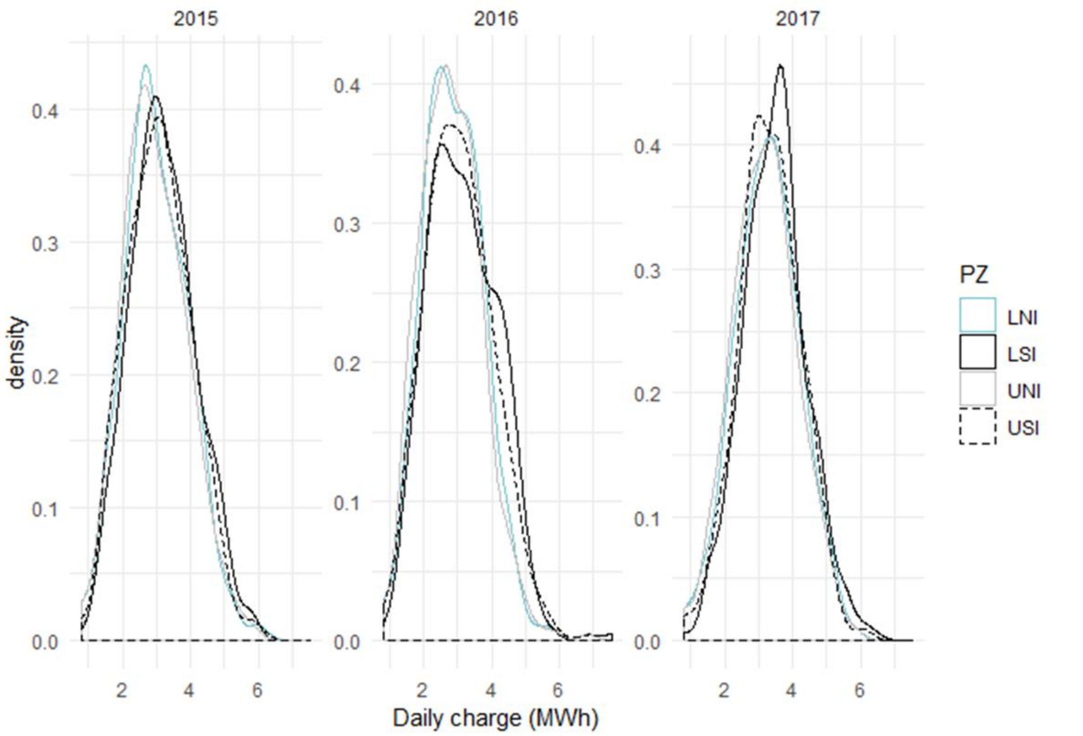


Table 7 Modelled average annual earnings per MW invested ($)[55]

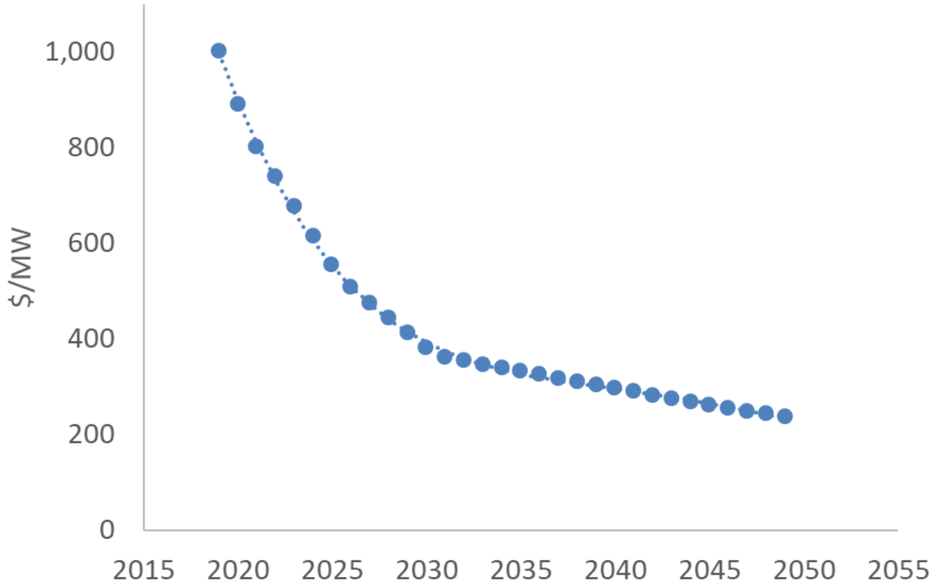
	Without RCPD charge, by pricing zone				With RCPD charge, by pricing zone			
MW	**UNI**	**LNI**	**USI**	**LSI**	**UNI**	**LNI**	**USI**	**LSI**
1	26,756	25,175	24,455	22,224	53,827	64,211	39,317	20,832
5	26,513	24,968	24,169	21,997	51,721	62,371	35,575	20,378
10	26,210	24,710	23,813	21,713	50,007	59,654	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

