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TRUSTPOWER CROSS-SUBMISSION: 2019 ISSUES PAPER: TRANSMISSION PRICING REVIEW

PART I INTRODUCTION AND OVERVIEW

1 Approach to preparing this cross-submission

1.1.1 Trustpower Limited (**Trustpower**) welcomes the opportunity to provide a cross-submission to the Electricity Authority (**the Authority**) following the receipt of submissions on its *2019 Issues Paper: Transmission pricing review Consultation Paper, 23 July 2019* (**the 2019 Issues Paper**).

1.1.2 Trustpower has read all 93 submissions filed in response to the 2019 Issues Paper including the associated experts' reports.

1.1.3 We have also sought expert advice from:

a) Creative Energy Consulting (**CEC**) on:

i. the issues associated with allocating a part of the residual charge to generators; and

ii. the case studies Transpower included in its submission on the 2019 Issues Paper, which apply benefits-based charging to simple transmission; and

b) HoustonKemp on:

i. the submissions on the cost benefit analysis (**CBA**) including the expert report from National Economic Research Associates Inc (**NERA**) for Meridian Energy, New Zealand Institute of Economic Research (**NZIER**) for the Major Electricity Users' Group (**MEUG**); and from Axiom Economics (for Transpower); and

ii. a set of material relating to the CBA released by the Authority in response to an official information request from Northpower (**OIA material**)

The advice of CEC and HoustonKemp is provided as attachments to this cross-submission.

1.1.4 Trustpower is also part of the TPM Group who jointly commissioned Mike Thomas of The Lantau Group (**TLG**) to comment on the expert reports filed by submitters on the 2019 Issues Paper.

2 Summary of our views

2.1.1 Our review of submissions has revealed that a number of submitters share the concerns with the CBA set out in the HoustonKemp Report, submitted as part of Trustpower's submission on the 2019 Issues Paper. This includes the expert report from Axiom Economics that undertakes a similar level of detailed analysis, and reaches similar conclusions, to HoustonKemp.

2.1.2 There is nothing in submissions which operates to 'repair' the errors with the CBA that the HoustonKemp Report had highlighted - the most significant error (the exclusion of $1.9 billion of generation costs) has been acknowledged by NERA, who otherwise offer a level of 'top down' support for the CBA framework. However, our advisers consider that if NERA had delved into the actual spreadsheets, this support may not have been sustained.

2.1.3 In addition, the OIA material provides evidence that some of the CBA issues were spotted by peer reviewers and advisers to the Authority. It is not clear why these concerns were not appropriately actioned. The Authority may need to review its processes in light of this outcome.

2.1.4 The errors in the CBA prepared for the Authority undermine the case for immediate publication of the Transmission Pricing Methodology (**TPM**) Guidelines set out in the 2019 Issues Paper (**Proposed TPM Guidelines**).

2.1.5 Our review of submissions has also highlighted that, aside from the CBA issues, there are also concerns with the scale and direction of the proposed reform, particularly from distributors and industrial companies who pay the majority portion of transmission charges.

2.1.6 A significant number of submitters in this group:

a) do not consider the problems with the TPM are as material as claimed (while accepting some elements of it may be inefficient, such as an overly strong regional coincident peak demand (**RCPD**) charge for the interconnection assets);

b) believe the removal of the RCPD charge will:

   i. harm efficiency as nodal prices cannot provide sufficient signals of emerging transmission constraints; and

   ii. result in increased reliability risk, loss of low-cost demand response, loss of adaptability, and inconsistency with distribution pricing reform;

c) have serious reservations about the workability of benefits-based charge with some submitters re-thinking their prior "*in principle*" support of benefits-based pricing as a result of concerns about the ability to accurately assess beneficiaries;

d) consider that it is difficult to defend the inclusion of seven legacy assets;

e) have concerns about the fairness of the proposed price cap; and

f) more generally, believe that incremental, rather than 'big bang' reform, is all that is required.

2.1.7 A number of other parties have expressed similar concerns in their submissions, suggesting that this reform does not have the foundational support it will need to be successful.

2.1.8 Problematically, the Authority's approach to assessing alternatives has not made it easy for us to gauge which is the next "cab off the rank".

2.1.9 We do think, however, that it is possible to build on the work completed to date to create a set of high level TPM Guidelines which will enable Transpower to develop a TPM that addresses the problems of concern to the Authority.

2.1.10 Appropriate time will need to be allowed for this development work.

3 Submission structure

3.1.1 The reasons for our views are set out in the balance of this cross-submission, which is structured in six parts.

3.1.2 In **Part II** we consider stakeholder feedback on the core components of the proposal, particularly from transmission customers and those entities whose distribution charges have a high transmission component. We think the views of this group will be important for the overall durability of the proposal. We also discuss whether the residual charge should be allocated to generators as well as load as suggested by a subset of distributors. Our view, based on expert advice from CEC, is that the Authority is correct in that it is more efficient to allocate the residual charge to load.

3.1.3 In **Part III** we analyse Transpower's views on the proposal and provide expert comment from CEC on the case studies submitted by Transpower on the modelling issues associated with applying the benefits-based charge. CEC advise that the Transpower case studies are not representative of the modelling challenges which would apply for a deep transmission investment, which is more representative of future transmission needs and as a consequence accurate benefits-based modelling is more complex than suggested by Transpower's high level case studies.

3.1.4 In **Part IV** we consider policy objectives and note that some submitters share our concerns on the extent to which this proposal is consistent with the Authority's statutory objective and the Government's wider energy objectives.

3.1.5 In **Part V** we discuss submitters' serious concerns about the robustness of the Authority's options evaluation and CBA.

3.1.6 In **Part VI** we note that some stakeholders who commented on the TPM development timeframe thought the Authority's proposed timetable too ambitious and should be extended, particularly given the time spent to date developing the TPM Guidelines.

3.1.7 In **Part VII** we conclude our cross-submission with a set of suggested next steps to capitalise on what has been learned to date and progress justified reform to the implementation stage.

3.1.8 We are very keen to see the resolution of this issue and would be happy to make available any resources the Authority's requires to take these ideas forward.

3.1.9 For any questions relating to the material in this cross-submission, please contact me directly on 021 953 104

Regards,

Peter Calderwood
General Manager, Strategy and Growth

PART II: FEEDBACK ON CORE ELEMENTS OF PROPOSAL

4 Introduction to Part II

4.1.1 In this part we discuss stakeholder feedback on the following matters:

a) the Authority's problem assessment;

b) the ability of the proposed benefits-based and residual charges to address the problems of concern to the Authority; and

c) the distributional impact of the Authority's proposal and the effect of the price cap.

4.1.2 We also discuss whether it is more efficient to allocate the residual charge to load or to generation.

5 The Authority's problem assessment

5.1 Materiality of problems and proportionality of response

5.1.1 In our prior submissions on TPM reform we have raised concerns about the adequacy of the Authority's problem definition and the need for evidence-based analysis rather than 'cherry-picked examples' to guide any reform of the TPM.

5.1.2 We acknowledge that some submitters agreed with the Authority's analysis of the problems with the current TPM, including Meridian Energy, Rio Tinto Aluminium, and Nova Energy.

5.1.3 These parties' submissions largely echo the Authority's reasoning:

a) Meridian Energy stated that it supports the Authority's description of the problems and:

> *"…agrees that these problems will likely increase as more grid investments are made to support growing regions and the transition to a low-emissions economy, and as distributed renewable generation and batteries become more affordable. Without reform, New Zealand faces the prospect of a vast misallocation of investment and an unnecessarily costly development path for the industry."*[1]

b) Rio Tinto Aluminium agreed that the Authority has correctly identified the flaws with the current TPM and commented that:

> *"… changing the TPM is necessary and urgent as those flaws are leading to inefficient investment and consumption outcomes."*[2]

c) Nova Energy also indicated it is comfortable with the Authority's problem definition.

5.1.4 Trustpower's review of submissions, however, suggests that a significant number of other submitters have concerns about the extent to which the Authority has properly justified the problems with the current TPM, and whether the solutions the Authority has put forward are proportionate to the identified problems.

5.1.5 The Electricity Networks Association (**ENA**), representing 29 distribution customers, stated:

> *"We still question whether there are material problems with current cost allocations that need a major rebuild of the TPM."*[3]

5.1.6 Northpower expressed the view that:

> *"In respect of the current consultation, we believe that the Authority has not provided a convincing and coherent account of why its proposal would lead to better outcomes for New Zealand's electricity*

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[1] Meridian Energy Submission on 2019 Issues Paper (October 2019), p. 6

[2] Rio Tinto Aluminium Submission on 2019 Issues paper (October 2019), p. 25

[3] ENA Submission on 2019 Issues Paper (October 2019), p. 7

customers. Regrettably, we believe the proposal fails to meet the three most basic criteria of regulatory best practice; namely:

- *it would not be addressing a material and enduring problem – indeed, the Authority has not articulated adequately a problem with the status quo that could not be 'fixed' within the existing guidelines or via more orthodox alternatives;*
- *the proposal clearly does not represent the smallest intervention possible – it would represent a substantial change to almost the totality of the TPM to implement a radical and internationally unprecedented methodology, at the expense of more incremental, conventional options; and*
- *it is not based on robust economic foundations or a sound CBA – the economics of the proposal simply do not stack up, and the quantitative analysis of costs and benefits contains errors that renders it totally unreliable."*[4]

5.1.7 Pan Pac Forest Products claimed that the existing TPM is not materially broken:

> *"The existing TPM has been operational since 2008 and has provided revenues to develop and maintain the network asset base with high reliability and availability."*[5]

5.1.8 Mercury accepted that there are some elements of the current TPM that may be resulting in inefficient behaviour but considers these can be addressed by changes to the current TPM and certainly does not justify 'big bang reform'.

5.1.9 Vocus' submission states that they do not support any radical change to the TPM.

5.1.10 TLG (for the TPM Group) submitted:

> *"…the proposals being advanced to address these themes go too far…"*[6]

5.1.11 The Independent Electricity Generators Association (**IEGA**) submitted that any change to the TPM must be implemented in an incremental manner:

> *"… so that the intended and unintended consequences can be assessed and the approach tweaked to ensure reliable electricity supply and strong competition in electricity generation and retailing."*[7]

5.2 Issues with RCPD

5.2.1 In relation to the RCPD charge, a number of submitters acknowledge the current signal may be too strong. Many did not agree, however, that the RCPD charge is inefficiently duplicating the signals provided by nodal prices.

5.2.2 Some submitters also pointed out that the Authority had changed its mind on this issue and that its original reasoning, presented in its LRMC working paper and TPM Options paper, was to be preferred.

5.2.3 Oji Fibre Solutions disagreed with the Authority's view on the flaws with the current TPM:

> *"In particular, our view is that the RCPD mechanism is an effective means for reducing peak demand and deferring grid investment.*[8]

5.2.4 The ENA observed that:

> *"…the Authority now considers that nodal pricing is a fully efficient signal that can direct use of location specific grid resources. The ENA retains a different view. Nodal pricing may be an efficient method of ensuring least-cost dispatch but in our view, it does not provide an enduring locational peak period signal for use of the grid."*[9]

5.2.5 Electric Kiwi believes the Authority's thinking on transmission pricing reform was, more or less, on the right track:

[4] Northpower Submission on 2019 Issues Paper (October 2019), p. 2
[5] Pan Pac Forest Products Submission on 2019 Issues Paper (October 2019), p. 2
[6] TLG Report in The TPM Group Submission on 2019 Issues Paper (October 2019), p. 1
[7] IEGA Submission on 2019 Issues Paper (October 2019), p. 9
[8] Oji Fibre Solutions Submission on 2019 Issues Paper (October 2019), p. 2
[9] ENA Submission on 2019 Issues Paper (October 2019), p. 5

"…in its LRMC working paper; albeit that it overstated the challenges in adopting LRMC pricing, particularly given that its benefit-based charging proposals would be far more complex to introduce. The LRMC working paper provided robust, orthodox economic explanation why nodal pricing only provides short-run pricing signals and is not adequate for signalling the cost of consumer demand decisions on the future cost of transmission."[10]

5.2.6 The view of Tilt Renewables was that:

"…an enduring transmission charge that is based on some measure of peak offtake is key to efficient transmission investment in the long term. Tilt Renewables considers that as transmission investments are lumpy by nature, by the time high nodal prices signal congestion at the peak, it is too late to act. Under the EA's proposal, transmission users will only face costs associated with transmission congestion in the real time market. Transmission investments are long term and take several years to implement, so prudent transmission owners will invest several years in advance to make transmission available when it is required. Under the proposed TPM users at peak times will not face a cost signal associated with the real costs that they are imposing on the system for these transmission investments, as the benefits-based charge is not directly related to actual peak time usage."[11]

5.2.7 Orion asserted that:

"The invocation of Hogan is heroic, but we see nothing that undermines the position set out in the Authority's LRMC working paper:

However, nodal pricing is likely to result in price signals systematically below LRMC [because]

(a) the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices do not reflect the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network. While scarcity pricing has been introduced in New Zealand, its application is limited to separate scarcity prices for the North and South Island, so the value of lost load at a more disaggregated level is still not priced. This means within-island price differences, at least, send a muted price signal below the true marginal cost of the network…'

Put another way, any grid owner that waited for a scarcity price to actually occur before considering investment would be grossly negligent. It is perfectly sensible for the grid owner to consider the current wholesale market outcomes and how they might change over time as a result of various scenarios. But it will never be acceptable to only do that. The results of a model that by necessity is a quick-to-solve short-run DC approximation of the grid can never substitute for a considered medium to long term view of the grid and the market acknowledging voltage, reactive power and reliability considerations. We are confident that VoLL is an important input to grid planning irrespective of how nodal prices are determined."[12]

5.3 Distortion in customer location decisions

5.3.1 Some submitters did not agree that postage stamp pricing was a big factor in locational decisions by generation.

5.3.2 For example, Mercury did not support the view that transmission charges have a material impact on generation location decisions:

"This is primarily because generation must be sited at the location of the best fuel resources, particularly where those resources are renewable. Other factors such as resource consenting are much more significant factors influencing locational decisions."[13]

5.4 Lack of incentives to scrutinise grid investment proposals

5.4.1 Meridian Energy agreed with the Authority that the current TPM provides poor incentives to scrutinise grid investment proposals.

[10] Electric Kiwi Submission on 2019 Issues Paper (October 2019), p. 3
[11] Tilt Renewables Submission on 2019 Issues Paper (October 2019), p. 4
[12] Orion Submission on 2019 Issues Paper (October 2019), pp. 7-8
[13] Mercury Submission on 2019 Issues Paper (October 2019), p. 2

5.4.2 However, other submitters who commented on this aspect of the Authority's problem definition disagree with the Authority's views and note the lack of evidence in support of its views.

5.4.3 For example, Fonterra commented that:

> *"The Paper proposes that greater scrutiny of transmission investment will result in more efficient outcomes. The Paper has not provided any analysis of past transmission investments to justify this problem; to show that a more efficient transmission option could be implemented; or that a different outcome would arise from the Commerce Commission's (the Commission) decision making process on the basis that there is an increased number of submissions on Transpower's proposal."* [14]

> *"Fonterra believes that it is unlikely that the proposed change to transmission pricing will result in more efficient transmission investments. We also do not believe that the EA have undertaken sufficient analysis of recent investments, nor of how increased submissions would alter the outcome of the application of the Commission regulatory regime to justify this assertion. Fonterra therefore maintains that an AoB charge is unlikely to result in more efficient transmission investments."*[15]

> *"The Commission have a regulated process to go through to review Transpower's proposed investments and if Transpower's proposal meets those requirements, then it is likely to proceed. The Paper …incorrectly assumes that those that will face an increased cost from a proposed transmission investment, will have the ability (either knowledge or resources) to submit an alternative more efficient investment proposal to the Commission. The majority, if not all, users do not have core expertise regarding transmission investment, nor should they…*

> *…The EDB's will have more knowledge to be able to provide an alternative solution, but they are not financially incentivised to do so as they do not bear the cost, as the transmission charge is passed through to users."*[16]

5.5 Distortion in the South Island generation investment market

5.5.1 There are different views about the extent to which the current high voltage direct current (**HVDC**) charge is adversely impacting South Island generation investment.

5.5.2 Meridian Energy suggested that this is an issue:

> *"Meridian agrees with the Authority that the HVDC charge is inefficient. The HVDC charge unnecessarily adds around 10% to the cost of South Island generation. This creates a strong disincentive to invest in South Island generation meaning investments in even higher-cost generation in the North Island take precedence, increasing electricity prices for all New Zealanders."*[17]

5.5.3 In contrast, Mercury did not agree the HVDC charge is the most significant factor impeding South Island investment. Instead, it considered that:

> *"Material differences in nodal prices and the risk of the Tiwai Aluminium smelter closing are the most significant factors. Shifting toward beneficiary-pays will not resolve these issues. Perversely, there is a risk historical cost reallocation may in fact act as a deterrent to future North Island geothermal investment."*[18]

5.5.4 Winstone Pulp International (**WPI**) commented on the lack of analysis on the effects of this charge and said:

> *"We do not agree that the cost recovery methodology for the existing HVDC assets from all South Island Generators needs to be changed. We view the status quo as workable and not detracting from the overall outcomes that may be achieved by the proposed methodology. It is not clear to us why the Authority considers it important to recover the historic HVDC investments through the benefit-based charge and a positive CBA for this, as a standalone change, has not been demonstrated."*[19]

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[14] Fonterra Submission on 2019 Issues Paper (October 2019), p. 4
[15] Ibid
[16] Ibid
[17] Meridian Energy Submission on 2019 Issues Paper (October 2019), p. 7
[18] Mercury Submission on 2019 Issues Paper (October 2019), p. 1
[19] WPI Submission on 2019 Issues Paper (October 2019), p. 2

6 Ability of new charges to address problems and improve efficiency

6.1 Impact of removal of RCPD charge on overall efficiency

6.1.1 A significant number of submitters disagreed with the Authority's view that the removal of the RCPD charge will enhance efficiency.

6.1.2 The IEGA's views were that:

> *"…eliminating the current peak demand charge overnight is a risky experiment which no-one can foresee the consequences of."*[20]

6.1.3 North Otago Irrigation Company stated:

> *"The suggestion that nodal prices provide '…a timely and efficient signal…' is not convincing in our view as we have limited visibility and will not be in a position to respond to nodal price signals, except through the signals that our retailer provides through repackaged energy prices. We will thus not be in a position to respond in a timely fashion to prevent transmission investments that could possibly be avoided were communicated through a sensible peak demand type signal."*[21]

6.1.4 TLG (for the TPM Group) explain why locational marginal prices (**LMPs**) may not have all the values they would need to have to operate as a stand-in for charges such as the RCPD charge:

> *"First, LMP is only short-term in nature and amounts to a volatile competitive market price signal often without a corresponding long -term contractual hedge available.*
>
> *Second, the New Zealand market is small with workable competition at best. The transmission network is long and stringy with many implications for competition and reliability and relatively fewer projects that would be dominated by economic considerations.*
>
> *Third, New Zealand is committed to decarbonisation which automatically infuse all planning scenarios and stakeholder expectations with the likelihood of even inevitability of future policy intervention or guidance to assure achievement -with likely implications for transmission development that go beyond LMP considerations.*
>
> *Fourth the wholesale market itself has been subject to numerous reviews -some quite deep and wide-ranging -canvassing market structure, market power, hedge market performance, hydro management, dry year reserve policy, and retail pricing. LMPs may be technically mature in New Zealand but the market is no more insulated from broader forces and factors than any other.*
>
> *Fifth, many if not most, of Transpower's proposals will have a significant "reliability" or other benefits component. Little of these benefits will have much to do with LMPs, though these projects may of course affect LMPS. To the extent such investments occur, they should manifest themselves through broad based charges not unlike a recalibrated RCPD charge suggesting that an RCPD type charge would be better than LMP at incentivising competition from possible alternatives more efficiently."* [22]

6.1.5 Interestingly, all distributor submissions expressed the view that a peak charge should be retained (at least) as a transitional measure.

