Distribution Group Submission

Transmission pricing review

Submission on the Electricity Authority's 2019 issues paper

1 October 2019

This submission is made on behalf of the following electricity distributors:

Alpine Energy

EA Networks

Eastland Network

Electra

Nelson Electricity

Network Waitaki

PowerNet, representing:

- Electricity Invercargill
- OtagoNet
- The Power Company

Scanpower

The Lines Company

Waipa Networks

Westpower

Submission contact: lynne.taylor@pwc.com

Submissions

Electricity Authority

PO Box 10041

Wellington 6143

submissions@ea.govt.nz

2019 issues paper – Transmission pricing review

Introduction

This submission has been prepared by a group of distributors with common views on a number of the topics raised in the Electricity Authority's (**the Authority**) 2019 issues paper: *Transmission pricing review, 23 July 2019*, and supporting papers (**2019 issues paper**).

The Distribution Group comprises small and medium sized distributors, including regulatory exempt and non-exempt businesses, and those owned by consumer or community trusts or local bodies. Together this group supplies approximately 285,000 customer connections (13% of all connections), maintains 26% of total distribution network length and services 43% of the total network supply area in New Zealand. We note that members of this group may make their own submissions on topics of particular interest.

We acknowledge and appreciate the comprehensive consultation material published by the Authority in support of the 2019 issues paper. We also appreciate the efforts of the Authority in making its staff and advisors available to discuss the proposals with stakeholders across the country during the consultation period.

This submission proceeds as follows:

Summary of submission

1. The proposal if implemented would result in material changes to the annual transmission charges incurred by many grid users. 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.

2. For this reason the Authority must proceed with caution, especially where significant judgements are to be made about inter-generational equity and future demand and reliability. Accordingly the transmission pricing methodology (TPM) proposal should not proceed until there is more clarity about a transmission pricing Government Policy Statement (GPS), as recommended by the Electricity Price Review Panel.

3. Consideration should also be given to any distribution pricing GPS, given the interrelationships between transmission and distribution pricing, and the requirement for distributors to pass on transmission costs through their use of system prices.

4. The distributors who support this submission are in favour of resolving the TPM debate as soon as practical. The timely introduction of the policy statements would greatly assist with this objective.

5. We support the retention of the current connection charge. This charge is effective and well understood by industry participants. We also support proposed solutions to address situations where the definition of a connection asset is not well aligned with the connection service provided, and more accurate opex cost recovery for connection assets.

6. We have previously submitted that due to the substantial redistribution impacts of the proposed move to a benefits based charge incorporating large historical investments, alternative approaches should be considered. We note that the Authority's Cost Benefit Analysis (CBA) has not quantified additional net benefits from including historical investments in the proposed benefit based charge.

7. We wish to highlight that the distributors which are party to this submission have different views on elements of the benefits based charge, including whether to include historical investments, and will be submitting directly on them.

8. We also 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. We note that distributors may respond in more detail in their own submissions with particular concerns about these calculations.

9. We acknowledge that a benefit based assessment of new investments may improve the decisions to invest in upgraded or new transmission assets, including the timing, location and scale of the investments. We consider these future benefits are the most critical component of any potential TPM efficiency improvements.

10. We note that there are significant challenges in quantifying and assigning the 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.

11. We acknowledge that currently the HVDC costs are fully assigned to South Island generators, even though the assets are sometimes used to transmit North Island generation to the south. For this reason we support an approach which shares this cost between generators in both islands based on their actual use of those assets.

12. If a benefit based charge is to be introduced for new investments, subject to alignment with a transmission pricing GPS, we support:

    - using an Indexed Historical Cost (IHC) recovery profile conditional on testing the impact on the residual charge of the wash-up effect of the revenue allowances derived from the Commerce Commission's (Commission's) Depreciated Historical Cost (DHC) approach. This is because the residual charge only applies to load customers but the benefits based charge is to apply to generators and load customers

    - the proposal to allow Transpower to apply a more simple method for determining net benefits for lower value investments, subject to ensuring the supporting analysis is sufficiently robust to support the resulting charges

    - the proposal to align the threshold for high value investments with the Commission's capex Input Methodology (IM) threshold

    - the proposals to adjust benefit based charges:

        i. to accommodate changes in Transpower's cost base

        ii. in response to substantial and sustained changes in the grid use of high value investments

        iii. for investments above $5m where their use is less than anticipated at the time of the investment

    - the proposal to include opex costs associated with transmission investments in benefit based charges. If opex was not included, it would be recovered through the proposed residual charge, which is to only apply to load customers

    - the proposal to treat future upgrades or replacements of existing grid assets as new investments and subject to updated assessments of benefits at the time the investment is made, without disrupting any net benefit assessment of the original investment.

