Waitaki Power Trust
100% Shareholder of Network Waitaki Limited

Submission to Electricity Authority

on

Transmission Pricing Methodology: 2019 Issues Paper

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PROPOSED NEW GUIDELINES FOR TRANSMISSION CHARGES, CONSUMER BENEFIT AND THE CONCEPT OF FAIRNESS

SUMMARY

Waitaki Power Trust's submission provides an analysis and assessment of the Authority's 2019 TPM proposal from a consumer based perspective.

The parameters within which the analysis and assessment are set include

- The Authority's statutory objective provided by section 15 of the 2010 Electricity Industry Act;
- The methodology used by the Authority to calculate financial outcomes should the new TPM be adopted;
- High level policies adopted by the Authority about durability, fairness, and human behaviour;
- The ever-present need for improved efficiency and
- Current TPM guidelines.

It was noted that the proposal to replace the current RCPD method of charging with a fixed GXP capacity charge is a major shift away from charging customers for the **use of the grid** under regionally averaged peak demand conditions, to a **GXP capacity based fixed charge** whereby grid capacity generally is **always available, as and when required, regardless of how frequently or infrequently, customer peak demand occurs.**

Trustees consider that the resultant re-allocation of costs due to the introduction of a fixed capacity based charge, would result not only in inefficient charges to summer peaking EDB's but also would increase transmission charges to our local consumer trust owned EDB Network Waitaki, from $3 million to $4.5 million annually, exclusive of a $1 million charge for connection costs which, given the circumstances Network Waitaki works under, consumers would struggle to meet and in addition, $1.5 million extra removed annually from a small district's economy percentage wise, would be a significant hit.

With respect to Trustees' analysis and assessment of other key components of the 2019 TPM proposal we have concluded

- That although increases in the nodal price of electricity under constraint conditions may provide helpful information to Transpower regarding the future need for transmission upgrades, nodal electricity prices provide a poor and entirely inadequate signal to the vast majority of consumers New Zealand wide about the cost of using the grid under varying constraint conditions.

- That recouping debt attached to previous projects involving major transmission investment by two different types of charges – the benefit based charge and the residual charge is a form of **double dipping** which both reduces the credibility of the

Authority's contention that consumers should only help pay for transmission investments they benefit from and introduces the prospect of cross-subsidisation by socialisation of costs under the fixed residual charge debt recovery process,

- That the dual method of debt recovery results in the benefit based charge being seen as a **sweetener or ploy**, strategically introduced by the Authority to engender a more favourable customer and consumer response to the 2019 TPM proposal than the 2016 TPM proposal received,

- That it is totally unacceptable to even propose EDB load customers contribute $12 million toward a $15.4 million price cap fund to be used primarily as a form of subsidisation, to soften the predicted transmission charge price shock, four large industrials will receive if the proposed TPM guidelines are adopted,

- That the Price Cap along with the Prudent Discount Policy can also appropriately be regarded as **sweeteners**,

- That there is evidence a large number of consumers are not as price sensitive as the Authority believes,

- That neither durability of the TPM nor realising the predicted financial outcomes derived from adoption of it will be achieved without considerable change in human behaviour, which is a very risky business practice to base success on,

- That it is difficult to envisage how a charging system based on a pure economist type fixed charge which implies rigidity, can be for the long-term benefit of consumers, since in the world where consumers use electricity there are few or no processes that are fixed or rigid; and

- That consumers in the Network Waitaki area will be faced with an exorbitant increase in Transmission interconnection charges as a result of farmers in the area being required to comply with Central government policy to replace border-dyke irrigation with spray irrigation.

Trustees' view is that in order for the 2019 TPM proposal to be consistent with the Authority's statutory objective the Authority needs to do more than what amounts to paying lip service only in the executive summary of the 2019 issues paper which states that

> "the proposal would be for the long-term benefit of consumers" (2019 issues paper, page vi).

Instead, the Authority needs to show consumers that a new TPM **is for their long-term benefit** rather than focussing the 2019 TPM directly on cost recovery to meet Transpower's annual budget**.**

In the case of the gross AMD fixed and inflexible capacity charge, the key question that needs to be asked is, would that type of charge be for the long term benefit of consumers?

Waitaki Power Trust's submission includes four recommendations. Trustees consider that the process outlined by Recommendation 4 indicates a move to providing long-term consumer benefit.

The recommendations are as follows:

Recommendation 1:

Trustees recommend that the Electricity Authority walks the talk and in cases where consumers face significant transmission cost increases due to peakier seasonal capacity requirements which are for the long term benefit of New Zealand Inc. steps are taken to address the issue of perceived unfairness.

Recommendation 2:

That Transpower's EDB customers are not required to contribute financially toward a price cap mitigation fund for industrial customers.

Recommendation 3:

That the Authority's final version of the 2019 TPM guidelines proposal includes the current information relating to charges applicable to direct connect designated load customers, even if it is to remain unchanged.

Recommendation 4:

To prevent the occurrence of inefficient transmission charges when peak load requirements occur in summer under low regional load conditions, the EA reconsiders the circumstances under which the fixed gross AMD applies by including an addition to the Additional Component TPM category that would allow Transpower to amend the gross AMD charges as and when appropriate.

INTRODUCTION

1. The 2010 Electricity Industry Act saw the demise of the Electricity Commission and the establishment of a replacement independent statutory body, the Electricity Authority (EA).

2. The 2010 Act also charged the new statutory body with the responsibility of overseeing the operation of New Zealand's electricity sector, but from a revamped perspective.

3. How the Authority's mandate is to be exercised is determined by Section 15 of the 2010 Electricity Industry Act, in combination with any policy statements concerning the electricity industry, determined by government.

4. It is especially noteworthy that in addition, the Electricity Authority may also write its own rules which third party organisations must follow.

5. For almost two decades now the EA has struggled to establish a generally approved set of guidelines within which Transpower can set a detailed charging regime for the different types of transmission services it provides to third party load and generation customers.

6. The Authority's latest attempt is detailed in its recently released 2019 issues paper, Transmission pricing review consultation paper.

7. Key words associated with the latest transmission pricing guidelines are:

    - costs and benefits
    - efficiency
    - consumer benefit
    - durable
    - inefficient investments
    - a postage stamp approach.
    - interconnection assets, and
    - price signals.

8. They are matched with a new and novel feature. That of **attributing wholesale electricity prices a role in determining specific aspects of a new grid Transmission Pricing Methodology.**

9. Discussion of these points will be returned to later.

10. The purpose of Waitaki Power Trust's submission is:

    - to examine the extent to which the EA has met its own requirements;
    - to make explicit, underlying implicit assumptions;
    - to consider consequences or outcomes of the proposal from the stand point of:

- the efficiency/inefficiency continuum,
- durability
- consumer benefit
- a postage stamp approach
- consumer behaviour change.

11. The analysis will expose potential and hidden agendas – and, be undertaken against the background of a summary account, of the Authority's 2019 transmission pricing guidelines.

A. THE PROPOSAL: A NEW SET OF GUIDELINES TO RE-SHAPE TRANSPOWER'S CHARGING REGIME

12. According to the EA, the 2019 transmission pricing guidelines include two new and distinctly different core charges, the names of which characterise the type of charges they will apply to.

13. On the one hand, payment of the **benefit based charge** will be levied from Transpower load and generator customers, to the extent that a transmission investment directly benefits a Transpower customer.

14. The benefit based charge is based on the principle that those who directly benefit will be required to pay, while those who don't can keep their hands in their pocket.