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

A.9 Battery costs have been revised to reflect recent analyses of current and expected battery costs, including operating and maintenance costs (fixed at 2.5% of capital costs).[56] Figure 10 below summarises the central projection for battery investment costs (present valued costs per MW).

Figure 10 Battery investment cost assumption

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



A.10 Under the revised CBA, large scale battery investment is now inhibited by a rapidly declining rate of return as total battery capacity increases, caused by:

- consumption in RCPD periods falling towards consumption in shoulder demand periods, making it harder to predict and shift load to avoid RCPD charges
- reduced opportunity for price arbitrage, as increased off-peak demand raises the cost of energy for charging batteries during off-peak periods.

56 Refer 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.

Appendix B Sensitivity analysis

Our approach to analysing the sensitivity of the grid use model

B.1 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 scenarios 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.

B.2 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, the approach involved:

- 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' scenario
  - the 'HVDC only' scenario
  - the alternative to the proposal
- weighting the model results by the relative likelihood of combinations of input assumptions.

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

B.3 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.

B.4 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.

B.5 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

B.6 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.

B.7 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[57]
- electricity demand growth shifters: -0.01, -0.005, 0.005, 0.01.

B.8 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.[58]

B.9 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.

B.10 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.

B.11 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.

B.12 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.[59] This compares to:

- a range for increased demand of 18% to 78% over 33 years in MBIE's 2019 refresh of its 2016 'Electricity Demand and Generation Scenarios'[60]

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

58 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.

59 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.

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

- 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*.[61]

B.13 (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.)

Simulations show significant variation in the grid use model's results

B.14 The simulations reveal significant variations in the grid use model's results, with large negative and large positive changes in consumer surplus depending on the sensitivity (see Figure 1 above).

B.15 There are no specific characteristics of the sensitivities to definitively classify, for example, high demand scenarios with high benefits. While most high demand scenarios have high benefits, some do not. In particular, different 'shocks' can push in different directions. For example, if demand is growing rapidly but generation investment costs constraint a supply response, then large price increases may cause welfare losses, or at least lower benefits compared to a situation with lower generation investment costs.

B.16 The Box over the page illustrates this point with some examples.

B.17 However, it is also the case that some input assumption values, and their combinations, have a higher or lower probability of occurring than others, which motivates our approach to assessing the **relative** likelihoods to weigh the different results.

Probabilities for input assumptions

B.18 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[62]
- analysing correlations between the series, to determine whether or not the probability distributions should be treated as independent probabilities.

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

62 For example: normal, uniform, exponential, logistic, beta, lognormal and gamma. 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).

BOX

By way of illustration, there are two outlier values under the alternative to the proposal. These simulations show changes in consumer surplus of $18-$19 billion (present values). By contrast, the third highest value is $2.6 billion.

The most extreme of these results reflects assumptions that provide high returns to investment and lower prices for consumers: high underlying demand growth, high short-run generation costs, and generation investment costs that are 5% lower, and battery investment costs that are 10% lower, than assumed for the ‘central’ scenario.

Under these assumptions, the model shows a substantial increase in investment in 2028 (see Panel A of Figure 11). Following the modelled decommissioning of 550 MW of generation at Huntly between 2023 and 2027, investment includes geothermal connected at Whakamaru (225 MW), wind generation connected at Redclyffe (81 MW in the Hawkes Bay), a capacity expansion to hydro generation at Benmore (247 MW), and two small hydro schemes in the upper South Island (totalling 122.5 MW).