13. 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.

14. The proposal to allocate the residual charge on the basis of anytime maximum demand (AMD) grossed up for distributed generation (DG) is not supported, because:

    - any estimate of size in respect of the use of the transmission system should be measured net of DG, because it is the net measure which best reflects use

    - combining non-coincident AMD measures for customers with multiple connection points does not provide a useful measure of relative size

    - it is not clear why the Authority would recommend a method which favours large load customers over the general load serviced by distributors.

15. We support the proposal to adjust the allocation of the residual charge following a substantial change in demand due to factors beyond the control of a distributor.

16. We support the proposal for Transpower to be able to adopt a peak charge. We submit that the Guidelines should not prescribe how or when this charge is to be applied, as the purpose of the

charge is to provide a signal to encourage efficient grid use, where other mechanisms are unable to do so. We consider it is difficult to predict these outcomes at this time, particularly given the momentum for increased electrification and uncertainty about market and consumer responses to the changing energy system.

17. Distributors and most load customers do not face nodal price signals. Therefore there is value in maintaining a peak signal to support continued use of distributor load control because this is a low cost option to assist with managing grid constraints. This will have little incremental impact on customer utility, given hot water control is a well-established network practice.

18. Accordingly we suggest that the Guidelines will be more durable if the opportunity for a peak charge is retained beyond the proposed 5 year transitional period. This will remove the complexity of Transpower having to apply or reapply at a later date to maintain the option for peak charges.

19. Given the primary benefit of the proposed TPM identified by the CBA is consumer benefits of increased grid use at peak times, we do not believe it is reasonable for the CBA to assume away distribution and retail pricing decisions, the impact on distribution costs and other distributor responses to such significant changes in demand patterns.

20. We also question the CBA assumption that most distributors have spare capacity. This is inconsistent with the expectation for accelerated electrification of industrial processes and transport during the CBA forecast period.

21. Transpower is best placed to respond to the proposed process for implementing any revised Guidelines which may be determined. We note that there are a number of practical difficulties which have been raised, which Transpower will need to resolve. We support the proposal for new Guidelines to provide more flexibility for Transpower in this respect, while setting out the principles of the TPM. We also support the proposal for Transpower to provide its customers with sufficient supporting information to explain how their transmission charges are derived.

22. The remainder of this submission responds in more detail to a number of the key proposals put forward in the 2019 issues paper.

Overview of proposals

23. The TPM paper proposes guidelines for Transpower to follow in developing a new TPM. The Authority expects that the new TPM could take effect from 1 April 2022.

24. The proposed TPM Guidelines would require Transpower to[1]:

- retain the current connection charge with only minor refinements
- remove the current HVDC and interconnection charges
- introduce a benefits based charge for generation and load customers that allocates the costs of eligible investments in the interconnected grid in proportion to the net private benefits each customer receives from the investments. The proposal is that the benefits based charge will recover the costs of seven major historical investments and new investments
- introduce a residual charge to allow Transpower to recover its remaining maximum allowable revenue, to be charged to Transpower's load customers based on size, with the intent that this charge does not influence customers' decision making
- expand the Prudent Discount Policy to cover more circumstances of off-grid bypass risk
- implement a price cap to limit increases in transmission charges resulting from the proposal, for a transitional period
- allow Transpower to implement additional features of the TPM where they better meet the Authority's statutory objective, including methods for:
    1. recovering the cost of assets that are subject to staged commissioning
    2. recovering the cost of connection assets that are modified and would otherwise become interconnection assets
    3. recovering the cost of connection assets using a method that is aligned to the method to be used for benefits based charges
    4. expanding the benefits based charge to include additional investments commissioned pre-2019
    5. a transitional peak charge to influence grid use at peak times for a transitional period
    6. allocating operating and maintenance costs to investments on an actual-cost basis, rather than using proxies
    7. a kvar charge on reactive load.