15. The benefit based charge would automatically apply to recover the costs of new transmission investments.

16. But seven high cost earlier transmission investments have also been identified where the current cost recovery process socialises costs across **all electricity users in New Zealand**, regardless of whether a Transpower customer benefits from the investment or not.

17. The second type of new charge, a **residual charge,** also reflects the purpose it fulfils.

18. Put simply, it is a series of cost centres, which enable Transpower to recover the revenue required in order to meet annual operational overheads and the costs associated with additional historical investments not covered by the benefit based charge.

19. Two specific residual cost centres are specifically identified.

20. A gross anytime maximum demand fixed GXP capacity charge and a nodal price for electricity determined at the wholesale electricity market level which sets the cost of electricity at grid exit points or GXP's under varying levels of transmission constraint.

21. The significance of nodal pricing as a key financial charging tool integrated within the EA's latest transmission pricing guidelines is not to be under estimated -

> "the wholesale market would signal **transparently** where grid congestion exists through higher nodal prices at congested nodes, and lower nodal prices elsewhere" (EA 2019 issues paper, 23 July 2019, 3.5, page 13).

22. Clearly both the gross AMD charge and short term transmission usage nodal pricing which the Authority believes influences demand provides benefit to Transpower and thus can appropriately be labelled Transpower-centric, rather than being for the long term benefit of consumers.

23. A third non-charge based component of the Authority's 2019 Transmission Pricing guidelines package is identified as the Prudent Discount Policy (PDP).

24. The Authority makes it clear that the PD Policy is

> "A discount to **avoid a customer disconnecting from the grid,** which would raise costs to others: (ibid, page iii).

25. The Prudent Discount Policy allows Transpower to discount transmission charges to a designated transmission customer who otherwise may decide to bypass the grid in favour of an alternative electricity supply.

26. The EA acknowledges that application of the 2019 guidelines will result in so called "winners and losers", a situation in which changes to transmission charges to some Transpower customers will decrease significantly, while others will see a dramatic increase in what they are required to pay.

27. To minimise the effects of price shock, a factor which halted the finalisation of the Authority's 2016 attempt to arrive at an updated version of the guidelines for transmission charges, the Authority this time has rounded off its set of guidelines with a policy enabling the annual level of transmission price increases to initially be capped.

28. Relative to existing transmission charges for the 2019/20 pricing year, the level of increase in transmission charges for customers serviced by the interconnected grid will be limited to 3.5% of their total annual electricity bill for at least the first five years.

29. As the EA puts it

> "The cap would limit any initial price rises due to the introduction of the benefit based charge and residual charge to 3.5% of a transmission customer's electricity bill (excluding inflation and demand growth)" (ibid, 3.30, pp 18-19).

B. THE ELECTRICITY AUTHORITY'S OBJECTIVES

30. It is important to note that the 2019 transmission pricing guidelines proposal was not drawn up in a vacuum.

31. Throughout the 2019 consultation document are reminders about what the Authority was endeavouring to achieve. Foremost in that context is section 15 of the 2010 Electricity Industry Act.

> "15 Objective of the Authority
> The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of the electricity industry for **the long term benefit of consumers**" (Electricity Industry Act 2010, Part 2, sub part 1, S. 15, page 20).

32. Elsewhere, the Authority acknowledges that every operational activity it engages in under its mandated purpose above, has but a single focus

> "Each of the three limbs of the Authority's statutory objective are directed towards achieving outcomes **for the long term benefit of electricity consumers**" (Electricity Authority, 14 February 2011, Interpretation of the Authority's Statutory Objectives, Appendix A, page 7).

33. Additionally, when drafting the 2019 TPM proposal the Authority's focus was set on eliminating a raft of operational outcomes associated with the current TPM, which it deemed to be unsatisfactory.

34. These included

    - sharing the costs of major transmission investments in capital projects across all of New Zealand's electricity users whether they benefit from the investment or not, and

    - charging the full $145 million annual cost of the high voltage direct current link between the South and North Island solely to South Island generators.

35. In combination then, it is evident that the task the Authority had set itself in putting in place a new TPM proposal for the long-term interests of consumers would involve two components.

36. The first requirement is a set of transmission pricing guidelines that would result in increasing the efficient operation of the transmission network.

37. The second requirement is that the guidelines must result in pricing outcomes which Transpower customers and electricity consumers will accept.'

38. It is clear that the Authority considers its revision to the current TPM guidelines has achieved its objectives

> "The Authority considers that the proposed revision to the current TPM guidelines would better promote the Authority's statutory objectives in particular the Authority considers that the proposed would promote efficient investment in and efficient operation of the electricity industry" (Electricity Authority, 2019 issues paper, page 16.)

39. The accuracy of the EA's assessment of its TPM guidelines proposal remains to be seen and will be discussed later.

C. METHODOLOGICAL CONSIDERATIONS

40. In a 2011 document, Interpretation of the Authority's Statutory Objective the EA notes the following points

> "The Act's definition of consumers … includes commercial and industrial firms, not just residential consumers …. The … definition of consumers … also includes both present and future electricity consumers …. In regard to assessing benefits to electricity consumers, "the Authority … take(s) into account **indirect effects** on all electricity consumers rather than just the direct (and most obvious) effect on them. This approach means the Authority considers the **net effect** on electricity consumers and assesses the benefits to them in **aggregate (the aggregate consumer approach) …** in virtually all circumstances only the efficiency gains of an initiative should be treated as benefitting consumers, with wealth transfers excluded. (EA February 2011, page 7, see also 2019 Issues Paper page 31)

41. Secondly, methodological concessions are made to reduce administration costs.

42. For instance, the level of the **benefit based charge** to be paid by load customers that benefit from any or several of Transpower's seven major investment project that still carry a high debt loading will be

> "determined by the Authority, in response to Transpower's view that this would reduce the administration burden" (EA, 2019 Issues Paper, page viii. But c.f. ibid page 140, page B. pages 150/51).

43. Likewise, the Authority comments in an undated document "TPM second issues paper questions and Authority responses, in reply to Oji Fibre (previously Carter Holt Harvey)

> "that the Authority's modelling of demand is determined at individual GXPs which the Authority considers is a **reasonable proxy for physical capacity**"

> (EA's response to Oji Fibre, TPM second issues paper questions and Authority responses).

44. And again, in response to a question from Oji Fibre about the definition of areas of benefit, the Authority responds as follows

> "The Authority proposes that areas of benefit are defined to **as granular a level as practicable … bearing in mind administration costs**" (ibid).

45. Further methodological concessions involving **trade-offs** are also acknowledged in the Electricity Authority's 2019 Issues Paper.

46. Attempts at modelling various factors such as **demand assessed by the method of cluster analysis based on peak shoulder and off-peak periods,** the Authority states

> "We do not distinguish between (different types of 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: (EA 2019 issues paper, 4.40, page 27, words in brackets our addition).

47. In modelling the distribution of benefits associated with the proposed benefit based charge we are told that the Authority's

> "objective was to reach a conservative allocation that would **not cause the benefits of the proposal to be overestimated** (recognising that the task of modelling benefits more precisely is outside the scope of the CBA" (ibid, 4.49 page 29).

48. Elsewhere the Authority states

> "We expect that Transpower will use more exacting methods to estimate the benefits of high-value post-2019 investments:" (ibid, Fn 53, page 30).

49. Further, while acknowledging the potential practical difficulties arising from endeavouring to identify the level of benefit an interconnected generator or load customer receives from a beneficial grid investment the EA acknowledges that

> "We have … endeavoured to design the proposal to take account of the potential practical difficulties (for example), by **allowing a proxy for the estimation of benefits**" (ibid, Fn 121, page 113).