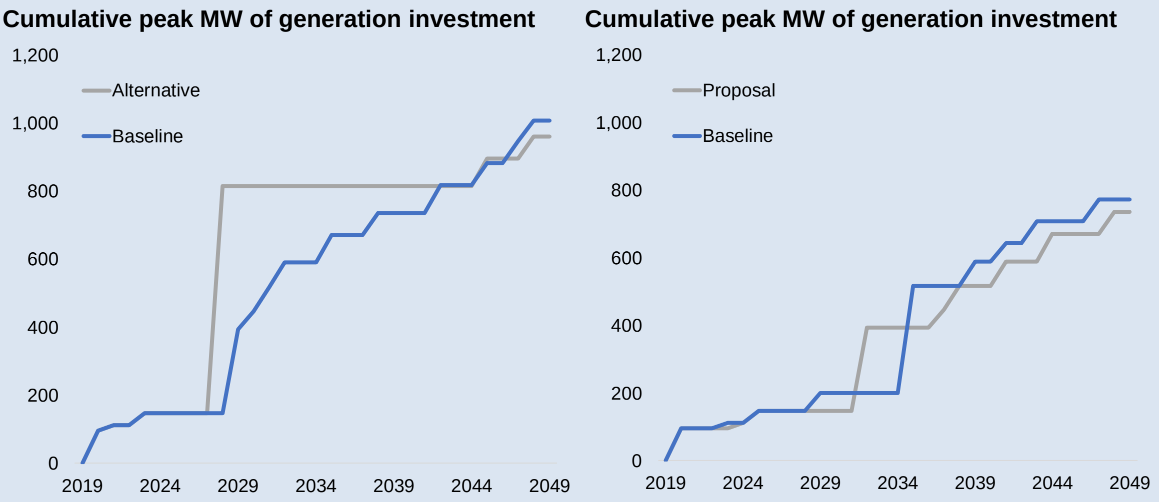
The simulation resulting in the largest negative change to consumer surplus under the alternative to the proposal only differs insofar as investment costs are not 5% lower than average. Under these conditions, generation investment does not proceed and consumers face substantially higher prices, on average, relative to the baseline.

Of all the simulations, the one with the largest reduction in consumer surplus is associated with low short-run costs of generation and high costs of generation investment. This comes from a simulation of the proposal ‘central’ scenario using short-run generation costs 20% below average and long-run generation costs 5% above average. Demand and battery costs are set at their average values.

Under these conditions, generation investment is lower under the proposal’s ‘central’ scenario than under the baseline, and off-peak electricity prices are sufficiently higher under the proposal’s ‘central’ scenario to make consumers worse off, despite a decline in peak electricity prices (see Panel B of Figure 11).

Figure 11 Generation investment in extreme scenarios

A. Largest increase in consumer surplus **B. Largest decrease in consumer surplus**



Short-run generation costs

B.19 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.

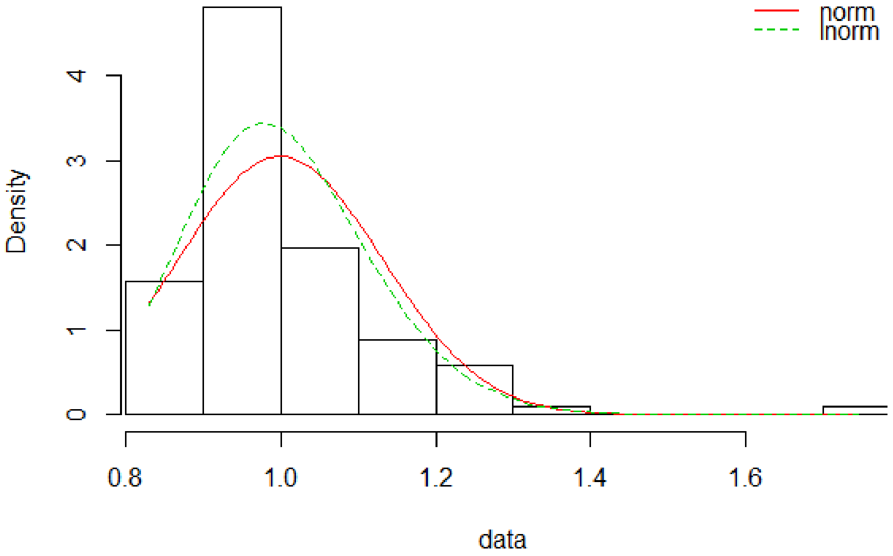
B.20 MBIE data on inflation-adjusted wholesale gas prices was also considered as a source of data on short-run generation costs. We decided not to use this data because:

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

B.21 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 12. The data in the plot are typical rates of increase after de-trending the data (deducting the average growth rate).