25. In addition the proposed TPM Guidelines direct Transpower to balance the economic benefits and costs of precision with practical considerations including robustness, simplicity, certainty and implementation costs.[2]

26. The Authority considers that its proposed TPM Guidelines will better meet its statutory objective, providing price signals for efficient grid use and efficient investment decisions, and thus operate for the long term benefit of consumers by reducing costs.[3]

---

[1] 2019 issues paper, Appendix A, Proposed TPM Guidelines, Policy objectives

[2] 2019 issues paper, Appendix A, Proposed TPM Guidelines, General matters

27. In support of this, the Authority's CBA identifies $2.36b of grid use efficiency benefits previously not identified. Total net benefits of $2.7b are identified, within a quantified range of $0.2b to $6.4b.[4]

Changes to proposed TPM Guidelines

28. In addition to the features outlined in paragraph 24 above, proposed refinements are also included in the restructured draft TPM Guidelines which:

- now include upfront policy objectives
- provide more discretion for Transpower in implementing the TPM, including practical considerations and proposing alternative methods where they better meet the Authority's statutory objective
- reduce Transpower's consultation requirements for investments less than $20m
- require Transpower to be transparent over how its charges are derived, and the inputs and assumptions applied
- include specific allocators for seven historical investments to be recovered via the benefits based charge. There were ten historical investments captured within the Area of Benefit (AOB) charge proposed in 2016
- reflect better alignment with expenditure approval processes undertaken by the Commission for Transpower
- allow for the adjustment of charges where significant parties enter or exit the market
- include additional guidance on data and formula to be used by Transpower.

[3] 2019 issues paper, Appendix B, B.5
[4] 2019 issues paper, Executive summary, page vi

Modifying the TPM

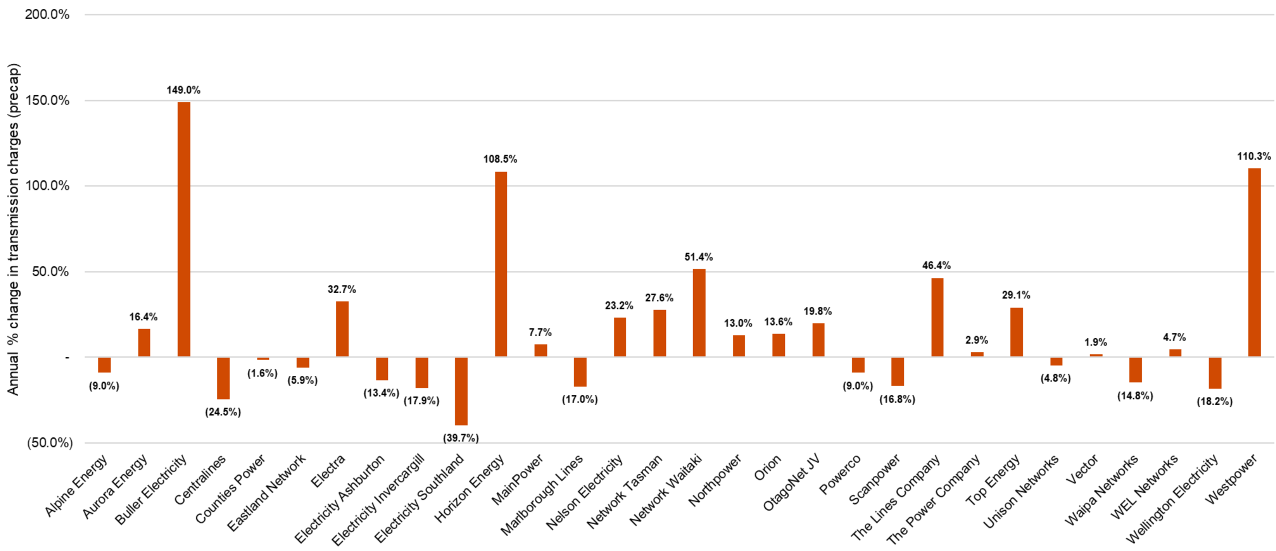
29. The 2019 issues paper identifies problems with the current TPM which the Authority is attempting to solve, including:

- a substantial proportion of transmission charges (70%) are recovered via a peak demand charge (Regional Coincident Peak Demand or RCPD), concentrated across 100 hours per year
- the majority of costs are spread across customers, irrespective of who benefits from the grid investments
- South Island generators pay all of the costs of the HVDC assets, even though the assets are also used to transport North Island generation.[5]

30. We note that the estimated impacts of the 2019 TPM proposal are significant for distributors, as illustrated below.

31. 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.