6.1.6 Many thought a peak demand charge should be a permanent feature of any revised TPM.

6.1.7 The ENA stated:

> *"Removing the current peak charge without another similar peak demand charge is of concern to ENA members. If it is structured appropriately, a peak-demand charge targets efficient peak demand response and allows ENA members to efficiently manage their networks."*[23]

6.1.8 Vector agreed:

> *"However, we do not believe that removing the RCPD charge entirely – without any replacement price signal for grid use at peaks – is the right solution."*[24]

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[20] IEGA Submission on 2019 Issues Paper (October 2019), p. 2
[21] North Otago Irrigation Company Submission on 2019 Issues Paper (October 2019), p. 2
[22] TLG Report in The TPM Group Submission on 2019 Issues Paper (October 2019), pp. 26-27
[23] ENA Submission on 2019 Issues Paper (October 2019), p. 10
[24] Vector Submission on 2019 Issues Paper (October 2019), p. 4

6.1.9 Wellington Electricity claimed:

"The proposed approach of removing peak demand pricing signals isn't consistent with what the EA are suggesting for Distribution pricing - that Distribution pricing is to become more cost reflective around peak demand periods. It is important that peak demand periods are signalled to encourage responses that either allows the higher price to recover the network reinforcement costs or consumers to receive the benefit of lower prices when load is used at non-peak demand periods."[25]

6.1.10 Orion said:

"There is no doubt that RCPD creates some perverse incentives - we have yet to see a network pricing arrangement that does not - but we do not believe that these manifest as material allocative efficiency losses and further that there are significant productive and dynamic efficiency gains."[26]

and:

"Whatever the apparent problems with RCPD, they also need to be considered in light of the flexibility inherent in the structure, notably:

The number of trading periods used for assessment is effectively completely variable anywhere between 1 and 17,520 (in any year) enabling almost continuous smoothing. It could even, in principle, be extended over multiple years,

It can accommodate any number of areas, and in principle the cost of service provision in those different areas could be different (that is, not postage stamp),

It tends to pick up changes in grid use over time reasonably well, and automatically, both across and within regions, and

Being a coincident demand measure it inherently allocates the cost of a shared service more reasonably than other demand measures."[27]

6.1.11 Unison Networks and Centralines (**Unison Networks**) were concerned:

"… that the complete removal of the peak charge and reliance only on nodal prices to incentivise efficient use of the electricity system is likely to result in less efficient outcomes. EDBs currently engage in controlling hot-water at peak times to reduce inter-connection volumes, even though this is a zero-sum activity that pushes the interconnection rate higher to compensate for the lower volumes. Nevertheless, it is likely to have an overall effect of lowering energy prices (lower volumes at times of RCPD potential peaks), for zero loss of consumer surplus, as consumers are indifferent to the timing of water heating because of the amount of storage in the hot water cylinder. Complete removal of the RCPD-based charge would remove the incentive on EDBs to control hot water."[28]

6.1.12 PricewaterhouseCoopers (**PWC**), on behalf of a group of 13 small and medium sized distributors (**the Distribution Group**) submitted:

"A fundamental change in the proposed TPM is that the proposed benefits based charge will not generate a price signal, unlike the current RCPD charge. Instead it is proposed that wholesale market nodal prices will be relied on to signal transmission constraints. The proposal relies on the assumption that nodal prices will influence the location of investment in new generation and load to manage transmission constraints, and as a result, generate more efficient grid investments.

In this respect we note that most retail customers do not face nodal prices and many larger load customers also use contractual arrangements to protect against exposure to them.

We acknowledge that as new technologies become more available to retailers and retail customers, the opportunity for more real time pricing will increase. However we anticipate that many customers will continue to prefer more simple pricing plans, and that retailers will continue to manage real time prices on behalf of their customers. Accordingly, we consider that the nodal price signal will be much less effective for the majority of load customers than suggested in the 2019 issues paper."[29]

"We agree that the current RCPD pricing signal is too sharp, however we consider that a more moderate transmission peak price signal should be retained. We acknowledge that the proposed

[25] Wellington Electricity Submission on 2019 Issues Paper (October 2019), p. 1
[26] Orion Submission on 2019 Issues Paper (October 2019), p. 5
[27] Ibid, p. 6
[28] Unison Networks Submission on 2019 Issues Paper (October 2019), p. 3
[29] Distribution Group Submission on 2019 Issues Paper (October 2019), p. 15

guidelines include provision for Transpower to initially retain a peak charge if the nodal price is not sufficient to efficiently influence grid use at peak times0. This is because it is not known how load will initially respond to the removal of the RCPD charge, including the use of load control by distributors. The peak charge is to be phased out over five years.

In our view hot water load control is a relatively low cost way of assisting to manage transmission constraints, in addition to its use for distribution constraints. There is value in maintaining the incentives to provide this service. We therefore recommend that the guidelines are amended to allow Transpower to use a peak charge over the longer term where this results in a TPM which better meets the Authority's statutory objective."[30]

6.1.13 Even EA Networks (who has been adversely affected by the operation of the current RCPD charge) said:

"We do not agree with the Authority's proposal that wholesale electricity nodal prices will highlight transmission constraints and thus influence the efficient investment in new generation and load location.

Very few customers in our region are exposed to nodal prices. This is because most mass market customers choose to remain insulated from their effects by seeking products that are hedged and provide stable fixed rates. In addition, Retailers bundle network charges and dull network signals that could be made available to end users if they were required to pass-through actual rates.

We are concerned that the Authority suggests behaviour and decision making will result from nodal prices alone. Our experience and research indicates that mass market customers seek simplicity in the electricity service they consume, specifically simplicity regarding pricing. Consequently, we do not believe that reliance on nodal pricing signals will have the desired effects since the signal will not be received by consumers in a timely manner (if at all). We therefore support the Authority's proposal to allow for a transitional peak charge, but question why this should only be temporary.

In our view it will be critical to retain a form of peak charging signalled by network charges (providing they do not lead to material volatility). This should be implemented by Transpower at their discretion and by their design. There should be no arbitrary time limit put on this since the need for such a signal cannot be forecast with any certainty."[31]

6.2 Benefits-based charge will promote overall efficiency

6.2.1 A number of submitters disagreed that a benefits-based charge will promote overall efficiency as claimed by the Authority.

6.2.2 Norse Skog Tasman did not think consumers would respond to a diluted signal as envisaged by the Authority and point to the evidence of the lack of consumer interest in dispatchable demand:

"…the historical evidence of the absence of consumer use of Dispatchable Demand, indicates that consumers may not be willing or able to respond to GXP Prices, and that RCPD continues to be the best tool, to limit peak demand i.e. the Proposal to use GXP pricing instead of RCPD probably will not work as well as RCPD."[32]

6.2.3 Network Waitaki said:

"At first glance, the idea of benefit-based charges might work, although the possibility for price shocks as a result of the increase in transmission cost directly after capacity is made available could be impediments to the efficiency of the initiative. In this regard, we agree with clause 2.32 that "an efficient cost reflective charge would rise when the grid gets congested and drop when there is spare capacity." However, the benefit-based charge approach will result in an increased cost of transmission as soon as the investment is made, exactly what the current RCPD charge is criticised for."[33]

6.2.4 Pioneer Energy said it is concerned that

"…the proposed detailed individual net private benefit analysis:

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[30] Ibid, p. 16

[31] EA Networks Submission on 2019 Issues Paper (October 2019), p. 2

[32] Norske Skog Tasman Submission on 2019 Issues Paper (October 2019), p. 2

[33] Network Waitaki Submission on 2019 Issues Paper (October 2019), p. 8

a. is a different to the regulatory test to that used to approve transmission investment

b. will always be subjective and therefore not necessarily durable

c. will incentivise parties to argue against any transmission investment even if it is required for grid reliability or is economically efficient

d. will incentivise parties to argue against any transmission investment even if they are a beneficiary to avoid paying for the investment

e. results in unnecessary delays in planning, consenting and constructing transmission infrastructure

f. is to be calculated by Transpower prior to the actual transmission investment

g. is sensitive to subsequent changes in load or new generation that do not meet the Authority's proposed thresholds for re-opening

h. is not flexible to moderate changes from innovation, changing demand etc."[34]

6.2.5 Mercury, Counties Power and Vector all indicate 'in-principle' support for the concept of benefits-based charging but have qualified their support by stating they think it needs to include beneficiary voting rights. We note that is not part of the Authority's proposal.

6.3 Improved transmission investment scrutiny

6.3.1 Submitters disagreed that the benefits-based charge will **improve** any weaknesses in the current grid investment processes.

6.3.2 Some suggest it might lead to worse outcomes as the focus shifts from public benefits of security/reliability to disputes about private interests and benefits.

6.3.3 For example, Electra noted that transmission investment will take longer and lead to the adoption of less efficient solutions:

> *"Challenge and debate of transmission investments are encouraged in the proposed TPM and will result in delayed investment to mitigate high real time nodal prices. This may create situations where high nodal prices can be exploited and transmission investment blocked by quick to implement, less efficient technologies."*[35]

6.3.4 Mercury said that allocating benefits-based charges to generators may result in less efficient grid investment decision-making:

> *"Mercury has also raised questions in previous submissions as to the value of allocating significant beneficiary-pays charges to generators who do not require the same level of reliability of the transmission grid as end-use consumers. This may create incentives for generators to oppose transmission investments that are in the long-term interest of consumers."*[36]

6.4 Accuracy of benefits-based assessments

6.4.1 A number of submitters commented on the variations in allocations in different iterations of benefits-based charges.

6.4.2 For example, Tauhara North noted that:

> *"…the various assessments of the value of the benefit supposedly derived by NAP of $0.8 million, $1.4 million and $0.5 million, shows that the Authority's statement that "benefits are relatively predictable in New Zealand" is simply not true."*[37]

6.4.3 PWC (for the Distribution Group) said:

[34] Pioneer Energy Submission on 2019 Issues Paper (October 2019), p. 4
[35] Electra Submission on 2019 Issues Paper (October 2019), p. 2
[36] Mercury Submission on 2019 Issues Paper (October 2019), p. 6
[37] Tauhara North Submission on 2019 Issues Paper (October 2019), p. 2

"We note how difficult it appears to be to apply a benefit based charge in practice. Analysis of the indicative calculations accompanying the 2019 issues paper reveal how sensitive the outcomes are to certain assumptions and judgements." [38]

"We note that there are significant challenges in quantifying and assigning expected future benefits of prospective investments. Robust analysis must be available to support any future benefit based charges. Where this is not possible, a more broad based cost recovery approach is recommended."[39]

6.4.4 Network Waitaki asserted that:

"Our analysis of the benefit-based charges did not convince us about the appropriateness of the charges in the way it is presented in the TPM proposal with alarmingly counter-intuitive results and obvious non-beneficiaries of Transpower investments shouldering surprisingly high portions of the cost.

In the majority of cases the benefit-based charges do not correspond with the understanding that consumers downstream would benefit from transmission investments when such investments, being part of the supply path, reduce the chances for constraints to such consumers. If the benefit payments are indeed as intended, a much better explanation regarding the concept of a benefit in the TPM environment would be needed to convince Waitaki consumers of the fairness of the TPM proposal. The analysis we have done exposed counter-intuitive results within the TPM proposal…

…The Modelling Workshop in Wellington confirmed that the benefit-based charges are overly sensitive to small variations in modelling variables (such as timing and virtual prices) and is reliant on substantial judgement calls that have a significant impact on results. The calculation process does not appear to be robust in any way – small variances in judgement could result in enormously different outcomes."[40]

6.4.5 The ENA expressed reservations about the ability to identify benefits in the manner envisaged:

"…the ENA could consider supporting a forward-looking benefits-based charge that has clearly identifiable local benefits from grid investments (as opposed to broadly based benefits) but only if the benefits can be forecast over the life of the investment with some accuracy. As commented elsewhere in this ENA submission we have reservations as to whether this is at all possible."[41]

6.4.6 Orion pointed out that the use of the scheduling, pricing and dispatch (**SPD**) method to allocate benefits has long been criticised:

"More technically, the use of an SPD approach for allocating benefits – be it to existing or future investments – has been consistently criticised by a number of parties since first being proposed in 2012. Amongst the criticisms has been that the results are very much dependent on the assumptions, to the point where pretty much any result can be produced. We do not believe the paper has adequately addressed these criticisms. We acknowledge that the guidelines provide some flexibility around what benefits-based method Transpower applies, but the status being given to SPD approaches still seems unjustified."[42]

6.4.7 Unison Networks, supported benefits-based charging in principle but also said:

"We are, however, concerned that if the identification of beneficiaries and quantification of benefits relies on such significant judgments, assumptions or speculation about what might have happened absent the transmission investment, that a wide range of outcomes is feasible with different, but plausible alternatives. If this is the case we think it would be better to dispense with the beneficiaries pay model entirely to avoid a TPM that is essentially arbitrary."[43]

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[38] Distribution Group Submission on 2019 Issues Paper (October 2019), p. 12
[39] Ibid, p. 13
[40] Network Waitaki Submission on 2019 Issues Paper (October 2019), p. 17
[41] ENA Submission on 2019 Issues Paper (October 2019), p. 9
[42] Orion Submission on 2019 Issues Paper (October 2019), p. 10
[43] Unison Networks Submission on 2019 Issues Paper (October 2019), p. 2

7 Suggested amendment to residual charge counterparties

7.1 Views of distributors

7.1.1 A subset of distributors considered that the residual charge should be allocated to generators as well as load.

7.1.2 PWC (for The Distribution Group) said:

> *"We submit that there are inconsistencies introduced by differentiating between load and generation customers for the benefits based and residual charges. This is because the residual charge is the balancing charge which washes up the impact of the remaining charges and various adjustments which may be made to them. This means that the consequences of changes to other charges which apply to all grid users only fall on load customers. Accordingly the residual charge should apply to all grid users to avoid this inequity."*[44]

7.1.3 The ENA said:

> *"Importantly the Authority expects that both the residual charge and if necessary, the benefits-based charge, to be "fair" – specifically that they will result in broadly equivalent charges for customers that are in broadly equivalent circumstances. We do not see that this is possible when residual charges are applied to only load and not generation who share use of the transmission grid."*[45]

7.1.4 Vector said:

> *"We strongly disagree with the Authority's proposal to allocate residual charges to load only. The rationale given by the Authority for this approach is that residual charges on generation would largely be passed on to load in any case in the form of higher energy prices, since new generators would delay entering until the prices they expected to receive would cover their residual transmission charge. However, the Issues Paper does not provide any empirical evidence to support this view.*
>
> *Compass Lexecon's 2015 expert report for Vector explains clearly why this view is incorrect. Specifically, the residual charge would be a fixed cost for generators that would not be affected by dispatching decisions, which in a competitive market are determined by marginal costs. It is therefore not the case that generators would be able to simply pass through fixed transmission charges to load customers, at least in the short run.*
>
> *Similarly, Professor Bunn notes in his paper that:*
>
> *'On the actual mechanism of implementing the residual charge, the case for charging it to load is a weak one… I do not agree with the EA argument, also advanced by Ofgem in GB, that there is no point in charging generators because they would simply pass it on through the wholesale market. If that were credible, then one could argue it makes no difference whichever way and therefore why not split the charges 50-50. But, as the transmission charges would be fixed, not short-run marginal, costs, one would not expect those to go through a simple pass though into the energy market. Rather, they would be part of all the annual fixed costs that have to be covered by wholesale market profit contributions.'"*[46]

7.2 Expert response

7.2.1 We asked CEC to provide us with an independent view on this issue. A copy of their report is provided as Attachment 1 to this submission.

7.2.2 CEC wholeheartedly support this aspect of the Authority's proposed charging structure for four reasons:

1. *"It is common international practice, except where there is an objective of grandfathering a pre-existing charging allocation, as in the UK.*
2. *A charge on generation is likely to be passed-through, in the short-term or the long-term, for a variable or a fixed charge, respectively. The structure of the pass-through "uplift" – effectively a*

[44] Distribution Group Submission on 2019 Issues Paper (October 2019), p. 5
[45] ENA Submission on 2019 Issues Paper (October 2019), p. 10
[46] Vector Submission on 2019 Issues Paper (October 2019), p. 12

residual transmission charge on load – may be unclear or uncertain. In general, it will not be ideal in terms of minimising distortions to transmission usage.

3. *A charge on generation may lead to a reduction in generation capacity and a resulting worsening of supply reliability.*

4. *Consumers, in aggregate, are better able than generators to bear the risks of volatility in the level of the residual charge."*[47]

8 Application of benefits-based charge to seven existing assets

8.1.1 The legacy assets element of the Authority's proposed reform has attracted strong criticism in the past (including from the Electricity Price Review Panel). This is still a controversial part of the Proposed TPM Guidelines.

8.1.2 For example, Vector observed that:

> *"…beneficiary-based charging for historic grid investments is internationally unprecedented and defies well-accepted economic principles."*[48]

> *"the apparent anomaly of including 7 legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward."*[49]

8.1.3 Northpower stated that:

> *"… it would be manifestly unfair to reallocate the past costs of existing investments – much less to limit that exercise to a handful of recent investments. It might also be said to be 'unfair' to change the way in which sunk costs are allocated so soon after a major investment programme. Rightly or wrongly, this might be viewed by some as it 'shifting the goal posts' and might even undermine the confidence that some participants have in future investment approval processes – and transmission pricing frameworks."*[50]

8.1.4 Mercury also did not support the inclusion of existing assets as:

> *"…there are no objective and unambiguous methods to accurately estimate beneficiaries in retrospect".*[51]

8.1.5 An example of the modelling issues involved in the inclusion of existing assets can be found in the contrasting views of Meridian Energy and Rio Tinto Aluminium (both of whom support TPM reform):

a) Meridian's submission:

> *"…supports the benefit-based charge applying to significant pre-2019 grid investments and considers the methods proposed by the Authority to be reasonable."*[52]

b) Rio Tinto's submission stated the proposed allocation;

> *"…is inconsistent with its own principles that benefits-based charging should take account of net private benefits."*[53]

and

> *"…does not conform with best practice for the use of technical analysis to support regulatory decisions."*[54]

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[47] CEC Memo on Generator Residual Charges in Trustpower Cross-Submission on 2019 Issues Paper, (October 2019), p. 6
[48] Vector Submission on 2019 Issues Paper (October 2019), p. 9
[49] Ibid, p. 9
[50] Northpower Submission on 2019 Issues Paper (October 2019), p. 23
[51] Mercury Submission on 2019 Issues Paper (October 2019), p. 3
[52] Meridian Energy Submission on 2019 Issues Paper (October 2019), p. 16
[53] Cover Letter in Rio Tinto Aluminium Submission on 2019 Issues Paper (October 2019), p. 2
[54] Rio Tinto Aluminium Submission on 2019 Issues Paper (October 2019), p. 15

8.1.6 As we noted in our primary submission, the inclusion of the legacy assets is all the more puzzling as the Authority's CBA indicates that the benefits would rise by some $18m if they were not included.