Figure 12 Distribution of changes in short-run costs

Data and fitted distributions: norm = Normal, lnorm=lognormal



Long-run generation costs

B.22 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.

B.23 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.

B.24 There are strengths and weakness in using any of these series to characterise long-run generation investment costs.

B.25 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).

B.26 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.

B.27 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.

B.28 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

B.29 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.

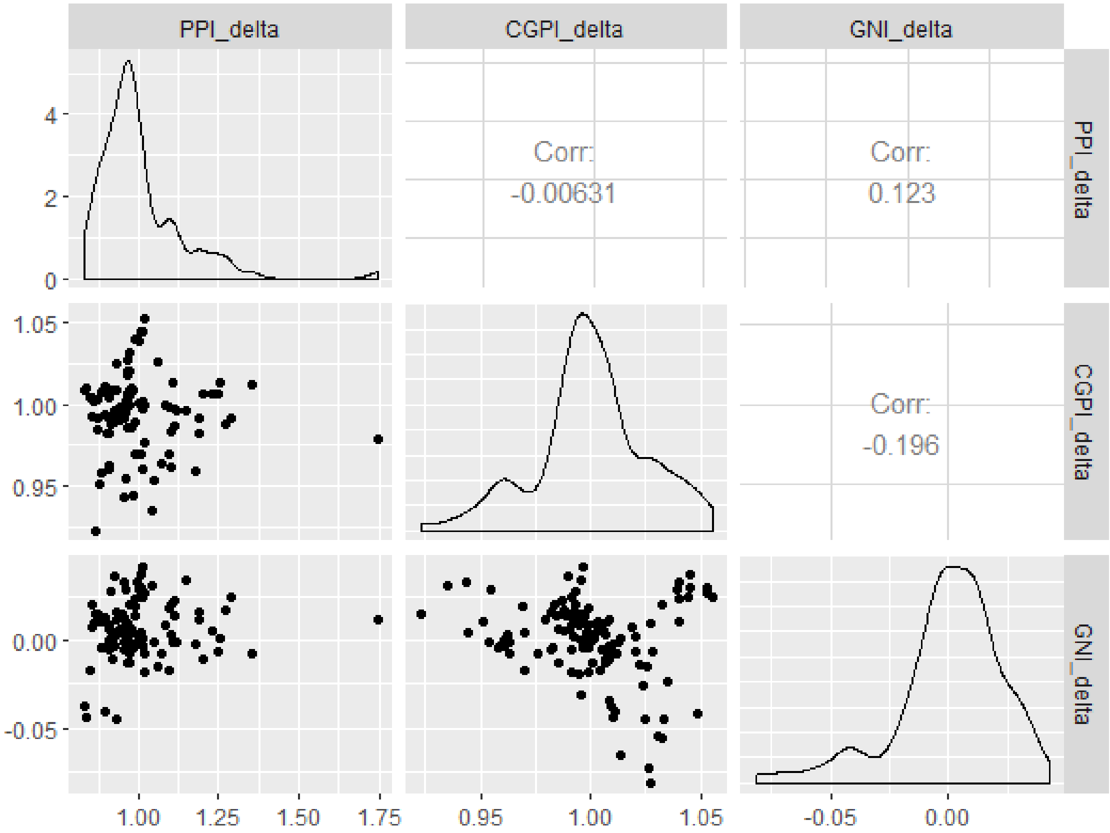
B.30 The distribution with the best fit for this data is a normal distribution, with a mean of 0 and a standard deviation of 0.011.

Distributions assumed to be independent

B.31 We have assumed the probability distributions chosen to depict variations in input assumptions are independent of one another.

B.32 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 13 below, which shows that the largest correlation is only -0.196 – between deviations in GNI (‘GNI_delta’) and deviations in the CGPI.