Figure 1: Percentage change in expected 2022 transmission charges for distributors (excluding capping)



GPS for transmission and distribution pricing

32. We note that the Electricity Price Review Panel's options paper[6] included recommendations for a GPS on transmission pricing. The reasons for this were that policy guidance on how the costs of shared infrastructure should vary between regions or users is an effective way of addressing the difficult and contentious issues faced by transmission pricing. There was substantial support for this option in submissions, including from the distributors which are party to this submission.

33. Accordingly we consider that it is necessary to wait until the Minister has responded to the Panel's recommendation on this GPS. Assuming the option is accepted by the Minister, the TPM proposal

---

[5] 2019 issues paper, Executive summary, page vi

[6] Electricity Price Review, Options paper, 18 February 2019, E1

should not proceed until the GPS is available, and the current proposal is reassessed for consistency with government policy.

34. We also note that the Panel recommended a GPS for distribution pricing, which was also widely supported. We consider that it would be prudent for the TPM to also consider any policy directives for distribution pricing, as distributors are tasked with passing through transmission costs to the majority of load customers through delivery prices. The structure and incidence of transmission charges will therefore influence distribution prices for load customers.

35. The distributors who support this submission are in favour of resolving the TPM debate as soon as practical. The timely introduction of the policy statements would greatly assist with this objective.

Comments on the proposals

36. In the remainder of this submission we comment on the following elements of the TPM proposal in turn:

- Connection charge
- Benefits based charge
- Residual charge
- Transitional peak charge
- Cost-benefit analysis
- Implementation.

Connection charge

37. We support the retention of the current connection charge. This charge is effective and well understood by industry participants.

38. Additional options for connection charges, where they would improve the achievement of the Authority's statutory objective, include:

    - transitioning cost recovery between connection and benefits based charges for assets which may be deemed to be connection or interconnection assets at different times, in order to reflect the benefits provided
    - ensuring assets which principally provide connection services, even where connected to other assets, are deemed connection assets
    - recovering the actual opex associated with connection assets via connection charges
    - connection charges for new connection assets to align with the methods for determining benefits based charges.[7]

39. We support the adoption of additional provisions to address situations where the definition of a connection asset is not well aligned with the connection service provided, as suggested in the first two bullet points in the above paragraph. We also support more accurate opex cost recovery for connection assets.

40. It is not clear under what circumstances the final bullet point would apply, and we note that distributors which support this submission are comfortable with the current basis for establishing connection charges. In this respect we expect customers will continue to engage directly with Transpower when establishing contracts for new connection assets and determine the arrangements via negotiation.

Benefits based charge

41. We have previously submitted that due to the substantial redistribution impacts of the proposed move to a benefits based charge incorporating large historical investments, alternative approaches should be considered, including:

    - retaining the status quo TPM, after incorporating an operational review to resolve issues with the current TPM in a low-cost way, and changing the Distributed Generation Pricing Principles (DGPPs) such that they provide for payments relating

[7] 2019 issues paper, Appendix A, 55-57, 64

to avoided transmission costs, rather than avoided transmission charges, to address the issue that the RCPD may incentivise inefficient usage of DG; or

- applying a benefits based charge to assets commissioned after the date the TPM Guidelines are published, thus avoiding the reallocation of sunk costs, for which there are no investment efficiency benefits available, and allow for a peak pricing signal such that there are incentives for prudent load customers to reduce their load at peak times.[8]

42. The 2019 issues paper does not promote either of these alternatives although some elements of these proposals are addressed in the paper. In this respect we note that:

    - changes to the DGPPs and the DG eligibility requirements for avoided cost of transmission (ACOT) have addressed some of the concerns with the RCPD incentives
    - the option of excluding past investments from the benefits based charge has a negligible but positive impact on the quantified net benefits in the CBA (this option increases the net benefits by $0.018b relative to the proposal)[9] [10]. The 2019 issues paper acknowledges that this option would still promote more efficient decision making about new investment in the grid[11]
    - a peak charge option is included as a transitional measure in the 2019 proposals. We comment on this option later in this submission.