50. Somewhat surprisingly, earlier criticism by submitters to the proposed 2016 TPM guidelines about the practical difficulties relating to assessing benefit based charges (then termed an Area of Benefit Charge) have prompted the Authority to address issues associated with

> "**Impact of approximation in** estimation of benefits" (ibid page 142).

51. After agreeing with concerns raised by various parties

> "that getting a precise estimate of who benefits from transmission investment and by how much will be difficult" (ibid, B 157 page 142),

and putting forward a range of counter-factual points, the Authority puts the issue to bed wrapped up in the following assertion

> "Perfection and total objectivity are not features of workably competitive markets and **should not be expected from the methods for the allocation of the benefit based charge"**
> (ibid, B161, page 142).

52. Hence, the Authority's overall assessment of its TPM guideline proposal relative to its overall objective and methodological tools used is that while

> "the proposal promotes efficient investment in and operation of the electricity industry (t)here **is a trade-off between a high level of granularity in providing benefit based charges and the costs of developing and administering the methodology.** There is also **a trade-off between dynamic efficiency**, which the Authority considers supports benefit based charges and operational efficiency where charges need to avoid distorting operational decisions" (ibid, 4.224, page 56).

D. ANALYSIS AND ASSESSMENT OF THE PROPOSAL – IS THE BABY BEING THROWN OUT WITH THE BATH WATER?

(a) Current debt recovery charges and the postage stamp approach

53. Under Transpower's current charging regime, based on the current TPM guidelines which have largely remained unchanged since 2010, a range of charges relating to investment in and use of the interconnected transmission grid are levied

> "across all customers regardless of where they live – the so-called postage stamp charge (ibid, page 7).

54. Current charges also include, the grid use regional coincident peak demand charge which according to the Authority "spreads the costs of investments across all customers regardless of where they live – a so-called postage stamp charge." (ibid, 2.19 page 7).

55. For example, Transpower's investment in

> "the $876 million North Island grid upgrade approved in 2007 … primarily to improve security of supply is also charged to transmission customers, in the same way" (ibid page 7).

56. Clearly the postage stamp one-size fits-all method of charging has two outcomes that can be described as unacceptable.

57. The first of these is the socialisation of costs which results in a form of cross-subsidisation.

58. The Authority argues that cross subsidisation is inefficient because it sends an inaccurate message about project costs, as is shown by the fact that of the $876 million North Island grid upgrade

> "two thirds of the costs are paid by households and businesses across the rest of the country" (ibid, page 7).

59. The second outcome is that if people are continually required to help pay for transmission capital investments and use which primarily benefits only interconnected grid customers, some more than others depending on where they live, then most Transpower customers, especially those directly connected either to a non-core transmission network or those, such as large industrialists receiving transmission services from a dedicated transmission line, would cry – that's unfair.

60. As consumer representatives and 100% shareholders of Network Waitaki, Waitaki Power Trust trustees agree.

61. Awareness of the situation whereby Network Waitaki is a direct connect transmission customer and its more than 13,000 consumers, are required not only to pay for all transmission services from Transpower on a 100% user pays basis, but in addition, NWL's share of capital investment upgrades to the interconnected grid, most of which NWL and its consumers do not receive any benefit at all from, truly rankles.

62. Taken at face value, addressing unfair outcomes falls outside of the Authority's statutory objective.

63. However, by focussing on the long term interests of consumers, and perhaps on the fact that inefficiencies arise as a result of charges being based on an approach which is inherently unfair, the Authority arrived at a charging method where people generally pay only for what they get, a situation most people generally regard as fair.

(b) The new benefit based charge

64. Coming to terms with the type of transmission investment the new "benefit based" charges apply to, has not been an easy task. Everywhere we checked, benefit based charge comments related only to matters associated with the **interconnected grid.**

65. The issue was resolved by the Authority's

> "definition of benefit based investment (which) means
>
> (a) Any post 2019 investments in the interconnected grid including any transmission alternatives,
> (b) The following pre-2019 investments in the interconnected grid:
> (i) The Bunnythorpe Haywards Reconducting Project to ….
> (vii) The Wairakei Ring Project" (ibid, page 90).

66. Because benefit based charges are to be paid only by load customers that benefit from capital investment upgrades to the interconnected grid, and are levied on a pro-rata basis according to the assessed ratio of benefit across all benefitting transmission customers, Trustees consider well designed benefit based charges cannot be regarded as unfair.

67. That is not to say, however, that they are a perfect solution as to who pays for what, either.

68. It is noted from the proposal that several benefit based charges have been apportioned to Network Waitaki where the benefit is negligible.

69. To the extent that pro-rata payment is required, benefit based charges socialise the costs of a particular interconnected grid investment across all benefitting customers, in a manner that cannot be other than in-exact, given the methodological trade-offs the Authority acknowledged above.

70. Clearly, where charges are in-exact, the potential for cross subsidisation cannot be ruled out.

71. Neither can the conclusion that in particular instances benefit based charges, better than they may be to continuing to use a postage stamp approach, can turn out to be an **inefficient** way of assigning costs.

(c) The Residual Charge: Regional Coincident Peak Demand (RCPD) versus gross Anytime Maximum Demand (AMD), Nodal Pricing and Consumer Benefit

(i) RCPD Charges

72. The introduction of a residual charge and its embodiment of two separate cost centres plus the role that nodal electricity prices play, is a major change away from the RCPD method of basing transmission costs on peak demand relating to grid usage.

73. As the EA puts it

> "The residual charge would recover transmission costs that are not recovered through other charges. These costs include **overheads** and the **costs of those historical investments that are not covered by the benefit based charges"** (ibid, 3.18, page 17).

74. Acknowledgement that the residual charge will provide a **second way in which historic debt can be recouped**, in addition to a benefit based charge, is enlightening, because of the manner in which the effect of benefit based charge has been presented.

75. For example, among the variables listed which the EA considers are factors that will result in more efficient grid use and a more durable TPM are the following **unqualified** statements about the effect of

> "rebalancing transmission charges so that **those who benefit** from the grid pay for it: (ibid, 3.6 (a), page 13).

while about proposed new charges we are told

> "At the heart of the proposal is a desire to ensure that transmission prices …… b) **allocate the cost of investments to customers that benefit from them**" (ibid, 3.2., page 13)

76. Lack of acknowledgement that the residual charge also includes a cost centre for recouping historical debt is a **form of double dipping** which entails that the above statements are not 100% correct and are thus, misleading.

77. The second major change made by the EA's 2019 TPM guideline proposal is a **change away from basing the cost of using the grid on peak demand as per the RCPD** model, to a **fixed capacity gross AMD charge**.

78. The fact that the RCPD method of charging plays a similar role to the nodal price charge that of driving the amount of transmission capacity needed and thus provides a basis for allocating transmission costs, is interesting.

79. It prompts queries about differences between the two and what the consequences of eliminating the current RCPD charging assessment tool are.

80. The Authority consistently argues that Regional Coincident Peak Demand Pricing varies inter-regionally across New Zealand and deprives customers, especially residential consumers, the use of electricity just when they need it most.

81. The assumption is that while large industrials are likely to invest in and use demand side management technology, such as solar power, storage batteries, and so on, to reduce peak load charges, residential consumers will turn off heaters, dishwashers, lights etc. to avoid peak demand prices.

82. We ask – where is the evidence of residential consumers behaviour change under peak and low demand electricity pricing?