Figure 13 Correlations between data used for input assumption probabilities



Using probability distributions to weight model results

B.33 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.[63]

B.34 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, 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 proposal's 'central' scenario (the central simulation (np_s)).

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. $w_s = np_s / \sum_s np_s$.

63 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.

Results are robust to changes in the weightings used

B.35 Key questions for this CBA are:

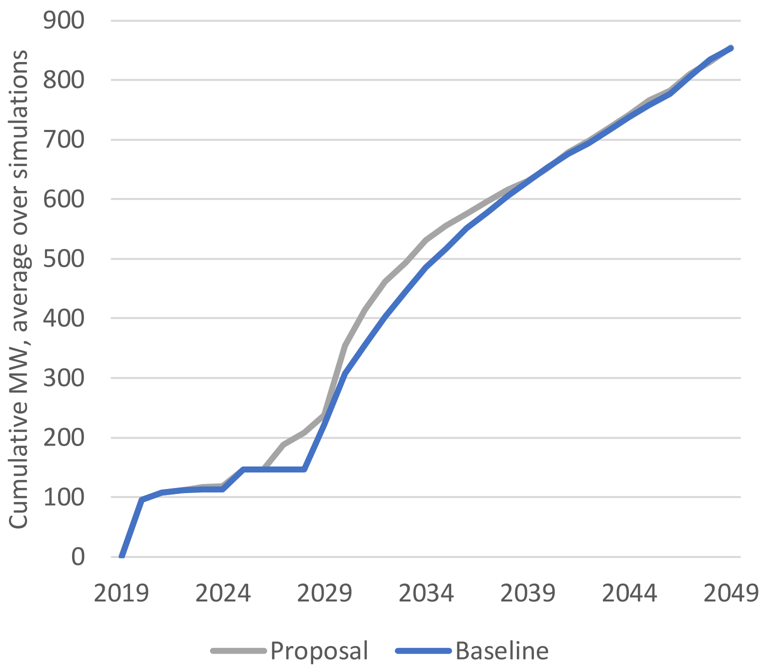
- To what extent are the findings robust, on average, to variations in input assumption values?
- Do the selection of input assumption values used, and the approach to weighting the results, cause the grid use model results to be biased in one direction or another?

B.36 The latter is particularly important given that small deviations in parameter values can create large deviations in overall results

B.37 To further test the robustness of the grid use model results, we carried out a limited Monte Carlo analysis. This involved 300 simulations of each of the proposal's 'central' scenario and the baseline, with parameter values drawn at random from the distributions specified above. Monte Carlo analysis is typically carried out using thousands of simulations but, as noted above, this was computationally impractical. But we consider that 300 simulations are sufficient for testing the sensitivity of the model results, on average, to the list of input values used in the main sensitivity analysis.

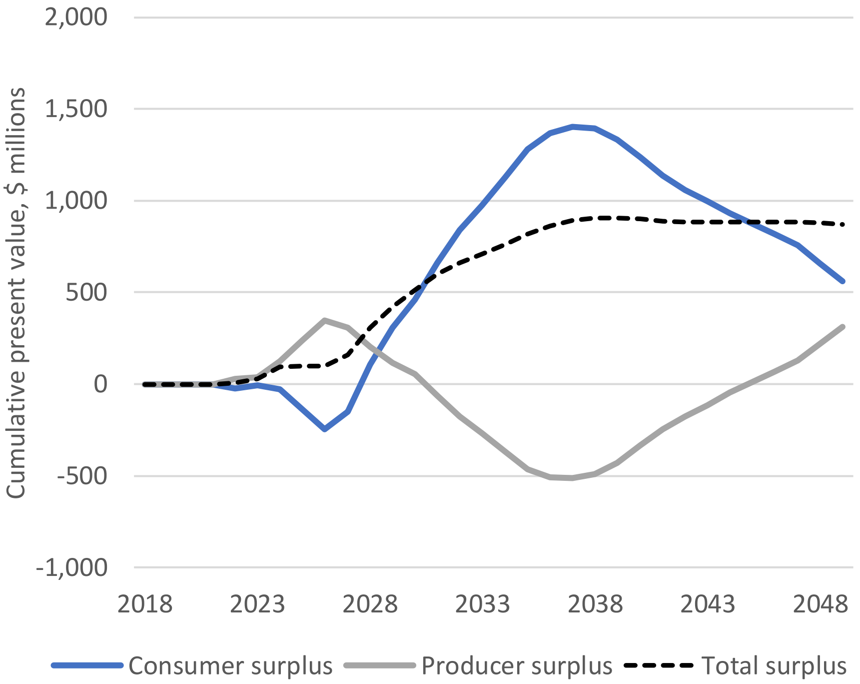
B.38 This limited Monte Carlo analysis shows that the key qualitative results of the modelling are robust to (not unduly affected by) the weighting schema used and that the key dynamics affecting the grid use model results and gains in consumer surplus are robust to small deviations in input assumptions. This can be seen in Figure 14, which shows the average of cumulative investment in generation under the 300 simulations of each of the proposal and the baseline.