43. A further issue with the current TPM is the HVDC cost recovery which is currently fully assigned to South Island generators, even though it is sometimes used to transmit North Island generation to the south. For this reason we support a solution which shares this cost between generators in both islands based on their actual use of those assets.

44. We retain significant concerns about the proposed introduction of a benefits based charge which results in such substantial reallocation of the costs of past investments. We highlight that the distributors which support this submission have different views on elements of the benefits based charge, including whether to include historical investments, and will be submitting directly on them.

45. We acknowledge that a benefit based assessment for new investments may improve the decisions to invest in upgraded or new transmission assets, including the timing, location and scale of the investments. We consider these future benefits are the most critical component of the potential efficiency improvements. This is consistent with the commentary in Appendix D of the 2019 issues paper which indicates that weight should be given to the promotion of dynamic efficiency in assessing TPM options, given the Authority's statutory objective.[12]

46. 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. We note that distributors may respond in more detail in their own submissions with particular concerns about these calculations.

---

[8] Submission to the Electricity Authority on Transmission Pricing Methodology Review: Second issues paper; and Distributed Generation Pricing Principles, Made on behalf of 14 Electricity Distribution Businesses, 26 July 2016, para 136-137

[9] 2019 issues paper, Appendix B, B.53

[10] The 2019 issues paper suggests that this finding should be discounted because the resulting TPM would not be durable because it would require customers to continue to pay for old investments they did not benefit from as well as new investments. The Authority therefore considers that the TPM would likely be overturned which would put at risk the other efficiency benefits identified (2019 issues paper, page 49). In response we note that the timing of the introduction of a benefits based charge is a central issue for stakeholders. As suggested above, a GPS can provide appropriate direction for resolving the issue. Notwithstanding the durability concerns, we note that the dynamic efficiency benefits are limited to new investments under the proposals.

[11] 2019 issues paper, Appendix B, B.47

[12] 2019 issues paper, Appendix D, page 188

47. 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.

48. In the remainder of this section we comment on the specific proposals for benefits based charges for new (post 2019) investments. These comments should be read in conjunction with our earlier comments on a transmission pricing GPS.

49. It is proposed that new investments will be recovered through a benefits based charge using an IHC method, which better aligns the cost recovery profile with the service profile of transmission assets than a DHC method. The IHC method results in flatter charges over time. The amount to be recovered is not impacted by the choice of method, as it only influences the profile of the cost recovery.

50. In principle we support using an IHC approach for new investments which avoids front loading cost recovery for new assets, and therefore is more consistent with the role of the investment. However, we note that as Transpower's allowable revenue is determined using a DHC approach, there will be timing differences which will flow through to the residual charge.

51. Therefore, we submit that an analysis of the impact of the proposal on the profile and value of the residual charge needs to be undertaken. This is important because the proposed benefits based charge and the residual charge are to be allocated to grid users on a different basis. It is only load customers which bear the residual charge under the proposal. If there are significant impacts on the residual charges faced by load customers then the IHC approach should be re-evaluated.

52. We support the proposal to distinguish between high value and low value post-2019 investments and to allow Transpower to apply a more simple method for determining net benefits for lower value investments, at their discretion. We note that even if a simple method is applied, Transpower is obliged to disclose the method, assumptions and inputs to affected stakeholders. We also note that any benefits that are identified and assigned to users must be able to be supported with robust analysis, even under a simple approach.

53. We support the proposal to align the threshold for future high value investments with the Commission's capex IM threshold of $20m. This would assist Transpower to leverage the capex IM application and approval processes for a benefits based charge for new investments. We note that if Transpower wished to, it could also replicate these processes for low value investments where there was justification to do so, ie: where the net benefit assessment was particularly complex or uncertain.

54. It is proposed that net benefits for post 2019 investments are assessed at the time of commissioning, and that the charges will be allocated between beneficiaries on an ex-ante basis. Changes to charges would be permitted to accommodate changes in Transpower's cost base (eg: a change in the WACC), or if there was a substantial and sustained change in the grid use of high value investments. We support these proposals which are pragmatic and may assist mitigate benefit gaming.