83. The only evidence offered related to an Australian example (EA, 2019 Issues paper, see 2.40, page 10).

84. So far as New Zealand residential consumers are concerned the fact is that **almost all pay a retail price for electricity which is not subject to the potential volatility of peak demand pricing.**

85. Included in a long list of reasons as to why to RCPD charge needs to be replaced (see ibid, pp 8-10), is a statement of the Authority's view that

> "the RCPD charge is a poor signal of economic costs. An efficient, cost reflective charge would rise when the grid gets congested, and drop when there is spare capacity" (ibid, 2.32, page 8.)

86. Quite so, but given that under the present TPM, the

> "RCPD charge is charged only during the top 100 periods in each of the four transmission pricing regions (ibid, 4.38, page 27),

the perception that the RCPD charge is not seen as cost-reflective is unsurprising, in that the RCPD method of charging for grid use averages charges across each charging region.

87. Even more telling is that, under the condition of a wide range of **peak data collection** and the application of a cluster based analysis of trading periods, by transmission pricing region, the EA's finding was that although,

> "six clusters of demand (were identified) …. The cluster of **chief interest is peak demand** – given its impacts on system capacity and costs … and the subsequent clusters have been combined into a single off-peak period" (ibid, 4.38, page 27).

88. The data relating to the cluster analysis of peak, shoulder, and off peak periods is shown in Figure 4 by way of a line graph (see ibid, Figure 4, page 27).

89. The obvious unasked and accordingly unanswered question relating to the cost reflectiveness and efficiency of RCPD charges, is **has a comparison with regional grid use transmission prices under low demand conditions been done** to demonstrate the effects of the impacts of the proposed change**?**

90. From a customer and EDB **consumer perspective**, the demise of the RCPD charge is of concern.

91. That is because the EA elaborates the manner in which each transmission customer's Anytime Maximum Demand capacity charge is to be calculated.

92. In the Authority's words

> "taking in a **pricing year** the highest value for any **trading** period which represents the sum of:
> A The highest net quantity of electricity flow from the **grid** at the **designated transmission customer's grid exit point**, and
> B Transpower's estimate of any concurrent generation by **distributed generators** or behind-the-meter generation that is indirectly connected to the **grid** through the **designated transmission customer**" (ibid, 40, page 95)

93. The Authority thus terms the **total quantity of peak electricity demand** used by a transmission customer from those three sources, **gross Anytime Maximum Demand**.

94. Elsewhere the EA makes it clear that in answer to the question of

> "whether demand should be grossed up for injection by distributed generation and behind-the-meter generation. Our current preferred option is that demand should be grossed up (by including both sources of demand side generation) as we see no compelling reason to treat these types of generation differently." (ibid B215, page 155, words in brackets our addition).

95. Focussing only on demand peaks because they are what drives the need for increased transmission capacity is a Transpower-centric approach to data interpretation.

96. Further, a range of direct connect and interconnected Transpower customers have made significant investments in demand side energy options.

92. Under the capacity-based gross Anytime Maximum Demand charge, existing demand side assets may become more or less stranded assets or have their value significantly lowered due to a reduced level of productive output.

93. The stranded and / or the potential depreciated values of EDB assets issue is a very real concern for New Zealand's twenty-two Power Trust trustees who own on behalf of the beneficiaries of each trust either a majority shareholding or hold 100% of the shares in an EDB.

94. Under Trust law, the absolutely fundamental responsibility Trustees of majority and 100% consumer trust owned EDBs have, **is to protect, and under certain conditions, endeavour to enhance the value of trust assets.**

95. From a consumer benefit perspective, low load conditions are equally important to customers whose load profile is out of sync with other EDBs in a cost region.

96. It is important to note that in order to model the strong price signal the RCPD charge sends to electricity consumers at times of peak demand and its impacts on system capacity and costs, the simplifying methodological assumption used about electricity demand, was based on only two distinctions:

    (a) transmission network connected consumers; and
    (b) distribution network connected consumers.

97. No distinction was drawn between the different categories of consumer connected to distribution networks.

98. Nor was a distinction drawn between the different types of connection distribution networks can have to transmission systems.

99. None-the-less, the Authority elsewhere acknowledges that in order to model the claimed electricity usage suppressing effect that RCPD price signals have at times of peak demand

> "We **need to specify the types of consumer affected by the RCPD charge and the time periods in which its effects are felt"** (ibid, 4.36, page 26),

100. The Authority's statement above makes it clear that the simplified modelling method adopted is not always adequate to meet the purpose of the analysis.

101. Trustees consider such outcomes occur when the prime focus is transmission cost recovery rather than holding the long term interest of consumers, sacrosanct.

102. We are to be assured however

> "The Authority's proposal is **expected** to lead to more efficient grid use. The net effect would **likely be** that consumers derive greater value from their use of electricity" (ibid, 4.29/4.30, page 26).

103. What the Authority has also chosen to overlook, is that the finding from assessment of its 'What's my Number' campaign showed that **residential consumers are not as price sensitive as the EA assumes.**

104. Additionally, it is Trustees' experience too, that residential consumers and other smaller agricultural businesses, such as those relying on irrigation, **prioritise electricity use ahead of electricity prices.**

(ii) Gross Anytime Maximum Demand and Nodal Electricity Pricing

105. Somewhat paradoxically, the proposed gross Anytime Maximum Demand GXP capacity charge appears to be intended to be implemented by using a postage stamp based approach.

106. All transmission customers, irrespective of their type of connection and whether the connection is to the inter-connected grid or to a non-core transmission network will pay a gross Anytime Maximum charge, designed in such a way that the charge is

> "independent of grid use and so hard to avoid" (ibid, page iii).

107. As a straight GXP capacity charge it is reasonable to assume that the same **rate per MW of capacity** is to apply at every transmission GXP, regardless of the type of customer connection.

108. If that is the case then obviously, the gross AMD charge will be subject to the same criticisms that under-lie the Authority's reasons for introducing benefit based charges to recover outstanding costs relating to previous large transmission investments and will apply also to financially significant large future investments on the inter-connected grid.

109. Similarly, unfairness can be perceived in situations where the same rate of charge applies to the same type of service, **regardless of circumstances**.

110. In the case of the nodal price of electricity to wholesale customers it is assumed that prices at a GXP rise because of the mismatch between transmission grid capability and heightened consumer demand for electricity.

111. However, that is **not invariably** the cause of transmission constraints.

112. Again, consider our local EDB, Network Waitaki as an example.

113. Network Waitaki is serviced from the lower Waitaki/South Canterbury non-core transmission network, its primary GXP being located at Weston on the outskirts of Oamaru which is known as the Oamaru GXP.

114. The level of security of the service is n-1.

115. That service has been constrained since at least 2009, due in part by the capacity of Transpower's assets supplying the Oamaru GXP.

116. But there has also been notable occasions where the constraint was due to **operational decisions** by Transpower, where both usage/demand and transmission line capacity were affected by weather conditions to the extent that Network Waitaki was instructed to decrease load or Transpower would turn off transmission supply to a

separate directly connected irrigation system that operates within the Network Waitaki distribution area.

117. Will the Authority's TPM proposal also provide guidance on charging issues where transmission constraints are the result of **operational decisions by Transpower**?

118. **Or**, is the form of charging guidance required when constraints are **operationally introduced** by Transpower a better fit for inclusion in the Electricity Industry Participation Code?

119. It is noteworthy that the EA's proposed decision to replace the RCPD charge with two new charges, and in particular, the gross AMD fixed GXP capacity charge, coupled with the role it will play in re-allocating transmission costs across transmission customers, will have the effect of increasing charges to eighteen distributors, across New Zealand, while eleven EDBs will have transmission charges reduced (see Table 12 below).

