



Attachment C: 2019 Issues Paper questions and answers

Chapter 2

Q1. Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

The Authority has identified some problems with the current TPM with which we agree. However, in our view, the problems could be dealt with more quickly, more effectively and efficiently than extensive reforms, with less risk and at a lower cost by incrementally reforming the existing TPM and Guidelines. Some suggestions for such reform are listed in **Appendix 1** of our submission.

While the current TPM is not perfect, it is not broken either. We reiterate our submission on the Authority's Second Issues Paper that:

with some limited exceptions the current TPM is generally acknowledged by stakeholders and our customers as working well. This is reflected in submissions to the 2014/15 Operational Review, and the Authority's consultations. The options which have found most favour are retention of the status quo, or targeted changes to address specific concerns with the TPM. ...

This reflects the fact that:

- 1. The existing deep connection charge is a cost reflective charge that directly assigns costs for a significant proportion of the grid ...*
- 2. While the peak price signal provided by the RCPD interconnection charge may be considered blunt, it has helped to defer transmission investment (as detailed, for example, in the Authority's first Issues Paper).*
- 3. The HVDC charge provides a clear North-South locational signal.*

The Authority's various TPM consultations have canvassed different problem definitions which, in our view, have tended to overstate the problems with the current TPM. As we said in our submission on the Second Issues Paper:

We caution the Authority against overstating problems with the status quo. We recognise that this is a natural tendency when making the case for change but, if unchecked, could lead to radical, disruptive change where targeted reform would be more proportionate, carry lower cost and risk and better promote the statutory objective.

Chapter 3

Q2. What are your overall views on the Authority's proposal for changes to the TPM guidelines?

Transpower does not support the Authority's proposal.

We acknowledge that there is scope to improve the current TPM and we are open to having discussions with the Authority and other stakeholders about the most expedient way to resolve these.



We note that the positions in the Authority's current proposal are consistent at a high level with the Authority's earlier transmission pricing review proposals. While our stance on these points is largely unchanged, we consider that it is important to restate our view that the Authority's current TPM proposal runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers. Moreover, we are concerned that the proposal may not support New Zealand's transition to a low-emissions economy.

In our view it is important for the TPM and Guidelines to:

- support timely, efficient transmission investment via the Commerce Commission's processes;
- limit the risk of unintended consequences (including of inadvertently undermining New Zealand's efforts to respond to climate change);
- be workable, practicable and understandable to our customers and stakeholders; and
- limit the risk of legal challenges to transmission pricing decisions by being objective and fair.

When considered in context and against the counterfactual, it is not clear to us that the Authority's TPM proposal is consistent with these requirements. We elaborate on these points in our submission.

We are supportive of a measured approach to amending the TPM and Transpower is appreciative of the extensive work the Authority has conducted in identifying a number of significant issues that require review. In our view, extensive reform of the sort proposed by the Authority may not be the most effective or efficient manner to address TPM concerns. We consider that the concerns with the TPM may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology. This would have the benefit of bringing the reforms to the market more quickly with a substantially lower risk of unintended consequences. Our submission proffers some practical options for such reform.

In the event that the Authority's proposal was to be implemented, then we consider that there are some workability issues in the drafting of the proposed new Guidelines that would benefit from further review.

Chapter 4

Q3. Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?

No. See our answer to Q4.

Q4. Do you have any comments on the matters covered in chapter 4?

The Authority considers its CBA supports a conclusion that its proposed approach to transmission pricing would promote the efficient operation of the electricity industry for the



long-term benefit of consumers. To inform our submission on this premise we commissioned an expert review of the CBA from Axiom Economics (**Axiom**). Axiom's report is **Attachment A** to our submission.

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

We consider such a material change in approach to transmission pricing should be supported by a CBA that achieves a high level of acceptance from the experts who review it. We are therefore interested to hear the opinion of experts commissioned by other submitters, and from the Authority as to its confidence in how its proposal would benefit consumers over these timeframes.

Axiom's view is that the CBA is compromised, including for the following reasons:

- Neither the grid use model (which generates 96% of the estimated net benefits) nor the top-down modelling reflect the Authority's proposal.
- The net benefit estimate mistakenly includes \$2.3b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry. The analysis also ignores a \$1.9b cost of additional investment that is estimated to be needed to produce the modelled benefits. Addressing these errors alone reduces the Authority's net benefit estimate to negative \$1.5b.
- The modelling rests on assumptions that do not reflect the ways in which the electricity market works, or market participants act.
- Aspects of the modelling hinge crucially on assumptions and inputs that are arbitrary or lack objective foundation.

Axiom concludes that the CBA has no probative value and lends no support to the Authority's proposal.

Chapter 6

Q5. How long should Transpower have to complete its development of the TPM and why?

Should the Authority proceed with its proposed new approach to transmission pricing, proper engagement with our stakeholders during TPM development would be critical to producing the most durable TPM possible within the constraints of the Guidelines.



Constructive and highly engaged stakeholder participation would be key to achieving a successful development and implementation of any new TPM.

In our view 18 months to submit a new TPM consistent with the Authority's 2019 proposal, would be an ambitious and very challenging timeframe. Any less time introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. We would be more comfortable with 24 months.

There remains uncertainty about how we would recover our costs of TPM development, implementation and ongoing operation, should the Authority decide to issue new Guidelines. Certainty about this early in the process would support our ability to develop the new TPM in a suitable timeframe.

Q6. What checkpoints (if any) should the Authority set in the TPM development process?