9 Impact of the proposal on transmission customers

9.1 Removal of transition clause

9.1.1 The current TPM Guidelines provide for transitional arrangements for TPM reform with significant impact. Clause 19 states that:

> *"Overall transitional arrangements should be proposed where revision of the methodology leads to large increases or decreases in current charges."*[55]

9.1.2 The Authority intends to remove this clause. We were surprised that there was not more comment on the implications of this for future reform given the evident concern about the scale of the impact of the initial reform. We suspect that the lack of comment was because there is no analysis in the Authority's paper of the pros and cons associated with the removal of this clause.

9.2 Scale of impact

9.2.1 It is clear however that stakeholders were concerned about the scale of the changes.

9.2.2 New Zealand Steel said:

> *"The Authority's proposal will have a significant financial impact on NZ Steel. Based on the Authority's modelling, the estimated charges for NZ Steel would increase by $9.5 million per annum without a cap, and be $3.5 million higher than they currently are with a temporary proposed cap in place.*
>
> *To put this amount into perspective, the reported EBIT for NZ Steel for 2018/19 was $87 million, with only $8 million of this recorded in the second half of the year. The previous five years had an average underlying EBIT of $34 million. The impact of the Authority's proposed changes to the TPM is therefore a significant factor in the cost model when NZ Steel's parent company, BlueScope, is considering future international investment/re-investment options, and may impact the longer term sustainability of the business."*[56]

9.2.3 PWC (for the Distribution Group) noted that:

> *"For some distributors, the estimated impacts of the proposal (pre capping) would more than double their transmission charges. Similar impacts could be faced by a number of large load customers. For this reason the Authority, must proceed with caution, especially where judgements are to be made."*[57]

9.2.4 Network Waitaki highlighted the impact that the proposal would have on its consumers:

> *"The proposal contends that consumers will experience significant benefits while seemingly ignoring the fact that pockets of consumers will be extremely disadvantaged. The proposal on page 58 indicates that the impact of the change on transmission customers is smaller than in 2016 due to several factors, such as fewer pre-2019 investments included and different modelling assumptions. However, in the case of Network Waitaki, the impact has doubled."*[58]

9.2.5 There were also concerns that the impact analysis focusses on impacts in the first year. For example, Buller Electricity expressed the concern that:

> *"A significant shortcoming of the Authority's Transmission Pricing Review – 2019 Issues Paper is that the impact modelling focuses solely on year one, and the information provided to assess the merit of alternative implementations is not exhaustive. No information is provided for transmission customers to assess the impacts on the TPM proposal beyond the initial 2021-22 year. For BEL, as a customer at the end of the transmission grid which makes use of a higher than average proportion of grid assets,*

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[55] Guidelines for Transpower: Transmission Pricing Methodology (March 2006), p. 4
[56] New Zealand Steel Submission on 2019 Issues Paper (October 2019), p. 4
[57] Distribution Group Submission on 2019 Issues Paper (October 2019), p. 4
[58] Network Waitaki Submission on 2019 Issues Paper (October 2019), p. 13

we have no idea how a shift to benefit-based charging will impact us and potentially increase our charges in the long-term."[59]

9.3 Design of proposed price cap not well supported

9.3.1 The Authority has sought to address concerns about the scale of the impact of its proposed reform by including a price cap in its proposal.

9.3.2 Our review of submissions suggest that while stakeholders are supportive of the concept of price cap to address the transition issues, many are not happy with the proposed design, including its energy charge base, the exclusion of some transmission costs, its one-off application, and the limited number of customers it applies to.

9.3.3 The ENA said it regards:

> *"…the inclusion of a cap on changes to TPM3 charges for grid connected customers to be arbitrary and it provides little protection against price rises. It also results in a transfer from consumers (via EDBs) to some generators and direct connected large businesses. This is a black mark on the fairness and efficiency of the proposed changes to TPM3."*[60]

and expressed the view that:

> *"…the capping mechanism as proposed will do precious little to limit the impacts of the TPM3 proposal on customer bills (distribution charges will certainly increase if the TPM3 proposal comes anywhere near having the impacts that it assumes and we consider it likely that spot prices will in reality increase, not decrease as is assumed in the CBA).*
>
> *We suggest that a more orderly transition could come from spreading the price reductions (for example to Meridian and NZAS) out over a longer period and fund the cap that way. "*[61]

9.3.4 Northpower found that:

> *"The cap provides virtually no protection at all against price shocks and, for the vast majority of customers, it would be removed after a single year – rendering it almost pointless."*[62]

9.3.5 Golden Bay Cement (**GBC**) said:

> *"The "Price Cap" proposal is of no help whatsoever for business planning and appears to signal a perverse outcome of minimal to nil effect in the network area that GBC operates in."*[63]

9.3.6 Genesis Energy support having a cap on transmission costs, not energy costs, and stated:

> *"…we see no credible reason why the price cap should not apply to all transmission customers."*[64]

9.3.7 WPI said:

> *"We think the cap should be funded only by those who would receive material private wealth benefits from the new methodology, i.e. only those who benefit by more than a pre -determined threshold."*[65]

9.3.8 Orion said:

> *"A capping mechanism should in our view involve the parties whose charges reduce under the TPM compensating those that pay more, with this phasing out over time. The example in the paper (as captured in Table 12) envisages parties that pay more also contributing to the cap. This seems counterintuitive."*[66]

9.3.9 Fonterra said:

[59] Buller Electricity Submission on 2019 Issues Paper (October 2019), p. 2
[60] ENA Submission on 2019 Issues Paper (October 2019), p. 5
[61] Ibid, p. 10
[62] Northpower Submission on 2019 Issues Paper (October 2019), p. 24
[63] GBC Submission on 2019 Issues Paper (September 2019), p. 3
[64] Genesis Energy Submission on 2019 Issues Paper (October 2019), p. 4
[65] WPI Submission on 2019 Issues Paper (October 2019), p. 5
[66] Orion Submission on 2019 Issues Paper (October 2019), p. 13

"The price cap only benefits industrial customers with direct connection to the grid. Fonterra's manufacturing sites are all connected via distributors and could expect additional cost to meet the capped residual charge.

Although the charge is allocated to the distributor, they will look to recover this cost from customers. For some sites this may provide an incentive to move to direct connect to avoid this charge, which is not the intention of the proposal. The price cap should be a mechanism to provide an equivalent rate of relief for consumers whether they are direct-connect or not."[67]

9.3.10 Vocus said:

"Aspects of the price cap we consider are problematic and should be revisited include:

(i) The cap is a cap on estimated retail prices rather than actual transmission charges.

(ii) The cap only applies to certain components of transmission charges.

(iii) The cap results in higher transmission charges for some transmission customers than if there was no cap.

(iv) The cap results in very uneven changes to different transmission customers, with the cap having a much bigger impact for some customers than others which is not related to the size of the price increases they face."[68]

9.3.11 MEUG said:

"The proposed mechanics of the cap using the base price year 2019/20 estimated sum of wholesale and transmission charges is unnecessarily complicated compared to the alternative discussed in the consultation paper [B.278] of limiting the cap to transmission charges. MEUG recommends the simpler approach be adopted."[69]

9.3.12 Energy Trusts of New Zealand (**ETNZ**) expressed the view that:

"This relatively complex formula makes the price cap far from transparent. We can see no useful reason for attempting to link a cap on transmission price increases to something more than the actual transmission price, plus an adjustment for inflation. Building in a proxy for the wholesale price of electricity, along with distribution charges, simply gives a misleading impression that the maximum transmission price increase will only be 3.5%, when it may well be double that or more. The EA view that customers tend to focus just on the impact on their delivered cost misses the point that customers will not be able to also understand the transmission component if it is not transparent. Such transparency would place some pressure on Transpower to control cost increases."[70]

9.3.13 Entrust were concerned that the changes would undo the effect of parallel transition arrangements proposed by the Commerce Commission:

"It should be noted the large size of these increases in millions of dollars terms are artificially suppressed by network price reductions expected under the Commerce Commission's 2020 price resets. The Authority is also planning on, in effect, 'banking' the expected network price reductions under the application of the price cap i.e. the price cap limits price increases based on higher pre-2020 prices rather than the lower actual prices consumers would be paying after the 2020 price reset. This allows substantially higher transmission price increases before the price cap takes [effect]."[71]

10 Conclusion on submission feedback on core components of proposal

10.1.1 The Authority will not be expecting unanimous support for its Proposed TPM Guidelines.

10.1.2 However, given the emphasis on durability in the 2019 Issues Paper, we think it should be seeking agreement from a substantial number of stakeholders on the need for the reform and on the merits of the core elements of its reform proposal.

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[67] Fonterra Submission on 2019 Issues Paper (October 2019), p. 4
[68] Vocus Submission on 2019 Issues Paper (October 2019), p. 4
[69] MEUG Submission on 2019 Issues Paper (October 2019), p. 8
[70] ETNZ Submission on 2019 Issues Paper (October 2019), pp. 6-7
[71] Entrust Submission on 2019 Issues Paper (October 2019), p. 3

10.1.3 Our assessment of submissions suggest that this agreement is not present. Instead submitters are concerned that the Authority has gone too far in removing the RCPD charge and have yet to establish that the benefits-based charge will work in practice as well as in concept.

10.1.4 There are also strong concerns about the equity of certain elements of the proposal including the inclusion of selected legacy assets and the price cap.

PART III: TRANSPOWER'S VIEWS ON THE PROPOSAL

11 Introduction to Part III

11.1.1 Transpower's views on the Authority's Proposed TPM Guidelines are critical as it:

a) has a shared responsibility with the Authority in relation to the TPM;

b) has extensive transmission pricing expertise; and

c) is a neutral party in this policy discussion.

11.1.2 In this Part we consider the extent to which Transpower agrees that fundamental reform is required, along with Transpower's views on whether the proposed reform will address the problems identified by the Authority and promote efficiency. We also outline Transpower's views on the effectiveness of the price cap in easing the transition to the new TPM.

11.1.3 We then provide feedback on the case study examples that Transpower included in its submission.

12 Transpower's views on proposal

12.1 Problem assessment and need for fundamental reform

12.1.1 Both Transpower and Axiom Economics expressed reservations about the Authority's assessment of the problems with the current TPM.

12.1.2 In relation to the risk that the RCPD charge duplicates nodal prices, Axiom Economics pointed to an inconsistency in the Authority's view that nodal prices are sufficient and, at the same time, that they are not (and hence the need for a benefits-based charge to improve efficiency). In Axiom Economics' view, both statements cannot be true.[72]

12.1.3 In relation to the need for more input into grid investment approvals, Axiom Economics stated:

> *"Irrespective of how the TPM is designed, the Commission will always have to weigh up a number of conflicting submissions – none of which will be motivated by maximising the net market benefit – and exercise its judgement. It will therefore invariably be its role to 'discover' the efficient transmission investment outcome. The TPM cannot short-circuit that process, and there is consequently no reason to think that the proposed reforms would have any bearing on the Commission's processes.*[73]

12.1.4 Transpower's submission also noted that it does not agree that the postage stamp methodology needs to be reformed to address the Authority's case study example of councils applying pressure to underground assets and said that any reform in this area should not be via the TPM:

> *"In our view, management of this risk is more appropriately within the jurisdiction of the Commerce Commission where it is already well managed via its decisions on our individual price-quality path and our capex investment proposals."*[74]

12.1.5 Transpower shared the concerns of submitters that the case for fundamental change to the TPM had not been made. Instead it submitted that the Authority's concerns with the TPM:

> *"…may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology. This would have the benefit of bringing the reforms to the market more quickly with a substantially lower risk of unintended consequences."*[75]

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[72] Axiom Economics Report in Transpower Submission on 2019 Issues Paper (October 2019), p. ix
[73] Ibid, p. 59
[74] Transpower Submission on 2019 Issues Paper (October 2019), p. 13
[75] Transpower Submission on 2019 Issues Paper (October 2019), p. C2

12.2 Ability of benefits charge and residual charge to address identified problems and enhance efficiency

12.2.1 Transpower did not consider the Authority's proposal is the best option to address the problems raised, as it has concerns that it:

- *"…may consciously encourage additional consumption during peak periods. This is likely **to put upward pressure on wholesale prices and cause more investment in gas-fired peaking generation, the transmission network and distribution networks**. The net result would be higher electricity prices and elevated greenhouse gas emissions."* [76]
- *is "…likely to create sources of dispute and may incentivise parties to withhold information rather than share it. Where disputes over price outcomes **hinder timely, efficient investment in transmission and generation**, higher electricity prices (a disbenefit to consumers) and elevated greenhouse gas emissions are likely consequences."*[77]
- ***"…would not ensure those who benefit pay for transmission investment in the longer term**: Customers' BB charges would be based on the benefits that Transpower estimates they will receive over the life of an investment at the time that it is made (or at the commencement of the new TPM in the case of the historical investments). Actual benefits will diverge from estimated benefits over time – perhaps dramatically. Moreover, the initial allocations would also apply to any upgrades made many years later. It is hard to see how such a regime could be durable…"*[78]
- ***"…appears to be unsympathetic towards retaining a peak pricing signal in the TPM.** We submit that a peak price signal for transmission saves consumers money by deferring new transmission investment. Real-time nodal energy prices cannot do this job – as the Authority has acknowledged in the past."*[79]
- ***"…does not, in our analysis, accord with international precedent** and appears to have been heavily influenced by the opinion of one international expert in electricity market design. By contrast, the contrary perspectives offered by several other equally well-qualified international experts preferring a more orthodox approach do not appear to have found favour in the Authority's evaluation."*[80]
- ***"…would not prevent price shocks or smooth the transition**… our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended (emphasis added).*[81]

12.2.2 Axiom Economics:

a) Did not agree that replacing the RCPD and HVDC charges with a benefits-based charge and a residual charge would provide the right forward looking price signals because:

- *"the explicit ex-ante signals provided by nodal prices and losses would not provide sufficient signals to grid users of the costs that Transpower would incur in the long run when it replaces or upgrades its assets;*
- *the implicit ex-ante 'shadow price' signals provided by BB charges would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so; and*
- *the proposal would therefore give rise to inefficient price signals that would cause load and generation to make undesirable consumption and investment decisions, compromising allocative and dynamic efficiency."*[82]

b) Did not consider the proposed TPM Guidelines would be fairer, more durable or improve the quality of the investment approval process because (amongst other things):

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[76] Transpower Submission on 2019 Issues Paper (October 2019), p. 4
[77] Ibid, p. 5
[78] Ibid
[79] Ibid
[80] Ibid
[81] Ibid, p. 6
[82] Axiom Economics Report in Transpower Submission on 2019 Issues Paper (October 2019), p. iv

- *"the proposal would create a tremendous amount of additional uncertainty and would lead to far more disputes in relation to countless matters;*
- *charging customers based on uncertain estimates of benefits would not necessarily be 'fairer' and applying BB charges to only a sub-set of existing investments would clearly be inequitable; and*
- *if the proposal has any effect on the grid investment approval process it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information."*[83]

12.3 Need for a peak demand charge

12.3.1 Transpower's view, that a peak demand charge is required, is unequivocal:

> *"Opportunities to incentivise peak-demand management through the design of transmission charges should not be passed up in favour of more expensive alternatives, such as paying for demand response as a transmission alternative or through the wholesale energy market. We are firmly of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry's climate change response."*[84]

12.4 Accuracy of benefits assessment

12.4.1 The Proposed TPM Guidelines require Transpower to allocate benefits-based charges to customers based on its estimates of the benefits they will receive over the life of an investment at the time that it is made.

12.4.2 Transpower's submission will not have given transmission counterparties any comfort that it is possible to correctly identify and allocate the costs of new transmission assets to the beneficiaries of those investments:

> *"Our customers' collective utilisation of the grid is constantly changing, and over time that change can be fundamental to what benefits (or disbenefits) are realised by individual customers. Inevitably, any forecast of benefits that will arise over several decades will be wrong. In our considered view, the probability of the benefits estimates proving to be right, or materially right, over the 30 to 50 year life of an interconnected grid investment is low."*[85]

12.4.3 Transpower further noted that:

> *"…it is relatively easy to deduce that upper North Island consumers would be 'immediate' beneficiaries from our proposed Waikato and Upper North Island Voltage Management project. However, once we start to get more granular and look further into the future, things get more complex. For instance, it is very challenging to forecast how the relative benefits of the investment would accrue between consumers in Top Energy's network relative to consumers in Vector's network, say, ten or twenty years from now."*[86]

12.4.4 In an Appendix to its submission, Transpower offered some case studies for how the charge might apply to an upgrade of our transmission line between Wairakei and Hawke's Bay (hypothetically). We comment on these case studies in the next section.

12.4.5 We note, however, that Transpower is not opposed to introducing all benefits-based pricing methods *per se*.

12.4.6 Transpower suggested that the difficulties in doing this at the granular level proposed by the Authority are insurmountable but considers that there are other forms of benefits-based pricing which could work in New Zealand:

> *"BB charges can be designed to adapt. For example, adopting a method consistent with that applied in the United States (US) would go some way to achieving this. There, charges are fixed ahead of time*

[83] Ibid
[84] Transpower Submission on 2019 Issues Paper (October 2019), p. 5
[85] Ibid, p. C10
[86] Ibid

to large beneficiary zones and then on-charged to individual parties (in the US context these are generally transmission owners) who themselves on-charge using traditional tariff structures, including peak charges. A similar approach in New Zealand would, in our view, significantly improve the chances of a successful move to BB charging.[87]

12.5 Inclusion of existing assets in benefits-based charge

12.5.1 In relation to the inclusion of seven legacy assets in the benefits charge, Axiom Economics stated:

> *"It is also unclear why it would be fair to subject some existing investments to BB charges, but not others. The Authority has endeavoured to explain why, in its view, it is important to reallocate the costs of existing investments. But why just seven? This makes no sense. There is undoubtedly an ostensible appeal to the argument that 'Christchurch consumers should not have to pay for upcoming upgrades, plus a share of the recent investments that have benefitted Aucklanders.' But, like most arguments predicated on notions of 'fairness', it cuts both ways.*
>
> *For example, it is equally valid to ask whether customers in Auckland and Northland should be required to pay for a relatively arbitrary selection of recent investments, as well as a share of older investments that may have benefitted predominantly customers in other parts of the country."*[88]
>
> *"Yet another distortion is created by the differential treatment of certain existing investments. The Authority has proposed to apply the BB charge to seven existing interconnection and HVDC assets. With the exception of the HVDC link, all of these investments were built after 2004 and had approved values of over $50m.The overall effect of imposing this cut-off is to improve the economics of generation investments undertaken in areas supplied predominantly by assets built before 2004, i.e., where the grid tends to be older.*
>
> *Regardless of whether assets are old or new, their costs are sunk. The proposed approach would impose an arbitrary 'tax' on investments in locations where assets are newer than average. This would be economically nonsensical and could only give rise to dynamic inefficiency."*[89]

12.6 Effectiveness of the proposed transition arrangements

12.6.1 Transpower shared the views of other submitters about the effectiveness of the proposed transition arrangements. It said:

> *"We support the inclusion of transition provisions in the Guidelines. However, our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended. The cap would also have the unusual consequence of increasing the price rises that most load customers would otherwise face in its absence."*[90]

and

> *"The choice to base the price cap on a percentage (3.5% initially) of the total consumer bill would not have the effect of capping increases in consumers' bills at that percentage, not only because the price cap does not apply to all transmission charges but also because the TPM does not control how distributors pass transmission costs onto their customers. The total consumer bill approach also introduces complexity and estimation error into the calculation."*[91]

13 Comment on Transpower case studies

13.1.1 CEC's comments on Transpower's case studies are set out in Attachment 2.

13.1.2 CEC's advice notes that Transpower's case studies relate to a relatively simple radial expansion of a line connecting two regions and thus cannot be seen as representative of the modelling

[87] Ibid, pp. C10-C11
[88] Axiom Economics Report in Transpower Submission on 2019 Issues Paper (October 2019), pp. 76-77
[89] Ibid, p. 54
[90] Transpower Submission on 2019 Issues Paper (October 2019), p. C15
[91] Ibid, pp. C15-C16

challenges which would apply to a major deep-transmission project such as the North Island Grid Upgrade (**NIGU**) or the HVDC expansion.