55. In addition, it is proposed that Transpower may reassign a portion of a benefits based charge to the residual charge for investments above $5m where the use of a grid investment is less than anticipated at the time of the investment. We support the lower threshold in this instance, which is particularly important for distributors who may otherwise be significantly exposed to the closure of large individual load customers on their networks.

56. It is also proposed that the opex costs associated with transmission investments will be included in benefits based charges. We support this proposal which ensures both load customers and generators contribute to the costs of operating and maintaining future grid investments which are

deemed to provide net benefits to them. If opex was not included, it would be recovered through the residual charge, which is currently proposed to only apply to load customers.

57. In a similar manner, future upgrades or replacements of existing grid assets are proposed to be incorporated into a benefits based charge as new investments, thus triggering an updated assessment of benefits at the time the investment is made. This is to be made without disrupting any net benefit assessment of the original investment which is reflected in benefits based charges. We agree that this is a sensible approach which is likely to be more durable than attempting to combine net benefit assessments of initial and subsequent investments.[13]

Residual charge

58. The 2019 issues paper explains that the residual charge is not intended to actively influence grid use and investment because this is to be achieved by:

    - wholesale electricity nodal prices
    - the potential for a transitional peak charge
    - the incentives for efficient grid investment created by the proposed benefits based charge and the Commission's capex approval process for Transpower.[14]

59. Accordingly the residual charge deliberately includes no price signal because if it did so it would be expected to disrupt the mechanisms listed above. The sole purpose of the residual charge is to allow Transpower to recover up to its annual revenue allowance because its other charges will not be sufficient to do so.

60. While we understand the rationale for a fixed type charge for residual costs, we note it is dependent on the effectiveness of the other pricing mechanisms. We comment further on nodal prices and the transitional peak charge below.

61. It is intended that the residual charge is only allocated to load customers. We acknowledge that the residual charge is expected to reduce over time as more investments are to be recovered through a benefits based charge. However we believe that there are inconsistencies introduced by differentiating between load and generation customers for benefits based and residual charges.

62. This is because the proposed residual charge is a 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 only fall on load customers. Accordingly, as we have previously submitted, the residual charge should also be allocated to generators.

63. It is proposed that the residual charge is allocated based on a measure of size and ability to pay. A historical measure of peak demand (AMD) is proposed, gross of DG[15]. Non-coincident AMDs would be added together for customers with multiple connection points.

64. An alternative is a measure of broad use such as consumption. The AMD measure favours large load customers who tend to have load which is less peaky than distributors. However the proposal also allows for Transpower to determine allocators that would better meet the Authority's statutory objective.

65. We make the following comments in this respect:

[13] Transpower's RCP3 15 year capex forecasts (submitted in November 2018) show that just 7% of forecast capex is growth related, the remainder is reliability/renewals driven. We note that if the proposed TPM is implemented, we might expect the growth related capex to increase to meet additional grid demand which is predicted.
[14] 2019 issues paper, Appendix B, B196
[15] Defined as concurrent generation by distributed generators or behind the meter generation that is indirectly connected to the grid through a transmission customer (Appendix A, 40(a) (i) B). This excludes demand response.

- any estimate of size in respect of the use of the transmission system should be measured net of DG, because it is the net measure which best reflects use
- combining non-coincident AMD measures does not provide a useful measure of relative size. Some distributors may have winter peaks in some regions and summer peaks in others. Distributors also have the ability to shift load between points of supply
- it is not clear why the Authority would recommend a method which favours large load customers over the general load serviced by distributors. We note that the proposed pricing cap also imposes initial costs on the general load serviced by the majority of distributors to the benefit of a number of large load customers[16].

66. It is proposed that the residual allocation will be adjusted where a customer has experienced a substantial change in demand due to factors beyond their control or influence.[17] We support this proposal which is relevant to smaller distributors who are particularly exposed to the loss of large customer load where historical data is used to derive allocators.

Transitional peak charge

67. 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.

68. 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.

69. 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.