120.

Table 12: Breakdown of estimated 2022 charges for each customer

Customer	Status quo $m	Benefit-based $m	Residual $m	Proposal pre cap $m	Pay to / (receive from) cap $m	Proposal post cap $m	Change in charges $m
Distributors							
Alpine Energy	11.3	1.4	8.9	10.3	0.2	10.5	-0.8
Aurora Energy	18.8	2.3	19.6	21.9	0.5	22.5	3.6
Buller Electricity	0.6	0.1	1.3	1.4	(0.3)	1.1	0.6
Centralines	1.9	0.3	1.1	1.4	0.0	1.4	-0.4
Counties Power	10.4	3.0	7.2	10.2	0.2	10.4	0.1
Eastland Network	4.9	0.4	4.2	4.6	0.1	4.7	-0.2
Electra	5.6	1.1	6.3	7.4	0.2	7.6	2.0
Electricity Ashburton	12.9	0.9	10.3	11.2	0.3	11.5	-1.5
Electricity Invercargill	8.1	0.9	5.7	6.6	0.2	6.8	-1.3
Electricity Southland[88]	0.5	0.0	0.3	0.3	0.0	0.3	-0.2
Horizon Energy	2.7	0.4	5.3	5.7	(0.1)	5.7	2.9
MainPower	9.5	1.4	8.8	10.2	0.2	10.4	1.0
Marlborough Lines	5.9	0.8	4.1	4.9	0.1	5.0	-0.9
Nelson Electricity	0.7	0.1	0.8	0.9	0.0	0.9	0.2
Network Tasman	7.7	1.2	8.7	9.9	0.2	10.1	2.4
Network Waitaki	3.0	0.6	3.9	4.5	0.1	4.6	1.6
Northpower	14.2	5.4	10.6	16.1	0.4	16.5	2.2
Orion	46.9	7.4	45.8	53.3	1.3	54.5	7.7
OtagoNet JV	4.0	0.7	4.2	4.8	0.1	5.0	0.9
Powerco	74.0	8.4	58.9	67.3	1.6	68.9	-5.1
Scanpower	1.2	0.2	0.9	1.0	0.0	1.1	-0.2
The Lines Company	3.3	0.5	4.3	4.9	0.1	5.0	1.7
The Power Company	7.0	0.8	6.5	7.2	0.2	7.4	0.4
Top Energy	3.8	1.0	3.9	4.9	0.1	5.0	1.2
Unison Networks	23.1	1.6	20.4	22.0	0.5	22.5	-0.6
Vector	162.0	47.6	117.5	165.2	4.0	169.1	7.1
Waipa Networks	6.0	0.9	4.2	5.1	0.1	5.3	-0.8
WEL Networks	17.9	2.2	16.5	18.7	0.4	19.2	1.3
Wellington Electricity	46.7	5.8	32.4	38.2	0.9	39.1	-7.6
Westpower	1.7	0.2	3.4	3.5	(0.2)	3.4	1.7

121. Network Waitaki is among the most significantly affected.

122. As Table 12 shows it is estimated that should the new Transpower charging regime become operative in the 2024 financial year, Network Waitaki's transmission charge will increase from $3 million per year under the status quo RCPD charging system to $4.5 million, exclusive of connection charges, under the new proposal.

123. The EA acknowledges that two factors will drive South Island transmission charge increases.

124. In general, the peak capacity required of South Island EDBs is

> "peakier than other … (customers), and because of the proposed gross (AMD) measure … to calculate the residual charge" (ibid, Table II, page 60, words in brackets our addition)

125. There is no interpretation of that level of increase which could be construed as being **'for the long term benefit of consumers'.**

126. Rather, the change in demand profile between network Waitaki's summer and winter peaks has been driven by Central government policy with respect to irrigation.

127. In the 1970's and 80's government funded projects facilitated border-dyke irrigation and now, only spray irrigation by means of pumps and pipes is permitted.

128. From a **consumer based perspective,** a significant increase in transmission costs in order to be able to contribute to the economy of New Zealand Inc., is more likely to be seen firstly, as unfair, and secondly, as a punishment rather than a benefit.

129. The EA acknowledges that

> "While fairness is not part of the Authority's statutory objective, the Authority has the long term interests of consumers at the centre of its decision making" (ibid, 2.25, page 7).

130. On that basis, Trustees put forward the following recommendation.

RECOMMENDATION 1

Trustees recommend that the Electricity Authority walks the talk and in cases where consumers face significant transmission cost increases due to peakier seasonal capacity requirements which are for the long term benefit of New Zealand Inc. steps are taken to address the issue of perceived unfairness.

(iii) Nodal Electricity Prices as a cost signal to consumers

131. The nodal price of electricity at a GXP is a use reflective variable charge driven by customer demand, the availability of electricity to the wholesale market and grid capacity.

132. According to the EA

> "Nodal prices provide a **timely and efficient signal of the actual cost of grid congestion at specific locations**. This avoids discouraging **consumers** from use of the grid even during peak periods (the times when **consumers** place the highest value on using electricity) particularly where there is spare capacity available" (ibid, page 17).

133. Further, the EA states

> "Nodal prices can do a better, more targeted job of providing a timely **signal of the actual cost of using the grid** (such as congestion) at specific locations than the blunt and typically excessive signal currently provided the RCPD charge or an alternative long run marginal cost (LRMC) charge: (ibid, page iii).

134. However, it is clear that nodal price **cost signals occur at wholesale market level and consequently are therefore unavailable to the vast majority of New Zealand's electricity users who access electricity under contract from the retail electricity market,** at a price set by their retailer.

135. So far as retail electricity market consumers are concerned, the wholesale nodal price of electricity, is nothing other than an unknown component of the retail price they pay for electricity.

136. For that reason alone, we consider that nodal pricing provides a poor signal of the economic cost of grid use under varying conditions.

137. The pertinent question is, however, how useful is this information if it is unavailable to the vast majority of **consumers.**

138. The short answer can only be what is unknown by a target audience **can never be useful** to those targeted.

139. That finding has significant consequences, especially for the Authority's objective of putting in place, a new and durable TPM, a topic we will return to later.

(d) The Sweeteners: A Price Cap and a Prudent Discount Policy

(i) The Price Cap

140. The Authority is well aware from the financial analysis carried out in 2016 and 2019 that the charging regime proposed on each occasion to recover the costs, determined by the Commerce Commission, for operating, maintaining and upgrading the inter-connected grid, will result in a significant

> "rebalancing of transmission charges between customers" (ibid, page vii).

141. Indeed, it was the furore about the level of price-shock increases largely from upper North Island customers and large industrials which this time round, has prompted the introduction of a price cap.

142. The Authority's main concern is the level of transmission cost increase to large industrials.

> "Increases would be significantly higher for some major industrial customers that have responded to different incentives and made operational investments that mean they **currently pay very low or no inter-connection charges**" (ibid, page vii).

143. For industrials and other load customers facing significant transmission charge increases, mitigation by way of an annual price cap, limits the increase to no more than 3.5% greater than the previous year's cost.

144. For directly connected

> "large industrials the cap would rise after five years by two percentage points per year" (ibid, page viii).

145. Modelling of charges under the current TPM proposal shows that three distribution networks, Buller Electricity, Horizon Energy and Westpower would benefit from the price cap by receiving $300,000, $1000,000 and $200,000, respectively.

146. For year one of the implementation of the new TPM proposal the price cap would also reduce transmission costs to at least

> "four directly connected industrial consumers" (ibid, page viii).