13.1.3 However, in its view, even the simple case study is more complex than implied by Transpower's high level analysis.

13.1.4 This is because New Zealand does not have isolated regions but interconnected regions. Changes in transmission flows will have flow on effects to other regions requiring larger and more complex modelling than appears to have been undertaken by Transpower, not just to represent the various transmission constraints but to also create forecast scenarios for demand and transmission and load.

13.1.5 CEC agrees that it is important to do case studies of before adopting the benefits-based pricing.

13.1.6 However, it considers these simple case studies are not enough. Instead, a full-scale case study should be undertaken on one or more actual historical investments:

> "*Ideally, these cases would be recent enough for full details of the assumptions and models used in the corresponding GIT analysis to still be available in the archives, but old enough for differences to have emerge between predicted and actual outcomes to bring the reopeners into play."*[92]

13.1.7 CEC states that:

> *"Transpower's case studies really only scratch the surface of the issues that will apply to designing and applying a BBCM under the proposed TPM. To understand this, consider first how complex the real-life GIT modelling for such cases would be. The reporting would run not to 4 pages but to 400. Next consider that a BBCM will be substantially more complex and contentious than the corresponding GIT modelling because, unlike the GIT:*
>
> - *it must model wealth transfers;*
> - *users are impacted differentially; and*
> - *old studies are liable to be regularly reopened to accommodate new or changed use.*
>
> *Finally, recognise that economic modelling of major, deep transmission projects such as the NIGU or the HVDC expansion are hugely more complex than these simple shallow cases.*
>
> *The only way to gauge these steps up in complexity is to run a complete, comprehensive and detailed BBCM analysis for a recent large historical transmission investment such as the NIGU. This should be to a depth that would satisfy the TPM guidelines and the affected users. It should cover both the initial BP calculation and any subsequent reopeners. Critically, such a project must be undertaken before the draft TPM guidelines are approved."*[93]

14 Conclusion on Transpower's views

14.1.1 Our submission analysis suggests Transpower's views are closely aligned with many of its transmission customers and orthodox pricing approaches overseas.

14.1.2 Transpower believes that it is not practicable to implement benefits-based charging at the granular level (as proposed by the Authority) and seeks to illustrate why through sharing the case studies of a particular project.

14.1.3 Our expert advice is that this case study is too simplistic. If the Authority intends to pursue its proposal further, they will need to test it with a full-scale case study on a major deep-connection project (such as NIGU). This is the most prudent way to test the efficiency, durability, and practicality of granular benefits-based charging in the New Zealand context.

14.1.4 We encourage the Authority to take note of these perspectives as it plans its response to the 2019 Issues Paper.

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[92] CEC Memo on Transpower Case Studies in Trustpower Cross-Submission on 2019 Issues Paper, (October 2019), p. 7

[93] Ibid

PART IV: FEEDBACK ON POLICY OBJECTIVES

15 Introduction to Part IV

15.1.1 In this Part we discuss submissions on the extent to which the adoption of the Proposed TPM Guidelines is consistent with the Authority's statutory objectives and the Government's wider energy objectives.

15.1.2 The first matter is relevant to the Authority's jurisdiction, the second to the likely duration of these reforms.

16 Impact on policy objectives

16.1 Impact on attainment of wider energy sectors goals

16.1.1 A number of submitters disagreed with the Authority's view that the proposal will support the Government's objectives of lower emissions.

16.1.2 GBC said:

> *"Overall the 2019 issues paper approach appears to be in conflict with the current drive for energy efficiency and economy decarbonisation."*[94]

16.1.3 Entrust found:

> *"The changes would bring forward unnecessary investment in traditional network capacity and result in higher carbon emissions: Entrust is concerned the Authority expects removal of peak-usage charges would bring forward unnecessary network and generation investment. This would drive up electricity costs and is counter to the Government's policy of promoting electrification of the economy and reducing carbon emissions. It is also the opposite of what the Authority is advocating for distribution pricing."*[95]

16.1.4 Oji Fibre Solutions said that:

> *"The Paper also makes the claim that the proposal supports the transition to a low-emissions economy at least cost to consumers. Our view is that the instead the proposal creates additional costs that will not only defer investment in new renewable energy, but will increase the emissions from non-renewable sources, particularly thermal electricity generation.*
>
> *In particular, we note that the proposal creates a significant disincentive for Oji Fibre to invest in energy infrastructure in the central North Island. Oji Fibre's potential investments would increase the supply of base-load renewable electricity. However, the increased costs arising under the proposal will reduce the commercial viability of such investments."*[96]

16.2 Impact on investor confidence

16.2.1 Some submitters referred to the adverse impact of the proposed reform on investor confidence.

16.2.2 These submissions are important as, since the 2019 Issues Paper was released, the Minister's response to the Electricity Price Review (**EPR**) was announced.

16.2.3 That response included a review of institutional arrangements to ensure that these, amongst other factors, take into account the importance of maintaining investor confidence so as to ensure investment in renewable generation and to promote supply security and affordability.

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[94] GBC Submission on 2019 Issues Paper (September 2019), p. 3
[95] Entrust Submission on 2019 Issues Paper (October 2019), p. 2
[96] Oji Fibre Solutions Submission on 2019 Issues Paper (October 2019), p. 2

16.2.4 We would also argue that maintaining investor confidence is critical to the efficient operation of the industry and ensuring that the costs of electricity are as low as possible for consumers.

16.2.5 Tilt Renewables said:

> *"Under the TPM proposed by the EA it will be difficult to provide potential debt providers or equity investors any degree of certainty around transmission costs over the life of a project. Transmission costs will be subject to risks around:*
>
> - *The timing of transmission investments that may affect a project location;*
> - *The cost of that transmission investment; and*
> - *The allocation of the transmission costs to a project, which for the benefits-based allocation could be substantial.*
>
> *These risks will be very difficult to assess at project inception for the life of a project and in our opinion will result in an increase in the overall cost of capital given the uncertainty in, and potentially large changes to transmission charges, translating to an increase in the Long Run Marginal Cost ("LRMC") of projects. There is a risk of large step changes in transmission charges at individual connection points, which is likely to be riskier to small players with few connection points (due to a smaller and less diversified asset portfolio) than more well-resourced market participants."*[97]

16.2.6 Pan Pac Forest Products said:

> *"We acknowledge that parties are motivated to reduce all costs of business, however significant business investment decisions have been made under the current allocation rules, hence changing the rules now that results in significant transfer of costs between parties is quite destabilising for future investment decisions by overseas shareholders."*[98]

16.2.7 GBC stated:

> *"GBC remains extremely concerned about any transmission cost uncertainty and volatility created by ongoing EA TPM reviews with potentials to significantly increase cost inputs…"*[99]

16.2.8 Refining NZ noted that:

> *"The inability of the EA to settle on a TPM regime after ten years of trying has created ongoing uncertainty for major industrials such as Refining NZ, is a strong disincentive for future investment in renewable capacity and has introduced sovereign risk to New Zealand's energy sector.*
>
> *Refining NZ makes investment decisions using long term assumptions for utility and infrastructure charges. Changes such as these can destroy the business case for investments already made and increase the risk of future investments."*[100]

16.2.9 Electra was of the view:

> *"The uncertainty introduced by such volatile regulatory change, which has significantly impaired the business model of existing distributed generation, will discourage long term investment because of the risk of such volatile change occurring again. Regulation is about management of risks and introduction of changed regulation should support this."*[101]

16.2.10 Vector stated:

> *"The suggestion that the TPM proposal would improve investor certainty is difficult to take seriously. The uncertainty around the TPM has largely been a consequence of the lengthy review process."*[102]

16.3 Statutory objective

16.3.1 As previously advised our view is that the Authority is not required to promote overall economic efficiency, but competition, reliability and operational efficiency, as section 15

[97] Tilt Renewables Submission on 2019 Issues Paper (October 2019), p. 2
[98] Pan Pac Forest Products Submission on 2019 Issues Paper (October 2019), p. 2
[99] GBC Submission on 2019 Issues Paper (September 2019), p. 2
[100] Refining NZ Submission on 2019 Issues Paper (October 2019), p. 3
[101] Electra Submission on 2019 Issues Paper (October 2019), p. 8
[102] Vector Submission on 2019 Issues Paper (October 2019), p. 17

assumes that this is where the interests of consumers will lie. In the context of transmission pricing the most relevant objective is the promotion of competition in generation and retail markets.

16.3.2 However, we also conclude, based on expert advice, the Proposed TPM Guidelines will not promote overall efficiency as claimed by the Authority.

16.3.3 A few submitters also commented on the extent to which the Authority's proposal is consistent with the Authority's statutory objective.

16.3.4 Transpower was concerned that the Proposed TPM Guidelines may not be consistent with the Authority's statutory objective and the Government's wider energy objectives. Transpower outlined that:

> *"…we consider that it is important to restate our view that the Authority's current TPM proposal runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers."*[103]
>
> *"The Authority has stated that addressing climate change is not part of its statutory objective. We consider this is an unnecessarily narrow interpretation of Section 15 of the Electricity Industry Act 2010 and does not take into account the importance climate change and the reduction of greenhouse gas emissions have in assessing the long-term benefit of consumers."*[104]

and:

> *"Our analysis indicates that the Authority's proposal may consciously encourage additional consumption during peak periods. This is likely to put upward pressure on wholesale prices and cause more investment in gas-fired peaking generation, the transmission network and distribution networks. The net result would be higher electricity prices and elevated greenhouse gas emissions. This would exacerbate energy affordability problems and compromise the achievement of climate change objectives."*[105]

16.3.5 New Zealand Steel said:

> *"The focus of the Authority's TPM proposal is on the objective of promoting the efficient operation of the electricity industry for the long-term benefit of consumers. However, as detailed further below, the Authority's proposal is inconsistent with this objective. For example, the Authority's proposal will penalise efficient load shifting, and encourage unnecessary and inefficient grid upgrades. There is also no apparent logical basis for the Authority's inconsistent treatment of:*
>
> *(a) large consumers (who are directly connected to the grid), who will have charges allocated based on their AMD;*
>
> *(b) other consumers, who are supplied through an electricity distribution business and are likely to have charges allocated based on ADMD rather than AMD."*[106]

16.3.6 The Authority has also received a large number of submissions from parties who were concerned about the regional impacts of the proposal on business or individual consumers.

16.3.7 This group includes submissions from local business (including suppliers), regional development agencies, local employers' associations and not-for-profit advocacy associations, iwi organisations, welfare and community organisations, a school, a Member of Parliament, and individual consumers. The group also includes some distributors (as advocates for the consumers in their regions).

16.3.8 The Lines Company noted there are exceptions to the Authority's view that consumers are better off under the proposal. In relation to the central North Island, represented by the Whakamaru backbone node, it drew attention to the fact that:

[103] Transpower Submission on 2019 Issues Paper (October 2019), p. C2
[104] Ibid, p. 6
[105] Transpower Submission on 2019 Issues Paper (October 2019), p. 4
[106] New Zealand Steel Submission on 2019 Issues Paper (October 2019), p. 7

"…the grid use efficiency benefits will not be sufficient to offset the increase in 'fixed-like' transmission charges as a result of the proposal. TLC, Eastland Network, Waipa Networks and Unison connect to this node. Accordingly, transmission charges for TLC would indicatively rise from $3.3 million to $5 million per year.

The exceptions that the proposal highlights include some of New Zealand's most vulnerable consumers with the greatest affordability issues."[107]

16.3.9 Electra outlined that

"The Authority may feel it has complied with its statutory objective however it is notable that significant impacts occur in regions where they are least affordable."[108]

16.3.10 Waitaki stated:

"It will be very difficult to defend a $1.6 million increase to consumers for no additional benefit. In the Network Waitaki supply area, small commercial and residential consumers make up about 85% of consumers (34% on the Low Fixed charge tariff), with large commercial, industrial and farming making up the balance. The median income in the area is only $25,200 per annum and half of the population in the area is above 65 years (22% of the Waitaki District population) and survive on less than $20,000 per year."109

16.3.11 Vector view was that it:

"… does not support implementation of the proposal in its current form, as we do not believe it meets the Authority's statutory objective to promote the long-term benefit of consumers."[110]

16.3.12 These submissions highlight the challenges associated with the Authority's interpretation of its statutory objective and its focus on geographical equity.

16.3.13 Future beneficiaries are not easily able to engage in this debate.

16.3.14 Now that these issues have been raised, the question remains: how should they be resolved?

16.3.15 TLG (for the TPM Group) discussed the practical challenges associated with implementing a future benefits-based charge and suggested that a Government endorsed framework is needed if these challenges are to be overcome:

"Given the size and lumpiness of transmission investment and the unavoidable links to economic development, it is not possible to identify beneficiaries robustly without considering both location and time, suggesting that a big challenge will emerge with respect to how to sculpt the time profile of cost recovery accordingly. Do the children of current parents ever leave home to get jobs in other parts of New Zealand? Do those possible employers use electricity? About seven percent of New Zealanders move more than 200km's every five years. The economy is interconnected and interdependent. Yet, the indirect benefits of such interconnectedness and the option value afforded by diversity of economic development are not reflected in any analysis of transmission benefits. Such calculations are fraught with their own interpretative challenges, of course, but the more important point is that any qualitative or quantitative consideration of such omitted factors tends to broaden, not narrow, the beneficiaries (direct and indirect) of transmission projects over time. Similarly, decarbonisation policies, industry support policies, economic development programmes, and broader competition and reliability considerations also tend to argue against being too narrow or even too prescriptive ex ante in defining beneficiaries.

A related challenge of beneficiaries-based schemes is the that the allocation of costs often comes without any allocation of rights…. Do late comers get to free-ride on the early payers? If the early stakeholders truly derive sufficient benefit to pay for everything now, then perhaps that is still efficient compared to the alternative of not investing in a particular transmission project. But what if the analysis of benefits indirectly attributes future stakeholders with the future benefits, but does not distinguish future beneficiaries from current ones? Will the analyses undertaken to determine beneficiaries be sufficiently time-sensitive and granular? Or will it be more generalised?

[107] The Lines Company Submission on 2019 Issues Paper (October 2019), p. 2
[108] Electra Submission on 2019 Issues Paper (October 2019), p. 9
[109] Ibid, p. 14
[110] Vector Submission on 2019 Issues Paper (October 2019), p. 3

If it was once determined that certain (types of) benefits were likely but then later they do not occur, are the associated costs to be covered only by the now unlucky non-beneficiaries? Was it really up to them? Or was the decision made on their behalf? What if the reason the benefits were not realised is that there was a change in government policy? For example, what if certain benefits do not arise due to a change in government policy pertaining to decarbonisation, economic development, or electric vehicle usage?

A framework is needed – complete with whatever reasonable compromises are required. Leaving these matters open ended, however, undermines the value of beneficiary-pays and argues against implementation at this time."[111]

16.3.16 We agree and think Government guidance is also required for wider distributional issues, including for those arising from any reallocation of existing assets. This is why, as part of the EPR, Trustpower recommended that a Government Policy Statement (**GPS**) on transmission pricing should be issued.

17 Conclusion on policy objectives

17.1.1 In Part II we summarised submitters' views that the core elements of the proposal will not promote overall efficiency. We think it is implicit that those same submitters do not think the proposal is consistent with the Authority's statutory objective.

17.1.2 Some submitters made this point explicitly as noted in this part. Others went further and expressed disagreement with the Authority's view that its proposal is aligned with the Government's wider energy objectives.

[111] TLG Report in The TPM Group Submission on 2019 Issues Paper (October 2019), pp. 19-20

PART IV CODE CHANGE REQUIREMENTS

18 Introduction to Part IV

18.1.1 In this part we analyse submissions on the Authority's options evaluation.

18.1.2 We also introduce our expert's analysis of the submissions on the CBA and on the OIA material.

19 Importance of these matters

19.1.1 At the end of the TPM development process, the Authority will need to consult on a code change proposal. As part of that process, the Authority must consider if the TPM is the best means of achieving the Authority's reform objectives and if the benefits of the TPM exceed the costs.

19.1.2 The Authority, appropriately, in our view, believes it is important to address these matters when the TPM Guidelines are developed as well as at the end of the process.

19.1.3 Problematically, however, a number of submitters do not think the Proposed TPM Guidelines meet the requirements of section 39 in respect of either the assessment of alternatives or the evaluation of the costs and benefits of the proposal.

19.1.4 This suggests that it might be necessary to build more flexibility into any amendments to the TPM Guidelines so the best combination of options to address the problems of concern to the Authority can be identified and tested by Transpower.

20 Submissions on assessment of alternatives

20.1 Submitters' views on the Authority's options evaluation

20.1.1 As previously noted, a significant number of submitters believe that any problems with the current TPM can be addressed by proportionate incremental reform rather than the "big bang" reform proposed.

20.1.2 This includes changes to the RCPD charge to address the inefficiencies associated with over-signalling future costs of transmission and potentially a bespoke solution to the HVDC charge competition issue such as allocation to all generators.

20.1.3 Other suggestions include a deeper connection charge to be applied to those new transmission investments where the benefits are readily able to be identified (effectively a deeper connection charge) and a simplified LRMC charge instead of benefits-based charge, as this would send a more direct signal of the long run costs of transmission.

20.1.4 In brief, submitters were not persuaded that the Authority's assessment of alternatives in Appendix E was as complete and as fulsome as required.

20.2 Experts' comments on the Authority's approach to the options evaluation

20.2.1 Axiom Economics commented on the Authority's assessment of alternatives in the following terms:

> *"The way in which the respective merits of alternative pricing options have been evaluated has also been conspicuous. It has been a common practice to contrast an unduly narrow version of an alternative proposal with an idealised and unrealistic variant of the preferred option. Shared traits are viewed through a different lens, depending upon which charge is under consideration at that particular moment. A prominent example is the way that the uncertainty and inaccuracy surrounding the derivation of BB and LRMC prices are respectively perceived:*

- *the Authority acknowledges the substantial uncertainties and inaccuracies that would afflict the estimation of private benefits under its proposed BB charge, but maintains that this does not represent a fundamental weakness,20 i.e., the charge is included in the CBA and, ultimately, recommended; yet*
- *when assessing LRMC pricing, the Authority emphasises repeatedly the uncertainties and potential inaccuracies associated with the methodology21 (all of which are surmountable given the approach's widespread application and none of which are as significant as those associated with the BB charge) and opts ultimately to not even include such an option in the CBA.*
- *one of the principal rationales for rejecting LRMC-based charging options is the proposition that nodal prices alone can be relied upon to elicit efficient long-term investment decisions – this is said to obviate the need for any additional explicit LRMC-based price signals; but*
- *if that contention were true (which it is not23), it would apply equally to the BB charge, i.e., The Third Paper states clearly24 that the BB charge would provide an implicit price signal to users and so, applying the same logic, it would also be unnecessary and inefficient."*[112]

20.2.2 TLG (for the TPM Group) refer to the perils associated with a process which sets up a comparison between two extreme scenarios and then obtains an extreme result.