Figure 14 Generation investment – limited Monte Carlo analysis



B.39 The key result is that the proposal's 'central' scenario, on average, leads to expansions in opportunities for mutually beneficial trade, which results in increases in investment, in consumer surplus and in producer and total surplus – see Figure 15.

Figure 15 Welfare changes – limited Monte Carlo analysis



Appendix C Responses to wider feedback

Consumer response to wholesale electricity prices

Feedback

C.1 Submitters said:

(a) it is contentious to assume that mass market load responds to combined wholesale electricity prices and transmission charges[64]

(b) it is unrealistic to assume that consumers' response to nodal prices and grid usage patterns would be the same regardless of whether retail customers are exposed directly to nodal prices[65]

(c) most demand curtailment results from distributors controlling customers' hot water heating, rather than from wholesale costs, because consumers do not see those costs and thus cannot benefit from changes in those costs[66]

(d) price signals are irrelevant where reliability is of paramount concern to consumers[67]

(e) consumers would not respond strongly to price signals, as assumed by the CBA.[68]

The Authority's current view

C.2 In the CBA model, average demand response from year to year was estimated using annual data over a decade. The model did not assume consumers would respond in real time to real time nodal prices, nor that all consumers respond (rather that only some consumers respond). It did not specify how prices are passed through to final consumers. The realism of the model was embedded in empirical models of observed, real-world demand changes in response to actual changes in prices.

C.3 The Authority considers that nodal prices do affect consumer demand and grid usage patterns. Delivered electricity prices are persistently higher in areas with low levels of local supply relative to areas with high levels of local supply. All traders, including retailers, must buy energy at higher prices in higher priced areas.

C.4 These wholesale cost differentials must (and empirically do) flow into consumer prices, or else traders would go out of business. There is empirical evidence for annual changes in wholesale electricity prices affecting residential retail prices.[69]

C.5 If consumers do not respond very much to changes in wholesale electricity prices inclusive of transmission charges – whether because they do not care about higher prices or because wholesale electricity prices inclusive of transmission charges are passed through very gradually – we would expect an empirical model to find evidence of low rates of demand response.

64 Tauhara North No. 2 Trust p. 4.

65 Axiom Economics, for Transpower, p. 18, p. 21 and pp. 142-143.

66 Northpower p. 8.

67 Waitaki Power Trust p. 28.

68 Mercury, p.8, Waitaki Power Trust, p.17, Flick Electric Co, p.5

69 See for example Table 10 in Sense Partners (2019) 'Impacts of the What's My Number? Campaign' available at https://www.ea.govt.nz/about-us/what-we-do/whats-my-number/annual-review/

C.6 The demand response parameters in the CBA model do indeed show low rates of demand response. An annual average price elasticity of demand of -0.11 is not high. This is the value for aggregate response of demand to average wholesale electricity prices inclusive of transmission charges with gradual demand adjustment, estimated in the dynamic panel model.

C.7 The model of demand by time-of-use shows even lower price elasticities of electricity demand by time-of-use. The empirical models estimate that peak electricity demand between 2008 and 2017 exhibited an average price elasticity of demand of -0.05, which is a very low rate of demand response by any measure, and substantially smaller than price elasticities of demand found in studies of time-of-use pricing.[70]

C.8 The reason why this estimated demand response is so low, relative to other studies, is that other studies are based on final (higher) prices – a change in those prices have a substantially larger impact on consumers' budgets than a change in only two components (wholesale electricity and transmission) of final prices.