147. The total value of the mitigation price cap has been estimated to be

> "$15.4 million in year one (which) would be funded by **all transmission customers** in proportion to their total benefit based and residual charges" (ibid, page viii).

148. What the Authority fails to explicitly state however, is that as Table 12: Breakdown of estimated 2022 charges for each (EDB) customer shows, is that of the estimated $15.4 million price cap budget, at least $12 million will mainly come out of the pockets of residential and small business retail consumers because that is the sum that figures in the

"Pay to/(receive from) cap $m"

column of Table 12, add up to. (see para 120, page 19 above).

149. Again, consider an example of the financial impact to residential and small business EDB consumers from being required to contribute to the price cap reimbursement fund.

150. According to Figure 12 Network Waitaki will be required to contribute $100,000 to the Price Cap Fund, for the benefit of others, which is socialisation of costs relating to debt recovery.

151. Network Waitaki's connection to Transpower is such that the distributor is directly connected to the Lower Waitaki/South Canterbury non-core network by means of a T connection in that network system.

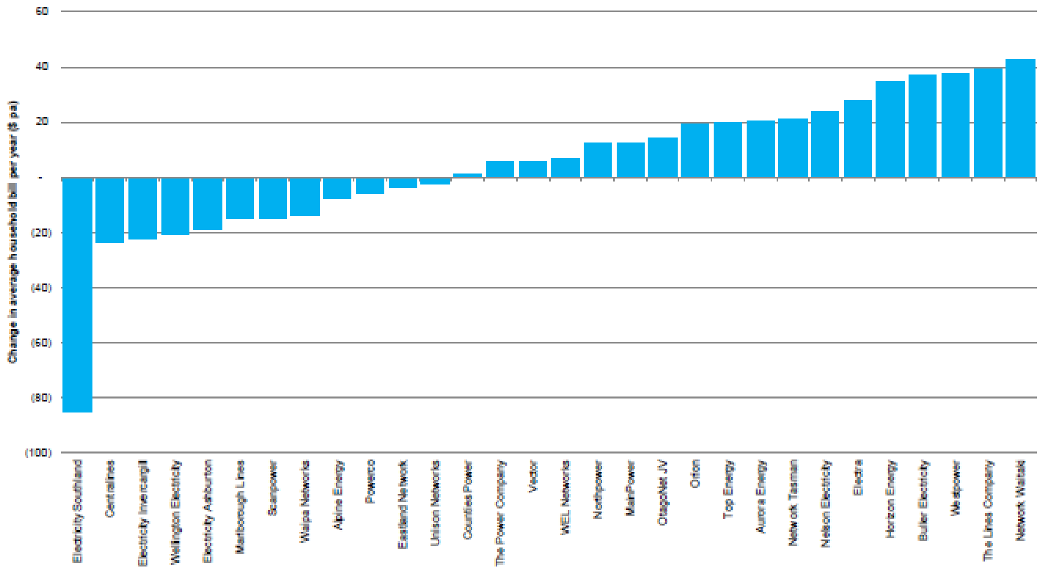
152. As we saw above, being at the end of a transmission line entails that Network Waitaki consumers are required to pay 100% of the connection asset costs Transpower incurs as a result of providing transmission services to Network Waitaki.

153. Of the more than 13,000 ICPs connected to the Network Waitaki distribution network, approximately 10,000 service residential and small business customers.

154. To convey a sense of the level of financial impact an additional $100,000 charge will have for residential and small business customers, it is important to also note that of the 10,000 consumers in those categories, around 4,300 qualify for the low daily fixed line tariff.

155. To add salt to the injury, so to speak, perusal of Figure 17 shows that of all the residential EDB consumers in New Zealand, Network Waitaki residential consumers will be the worst affected of all.

Figure 17: Change in the transmission cost part of the average residential electricity bill estimated by distributor in 2022



156. Indeed, the situation whereby Network Waitaki's residential consumers being required to contribute to reduce the price shock to industrials who

> "currently pay very low or no interconnection charge" (ibid, page viii).

beggars belief.

157. And while Network Waitaki's residential consumers may be regarded as an extreme case, it is important to note that Network Waitaki's residential consumers are but one example of a total of fourteen EDBs where residential consumers will be financially penalised overall by implementation of the EA's new TPM proposal. (See Figure 17 above).

158. That residential consumers are required to contribute financially to help mitigate the level of transmission price increase to large industrialists is simply a **step too far**.

RECOMMENDATION 2

That Transpower's EDB customers are not required to contribute financially toward a price cap mitigation fund for industrial customers.

(ii) The Prudent Discount Policy

159. The 2019 TPM proposal expands the current Prudent Discount Policy primarily

> “to extend access to a prudent discount to consumers that would disconnect from the grid in favour of alternative supply” (ibid, 4.147 (a), page 45).

160. In other words, instead of Transpower disconnecting either a load customer or a customer opts to build its own generation or connect to distributed generation in its distribution area, the preferred option is that the load customer continues to receive transmission services, but at a discounted price.

161. Further, the resultant discount

> “would be available for the remaining life of the relevant (transmission) asset: (ibid, Table 2, page 14, words in brackets our addition).

162. Trustees can but ask – what is really going on here?

163. For any customer to take up the discounted cost of transmission option, the difference in cost between the usual and discounted transmission charge would need to be worthwhile, in which case the extent to which the discounted payment reduces transmission costs to other Transpower customers will be limited.

164. It is more likely that any move to retain transmission customers is based on the implicit assumption that commonly underpins financial decisions by any network type operator – that in order to retain and grow the value of the asset while keeping charges to all customers reasonable, customer retention is essential.

165. The Authority’s uncertainty relating to the likelihood of prudent discount options being taken up (see 4.153, pp 45/6) coupled with the total overall costs of development, implementation and operation of the TPM guidelines which is estimated at

> “a net cost of approximately $26 million (2018 dollars) (and) applying a +/- 50% sensitivity to the estimate gives a range of net costs associated with the proposal of $13-$39 million” (ibid, 4.170, pp 47/8),

prompts the question of whether including amendments to the current Prudent Discount Policy in the 2019 Proposal, is cost reflective?

166. Trustees suggest that the Authority re-considers any future work on PDP amendments, in that light.

(e) The Concept of Durability

167. Throughout the consultation document the Authority repeatedly emphasises the importance of establishing a **durable** TPM.

168. For example, at the outset we are told

> "The Authority's **key reason** for applying benefit based charges to **some historical investments** is to make a new TPM **durable"** (ibid, page iv).

169. According to the EA the crucial element in determining whether a proposal turns out to be durable is, that

> "Consumers need to be able to accept the pricing methodology and pricing outcomes" (ibid, page iv).

170. Hence,

> "Uneven sharing of costs and benefits of the transmission grid … will raise questions about whether the pricing methodology is reasonable" (ibid, 2.23, page 7).

171. And additionally,

> "Perceptions of unfairness can detract from … durability" (ibid, 2.25, page 7).

172. Consequently, the Authority's views is that

> "A pricing approach where people pay for what they get is likely to be more durable" (ibid, 2.25, page 7).

173. For those and similar reasons, the Authority contends

> "the current TPM is not durable" (see ibid, 2.24, page 7),

174. In fact, the EA acknowledges that the search for a durable TPM has resulted in a situation where significant sums have already been spent over the last decade responding to lobbying for and against change.

175. The Authority factored in reasons why they saw durability of the new TPM as an important pre-requisite for a new TPM to meet.

176. First, durability of a new TPM

> "is important if the **efficiency benefits** (of the proposal) **are to be achieved**, and to stop on-going uncertainty (which) is not conductive to making long term investment decisions" (ibid, page iv, word in brackets our addition).