> *"The base "business-as-usual" (BAU) case is so significantly flawed from the start and the alternative case is so extremely different from the flawed BAU case that the results cannot help but be both flawed and extreme.*
>
> *The inherent issue in the BAU scenario is that the current RCPD charge is clearly far too high during the peak period (to the point that we do not need a CBA to tell us about the potential benefits of reducing this charge). This problem can be fixed easily by recalibrating the RCPD charge; and doing so would create a much more appropriate basis for then evaluating the relative benefits of possible further refinements. Yet this is not the focus of the Authority's analysis or proposal; the focus of the core CBA is very much on the alleged benefits of switching all the way from the current RCPD charge which is unambiguously too high, to a charge that is broad-based across all usage. Unfortunately, the wide range of possible, and more pragmatic, alternatives in the 'middle ground' of these two extremes remain overlooked. Accordingly, the case for the 2019IP specifically proposed recommendations is weak (as a case, let alone a strong one, against eminently plausible alternatives is not made), though many of the associated inferences and discussion points are still useful. Instead, we strongly urge consideration of a modified or transitional alternative approach that addresses the identified problems more efficiently and effectively while robustly avoiding additional risks. "*

21 Submissions on the Authority's CBA

21.1 Submitters' concerns about the CBA results

21.1.1 Our review of submissions has revealed that a number of submitters share the concerns with the CBA set out in the HoustonKemp Report submitted as part of our submission on the 2019 Issues Paper.

21.1.2 This includes an expert report from Axiom Economics that undertakes a similar level of detailed analysis and reaches similar conclusions to HoustonKemp.

21.1.3 Transpower's submission notes:

> *"Axiom considers that correcting two of the more serious errors in the Authority's CBA would turn the estimated net benefit into a substantial net cost. If the CBA was to be taken at face value, the modelling concludes that the proposal may not deliver a material net benefit for 12 years. However, the modelling also expects there to be a significant "political uncertainty event" within 11 years, which could take the form of another substantial change to the TPM.4 In other words, the Authority's CBA suggests the proposed TPM reform might deliver no net benefit for eleven years before it is itself supplanted by another reform."*[113]

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[112] Axiom Report in Transpower Submission on 2019 Issues Paper (October 2019), pp. x-xi
[113] Transpower Submission on 2019 Issues Paper (October 2019), p. C3

21.1.4 Some submitters indicated that they were only able to look at the CBA at a high level but, even at this level, found causes for concern.

21.1.5 For example:

a) Mercury stated that:

> *"From an analytical perspective, Mercury is doubtful the overall net benefits from the proposal could be as high as $6.4 billion. Comparing this to the net benefit from the 2016 proposal of $0.2 billion, the high end 2019 proposal is 30 times the expected net benefit for what essentially the same proposal."*[114]

b) ENA said:

> *"We have undertaken some high-level checks on the assumptions underlying the analysis of benefits which leave us questioning whether the consumer benefits will be realised at all."*[115]

c) Vector suggested:

> *"It is implausible that such a large category of benefits could suddenly materialise between 2016 and 2019. The reasons given in the Issues Paper, namely that consumers in the mass-market are expected to "become increasingly exposed to cost-reflective distribution pricing and real-time wholesale prices over time" are not new issues."*[116]

21.2 Submitters' concerns about the methodology

21.2.1 PWC, for the Distribution Group, expresses reservations about the methodology used:

> *"Importantly the updated CBA has identified $2.37b of net benefits previously not assessed. These reflect consumer benefits of increased grid use at peak times. The net benefits of more efficient investment (in batteries, generation, large load and the grid) make up the remaining $0.34b of the central estimate of the net benefits.*
>
> *We are surprised by this outcome, which suggests that less than 15% of the net benefits are directly aligned with the objective of the TPM review, which as stated above (at paragraph 45), is primarily focussed on the dynamic efficiency aspect of the Authority's statutory objective.*
>
> *We note that the CBA includes the following key assumptions:*
>
> - *'We do not distinguish between consumers connected to distribution networks. Rather, we model all load connected to a distribution network as a single entity. This is an important simplifying assumption. It means the model does not consider the degree to which distribution prices reflect transmission prices, or the extent to which distribution price signals are passed through into retail prices'*
> - *'… a key assumption of the grid use modelling is that mass-market load will respond to both transmission and wholesale price signals over the period to 2049'*
> - *'It follows that under the status quo, RCPD price signals would increasingly be passed through into distribution prices'*
> - *'The CBA does not take account of any distribution investment brought forward'*
> - *'The Authority is aware that most distribution networks around New Zealand have spare capacity'*
>
> *We understand the need to make assumptions about future behaviours when undertaking the CBA. We also understand the complexities of the electricity market, including the translation of transmission and distribution costs into retail prices. However, given the primary benefit identified under the CBA reflects consumer demand response to pricing signals, it does not seem appropriate to assume away distribution and retail pricing influences.*
>
> *In addition, as the key benefit reflects more consumption at peak times, it does not seem reasonable to assume away the impact on distribution costs, or distributor response (such as through demand management or pricing) to such a significant change in demand patterns.*

[114] Mercury Submission on 2019 Issues Paper (October 2019), p. 8
[115] ENA Submission on 2019 Issues Paper (October 2019), p. 12
[116] Vector Submission on 2019 Issues Paper (October 2019), p. 15

We note the recent ICCC report, which has recommended that the Government prioritise accelerating the electrification of transport and process heat, supports this assumption. Accordingly, spare distribution capacity may be expected to be consumed between now and 2049, the period over which the CBA net benefits are assessed."[117]

21.3 Concerns about particular assumptions

21.3.1 A number of parties queried some of the assumptions. For example:

a) Mercury stated:

"We strongly doubt the EA's modelled exposure and ability of mass market customers to respond to real-time pricing will increase to 50% by 2032. Also, while some customers will want a cost-reflective tariffs, there will be a significant proportion of the population who will continue demanding a FPVV style tariff given the certainty this provides;

The EA's modelling seems to assume that there will be increased long term demand for energy as a result of a new TPM and that this increased demand, at lower prices, will be met with generation built at lower prices. This assumption seems questionable to us as generation investment is unlikely to respond to decreasing price signals."[118]

b) Tauhara North noted it was puzzled by:

"… by the exclusion of generation costs brought forward by the proposal on the basis that those investments are assumed to be efficient. The fact that the proposal makes new generation viable earlier does not mean it is not a cost associated with the proposal."[119]

c) Flick Electric outlined that:

"Based on our experience with electricity consumers choosing to be directly exposed to the wholesale spot price in times of volatility;- we submit the EA has grossly overestimated the potential benefits of consumer responsiveness in support of its TPM proposal."[120]

d) Unison Networks concluded that:

"Overall, Unison and Centralines submit that the Authority needs to substantially redevelop the model for assessing the cost-benefit impact of changing the residual cost recovery from RCPD to a more fixed approach. Network pricing, particularly at the residential level is increasingly becoming a constrained optimisation challenge, not purely an exercise in translating cost structures into a one-to-one pass-through calculation. Regardless of the form of transmission charges, under the constraint of the Low Fixed Charge Regulations EDBs have to translate transmission charges into compliant variable charges. We submit that the assumptions that sit behind the calculations in Figures 6 and 7 of the consultation paper are unrealistically simplistic and, in our view, lead to a substantial over-statement of the allocative efficiency benefits of the proposal."[121.]

21.4 Support for the CBA

21.4.1 In marked contrast to these views, Meridian supported the Authority's CBA.

21.4.2 Meridian's submission commented that the direction and magnitude of benefits is clearly in favour of change and says it believes the assessment of benefits is realistic and observes that, in its opinion, the Authority has given appropriate regard to unquantified benefits.

21.4.3 Meridian also referred to the assessment of its expert NERA that the Authority's broad approach is appropriate and the quantified net benefits are plausible.

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117 Distribution Group Submission on 2019 Issues Paper (October 2019), p. 17
118 Mercury Submission on 2019 Issues Paper (October 2019), p. 8
119 Tauhara North Submission on 2019 Issues Paper (October 2019), p. 4
120 Flick Electric Submission on 2019 Issues Paper (October 2019), p. 4
121 Unison Networks Submission on 2019 Issues Paper (October 2019), p. 6

21.4.4 However, there is an exception to the NERA endorsement of the Authority's approach which is worth noting. This is the exclusion from the CBA of the costs of additional generation required to realise the benefits of the proposal as NERA said that:

> *"In excluding this cost from the CBA, the Authority treats it differently from other costs such as the saving in battery costs and the increased cost relating to grid investments brought forward."*[122]

21.4.5 Given the Authority has quantified these costs at $1.9billion, their omission is not insignificant.

21.5 HoustonKemp advice concerning expert views on the CBA

21.5.1 As noted earlier, we asked HoustonKemp to review all submissions on the CBA and give us an expert view on their content. Its advice is attached to this submission as Attachment 3 and the Authority is urged to read it in full.

21.5.2 By way of summary, HoustonKemp has advised:

> *"Our review indicates that several of these submissions raise issues of substance in relation to the cost benefit analysis. Within this subset:*
>
> - *one report by Axiom Economics (on behalf of Transpower), undertakes a detailed review of the cost benefit analysis and raises substantial concerns about its reliability;*
> - *two further reports, prepared by John Culy (on behalf of Trustpower) and NZIER (on behalf of MEUG) respectively, undertake detailed reviews focused more narrowly on specific aspects of the cost benefit analysis which highlight additional concerns;*
> - *a further thirteen reports and submissions, while not undertaking detailed reviews, indicate concerns of substance with one or more aspects of the cost benefit analysis; and*
> - *one report prepared by NERA (on behalf of Meridian) provides qualified support for the EA's approach and estimates of net benefits.*
>
> *The overwhelming opinion voiced in these opinions is consistent with the messages in our report. In particular, our concerns are aligned with results of Axiom's detailed review and reinforced by other submissions. While NERA's stated view diverges from these conclusions, we note that its opinion is not drawn from a bottom-up assessment of the actual modelling approach and assumptions, and instead accepts to a large degree (without any critical analysis) high-level contentions about the analysis."*[123]

21.5.3 HoustonKemp notes that neither it, nor Axiom Economics, think the Proposed TPM Guidelines will give rise to any net benefits.

21.5.4 Instead, HoustonKemp estimate:

> *"…net costs of $2.3 billion arising from the grid use model and Axiom estimates net costs of $1.5 billion associated with the entire proposal."*[124]

21.5.5 HoustonKemp also looked at the OIA material on behalf of Trustpower.

21.5.6 This material provides evidence that some of the CBA issues were spotted by peer reviewers and advisers to the Authority.

21.5.7 HoustonKemp notes:

> *"Finally, we observe many of the issues raised by submitters on the cost benefit analysis could have been addressed at an earlier stage had the EA acted on concerns that were raised in internal reviews that it commissioned. Reviews conducted by Brian Bull and Advisian identified critical concerns with the cost benefit analysis. However, the substance of those concerns appears not to have significantly influenced the EA's approach, since the same concerns are now echoed in submissions made to the EA in response to its proposal."*[125]

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[122] NERA Report in Meridian Energy Submission on the 2019 Issues Paper, (October 2019), p. 16
[123] HoustonKemp Memo in Trustpower Cross-Submission on 2019 Issues Paper, (October 2019), pp. 1-2
[124] Ibid, p. 3
[125] Ibid, p. 2

21.5.8 It is not clear why these concerns were not appropriately actioned. The Authority may need to review its process in light of this outcome.

21.5.9 We would also encourage the Authority to consider, as part of any such review, the accessibility of its CBA analysis. A number of our consultants described the Authority's spreadsheets as bordering on 'impenetrable'. We also note the OIA material includes emails acknowledging that the coding is extensive and difficult to access, and that the documentation may not be adequate for anyone to check the Code.

21.5.10 This makes it very difficult to "*peer beneath the bonnet*". If stakeholders are going to be enduring cost increases for the "*greater good"*, we would argue that they should be entitled to satisfy for themselves that the "*greater good*" is real.

22 Conclusion on Code change requirements

22.1.1 In this part we have considered the extent to which the Authority has complied, and has been seen to comply, with the requirements of section 39 of the Act.

22.1.2 Our view is that the options analysis undertaken by the Authority is not robust enough to justify a set of TPM Guidelines which will operate as default terms.

22.1.3 This is because, as experts have commented, the focus of the analysis is often on extreme scenarios: the status quo without change or 'big bang reform', a narrow LRMC charge versus a highly idealised benefits charge.

22.1.4 Our view is that durable reform requires thorough exploration of the options between these extremes to identify the best alternatives to address the problems of concern to the Authority. These options include staged or incremental reform. A number of stakeholders agree with this statement.

22.1.5 We have also read, and had our expert adviser review, all submissions on the Authority's CBA to see if there are any new insights in this pivotal piece of work.

22.1.6 HoustonKemp's advice is that the overwhelming opinion surfacing from those stakeholder submissions that considered the CBA, and the in depth analysis from experts such as Axiom Economics, closely aligns with the analysis in their initial report and reinforces the conclusions derived from that analysis.

22.1.7 We think this is fatal to the Proposed TPM Guidelines.

PART VI: FEEDBACK ON TPM DEVELOPMENT PROCESS

23 TPM development process

23.1 Stakeholder views on the length of time required to develop a TPM

23.1.1 In our submission on the proposed TPM development process we said we thought Transpower would need more time.

23.1.2 Meridian does not agree. It considered that the proposed timeframe of implementation of the TPM in 2024 is too long and that a shorter timeframe would be more appropriate and achievable to realise benefits sooner.[126]

23.1.3 Rio Tinto also does not agree. Its submission suggests that two years can be cut from the proposed timetable because of:

> *"…the decade that the Authority has spent considering the TPM (and Transpower having been engaged over that whole period)…"*[127]

23.1.4 Other submitters think that the time taken to get to this stage (publication of TPM Guidelines) actually points to more time being needed for the next phase:

23.1.5 Nova Energy believed:

> *"…a minimum of two years, and a maximum of three years is appropriate. There are parts of the TPM implementation that Transpower should still consult on and provide time for constructive input and feedback in the process. There also needs to be enough lead time for EDBs to factor the new charges into their pricing regimes."*[128]

23.1.6 Buller Electricity said:

> *"Given the length of time the Authority has taken to progress TPM reform to its current status, the proposed timeline for Transpower to develop and implement the TPM is ambitious. This is especially the case as the guidelines now provide Transpower with more flexibility and consequently more development and decision-making responsibility on key issues."*[129]

23.1.7 PWC (on behalf of the Distribution Group) said:

> *"We note the significant level of engagement and alternative views put forward by Transpower's customers and stakeholders during the Authority's consultations on the revised Guidelines. We acknowledge that this in part reflects the significant redistribution of transmission charges between grid users that will result if the proposals are implemented. We expect that Transpower may face similar responses when it gets to the sharp end of the process. If that is the case, then the proposed timetable may be disrupted."*[130]

23.2 Transpower also believes more time might be needed

23.2.1 Transpower stated:

> *"Should the Authority proceed with its proposed new approach to transmission pricing, proper engagement with our stakeholders during TPM development would be critical to producing the most durable TPM possible within the constraints of the Guidelines. Constructive and highly engaged stakeholder participation would be key to achieving a successful development and implementation of any new TPM.*
>
> *In our view 18 months to submit a new TPM consistent with the Authority's 2019 proposal, would be an ambitious and very challenging timeframe. Any less time introduces a very high level of risk to our*

[126] Meridian Energy Submission on 2019 Issues paper (October 2019), p. 4
[127] Rio Tinto Submission on 2019 Issues Paper (October 2019), p. 26
[128] Nova Energy Submission on 2019 Issues Paper (October 2019), p. 4
[129] Buller Electricity Submission on 2019 Issues Paper (October 2019), p. 2
[130] Distribution Group Submission on 2019 Issues Paper (October 2019), p. 18

ability to deliver a durable TPM proposal to the Authority. For reasons we have stated previously, we would be more comfortable with 24 months."[131]

23.3 Expert advice

23.3.1 Experts have advised that the CBA and assessment of alternatives needs to be redone.

23.3.2 CEC has also made the sensible suggestion that a full case study of one or more deep transmission investment needs to be done before benefits-based charges is becomes mandatory.

23.4 Conclusion

23.4.1 We agree with Powerco's submission:

> *"It would have been difficult to predict a timeline of the Authority's TPM development (and hold the Authority to it). We should learn from that experience and apply a pragmatic approach to Transpower's implementation process. It'll take the time it takes, and it's worth taking the time to get it right."*[132]

[131] Transpower Submission on 2019 Issues Paper (October 2019), p. 10

[132] Powerco Submission on 2019 Issues Paper (October 2019), p. 3

CONCLUDING REMARKS

23.4.2 We acknowledge, as noted in our submission on the Authority's February 2017 supplementary consultation on the Second Issues Paper, that the current TPM Guidelines need updating to reflect the legislative changes since the Electricity Commission developed them.

23.4.3 We do not think the Authority is in a position, however, to publish the Proposed TPM Guidelines for the reasons set out in this cross-submission.

23.4.4 By way of recap, our review of submissions suggests that:

a) submitters accept the RCPD charge may distort the use of the grid (particularly at its current high levels) but this negative feature also needs to be balanced by the RCPD's positive attributes including its role in providing a long term stable signal of the cost of peak usage and its adaptability;

b) submitters consider the risk of investment in inefficient batteries to be overstated and are less persuaded than the Authority that the RCPD charge leads to inefficient location decisions;

c) there are differences of view about the extent to which current allocation of the HVDC charge is impacting on entry into the South Island generation market with one submitter stating that a far bigger impact is the risk of the closure of the Tiwai aluminium smelter;

d) there is very limited support for the concept that the benefits-based charge will reduce disputes, replace the need for a long-term transmission congestion price signal, and improve grid investment scrutiny; and

e) there is also a real and growing concern that the Authority has underestimated the modelling challenges of implementing a benefits-based charge in a robust manner.

23.4.5 In order to move this debate forward, we think it is necessary to quantify, as robustly as possible, the size of the detriment associated with the identified problems with the current TPM. We then recommend using a sound CBA process to assess which combination of options will best address those detriments over time.

23.4.6 For example:

a) An immediate change could be made to the RCPD charge while work is done to evaluate whether a simplified LRMC charge, or less granular benefits-based charge would provide the best signal of long-term transmission prices; and

b) Consideration could be given to reallocating the HVDC charge amongst all generators whilst analysis is done of the extent to which it would be in the long-term interests of consumers for this charge to be gradually included with the interconnection assets.

23.4.7 Consequently, we recommend that the Authority develop and consult on a set of high-level guidelines which would give Transpower the flexibility to explore TPM reform options that address the problems set out in pages 8-11 of the 2019 Issues Paper.

23.4.8 As we are all discovering, there are no shortcuts to durable transmission reform.

Issues around allocating Residual Charges to Generation

Note prepared by Creative Energy Consulting for Trustpower – 23rd October 2019

Overview

The EA proposes to allocate the residual charge entirely to load: ie transmission customers. Whilst my submission to the third TPM issues paper[1] was critical of several aspects of the EA's proposed residual charging structure, this is one aspect that I can wholeheartedly support, for reasons that are set out in this note. However, whilst this approach is generally supported by stakeholders, there are a few submissions which argue that a part of the charge should be allocated to generators.

Trustpower has asked my firm, Creative Energy Consulting, to consider this issue and, specifically, to respond to points in submissions to the TPM third issues paper made by:

- Derek Bunn[2]
- PwC[3]

Some other submissions have also referred to this issue.

This note presents the views of myself and my company, CEC, and does not necessarily, and is not intended to, represent the views of Trustpower.

Role of Residual Charge

The need for a residual charge arises from the fact that, due to economies of scale in electricity networks, the revenue from efficient, forward-looking transmission prices generally provides insufficient funding for the owner of the network. Thus, a residual charge is needed to recover this additional revenue requirement.