C.9 We appreciate that distributors carry out a considerable amount of demand curtailment and that this affects observed levels of peak demand. However, the demand models control for this by accounting for regional variations in average electricity demand and thus variation in the extent to which distributors engage in demand control.

C.10 The CBA model does not control for significant changes in distributors' demand control, from year to year, between 2008-2017. This could bias the demand models, if changes in demand control are correlated with wholesale electricity prices inclusive of transmission charges.

C.11 We assume that load control is a fixed feature of the demand landscape, varying only by distributor. This assumption is based on the observation that load control has been used in New Zealand for a very long time primarily for distributors to control their networks and network costs.[71] In practical terms, if peak load is controlled the same way each year (such as by ripple control) as a matter of course and not in response to consumer demand for load control due to changes in wholesale electricity prices or transmission charges, then distributors' load control will not form part of measured demand response.

C.12 If decreases in wholesale electricity prices or transmission charges cause consumers to place less value on the differential between controlled and uncontrolled tariffs and this then causes more consumers to choose uncontrolled tariffs over controlled tariffs, then any corresponding change in demand (control) is a bona fide consumer demand response to prices and, empirically, will be captured in the model.

C.13 We also note that criticising empirical estimates of the effect of wholesale electricity prices inclusive of transmission charges on consumer demand, on the grounds that consumers neither see nor respond to these prices, is inconsistent with claiming that some form of peak demand pricing is important for controlling peak demand – whether in the form of a peak demand charge based on LRMC or a modified RCPD charge.

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70 For one summary see, for example, Frontier Economics, Peak-use charging; A review of price elasticity of demand, October 2018 https://www.transpower.co.nz/sites/default/files/plainpage/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf

71 Concept Consulting, 2020, Winter capacity margin – potential effect of possible changes to transmission pricing Feb 2020, https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-information-papers-and-reports-published/

Price pass-through to final consumers

Feedback

C.14 Submitters note that final electricity prices faced by consumers involve relatively few time-of-use tariffs and retail consumers do not face wholesale electricity prices.[72] The implication is that the benefits from changing wholesale electricity prices inclusive of transmission charges are overstated.

C.15 For example, NZIER[73] notes that:

- for New Zealand's 10 largest distributors (accounting for approximately 80% of the interconnection charges paid by distributors), the typical definition of a peak demand period covers 4,140 trading periods
- most electricity distribution businesses do not recover most of their interconnection charges through per-MWh peak demand pricing
- residential consumers account for about half of distribution load but two-thirds of the interconnection cost recovery.

The Authority's current view

C.16 We do not agree that the peak transmission price signal is as muted as submitters contend, based on distributors' definitions of peak periods.

C.17 In aggregate, peak demand charges can constrain electricity use during peak demand periods without explicitly placing a cost on consuming during, say, 1,600 or 100 trading periods.

C.18 Even if all consumers faced a flat c/kWh tariff, current retail and distribution pricing practices would cause consumers that consume during peak demand periods to have higher c/kWh charges. Most distributors explicitly assign transmission costs to consumer groups based on the alignment of their load profile to regional coincident demand peaks. This is what causes the observation that residential consumers account for about half of distribution load but two-thirds of the interconnection cost recovery.

C.19 This means that changes to peak electricity prices can have two effects. One is a direct price effect, for the few mass market customers on real time or time-of-use pricing. The other is an indirect effect, where the way that transmission charges are allocated changes the cost of electricity for those who typically consume at peak, such as the average residential consumer.

C.20 The CBA's empirical demand models will be capturing this latter effect – rather than the effect of consumers responding to real-time prices. Thus, the CBA does not rely on a strong assumption about exactly how transmission charges are passed through to consumers, other than the assumption that transmission prices will continue to be passed through to consumers in a manner broadly consistent with the approach used over the past several years.

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72 Unison pp.5-6., NZIER for MEUG pp. 4-8, The Lantau Group, for the TPM Group, pp. 32-33, The Lantau Group, for the TPM Group, cross-submission p. 22.