177. Secondly,

> "lack of durability leads to **further inefficiency through uncertainty and added cost**" (ibid, 2.28, page 8).

178. In other words, the Authority considers that **durability** or being **‘durable’**, is what could be termed an **‘enabler’** that has a role to play in promoting the ‘efficiency’ arm of Section 15 of the 2010 Electricity Industry Act.

E. EFFICIENCY AND BENEFITS OF THE PROPOSAL FOR ELECTYRICITY CONSUMERS AND THE NEW ZEALAND ECONOMY

179. According to the EA the net financial benefit to New Zealand’s economy from replacing the existing TPM with the 2019 Proposal is between $2.7 billion and $6.4 billion, the central estimate being $2.7 billion.

180. The most important message conveyed to Trustees by the **enormity of the range of potential net financial benefit** is that, as it stands, there is a missing ingredient from the new 2019 TPM.

181. Clearly, the characteristics of the missing factor are such that

- It is typically variable; and
- along with durability **facilitates** or **enables** outcomes to be achieved.

182. The missing ingredient we refer to is **human behaviour.**

183. The Authority makes the point as follows

> “The main benefits to consumers come from **improving transmission price signals** which will **encourage more efficient grid use**. These types of benefits had been assessed as minor in previous modelling but we consider are in fact, significant” (ibid, page vii).

184. Change in human behaviour also features in the Authority’s account with respect to price signals about using the grid

> “The Authority expects consumers to **become more responsive** to nodal prices” (ibid, 3.24, page 17).

185. And, as we saw above the durability of the 2019 TPM Proposal is fully dependant on a **consumer behavioural response to perceived fairness.**

186. The importance of the relationship between achieving efficiency benefits, durability and consumer behaviour, is implicitly stated by the EA

> “A durable TPM is important **if the efficiency benefits are to be achieved.”** (ibid, 3.26, page 18).

187. The Authority seeks to justify the load which has been placed on **consumer and customer behaviour** with respect **to attaining the financial and efficiency benefits** the EA's analysis has identified, by commenting on its assessment of the net financial benefits of the 2019 Proposal –

> "Presenting a range is good practice. It gives readers a sense of the **effect of uncertainties and unknowns** to which professional judgement has had to be applied" (ibid, page vi).

188. Trustees agree, customer and consumer behavioural response to the proposed new TPM is both uncertain and unknown, and would point out that **based on our knowledge and experience,** the only certainty relating to **assumptions about human behaviour** is that such assumptions, **are fallible**.

189. It is also our experience that in cases where a reliable electricity supply has the greatest value to consumers, **price signals are irrelevant**.

190. A home grown example makes the point.

191. Two thirds of irrigated land in the Otago Region, most of which is spray irrigated, receives electricity from Network Waitaki.

192. In 2018/19 Transpower endeavoured to reduce Network Waitaki's peak load requirement by offering **financial compensation to farmers who were prepared to turn pumps off at specified times for a pre-determined duration.**

193. All farmers with large pumps were directly contacted by Transpower.

194. Guess what – there were absolutely **no takers**!

195. Trustees contend situations like that do not bode well for attaining the financial and efficiency outcomes the Authority has derived by extrapolating from the terms and conditions outlined in the TPM proposal.

196. Further, we would note that the same offer to irrigators from Transpower has already been made for the 2019/20 irrigable year.

F. CONSIDERATION OF ADDITIONAL MATTERS:

(a) TPM Charges for Direct Connect Load Customers and Summer Peaking EDBs

(i) Direct Connect Load Customers and the Principle of User Pays

197. Trustees are aware that as a designated Transpower customer connected to a GXP at the end of a line from the Lower Waitaki/South Canterbury non-core interconnection

transmission network, Network Waitaki, our local distribution network is required to pay 100% of Transpower's

- connection charge
- operational charges
- maintenance charges; and
- capital upgrade charges if and when required, on the transmission system that services Network Waitaki.

198. The EA states unequivocally that charges for connection assets provided to enable both direct connect and interconnected Transmission customers to receive electricity from the transmission system

> "are on a user pays basis. Parties that **demand** these assets are identifiable." (ibid, 2.7a, page 4)

199. We would point out, however, that the fact Network Waitaki is now a direct connect EDB is definitely not because the company **demanded** to be directly connected to transmission assets.

200. Rather, in the early to mid-1990's the newly embryonic established company, Transpower so decided to re-configure the transmission system between Roxburgh Dam and Lake Waitaki via Halfway Bush Dunedin which at that point in time, was part of the inter-connected grid and with n-1 level of security provided electricity to Waitaki Electric Power Board at Transpower's Oamaru GXP.

201. The outcome – by 1998 the transmission system between Transpower's Halfway Bush substation and Oamaru not only had been de-commissioned but also, actually dismantled, leaving Waitaki Electric Power Board / Network Waitaki at the end of an n-1 sub-transmission network originating from Waitaki Dam.

202. The EA defines connection assets as:

> "the **assets** owned by **Transpower** to connect a **designated transmission customer** to the **grid** and may have a more precise definition in the **transmission pricing methodology** as amended from time to time." (ibid, page 101)

203. Accordingly,

> "the TPM must provide for the costs of connection assets to be recovered from those connected to them" (ibid, 10 page 89)

204. Further the EA proposed that

> "the current guidelines for charging for connection assets would be largely retained." (ibid, 323 page 110.)

205. Indeed, it is clear that for several reasons, the Authority looks favourably on the user pays method of charging

> "because it charges parties for the cost of connecting them to the grid. It therefore provides parties with incentives to take connection costs into account in their own investment activity and operations, and to **seek the connection option (or on alternative / to connection) that most cost effectively meets their needs**" (ibid B24, page 110)

206. Unfortunately, from a consumer perspective, Network Waitaki's connection charge is considerably more than it would have been than if the transmission system had not been reconfigured.

207. The system of conductors and associated infrastructure from the T connection at Glenavy to Oamaru, a distance of 26 kms, **remains at n-1 level of security** which Network Waitaki is required to pay for on a user pays basis.

208. As a consequence, Trustees consider Transpower's reconfiguration of the interconnected grid in our area has resulted in Network Waitaki being required to pay a significantly higher transmission connection charge since the late 1990's.

209. For that reason, it is important to note that Network Waitaki has chosen to consider an

> "**alternative to a transmission connection**"

as is allowed for in the quotation cited at paragraph 205 above.

210. Going forward, it is a matter of "watch this space".

RECOMMENDATION 3

That the Authority's final version of the 2019 TPM guidelines proposal includes the current information relating to charges applicable to direct connect designated load customers, even if they are to remain unchanged.

(ii) Summer Peaking EDB Problems

211. The Authority's statutory objective in section 15 of the 2010 Electricity Industry Act is

> "to promote … the efficient operation of the electricity industry for the long term benefit of consumers" (ibid, 4.223, page 55).

212. One way in which **efficiency** can be **promoted** involves eliminating or putting in place a strategy which will mitigate the effects of inefficiency, whatever they may be.

213. Furthermore, the prerequisite for promoting efficiency must be whatever decision is made is **for the best long term interests of consumers**.

214. As we saw above, Network Waitaki, a designated load customer on the east coast of the South Island will have a significant increase in transmission charges following the introduction of the new 2019 TPM proposal.

215. That outcome has been flagged by acknowledgement from the EA as the result of **rebalancing transmission costs.**

> "Figure 17 shows the estimate of the change in the average residential electricity bill following the **rebalancing of charges** expected to result from the proposal …. Network Waitaki consumers would experience the largest average increase of $43 over 2022" (Refer para 155, page 23, above).