The benefit-based (BB) prices in the EA's proposed TPM are neither forward-looking nor efficient. Nevertheless, they also have this problem of recovering insufficient revenue. This is because BB pricing is designed only to recover the costs of "new" (ie post-2019) assets and a few "historical" (pre-2019) assets.

The issue with residual charging is that, if the forward-looking prices are already efficient, adding the residual charge will inevitably reduce efficiency, by over-pricing. Given that the BB charges are likely to *under*-signal[4], the addition of a residual charge could, in some instances, actually improve efficiency. This raises different issues to those conventional faced in designing residual charges.

For the purposes of this note, I will assume the conventional residual charging problem, rather than the particular issues arising under the proposed TPM. This should not be taken to imply that I consider the proposed TPM to provide efficient prices; I don't.

[1] I have made several submissions over the course of the TPM review. When I refer to "my submission" in this note, I am referring to this latest submission, unless otherwise indicated.
[2] expert report attached to Vector submission
[3] para 13 Distribution Group submission
[4] for reasons described in my submission to the third TPM issues paper

International Experience

Bunn notes that:

> "On the actual mechanism of implementing the residual charge, the case for charging it to load is a weak one. International evidence is mixed on this…" (P7)

It is unclear what international evidence he is referring to. He references a paper by CEPA[5], but this paper does not seem to back up this "mixed" position. In most of the markets the CEPA paper discusses, the residual charge is allocated entirely to load[6]. Only in the UK and in Spain is there a policy of recovering some residual revenue from generation. In the UK this appears to be a grandfathering of a prior allocation of transmission costs, existing more than 20 years ago. In any case, EU rules on transmission charging seem to have now forced the UK to remove this charge. In neither case is any economic argument or justification presented for this allocation.

My own understanding is that the international consensus view in transmission pricing design is to recover the residual revenue entirely from load and not from generation.

Pass-through makes it Irrelevant

An important question is whether, and to what extent, generators are able to pass through the residual charge to customers. Bunn notes:

> "I do not agree…that there is no point in charging generators because they would simply pass it on through the wholesale market. If that were credible, then one could argue it makes no difference whichever way it is applied... But, as the transmission charges would [as proposed by OFGEM in the UK] be fixed, not short-run marginal, costs, one would *not* expect those to go through a simple pass though into the energy market." (pp7-8)

There are two separate points made by Bunn here:

- That fixed (independent of output) transmission charges would *not* be passed on; but
- If they *were* passed on, the split of residual revenue recovery between generation and load becomes irrelevant.

I will address the second point here and the first point in the next section below.

As Bunn notes, if the generator residual charges were to be passed onto customers, this would have to be through higher prices in the wholesale energy market. So, in a sense, the residual charge is no longer being allocated to generation, but to load via this "uplift" in the energy price. I think that is what Bunn means by "makes no difference": in effect, load is paying 100% of the residual charge. In taxation theory, this end-point for the tax burden is referred to as the *incidence* of the tax. Bunn is arguing that, if the "tax" incidence of the residual charge is borne 100% by load, then the chosen tax allocation is irrelevant.

But what this argument misses is that, for minimising inefficient distortions in transmission usage, the *structure* of the residual charge is important, as well as the *level*. Would this uplift price have an efficient structure? As discussed below, the detailed structure of this uplift is unclear. However, what is clear is that it will be variable (ie depending on consumption). It must be, because it is a

[5] *International Review of Cost Recovery Issues*, February 2017, Cambridge Economic Policy Associates Ltd and TNEI Services Ltd

[6] as far as I can tell from the discussion in the paper

component of the wholesale energy price. So if one were to argue[7] that, to minimise distortions, the residual charges on load should be fixed rather than variable, it is impossible to achieve this outcome if a proportion of the residual is levied on generation and then passed-through in the energy price.

Therefore, Bunn is incorrect to assert that the split of residual revenue recover is irrelevant if generators can simply pass it through.

Will it be passed through?

If a residual charge is levied on generators as a variable ($/MWh) component, generators will simply add this to their offer prices, to ensure that they can cover all their costs (generation operating costs plus transmission charges) when they are dispatched. If demand is inelastic, this will simply raise the energy price accordingly and the charge is passed on directly to load. In this situation, the pass-through uplift is likely to have a similar structure to the generation residual charge, so Bunn would be broadly correct in asserting that the allocation of the residual to generation is irrelevant.

On the other hand, if the residual charge is fixed, there is no reason for generators to raise their offer price to recover it; if the generation market is competitive, this would simply cause them to lose market share[8]. So, the imposition of the charge is unlikely to lead to substantial changes to bidding strategy; in the *short-term*, the charge will *not* be passed through.

However, in the longer-term, this charge will raise the cost of generation entry and reduce the cost of generator exit. A new investor will account for this charge in its investment appraisal and this may cause it to cancel or defer the investment. For an existing generator with a low operating margin (ie operating revenue minus avoidable operating costs), the new charge might be the last straw which leads to a closure decision. In both these cases, the reduction in generation capacity is likely to lead to higher wholesale energy prices. So some, at least, of this charge is passed through to load.

The structure of the "uplift" in this case is unclear. For example, if the generator residual charge caused a reduction in baseload generating capacity, this might lead to a rise in energy prices across all periods, although the rise would be sharper in peak periods when the generation supply curve is steeper. If, on the other hand, it caused a reduction only in peaking capacity[9], this would lead to higher energy prices only at peak times.

So, in summary, a fixed generator residual charge is likely to be passed-on – in the longer-term – as a variable uplift to load, and Bunn is incorrect to assert that it wouldn't be. The structure of the uplift is uncertain, but it is unlikely to be optimal in terms of minimising distortions.

[7] as the EA does, although I disagree with this

[8] and, if the market was uncompetitive, they wouldn't need the excuse of a transmission charge to raise their prices

[9] and this seems plausible, given that a fixed charge based on generator capacity would have a greater proportionate impact on a peaking generator

Reliability

It is possible that the loss of generating capacity could lead to lower reliability: ie more frequency load shedding at demand peaks. A peaking generator must recover its fixed costs over the few periods when it is dispatched to run. This ability is limited by a *de facto* or *de jure* cap on wholesale prices[10]. A residual transmission charge would add to its fixed costs, making this cost recovery even harder. The consequential delayed entry – or advanced exit – of peaking plant may leave insufficient generation capacity to cover peak demand, leading to an increase in load shedding.

As I discussed in my submission, load shedding is an extremely inefficient form of load response, because it indiscriminately curtails low-value and high-value load equally. A pricing signal – *any* pricing signal – is preferable to load shedding. So, to the extent that a generation residual charge might lead to lower reliability it should be avoided, even if this means high residual prices for load.

Ramsey Pricing and Network Externalities

As discussed in my submission, Ramsey Pricing is a conceptual approach that minimises the distortionary effect of residual charges (or, more generally, of taxes) by levying the charge at different rates on different products in inverse proportion to the price elasticity of the product. So a product with inelastic demand should face a relatively high charge, on the basis that the distortion (in terms of change to consumption) nevertheless remains fairly low. In the electricity context, a "product" would be supply of electricity at a particular time or under particular conditions: eg a peak-period supply or an off-peak supply. So if, say, peak-period electricity consumption is highly inelastic, the residual charge should be levied primarily in peak periods.

Connection to the grid could also be considered a "product", with a "fixed charge" or capacity charge being attached to that product. So if grid connection is inelastic, Ramsey Pricing would imply recovering the residual through a fixed charge.

However, the Ramsey analysis relates to taxing *consumers*. Taxing producers (or sharing the tax between producers and consumers) is more complicated, because of the pass-through issue discussed above. The change in behaviour depends upon the incidence of the tax; if the producer can simply pass it through, they do not need to change their generation, but the price change will instead impact on consumption. Therefore, a simple Ramsey analysis may not be useful or applicable to this question.

In an earlier note on this issue[11], NERA considered whether network externalities should be factored into the decision. If generators provide positive externalities through the network effect, this would be another reason for avoiding "taxing" them with residual charges. NERA argued that this was the case, particularly in relation to reliability. This leads to a similar conclusion to the one that I made above: that charging generators should be avoided if this could lead to a lower reliability.

[10] there is no formal regulated price cap in the NZEM currently. However, the scarcity pricing schedule introduced as part of the real-time pricing initiative will effectively cap prices at these specified levels.
[11] *Review of Electricity Authority's transmission pricing review 2019 papers,* NERA 2019, at 4.5

Risk Allocation

Variability in transmission prices creates risks for users. For the efficient price component, this is similar to market risks: eg from volatile energy prices. It is not ideal but, trying to remove it might lead to the alternative problem of not properly signalling future transmission costs. However, for the residual charge, the aim should be to minimise this risk. The risk arising from volatility in the *aggregate* residual revenue cannot be avoided, since this is simply an outcome of the interaction between the transmission revenue requirement and the efficient charges. However, risk can be reduced by recovering this revenue from parties best able to bear or manage this risk.

Generators are generally large companies, with big balance sheets, able to bear a certain amount of risk. However, they are dwarfed – in aggregate – by electricity consumers who collectively make up pretty much the entire NZ economy. So, clearly, consumers are better able to bear the risk than generators. Neither sector can significantly manage the risk, for the reasons set out above.

In the submission that it prepared, PwC argued that:

> "the residual charge should apply to all grid users to avoid … inequity" (para 13)

PwC didn't explain how or why it considered an allocation to load only to be "inequitable". Of course, it would be *asymmetric*, but given that generators and consumers are entirely different categories, it is unclear why a symmetric charge would be more equitable.

On the other hand, allocating risk to those who are best able to bear it *does* seem to be reasonably equitable, as well as efficient. So, in this respect, allocating entirely to load would seem to be equitable.

Competition

A key issue with transmission charging, which the EA has discussed at length in various issues papers and consultations, is the distortions arising due to the differential charging of transmission-connected generators (TG) versus distributed generators (DG). In relation to residual charges, TG will face the generator residual charge, whereas DG will be credited[12] the load residual charge. So, the aggregate charging difference for the two categories is the sum of the generation and load residual charges. However, since this sum is proportionate to the residual revenue to be recovered, it does not make any difference (to first order) how revenue recovery is split between generation and load. So, this aspect does not provide any guidance.

For example, suppose the residual charge is $50/kW. If this is charged entirely to load, DG will be credited $50/kW for its peak output. TG pays, and receives, nothing. So, relatively speaking, there is a $50/kW benefit to DG.

Now suppose instead the charge is split: $20/kW to generation and $30/kW to load. TG now pays $20/kW; DG now receives only $30/kW. The difference remains at $50/kW. So, to first order, the choice of allocation has no impact on this competition issue.

[12] through ACOT, to the extent that this is permitted, or as a result of netting for behind-the-meter generation

Conclusions

There are several reason why the residual charge should be allocated entirely to load, rather than allocated in part of whole to generation:

1. It is common international practice, except where there is an objective of grandfathering a pre-existing charging allocation, as in the UK.
2. A charge on generation is likely to be passed-through, in the short-term or the long-term, for a variable or a fixed charge, respectively. The structure of the pass-through "uplift" – effectively a residual transmission charge on load – may be unclear or uncertain. In general, it will not be ideal in terms of minimising distortions to transmission usage.
3. A charge on generation may lead to a reduction in generation capacity and a resulting worsening of supply reliability.
4. Consumers, in aggregate, are better able than generators to bear the risks of volatility in the level of the residual charge.

Bunn is wrong, in my view, to say:

1. *that international practice is "mixed"*: in fact, it strongly favours allocation to load.
2. *That fixed charges would not be passed through*: albeit not in the short-term, they *will* be passed through in the longer-term.
3. *That is does not matter whether they are passed through*: it *does* matter, because the structure of the pass-through "uplift" may create unnecessary distortions.

In my view, the PwC argument that allocating only to load is "inequitable" is unsupported and unjustified. One measure of equity would be how well a party is able to bear the risk. This would imply that an allocation to load is most equitable.

Issues around Transpower Case Studies on benefit-based charging models

Note prepared by Creative Energy Consulting for Trustpower –23rd October 2019

Overview

As part of its submission to the Electricity Authority's (EA's) third issues paper on the transmission pricing methodology (TPM), Transpower has included some results and discussion of applying benefit-based charging methods (BBCMs) to some simple case studies of transmission expansions[1].

Trustpower has asked Creative Energy Consulting (CEC) to review these studies and identify and discuss any issues arising pertinent to the efficiency, durability and practicality of the EA's proposed TPM.

This note presents the views of myself and my company, CEC, and does not necessarily, and is not intended to, represent the views of Trustpower.

Topology

Transpower's case studies are confined to a simple situation relating to the expansion of a radial line interconnecting two regions: Wairakei and Hawke's Bay. It seems to be implicitly assumed in these studies that these expansions do not affect the wider market outside of these two regions.

Clearly, Transpower chose this situation to simplify the modelling. However, these topology assumptions are unrepresentative and unrealistic and are likely to present a distorted picture of the issues and challenges of BBCM.

Admittedly, radial situations exist in NZ, but isolated regions do not. Wairakei is interconnected to regions to the north and south and, via the HVDC, to the South Island. Any change in transmission flows between Wairakei and Hawke's Bay will inevitably have some flow-on effects to these other regions.

Modelling these effects will require a larger and more complex model, not just to represent the various transmission constraints between all of these regions but also to create forecast scenarios for generation, transmission and load.

The situations in the case studies are examples of "shallow" transmission expansion whereby generation or load changes in a region prompt expansion of *nearby* transmission. As I discussed in my submission[2], this is also the kind of situation favoured by the EA and one which it typically refers to when qualitatively considering the incentives created by beneficiary-pays (BP) charges. In these shallow situations, transmission expansion is largely prompted by changes in load or generation that have already occurred. On the other hand, "deep" expansion projects (such as the NIGU or HVDC expansion), are largely driven by forecasts of what is predicted to occur in the future. It is notable that Transpower's case studies do not refer to the future at all. As discussed below, future entry is a critical issue.

[1] Appendix 3 of Transpower submission

[2] I have made several submissions over the course of the TPM review. When I refer to "my submission" in this note, I am referring to my latest submission, to the third TPM issues paper, unless otherwise indicated

Counterfactual

In the BP charging approach proposed by the EA, the relevant benefits to measure are – as I understand it – based on a comparison of outcomes with and without the relevant transmission project. Thus, there is necessarily a "do nothing" counterfactual that must be defined and modelled.

In this counterfactual, it is only Transpower that "does nothing", not the rest of the market. For example, in Transpower's case study A, load growth in Hawke's Bay triggers the need for transmission expansion. If this expansion were *not* undertaken, nodal energy prices in Hawke's Bay would continue to rise, and this would be likely to prompt generation entry and also demand response: plausibly it might even lead to price-sensitive customers exiting the region; perhaps, relocating elsewhere.

In the case study, Transpower has included new diesel generation in its counterfactual. This seems plausible, but there may well be other options (demand response, storage etc) that are more economic. For the BBCM, these options must be modelled and the likely outcome incorporated into the analysis. This will be difficult enough in this simple situation, and far more complex in the general situation where multiple regions – and even the entire country – are impacted by the "do nothing" decision.

Even Transpower itself might be impacted. If one expansion project is, or is not, undertaken, this might affect the timing or design of future transmission expansions elsewhere: in the general case, if not in the case studies.

The problem of defining the counterfactual is an issue for the grid investment test (GIT) currently, but probably not such a difficult one. The "do nothing" counterfactual is only relevant for measuring whether there is a *positive* net benefit[3] in undertaking the expansion. Once this is demonstrated, the more detailed analysis is likely to be around comparing alternative project designs, sizes and timings. For example, in the case study situations, the GIT would be comparing different sizes and timings for the new expansion, taking into account both shorter-term load shedding impacts and longer-term demand growth. Transpower would likely consider the diesel generation as a non-network option, rather than as a "do nothing" counterfactual.

Wealth Transfers

The major components of the private benefits being calculated in the BBCM are likely to be *wealth transfers* associated with the consequential changes in nodal energy prices. For example, in case study D, the expansion removes export constraints out of Hawke's Bay, leading to higher prices, benefits for generators located in this region, and corresponding detriment for local customers. There is a wealth transfer from the customers to the generators.

Across the entire market, wealth transfers must always net out to zero: if one party is being paid more, this must be from another party who is *paying* more. Put another way, total payments in the market must always net to zero[4], under every possible scenario. Thus, in the GIT, which is solely concerned about aggregate benefit across the market, wealth transfers can be and are ignored.

[3] for economic investments. This is not required for reliability investments

[4] after including the Loss and Constraint Excess which is also paid out to the market

Although this does not seem to have been fully recognised by the EA in its drafting of the proposed TPM guidelines, wealth transfers are the essential difference between market benefits and private benefits, in that:

- *market benefits*: are measured by the GIT and exclude wealth transfers[5]; whereas
- *private benefits* are measured by the BBCM and include wealth transfers[6].

Whilst it is by no means straightforward to estimate and predict market benefits, these relate generally to things that have an objective, measurable, cost or benefit: a transmission line or new power station, reduced load shedding etc. However, future nodal prices are not objectively measurable but must be estimated using a market model. Market outcomes depend upon the bidding and investment strategies of market participants and incorporate many factors that can only be guessed at. Outcomes in oligopoly markets (of which the NZ generation market is one) are particularly difficult to model.

In the case studies, Transpower models the market by assuming cost-based bidding. This is understandable (at least generation costs are objectively measurable[7]) but unrealistic. Electricity markets simply do not operate in this way, and to assume they do will give rise to inaccurate and unrealistic estimates of benefits. On the other hand, the modelling of oligopolistic bidding strategies, necessary to accurately estimate private benefits, will inevitably be fraught and contentious.

Scenarios

As noted above, market scenarios must be developed in detail for the transmission expansion and the do-nothing counterfactual. These must contain forecasts for generation entry and exit, load growth, other transmission expansions, fuel prices and (to calculate wealth transfers) bidding strategies. Under the GIT, as I understand it, several different scenarios must be modelled and a weighted-average of the associated market benefits is calculated.

It is not clear how many and how sophisticated are the scenarios used in the case studies. In this respect, it is disappointing that Transpower chose *fictitious* cases, rather than *actual* cases of transmission investments that have been put through the GIT in recent years (discussed further below). Presumably[8], the same scenarios will be used for the GIT and for the BBCM, to ensure that benefits are aligned. As noted above, however, there might be a need to develop more detail for the "do nothing" counterfactual scenarios for the BBCM than is required currently under the GIT.

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[5] *Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination)*, Commerce Commission, Clause D4

[6] implicitly, although as drafted, the TPM guidelines only refer to market benefits: see definition of "net private benefit" on P102 of the third issue paper

[7] Although even this is problematic for energy-constrained generation such as hydro, where bidding must reflect the scarcity value of the stored energy which, in turn, will depend upon subjective factors such as forecast inflows.

[8] although neither Transpower nor the proposed TPM guidelines are clear on this

Reopeners

The BP philosophy, as espoused by the EA, are that BP charges are *fixed* at the time of the relevant transmission investment and then left unchanged. This is, in the EA's view, necessary to prevent use of transmission being distorted by charging for the sunk costs of existing assets on a variable basis. Nevertheless, the TPM guidelines do envisage two situations where these BP charges can be "reopened" and changed:

- when there is a substantial and unanticipated change in the *use* of the relevant transmission assets[9]; and
- when there is a change in the *users* of those assets[10]: eg new entrant customers or generators.

Transpower alludes to the first case in its case studies report. It does not mention the second case.