73 NZIER for MEUG pp. 4-8, also referenced in The Lantau Group, for the TPM Group, cross-submission p. 22.

Empirical issues

Issues

C.21 A few submitters claimed that:

- model fit statistics and parameter p-values indicated that model parameter estimates were unreliable[74]
- the CBA model's demand parameters should have been taken from the economic literature rather than estimated, considering the perceived unreliability of the estimates[75]
- model parameters estimated on data in the presence of a peak demand charge will overstate the responsiveness of demand when that charge is removed.[76]

The Authority's current view

C.22 The Authority considers there is a risk of placing too much emphasis on statistical tests that have limited informational content except to reflect the unavoidably large variance in the data.

C.23 We agree that referring to existing research can be helpful. However, the CBA is focussed on understanding the effects of changes in transmission and wholesale prices on wholesale demand for electricity in New Zealand by time-of-use. There is no existing research we are aware of that provides this information.

C.24 New Zealand is quite different to many other OECD countries in terms of its isolation, climate, industry mix, energy mix, incomes and other factors. If overseas elasticity estimates (or de-meaned function parameters more generally) were adopted for this analysis, they would bring with them non-trivial estimation errors.[77]

C.25 Estimating models that are specific to New Zealand, wherever feasible, helps to ground the demand models in local realities and brings transparency to the analysis by acknowledging the variability of data (and therefore precision of estimates) in a New Zealand context. It also permits consideration of the similarity of the estimates with existing research – which we have done and have found the results to be within the very wide bounds of comparable studies in other markets.

C.26 It is true that the demand parameters estimated in the model are dependent on data produced in a world in which peak demand charges exist. This is unavoidable. It is not, however, the case that the CBA model is biased by using elasticities of peak demand that were estimated when peak demand charges were in place. The time-of-use demand elasticities in the model are not fixed but rather change over time. The peak demand elasticities in the model are a function of underlying (estimated) parameter values and shares of expenditure by time of use.

74 Axiom Economics, for Transpower, pp. 105-106., HoustonKemp, for Trustpower, pp. 64-65.

75 HoustonKemp, for Trustpower, pp. 64.

76 The Lantau Group, for the TPM Group, pp. 32-33

77 It is important to note that borrowing parameter estimates does not avoid having to specify a model and it does not avoid the problem that the borrowed estimates will result in model errors. It only avoids having to test that model against data and estimate model errors.

Modelling uncertainty: 30-year timeframe and ranges

Feedback on 30-year timeframe

C.27 Some submissions expressed concern that the CBA adopts a 30-year timeframe and that many of the benefits of the proposal occur only in the distant future. Questions were raised about how much weight could be placed on effects that are so far off, given that they must, inherently, be less certain.[78]

The Authority's current view

C.28 Using a 30-year timeframe is reasonable given the TPM affects investment in assets that have lives in excess of 30 years. There are no hard and fast rules for specifying the timeframe for a CBA, although it is standard in infrastructure CBAs to consider the effects of an infrastructure investment over the life of the asset.

C.29 There is generally little practical use in measuring costs and benefits beyond 30 years because the effect of discounting costs and benefits means that any effects after 30 years will have a trivial effect on the overall CBA. The finding of non-trivial net benefits of the TPM proposal overall is not contingent on a 30-year evaluation period. A shorter evaluation period still shows net benefits from the proposal.

Feedback on wide range around central estimate

C.30 Submitters also expressed concerns about the reliability of the CBA given the wide range of estimated benefits of the proposal.[79] Others suggested more sensitivities should be conducted.[80]

The Authority's current view

C.31 The wide range around the central estimate should provide stakeholders some comfort that the overall result of the CBA was robust to misspecification of effects. This is because the range of results was driven by excluding, or varying, certain aspects that contributed to significant net benefits. Nevertheless, the revised CBA does present a more extensive sensitivity analysis.

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78 Energy Trusts of New Zealand p. 8. Electra p. 6. HoustonKemp, for Trustpower, pp. 93-95. The Lantau Group, for the TPM Group, cross-submission p. 8. Vector p. 16 and Professor Bunn, for Vector, pp. 9-11. The Lantau Group, for the TPM Group, p. 5.

79 Molly Melhuish, p.2, Energy Trusts of New Zealand, p.2

80 The Lantau Group, for the TPM Group, pp. 35-36. Marlborough Lines p. 3. Energy Trusts of New Zealand p. 8. Mercury (cross-submission p. 4) suggested that potential closure of the NZAS smelter could be included in the baseline and Marlborough Lines (p.3) suggested sensitivities over Transpower's allowable revenue.