70. The 2019 issues paper acknowledges that locational marginal prices (LMP), represented by nodal prices in the New Zealand market, may have limitations in restricting grid use to capacity, or ensuring efficient grid use. The 2019 issues paper identifies the following issues in this respect:

    - insufficient price sensitive demand at a node
    - some customers may not face or react to nodal prices
    - nodal prices may not reflect the full SRMC of the grid
    - an additional peak charge may be needed to ensure efficient investment by grid users and so efficient grid investment[18].

71. We note that Transpower supports retention of a peak charge.[19]

---

[16] We note that 3 distributors also benefit initially from the cap
[17] 2019 issues paper, Appendix B, B.218
[18] 2019 issues paper, Appendix D, D.41
[19] 2019 issues paper, Appendix E, E.15

72. It is suggested that the current RCPD charge generates avoidance behaviour which is, and will continue to, result in inefficient investment in peak load management and DG. The Authority predicts that if the RCPD charge were to remain, there would be escalating investment in grid scale batteries, resulting in higher costs of supply than grid based alternatives.

73. We note that recent changes to Part 6 of the Code in respect of the DGPPs and the introduction of a regulatory process to confirm which DG is eligible for ACOT payments, has reduced the incentives for investment in DG to avoid interconnection charges.

74. 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 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 times[20]. 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.

75. 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. This would be consistent with the issues identified by the Authority and summarised in paragraph 70 above.

76. Accordingly we submit that the proposed five year limit and phase out process for the peak charge option should be removed because:

    - Transpower supports retaining a peak charge option to manage load at peak time
    - as distributors do not face wholesale energy price signals, load control is unable to respond to grid constraints. Load control is a low cost option to assist with such constraints, with little utility impact on consumers
    - it is uncertain whether and when significant consumer response to price signals, including real time pricing, demand control technologies and new business models, will emerge
    - it is not certain that an ongoing peak charge will distort efficient operation of nodal prices
    - it is not certain that relying primarily on nodal prices will result in efficient grid use and investment, including the timing of that investment
    - Transpower will be required to monitor the impact of any peak charge.

77. We submit that this option provides more certainty for Transpower and stakeholders. The alternative proposal which provides for Transpower to apply to the Authority to extend the transitional period or reintroduce a peak charge at a later date is overly complex and unnecessary.

Cost-benefit analysis

78. The CBA which accompanies the 2019 issues paper differs substantially from the CBA presented with the 2016 TPM proposal. The 2019 proposal is assessed as providing estimated net benefits of \$2.71b, within a range of \$0.2b - \$6.4b. The breadth of this range reflects the significant assumptions that are made, and the sensitivity of the results to those assumptions.[21]

[20] Any revenue earned via a peak charge would reduce the amount to be recovered via the residual charge

[21] 2019 issues paper, Consultation paper, page 21

79. 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.

80. 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.

81. 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'[22]

82. 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.

83. 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.

84. 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.

Implementation

85. The 2019 issues paper suggests that the revised TPM could be implemented as follows:

- Guidelines published in April 2020
- new TPM developed by Transpower by October 2021
- new TPM included in the Code by July 2022
- new TPM implemented by July 2023, with the first year of prices consistent with new TPM published in November 2023, to apply from April 2024.[23]

[22] 2019 issues paper, Consultation paper, pages 27-28, 46
[23] 2019 issues paper, Executive summary, page 72

86. Subject to the comments above on the GPS, we suggest that Transpower is best placed to respond to the proposed implementation timetable.

87. We note that it is proposed that the revised TPM Guidelines include considerable discretion for Transpower in how it practically implements the revised TPM. We agree that Transpower needs to work out the details of the proposal, and should have some flexibility in how it achieves this, including the ability to use transitional measures, estimates and alternative methods where appropriate.

88. 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.

89. In responding to earlier versions of the proposals, submitters including Transpower, have raised a number of practical implementation challenges with the proposed methods for calculating and allocating benefits based (or AOB) and residual charges. The various issues papers have acknowledged these challenges.

90. The 2019 issues paper proposes that Transpower will be primarily responsible for resolving them.[24] We support this approach, and submit that the TPM Guidelines should not be overly prescriptive in this respect, and should focus on guidance about pricing principles.

91. We also support the proposal that Transpower provide its customers with information supporting the derivation of benefits based and residual charges, including methodology, assumptions and information relied on.

[24] A notable exception is the proposal to define the allocation of the benefit based charge relating to seven historical investments in the Guidelines.