The relevant change in use is relative to that which was assumed in the original benefits calculation[11]. So, the scenarios used in this original modelling would need to be preserved and then compared periodically to later outcomes and revised forecasts. Where multiple scenarios were used (as discussed above), it is unclear how this comparison would be made. For example, if a scenario X was predicted, with a 10% probability, and the actuals then follow this scenario X, would this be outcome be considered as anticipated or unanticipated?

A reopener mechanism has fundamental problems of governance, stability and philosophy. The governance problem has already been discussed: what is a "substantial change"? The stability problem is that it is "all or nothing": no change in BP charges if there is no reopening; a potentially substantial change if there is one. The philosophical difficulty is this: why fix the BP charges in the first place if you are then going to allow them to be reopened? If fixing is the right thing to do (ie to avoid distortions arising from charging for sunk assets), why would you ever reopen? Conversely, if reopening is appropriate, why not do this on a gradual, variable basis, to avoid the governance and stability problems[12]? The philosophical issue is pertinent because Transpower – in developing the TPM - should seek to follow the spirit, as well as the letter, of the TPM guidelines. But in this case, the spirit is unclear.

A reopening creates an opportunity to not just factor in the change of use but also any changes in methodology. For example, suppose Transpower operates initially with BBCM v1.0 but then, after a few years, improves its method to v2.0. A BP calculation initially done using BBCM v1.0 would presumably, if reopened, use BBCM v2.0. This change, *on its own*, could cause substantial changes to the BP charges: for example, if BBCM 1.0 used a cost-based bidding model whereas BBCM 2.0 modelled oligopoly bidding. A user who stood to gain from using the newer version might continually press for a reopening[13].

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[9] clause 26 of the proposed TPM guidelines
[10] ibid clause 42(a)
[11] ibid clause 26(b)
[12] Some submissions have suggested a periodic review: for example, aligned with Transpower's five-yearly regulatory reset. This addresses uncertainty over the timing of any reopening, but not around its potential impact. Nor does it address the philosophical question of why you would facilitate reopeners when the aim is to fix BP charges.
[13] Similar issues would arise for historical assets for which BP charges have been levied based on a special BBCM (proposed TPM guidelines clauses 62-63) but which may be recalculated using a different BBCM (under clause 26) if reopened.

The other form of reopening (for new users) is not discussed in the case studies, because the focus is on existing (at the time of the expansion) users. In practice, the GIT decision will also depend upon growth forecasts of new or increased transmission use. For example, in case study D, the expansion occurs only after the second new generator enters. But, plausibly, if this second entry could have been anticipated, the expansion might have been economic after the first entry. Furthermore, in sizing the expansion, Transpower would consider the prospects for entry of third and fourth generators.

Suppose that the expansion *had* occurred after the first entry. So, the first generator is known, whereas the second generator perhaps exists only in the mind of the Transpower modeller[14]. When calculating benefits in the BBCM, some benefits will go to this second generator. However, given that it doesn't actually *exist*, it is not possible to allocate charges to them. Since the full cost of the investment must be allocated through BP charges, the other beneficiaries must pick up this generator's share[15].

If and when the second generator *does* arrive, presumably the BP charges would be reopened so that the second generator can be charged, and the other parties can be relieved of the burden of paying "for" it. But there are practical and philosophical difficulties here too. Practically, the second generator might be somewhat different (eg in size or technology) to what was predicted. So, how are the BP charges adjusted? Is there a need to re-run the BBCM model? And, if so, is the re-run backdated to the timing of the expansion, or done for the current time?

Philosophically, what if these BP charges were to put off this second generator from entering? How would Transpower know this? Should they discount the charges accordingly[16]?

These reopening situations are critical problems with the BP method and give rise to severe practical and philosophical difficulties. Transmission investment is usually *strategic* rather than *tactical*, at least in part, in that it is designed to accommodate forecast growth, to provide value under a range of scenarios, and to facilitate subsequent upgrades. These considerations arise even in the shallow expansion considered in the case studies; they become substantially more important in the deep expansions (eg NIGU and HVDC) which are both more material and more contentious.

By simplistically applying BP charges to only those parties who exist at the time of the investment decision – and relying on unclear reopener provisions to accommodate the uncertain future – the proposed TPM is creating severe future problems for Transpower and its BBCM.

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[14] In practice there are generally *three* categories of future generators used in transmission planning. Committed new generators, for which the specifics are known. Anticipated generators who are at various stages of planning but have not yet committed and whose specifics might vary from anticipated if and when they finally commit. And modelled generation which is typically generic and does not refer to any known project

[15] this appears to be, anyway, the implication of the proposed TPM guidelines as drafted. However, given that this could potentially cause the BP charge to the generator to exceed the benefit that it receives, this does not seem tenable or consistent with the EA's philosophy. So perhaps instead the shortfall would be covered by an increase to the residual charge.

[16] Clause 42(c) of the proposed guidelines refer to a possible discount where the generator might otherwise choose a different connection point, but not the scenario where the generator decides not to connect at all.

Hedging

Market participants will generally enter into hedging arrangements to manage exposure to volatile spot energy prices. This might be contractual (eg generator sells contract for difference to retailer) or structural (gentailer company has generator and retail arms). I infer that the BBCM in Transpower's case studies does not reflect or represent these hedging arrangements, but simply assumes that benefits are related to spot price movements.

To be fair, it would be problematic to reflect hedging arrangements, because it is transmission customers (distribution businesses and directly-connected end-users) who pay transmission charges, not retailers[17]. Even if Transpower knew who was hedging with whom, it would be practically impossible to arrange for different transmission charges depending upon who the retailer was.

But this means that the BP charges do not reflect the benefits received. For example, in case study D, the first generator locating in Hawke's Bay may have hedging arrangements with local retailers, meaning that it is largely indifferent to spot prices. With the transmission expansion, spot prices rise and the generator faces BP charges, despite receiving no actual benefit from the expansion.

Conversely, in case study A, some customers in the region may have fixed price contracts with a retailer who, in turn, has hedged its spot price exposure. These customers see less benefit from the expansion: they don't benefit from the lower spot prices, although they *will* benefit from the improved reliability.

Retailers can offer fixed-price contracts to customers by hedging their spot price risks. But it would be hard to hedge transmission price risks, because there would be no natural counterparty (with equal and opposite risk) to offer such hedges. Thus, retailers may simply pass-through transmission charges to their customers. So, a consumer who was deemed to benefit from a transmission expansion would not receive that benefit (because its energy price is fixed by the retailer) but be liable to pay the BP charge anyway. Of course, this only applies for the term of the retail contract. On renewal, retail offers *will* reflect the lower energy prices. So, to avoid this anomaly – which could severely impact some consumers – new BP charges should be phased in gradually.

GIT Retrospective

The above discussion raises several difficult issues around the BBCM which are not addressed – although they may be alluded to – in Transpower's case studies:

- complex transmission topologies and impacts on remote regions,
- modelling benefits for deep, as well as shallow, transmission expansions,
- defining the "do nothing" counterfactual,
- averaging benefits across multiple scenarios,
- modelling of an oligopolistic energy market,
- defining "unanticipated change in transmission use" for the purpose of reopening the benefits allocation,
- accommodating predicted (but fictitious) new entrants and
- allocating BP charges to subsequent entrants.

[17] although the associated costs *will* be passed on to retailers

These issues raise potential concerns around philosophy, stability and practicality. These concerns may be so severe that the EA's proposed BP concept is fatally undermined: because it is philosophically incoherent, gives rise to unsustainable charging outcomes, or is practically infeasible.

The magnitude and materiality of these issues can only really be calibrated by undertaking a full-scale case study, based on one or more actual historical investments. Ideally, these cases would be *recent* enough for full details of the assumptions and models used in the corresponding GIT analysis to still be available in the archives, but *old* enough for differences to have emerge between predicted and actual outcomes to bring the reopeners into play.

This would be a major undertaking and would inevitably delay the final decision on the proposed TPM guidelines. However, better to delay than to promulgate guidelines that turn out to be unimplementable.

Conclusions

Transpower's case studies really only scratch the surface of the issues that will apply to designing and applying a BBCM under the proposed TPM. To understand this, consider first how complex the real-life GIT modelling for such cases would be. The reporting would run not to 4 pages but to 400. Next consider that a BBCM will be substantially more complex and contentious than the corresponding GIT modelling because, unlike the GIT:

- it must model wealth transfers;
- users are impacted differentially; and
- old studies are liable to be regularly reopened to accommodate new or changed use.

Finally, recognise that economic modelling of major, deep transmission projects such as the NIGU or the HVDC expansion are hugely more complex than these simple shallow cases.

The only way to gauge these steps up in complexity is to run a complete, comprehensive and detailed BBCM analysis for a recent large historical transmission investment such as the NIGU. This should be to a depth that would satisfy the TPM guidelines and the affected users. It should cover both the initial BP calculation and any subsequent reopeners. Critically, such a project must be undertaken *before* the draft TPM guidelines are approved.

HOUSTONKEMP Economists

Memo

To	Peter Calderwood, Fiona Wiseman – Trustpower
From	Daniel Young – HoustonKemp
Subject	Submissions on the cost benefit analysis of the Electricity Authority's proposed transmission pricing methodology guidelines
Date	30 October 2019

1. Overview

On 30 July 2019, the Electricity Authority (EA) released an issues paper, which sets out its proposal to change the guidelines that Transpower must follow in developing the transmission pricing methodology (TPM). The TPM establishes how Transpower's regulated revenues will be recovered from users of the transmission system.

Alongside its proposal, the EA also quantifies the net benefits of its proposal using a cost benefit analysis. It assesses the net benefits of its proposal as $2,711 million, in present value terms.

Acting on behalf of Trustpower, we prepared a review of the EA's cost benefit analysis which raises material concerns, including that the analysis:

- contains errors in its conceptual framework that cause it to overestimate benefits and underestimate costs and which, when corrected, show the proposal to give rise to net costs, including:
  - benefits due to increases in consumer surplus which are comprised almost entirely – 98 per cent – of transfers from generators to consumers; and
  - costs which exclude the impact of higher peak demand on investment in new generation and distribution capacity as well as underestimating the impact on investment in new transmission capacity;
- contains further errors of assumption and approach that render its results unreliable and not fit for its intended purpose, including:
  - unrealistic and uneconomic investment in batteries under the status quo, in response to the RCPD charge, which cause it to overestimate the benefits of its proposal;
  - implausible assumptions for generation entry and wholesale prices that give rise to large new generation investment under the EA's proposal despite falling wholesale prices; and
  - estimates benefits arising from greater scrutiny of transmission projects and increased durability under the EA's proposal, which are supported by unexplained and unreliable assumptions;
- does not support reform to the TPM guidelines in the near term since, even on its own estimates, the EA does not establish substantial net benefits arising from its proposal over the next decade.

Further detail of our concerns and the reasons for them are set out in our report.[1]

The EA received 93 submissions in response to its issues paper. Trustpower has asked us to review these submissions and comment on matters raised in relation to the cost benefit analysis.

Our review indicates that several of these submissions raise issues of substance in relation to the cost benefit analysis. Within this subset:

[1] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019.

- one report by Axiom Economics (on behalf of Transpower), undertakes a detailed review of the cost benefit analysis and raises substantial concerns about its reliability;
- two further reports, prepared by John Culy (on behalf of Trustpower) and NZIER (on behalf of MEUG) respectively, undertake detailed reviews focused more narrowly on specific aspects of the cost benefit analysis which highlight additional concerns;
- a further thirteen reports and submissions, including work undertaken by the Lantau Group (on behalf of the TPM Group) that, while not undertaking detailed reviews, indicate concerns of substance with one or more aspects of the cost benefit analysis; and
- one report prepared by NERA (on behalf of Meridian) provides qualified support for the EA's approach and estimates of net benefits.

The overwhelming opinion voiced in these submissions is consistent with the messages in our report. In particular, our concerns are aligned with results of Axiom's detailed review and reinforced by other submissions. While NERA's stated view diverges from these conclusions, we note that its opinion is not drawn from a bottom-up assessment of the actual modelling approach and assumptions, and instead accepts to a large degree (without any critical review) high-level contentions made by the EA about its cost benefit analysis.

Finally, we observe many of the issues raised by submitters on the cost benefit analysis could have been addressed at an earlier stage had the EA acted on concerns that were raised in internal reviews that it commissioned. Reviews conducted by Brian Bull and Advisian identified critical concerns with the cost benefit analysis. However, the substance of those concerns appears not to have significantly influenced the EA's approach, since the same concerns are now echoed in submissions made in response to its proposal.

2. Detailed assessments across all aspects of the cost benefit analysis

Axiom Economics, on behalf of Transpower, undertook a detailed assessment of the EA's cost benefit analysis. Aside from our own review, Axiom's is the only assessment that reviews the totality of the EA's cost benefit analysis – including both the economic logic of the framework and the methods and assumptions employed to implement this framework.

Axiom's key conclusions drawing from its assessment are in close alignment with the results of our own review. In particular, Axiom raises significant concerns about the assumptions and approaches that the EA employs. These concerns include that the cost benefit analysis:[2]

- does not assess key aspects of the EA's proposal and instead reflects a generic methodology that relies on fixed charges combined with forward-looking price signals;
- includes substantial wealth transfers from generators to consumers that should not be counted as benefits;
- ignores the significant costs of additional investment in generation and distribution networks that would be required to meet the increase in peak demand estimated by the EA under its proposal;
- relies on assumptions that give rise to nonsensical outcomes, including that increases in peak demand would give rise to reductions in price, and that generators will not consider future returns such that they will continue to undertake new investments even in the face of declining wholesale revenues; and
- estimates benefits that are unreliable and based on arbitrary assumptions, such as those relating to greater scrutiny of transmission investments and increased certainty for investors.

Drawing from these observations, Axiom notes that if concerns relating to transfers and missing generation costs were addressed, the net benefit of the proposal would drop to -$1.5 billion. However, it concludes that:[3]

[2] Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, pp 80-81.

> In our opinion, this latest CBA does not – and cannot – provide any meaningful insight into the merits of the Authority's proposal. There is no basis for the Authority to conclude that its proposal would yield a net benefit at all, much less the $2.7b sum it has suggested.

These views are consistent with our own, including that the cost benefit analysis is not sufficiently reliable to draw any inferences as to whether there are positive or negative net benefits associated with the EA's proposed TPM guidelines.[4]

Both reviews similarly observe that when the EA's modelling is corrected so as to exclude transfers and to include missing costs, the estimate of net benefits is less than zero. We estimate net costs of $2.3 billion *arising from the grid use model* and Axiom estimates net costs of $1.5 billion *associated with the entire proposal*. The difference between these values is in large part reconcilable, reflecting that:

- our estimate is derived as the total net benefit estimate in the grid use model ($2.6 billion), deducting transfers ($2.5 billion), increases in generation costs ($1.9 billion), increases in distribution costs ($0.3 billion) and unaccounted for transmission costs ($0.1 billion);[5] whereas
- Axiom's estimate is derived as the total net benefit estimate across the EA's modelling ($2.7 billion), deducting transfers ($2.3 billion) and increases in generation costs ($1.9 billion).[6]

There are minor differences between our estimates of the value of transfers included in the EA's assessment of net benefits. These differences relate to our different approach to calculating this value – we estimate this value by approximating the impact of the removal of the RCPD charge as a move along a single demand curve, whereas Axiom calculates the value within the EA's modelling reflecting movements along component demand curves.[7]

There are also differences between our estimates of the missing costs of distribution investment due to increases in peak demand. Whereas we estimate these to be within a range from $106 million to $428 million, Axiom assesses them to be within a range from $27 million and $81 million.[8] The source of these differences is not readily apparent, since the estimates appear to have been calculated using broadly similar methods and assumptions.

3. Detailed assessments focusing on specific issues

In addition to the detailed and broad reviews conducted by Axiom, two further reports undertake detailed assessments of specific assumptions and methods used in the EA's cost benefit analysis:

- John Culy, on behalf of Trustpower, reviews the approach used to forecast battery investment; and
- NZIER, on behalf of MEUG, assesses the strength of the RCPD price signal and the likely effect of its removal on peak prices paid by consumers.

Both of these reports raise concerns of substance which, in these specific areas, go beyond the analysis that we and Axiom undertake.

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[3] Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, p 79.

[4] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 42, 52.

[5] Figures do not add due to rounding. See HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, p 42.

[6] Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, p 81.

[7] See HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 43-46; and Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, pp 128-134.

[8] See HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 47-50; and Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, pp 135-137.

John Culy reviews the approach used by the EA to forecast battery investment. This is important because the EA assesses benefits of $202 million associated with avoiding inefficient investment in batteries that it forecasts will be promoted by the RCPD charge.

John Culy finds that the EA's modelling of battery investment is highly simplified, because it does not take into account half hour demand profiles, does not address peak shifting and does not consider the declining marginal value of further battery investments. Employing a revised approach to modelling battery investments, which adopts industry norms and considers the effects of incremental battery investments, he concludes that:[9]

> …the errors and inappropriate assumptions concerning battery investment and operation leads the EA to overstate the potential risk of excess "inefficient" battery investment in response to the RCPD price signal by a factor [of] around 6x.

NZIER reviews in detail the assumption made by the EA that, over time, price signals for mass-market consumers will be affected by the removal of the RCPD charge. The demand response resulting from this assumption gives rise to other effects in the EA's modelling, contributing to its very large estimate of net benefits under the grid use model.

This review highlights several factors that, together, suggest that peak demand pricing signals received by many customers are much weaker than assumed by the EA, because:[10]

- 81 per cent of distribution customers are not affected by time of use pricing and would likely receive no signals from changes to peak transmission charges;
- the typical peak demand period is 4,140 trading periods – considerably longer the 1,600 period modelled by the EA, which would mute the price signal for customers facing time of use pricing; and
- most distribution businesses do not pass through their interconnection charges into peak demand charges.

NZIER concludes that:[11]

> Together these factors indicate that the actual peak demand pricing signal sent by EDB transmission cost recovery charges to electricity retailers is not only much weaker than estimated in the CBA modelling but also varies across EDB regions. The CBA assumes that the RCPD signal in the status quo will become more intense over time as consumers are moved to TOU pricing and the interconnection charges are recovered over a much shorter peak period than is currently used by EDB. This requires both EDB to standardise their tariff structures and retailers to pass them on in their pricing. The CBA does not explain why the continuation of the status quo alone would lead to these outcomes.

NZIER also makes a number of comments about other aspects of the EA's cost benefit analysis at a lower level of detail, which we discuss at section 4 below.

4. Other submissions on the cost benefit analysis

In addition to the reports noted above, fourteen reports and submissions provide substantive commentary on the EA's cost benefit analysis. Of these, only NERA's report indicates a degree of comfort with the reliability and results of the analysis. We discuss NERA's report in more detail at section 5 below.

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[9] John Culy Consulting, *Battery analysis*, 24 September 2019, p 4.

[10] NZIER, *TPM 2019 cost benefit analysis | Initial review*, 1 October 2019, pp 3-4.

[11] NZIER, *TPM 2019 cost benefit analysis | Initial review*, 1 October 2019, p 4.

The general tone of other submissions that addressed the substance of the cost benefit analysis was one of concern. These submissions each raise one or more substantive concerns about the assumptions and approach employed in the cost benefit analysis, and therefore its reliability.

Broadly, these comments can be organised into seven themes, which we set out below, along with selected quotes demonstrating the nature of the concerns raised. Each of these themes is consistent with concerns that we raised in our report assessing the EA's cost benefit analysis.