216. However, elsewhere the EA makes it clear that rebalancing of charges per se, is but the outcome of applying the gross AMD charge under the proposed Residual charge component of the new TPM proposal.

217. In general terms

> "South Island distributors' transmission charges would rise 11.1% compared to under the current TPM. This is mainly because in general they are peakier users than other groups and because of the proposed gross measure of demand to calculate the residual charge" (Ibid, Table 11, page 60).

218. More specifically, for summer peaking transmission customers with peakier or load demand that is significantly greater in summer than winter, such as Network Waitaki the introduction of a fixed charge gross AMD GXP, capacity charge, if implemented, would appear to be solely focussed on recovery of costs incurred by Transpower associated with operating the grid.

219. From a consumer perspective, the application of a fixed capacity charge completely divorced from consideration

- about the conditions under which peaks occur,
- what the low load cost would be for peakier distributors under the RCPD charge, and
- whether application of the gross AMD charge 365 days of the year is cost reflective, fair, reasonable and efficient

is indefensible.

220. Authority considers that the proposed new method of recouping transmission costs is similar to the change away from variable line tariffs, to fixed capacity charges, for EDB consumers.

221. There is however, a significant difference.

222. A farmer with a 500 kW transformer, used maybe two or three times a season in association with drying grain, can change from electrical grain drying equipment to a **gas fired system.**

223. The parallel investment options for EDBs would be to increase demand side management options.

224. But since uneconomic demand side activity is factored in to the gross AMD charge, for example, distributed generation to reduce peak charges and that the demand side distributed generation capacity would be charged for twenty four seven, 365 days of the year, distributor options are not flexible like the grain dryer situation.

225. It is worth bearing in mind that whether the projected financial benefits to New Zealand's economy are achievable and whether the efficiencies resulting from adopting new TPM guidelines occur, will be, as we saw earlier, **primarily based on consumer perception and behaviour change.**

226. The fact that under the new TPM guidelines Network Waitaki consumers would be paying **higher transmission charges for the same level of service they currently receive** does not inspire confidence that they will support the new 2019 proposal.

227. Added to that reservation is the fact that according to the EA the increase in Network Waitaki's transmission costs will also be partly attributable to the

> **"rebalancing of charges** expected to result from the proposal" (ibid, 5.37, page 69).

228. However, since Network Waitaki currently pays 100% of the transmission costs associated with transmitting electricity from a link into the Lower Waitaki – South Canterbury non-core transmission network at Glenavy, to the Transpower GXP at Oamaru, **any** additional increase resulting from **rebalancing** transmission charges **can only come from an increase in the residual charge historic debt recovery cost.**

229. What we have arrived at is a situation under which Network Waitaki consumers may see a reduction in the level of socialised historic debt recovery from the introduction of benefit based charges BUT on the other hand an increase in historic debt recovery costs captured under the **residual charge regime.**

230. It is thus extremely difficult to gauge exactly what Network Waitaki and its consumers will end up paying for what.

231. And, as the Authority has noted

> "uncertainty about the TPM …. Is not conducive to making long term investment decisions" (ibid, page iv).

232. In that context, it is important to note that Network Waitaki currently is in the position of needing to make long term investment decisions with respect to resolving transmission issues.

233. Lack of clarity and a forthright account with respect to historic debt recovery charges by the EA, is unhelpful.

234. So too, is the fact that the postage stamp based approach to the manner in which the gross AMD charge will be implemented will create a situation whereby Network Waitaki invariably pays the full transmission capacity charge in circumstances where **regional transmission loads are low**.

235. Trustees note that in addition to the key features of the 2019 TPM proposal there is also a list of **additional components** that Transpower could invoke in order to do deals with individual transmission customers under certain circumstances.

236. Against that background, the following recommendation is put forward for the EA to find the appropriate wording that would allow Transpower to amend the postage stamp based approach associated with the application of the gross AMD charge, under specific conditions.

RECOMMENDATION 4

To prevent the occurrence of inefficient transmission charges when peak load requirements occur in summer under low regional load conditions, the EA reconsiders the circumstances under which the fixed gross AMD applies by including an addition to the Additional Component TPM category that would allow Transpower to amend the gross AMD charges as and when appropriate.

237. Trustees consider that the inclusion of an additional component to the proposed new TPM guidelines, along those lines would be fair and reasonable given the terms and conditions of clause 9.23 of the Code which permit Transpower to request consumers to voluntarily reduce electricity usage when storage in hydro-electric lakes is low.

238. An alternative would be to leave the RCPD charge in place and to change the way it is used, to ensure that transmission charges are fair, cost reflective and therefore efficient, a point that was strongly argued for by EDB representatives at the TPM

Christchurch workshop.

G. CONCLUSION

239. Waitaki Power Trust's submission has considered the key features of the EA's 2019 TPM guidelines proposal.

240. We have identified and assessed a range of unstated outcomes that logically and hence necessarily, follow from the terms and conditions of the EA's account of the key features of the proposal, as well as issues that ring alarm bells for consumers.

241. A major concern is that recovery of historic debt is proposed to occur through two entirely different cost centres, namely, benefit based charges and a general **non-specific mop-up cost centre** under the residual charge category.

242. The EA's failure to discuss openly and identify that a historic investment mop-up charge would apply, in the same way as the benefit based charge was elaborated on, can be seen as inferring that the sole purpose of the benefit based charge is to act as a 'sweetener' in much the same way as the Price Cap and amendments to the Prudent Discount Policy, can be regarded.

243. That is unfortunate.

244. Leaving the door open to scepticism does not enhance the durability of the EA's proposal.

245. A second major concern resulted from consideration of transmission price signals provided by the nodal price of electricity.

246. The fact that nodal prices are set at the level of the wholesale electricity market entails that nodal price signals are unavailable to retail electricity market consumers.

247. Because an increase in nodal or GXP electricity charges are not generally available to all consumers they can be regarded as Transpower-centric, **rather than being for the long term benefit of consumers,** a situation which introduces a black hole, with respect to the EA achieving its objectives.

248. Further it is noteworthy that Transpower-centric TMP factors show clearly that the Authority's focus is not directly on long-term consumer benefit.

249. Our Penultimate point relates to concern that

- without significant change in consumer behaviour, neither
- the full financial benefit,
- nor the durability of the new TPM,
- or the raft of consumer benefits resulting from increased efficiencies

will occur.

250. It is one thing to promote and improve the efficient operation of the electricity sector, **ensuring that the outcomes are for the long term benefit of consumers** is quite a different matter.

251. The assumption on which Section 15 of the 2010 Electricity Industry Act is based, and which appears to be endorsed by the EA is that improved efficiency **itself**, will ensure long term benefits for consumers.

252. Trustees consider that assumption is fallacious.

253. Local experience cited above relating to the unwillingness of irrigators to turn off pumps if paid to do so by Transpower, is evidence that there are no certainties.

254. Despite the Authority endeavouring to set the scene by promoting all types of efficiencies, long term consumer benefit **will only occur as a result of change in consumer behaviour**.

255. Our final point relates to the unfairness resulting from the requirement that EDB consumers contribute to the Price Cap fund to reduce the initial level of price increase to four large industrial consumers under the new TPM proposal.

256. Failure to rescind that proposal is considered by Trustees equivalent to putting residential consumers back to the well-recognised situation from 1995 on, whereby, residential electricity prices served to cross-subsidise the cost of electricity to big industrials.

257. That truly would be a step too far and would surely serve to confirm that the baby really has been thrown out with the bath water.