1. **Substantial increases in generation investment estimated in the cost benefit analysis under the EA's proposed TPM guidelines are not plausible given lower wholesale prices.** For example, the Electricity Networks Association (ENA) comments that:[12]

   > … the single source of benefit that tips the CBA into net positive territory is the assumed reduction in average nodal prices (to $75?) that is timed to take place in 2034 … we observe that this price reduction is assumed to take place immediately following a substantial amount of generation investment – we suggest this assumption is not credible as it would hollow out the profitability of those generation investments which would not take place under these nodal price conditions…

   Other submitters that highlighted this concern were Mercury, Northpower, NZIER, Oji Fibre Solutions and Vocus.

2. **The cost of additional investment in generation capacity is incorrectly excluded from the calculation of net benefits.** Tauhara North No.2 Trust notes that:[13]

   > We are also puzzled by the exclusion of generation costs brought forward by the proposal on the basis that those investments are assumed to be efficient. The fact that the proposal makes new generation viable earlier does not mean it is not a cost associated with the proposal.

   Electra, ENA, the Lantau Group, Northpower and Vector also observed that generation costs should be included in the cost benefit analysis,

3. **The approach to modelling battery investment does not correctly consider the diminishing marginal returns associated with additional investment.** Orion puts this best:[14]

   > …the RCPD battery investment model appears to assume that incremental investment in batteries will continue to provide material gains when it would appear more logical that these would reduce over time. As battery capacity increases it will become increasingly difficult for a battery owner to avoid RCPD peaks (which, as a reminder, are determined retrospectively) given that many other battery owners will be trying to do the same.

   The Lantau Group also identified deficiencies in the EA's approach to modelling battery investment.

4. **The cost benefit analysis includes transfers in the calculation of net benefits.** Northpower stated that:[15]

   > Even if entry decisions took place as depicted in the CBA modelling, the resulting wholesale price reduction would not give rise to $2.6b in net benefits. Final consumers would certainly benefit from those reduced spot rates the model is predicting since they would, in time, receive lower prices (e.g., reduced retail tariffs). However, nearly all of that benefit is simply a wealth transfer from existing generators. There might be a small increase in overall demand (i.e., a

[12] Electricity Networks Association, *Transmission pricing review | 2019 issues paper consultation*, 1 October 2019, para 47.

[13] Tauhara North No.2 Trust, *TPM submission 2019*, 1 October 2019, p 4.

[14] Orion, *Submission on transmission pricing review – 2019 issues paper*, 1 October 2019, para 22.4.

[15] Northpower, *2019 issues paper | Transmission pricing review*, 1 October 2019, pp 8-9.

reduction in deadweight loss), but the majority of that 'benefit' would come simply from generators receiving lower prices for electricity that they would have sold anyway at the previous, higher price.

Other submitters that highlighted this concern were the Lantau Group and Vector. Vocus' submission suggests that the EA should take into account welfare transfers but does not state whether it considers that the cost benefit analysis already does this.[16]

5. **The cost of additional investment in distribution capacity is incorrectly excluded from the calculation of net benefits.** The Distribution Group explains that:[17]

> … as the key benefit reflects more consumption at peak times, it does not seem reasonable to assume away the impact on distribution costs, or distributor response (such as through demand management or pricing) to such a significant change in demand patterns.

Other submitters that identified this concern were ENA, NZIER, Northpower, Vector and Vocus.

6. **The cost benefit analysis incorrectly assumes that end-users face charges that reflect transmission prices and therefore the response from consumers will be much less than the EA assumes.** Unison and Centralines submitted that:[18]

> …it is incorrect for the Authority to assume that marginal distribution prices will perfectly (or even imperfectly) reflect marginal interconnection prices.…
>
> Even if EDBs move away from consumption-based pricing (including TOU approaches) to capacity or demand charging (coupled with requirements to offer low fixed charges), similar considerations will apply in calibrating marginal distribution price signals to recover revenue requirements while least distorting use of the network. In this context, changing from an RCPD to fixed charge basis for interconnection revenue recovery is likely to have negligible, and possibly no impact on marginal network pricing signals to residential and smaller commercial consumers.

The Distribution Group, NZIER, Oji Fibre Solutions and Orion also expressed concern about the EA's assumption that transmission price signals are passed through to consumers.

7. **Substantive benefits estimated by the cost benefit analysis will not occur in the short to medium term under the EA's assumptions.** Professor Derek Bunn, on behalf of Vector, stated that:[19]

> CBA analyses by their very nature tend to be controversial in their assumptions and speculative in their projections. And that is true in this case. Most concerning in this CBA is the observation that through the projections the net benefits appear to depend most substantially upon what may happen between 2030 and 2050. Power markets change a lot and after a decade, in my experience from over 40 years work in the sector, market circumstances have always been very different from original expectations. That does not mean we should not plan for the future – we have to – but a CBA which relies mostly upon what happens after ten years is not appealing and may not be robust.

Electra, the Lantau Group and Vector also raised similar concerns about the back-loaded delivery of net benefits, as estimated by the EA.

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[16] Vocus Group, *Transmission pricing review – 2019 issues paper*, 1 October 2019, p 3.

[17] Distribution Group, *Transmission pricing review | Submissions on the Electricity Authority's 2019 issues paper*, 1 October 2019, para 83.

[18] Unison Networks and Centralines Limited, *Unison and Centralines submissions on TPM proposals*, 26 September 2019, pp 5-6.

[19] Derek Bunn, *A commentary on the Electricity Authority 2019 issues paper on the transmission pricing review*, 25 September 2019, p 9.

5. NERA's review of the cost benefit analysis

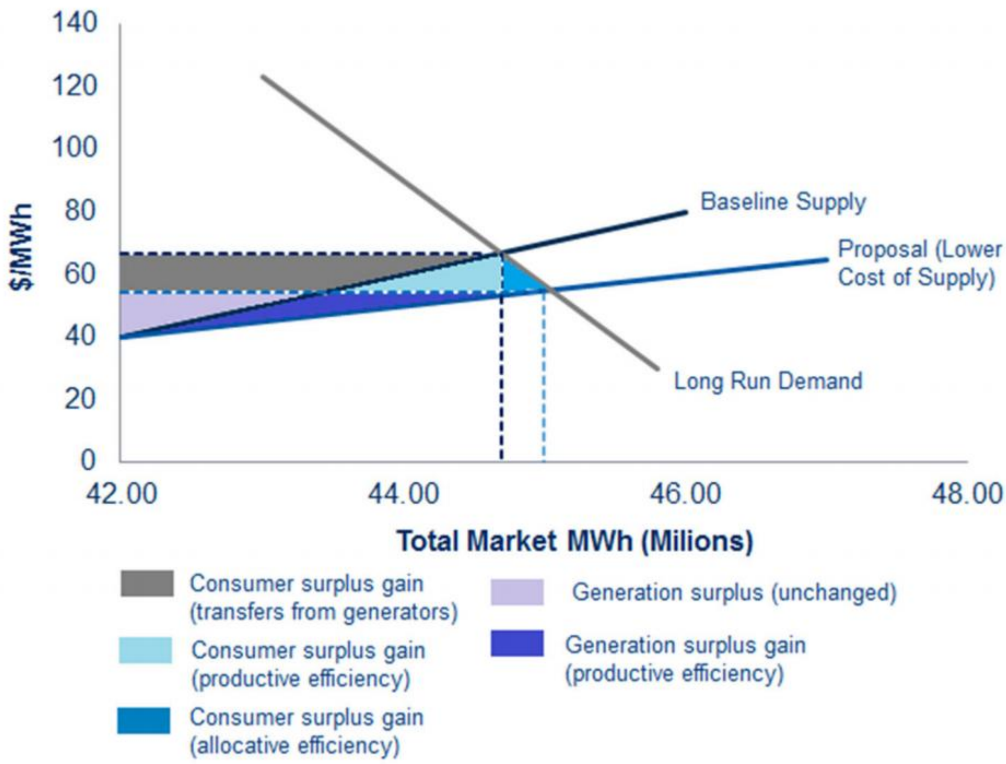
NERA was asked by Meridian Energy to undertake a review of, amongst other things, the technical paper describing the EA's cost benefit analysis. Based a high-level assessment of the EA's report, and testing its estimates against external benchmarks, NERA concludes that:[20]

> Because of the interdependency of the grid and the broader wholesale electricity market, more efficient grid pricing would lead to a more efficient wholesale electricity market. The Authority's cost benefit analysis ("CBA") captures this interdependency and more generally appropriately approaches the quantification.
>
> Furthermore, the magnitude of the CBA results is plausible, on the basis of empirical and regulatory estimates of allocative efficiency in industries across economies.

These broad conclusions are drawn from a review of the cost benefit analysis that never goes beyond the statements set out by the EA in its published papers. That is, NERA does not seek (and may not have been asked) to examine the actual assumptions and methods adopted in the EA's modelling, and constrains itself to restating the EA's explanation of its approach.

Providing an example of the limitations of this type of review, NERA draws from a chart provided by the EA in the modelling workshop to illustrate the effects of lower wholesale market prices in the long run. This chart is reproduced below.

Figure 5.1: Effect of lower wholesale market prices in the long run



Source: NERA

[20] NERA, *Review of Electricity Authority's transmission pricing review 2019 papers*, 1 October 2019, p 1.

In presenting this figure, NERA restates the EA's explanation that it is difficult to disentangle the increase in consumer surplus into transfers and efficiency gains. It accepts at face value the assumption presented in the figure – that the EA's proposal would give rise to a lower cost of supply.[21]

However, if NERA had investigated the EA's modelling it would have found that, on its own assumptions, the EA's proposal gives rise to a *higher* cost of supply. While the EA finds that the cost of battery investment would be $202 million less under its proposal than the status quo, it finds that the cost of generation investment would increase by $1,940 million under its proposal. On net, the cost of supply to the wholesale market will *increase*, not decrease, under the proposal.

Conclusions that are drawn based on incorrect assumptions about the approach used in the cost benefit analysis, and the results derived from it, are of little value in informing an assessment of the reliability of the analysis. This is a risk with any high-level review of a complex and highly detailed modelling exercise. By way of example, a similar high-level review undertaken by NERA of Oakley Greenwood's 2016 cost benefit analysis did not uncover any major concerns, concluding that it was 'informative and appropriate'.[22] The analysis was later shown to be affected by serious errors.

In addition to its review of the approach used, NERA also undertakes high level cross-checks of the results of the cost benefit analysis.

NERA notes that the net benefits estimated by the EA amount to approximately 1.6 per cent of the present value of the sum Transpower's expected revenue and expected wholesale market revenue over the next 30 years. Drawing from other assessments of allocative efficiency effects, NERA concludes that a gain of this magnitude seems 'quite plausible'.[23]

There is a material difference between a conclusion that an estimate is 'quite plausible' and a conclusion that it is 'reasonable', or the 'best estimate in the circumstances'. We note that the examples that NERA draws from in support of its contention do not reflect estimates resulting from changes to transmission prices but rather:[24]

- an estimate of the deadweight loss associated with labour taxes as a proportion of revenue raised in 1991; and
- various estimates of the deadweight loss arising from market power, including as estimated by the Commerce Commission in the context of the potential competitive effect of a proposed acquisition by Cavalier Wool Holdings of the wool scouring and wool grease business of New Zealand Wool Services International.

These examples establish that efficiency gains of substantial magnitude may be possible in some circumstances. However, they do not establish that the EA's estimates of net benefits in the context of its proposed changes to the TPM guidelines are either plausible or reasonable.

6. Internal reviews commissioned by the EA

In our opinion, many of the issues raised by submitters on the cost benefit analysis could have been addressed at an earlier stage had the EA acted on concerns that were raised in internal reviews that it commissioned.

During the course of its development of the cost benefit analysis, the EA sought advice from:

[21] NERA, *Review of Electricity Authority's transmission pricing review 2019 papers*, 1 October 2019, pp 15-16.

[22] NERA, *Transmission pricing methodology – review of second issues paper*, 26 July 2016, p 23.

[23] NERA, *Review of Electricity Authority's transmission pricing review 2019 papers*, 1 October 2019, pp 16-17.

[24] NERA, *Review of Electricity Authority's transmission pricing review 2019 papers*, 1 October 2019, p 17.

- Brian Bull as a 'data integrity and calculations checker';[25] and
- Advisian as a peer reviewer of the modelling.[26]

These reviewers raised concerns about the EA's cost benefit analysis that covered many of the most material points raised in the HoustonKemp and Axiom reviews of the published information. While we cannot see the full reasoning that led to these concerns not being reflected in the EA's issues paper, the chain of communication that we can observe reveals a lack of understanding of economic principles and a process that suggests not all concerns might have been fully addressed. We discuss the concerns that were raised in more detail below.

6.1 Brian Bull's review

In an email to EA staff on 20 March 2019, Brian Bull set out his view that the net benefits assessed by the analysis included transfers. In support of this view, he described a simple example demonstrating the economic nature of a transfer, as against an efficiency gain:[27]

> Suppose all prices in the model decreased by $10/MWh, for all consumers, at all times, in all years. Suppose further that demand was perfectly inelastic and so there was no corresponding increase in quantity.
>
> - Is there an allocative efficiency gain? Clearly not, with no elasticity and no changes in Q. The net economic benefit is nil.
> - Is there an increase in the Sense consumer welfare measure? There sure is – billions of dollars PV!

Benefits to society are the sum of benefits to consumers (consumer welfare) and benefits to producers (producer welfare). A decrease in price can increase benefits to society if it gives rise to new transactions (which otherwise would not have occurred) between consumers who value the good/service at more than the new price and producers who can supply the good/service at a cost less than the new price. Economists describe the new surplus created by these transactions as a reduction in deadweight loss.

The $10 example clearly sets out why decreases in price do not, by themselves, give rise to benefits to society. In the example, the change in price does not affect consumption of electricity, so the effect is that consumers pay less, and generators receive less, for the same quantity. This is a transfer of benefits from generators to consumers, with no change to net benefits for society as a whole, since no new transactions occur as a result of the change in price.

Despite Brian Bull's crisp presentation of these concerns, they gained no traction with the EA and the modellers that it had commissioned to undertake the cost benefit analysis. In response, the EA was advised by its modellers that:[28]

> There is a very large effect in the model from changes to the sequencing of investment in generation. This changes the sequencing of transfers that occur to-and-from consumers and producers in the electricity market, over time through investment cycles (when capacity is low, producer rents increase and invite investment and then capacity increases and producers lose their rents and consumers win and then demand grows and rents reappear etc…).

[25] *Consultancy Services Agreement | Electricity Authority and Brian Bull*, 24 February 2019, Schedule 1, para 2.

[26] *AoG Consultancy Services Order*, 11 September 2018.

[27] Email from Brian Bull to Tim Sparks, *Re: Wealth transfers in the TPM CBA*, 20 March 2019.

[28] Email from John Stephenson to Tim Sparks, *Re: FW: Wealth transfers in the TPM CBA*, 21 March 2019.

This explanation appears to confirm that net benefits include transfers but introduces confounding concepts of investment cycles – which as many submitters have since noted are not appropriately captured by the modelling. The response goes on to state:[29]

> I don't quite follow the $10 example. If all prices fell by $10 then people could e.g. (a) work less and enjoy the same consumption benefits (b) save and invest in something without foregoing any of their consumption benefits (c) buy more of something else to use/consume. So even if they have zero elasticity in the market in question there is still scope for substantial welfare improvement – depending on why the price changed.

This statement discloses a fundamental lack of understanding within the EA and its modellers about the difference between transfers and efficiency gains. The original point made by Brian Bull was that benefits to consumers that are themselves costs to producers are not gains to allocative efficiency. The response merely identifies various ways in which consumers might benefit from reduced prices, rather than establishing that these benefits would not be at the expense of producers.

If these concerns had been carefully considered by the EA, it seems unlikely that it would have published a cost benefit analysis that estimated net benefits of $2.7 billion, made up in very large part of transfers rather than efficiency gains.

6.2 Advisian's review

In an email to EA staff on 8 May 2019, Erik Westergaard of Advisian attached a copy of the EA's draft assessment of the costs and benefits of its proposal, which he had marked up with his comments.[30]

The content of these comments echoes many of the concerns raised by submitters to the EA and the tone of the comments was highly critical in some areas. Table 6.1 highlights some of the comments noted in Advisian's review that were later raised in submissions to the EA.

Table 6.1: Selected comments from Advisian's review of the EA's draft cost benefit analysis report

Comment	Issue	Advisian's comment
76	Scale of the benefits	This is a marked increase in benefits when considered against the Oakley Greenwood CBA. It begs the question, if the OG work was deemed inaccurate is this work "more" inaccurate.
77	Transmission, distribution and generation costs	I don't see any evidence of increased transmission, distribution or generation investment being included in the model to explicitly address this increase in peak demand – as opposed to transmission and generation which is required for forecast demand growth and is included.
78	Estimating changes in energy prices	How has price volatility been modelled? Arguably to reach these conclusions requires use of a complex model which simultaneously solve for generation strategy, dispatch and long term expansion of transmission and generation.
85	Changes in peak demand	Two points – to what extent do consumers see a peak demand premium because of the current transmission charge allocation method? Would removal of the premium arising from transmission allocations get outweighed by energy price impacts if demand increased in peak periods?
91	Inefficient investment in distributed generation	Two issues, this flies in the face of almost all international experience. DG is more efficient than the alternatives. A 100MW solar, wind or other new technology plant located at the point of consumption must by definition be more efficient than the same plant located remotely from the load. This assessment must be backed up by evidence.
92	Inefficient investment in batteries	The primary revenue streams from storage do not relate to energy arbitrage. See the Horncastle Power Reserve plant (Telsa battery in South Australia) for details. My experience with similar plant in Australia highlights that the expect to get the majority of revenue from similar schemes.
105	Benefits from greater scrutiny of	Under the Capex IM Transpower is required to identify and consider a range of alternatives. If this is the case is there any benefit?

[29] Email from John Stephenson to Tim Sparks, *Re: FW: Wealth transfers in the TPM CBA*, 21 March 2019.

[30] Email from Erik Westergaard to Jo Mackay, *Report Comments*, 8 May 2019 and attachment.

109	investments	It is a requirement of the regulatory process for Transpower to consider alternatives – they would undoubtedly have consulted with parties with alternatives.
111		This does not reflect the process taken. A large number of potential alternatives were considered with a subset of these subjected to detailed analysis.
115	Benefits from greater certainty	Any TPM is subject to change – it cannot be claimed that the proposed option will be any more durable than previous ones. There is considerable effort going into identifying new alternatives for transmission pricing given the impact technology change is having.

Source: Advisian

It is unclear how the EA used the comments provided by Advisian. We observe that many of the issues highlighted remained a concern in the proposal that the EA eventually published on 30 July 2019.

We note also that the EA sought a letter from Advisian commenting on the suitability of the cost benefit analysis for its intended purpose. The letter was provided on 25 June 2019, only a number of weeks prior to the publication of the proposal.[31] The letter discloses that Advisian:

- could not describe the cost benefit analysis as consistent with "best practice", but acknowledged that what is described in the EA's report is consistent with "good practice", subject to the caveat that Advisian did not review the models; and
- had previously provided comments on several assumptions used in preparing the cost benefit analysis but had not seen the final report, taking comfort instead from representations by the EA that these comments had been addressed.

It appears on its face that Advisian's expectation that its comments on the cost benefit analysis had been addressed by the EA were optimistic, given that many of the concerns that it raised were reflected in comments made in submissions responding to the EA's proposal. If Advisian's concerns had been carefully considered by the EA, it would likely have revisited many of the assumptions and methods underpinning its cost benefit analysis – potentially giving rise to a very different quantitative outcome.

[31] Advisian, *Transmission pricing methodology cost benefit analysis report*, 25 June 2019.