Transpower disagrees with some aspects of the proposed checkpoints:

- Two or three months after the Guidelines are published would certainly be too soon for the first checkpoint. That would not be enough time for us to make "key design choices on allocation methods for the benefit-based charge and peak charge". We note that in our submission on the Second Issues Paper Supplementary Consultation we did not anticipate confirming the design of the benefit-based (then area-of-benefit) charge until around 12 months after publication of the new Guidelines, following at least two rounds of stakeholder consultation.

In our view a first checkpoint after six months to present preferred design options for the benefit-based and peak charges would probably be achievable.

- We do not think we should be required to provide a preliminary draft of the TPM at the second checkpoint. At the second checkpoint, which should be no earlier than 12 months after publication of the new Guidelines, we anticipate being in a position to confirm final design choices for the benefit-based and peak charges. We may illustrate those choices with some preliminary drafting of the TPM, but the important information would be the choices themselves.

Q7. How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

Transpower would certainly be engaging with all stakeholders during the TPM development phase. We provided an indicative plan for that engagement in our submission on the Second Issues Paper Supplementary Consultation.

We do not consider the Authority should set requirements for how and when Transpower engages with its customers and other stakeholders (other than the Authority checkpoints). How we do this should be kept flexible, working within the constraints of the Authority



checkpoints and the overall timeframe for submitting the proposed TPM. This would allow our approach to adapt to specific TPM design issues that arise during the development phase and the resources and time we have available to engage with stakeholders on them. We agree with the Authority that the process would involve “balancing an appropriate level of engagement with timely completion”. We consider it is unwise to attempt to predict what that level will be in advance.

We do not agree with the Authority’s view that multiple full consultation rounds would be unnecessary. Although the proposed Guidelines are prescriptive in some areas, there are still a significant number of design choices we would be required to make in producing the TPM. Consultation on the Guidelines does not equate to consultation on those design choices.

In our view, strong engagement with our stakeholders would save time and work in the end.

Q8. In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

We do not agree that six weeks for consultation by the Authority on the proposed TPM would be enough time. This would likely be the first time stakeholders see the complete TPM, and there may have been significant design choices made since stakeholders were last consulted (especially if the Authority had referred the proposed TPM back to Transpower or made changes to the proposed TPM itself). The balance of six weeks for consultation and six-and-a-half months for the Authority’s processes does not seem right.

While we agree the new TPM would need to be treated as a Code change, we do not think it would be appropriate for the Authority to make changes to the proposed TPM after consultation without coming back to Transpower to check on the workability of those changes. The Code makes Transpower responsible for drafting the TPM because it is Transpower that has to administer it.

We do not agree with the Authority that the upgrade to our transmission pricing software in 2019/20 would mean we could cut the TPM implementation time down to 13 months (from up to 28 months). The time it takes to implement any approved new TPM would depend on what the new TPM says, which is not known yet.

As we say in our answer to Q5, finding an appropriate way for Transpower to recover its costs of TPM development, implementation and ongoing operation remains a pressing issue. We look forward to continuing to work with the Authority and Commerce Commission to resolve this matter.



Appendix A: Proposed TPM Guidelines

Q9. What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

The 2019 Issues Paper draft Guidelines are a significantly better and more workable than the 2016 version.

We have challenged ourselves to consider afresh how we could make the Authority's proposal work. A significant focus of our review of the Authority's proposal has been on the draft Guidelines and what changes to them would be needed if the Authority were to adopt its current proposal.

We have identified a number of drafting and workability issues in the draft Guidelines that need to be resolved. These are highlighted in our clause-by-clause comments on the Guidelines in **Attachment B** of our submission. We would welcome the opportunity to work through these issues with the Authority and other stakeholders. Some of the issues remain from previous drafts of the Guidelines.

In our view it would be prudent for the Authority to undertake a technical drafting consultation once it has made final decisions on whether to replace or amend the Guidelines.

Appendix B: Reasons for policy positions in the proposed guidelines

General matters

Q10. Do these [Appendix B] provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

We reiterate our submission on the Second Issues Paper that:

no bright line delineates the boundaries between the Guidelines and the TPM ... care is needed to ensure the Guidelines direct Transpower by laying out clear principles for the TPM but does not unduly foreclose design options.

The latest draft Guidelines provide greater flexibility for Transpower in some areas, including providing for Transpower to apply proxies to estimate the net private benefits of individual transmission customers when determining the benefit-based charges. However, we consider the draft Guidelines need further work to avoid over-prescription. The proposed re-openers for the benefit-based charges, for example, constrain Transpower unduly and over time would make the charges inconsistent with the definition of beneficiaries-pay in the Authority's Decision-Making and Economic Framework (**DMEF**).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission.

*Connection charge***Q11. Should the current guidelines on connection charges be largely retained or are changes required?**

Connection charges should be retained in substantially the form they are now.

We agree with what we understand to be the intent of Additional Components A and B in the draft Guidelines (relating to connection charges), though not the execution. See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 55 and 56).

Q12. Should first-mover disadvantage be addressed in the TPM, and if so, how?

The new Guidelines and TPM are an opportunity to address the first mover disadvantage for investments that are funded by one or a few parties through investment agreements. The problem arises because, currently, subsequent customers who benefit from those investments do not pay a capital contribution to them through transmissions charges.

We have suggested a change to the draft Guidelines to introduce a “funded asset charge”, which is one way to tackle this problem. See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (proposed new clause V). We note however, such a change to the TPM could equally be resolved under the current TPM Guidelines.

*Benefit-based charge***Q13. Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?**

No. Transpower does not think a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers. Where BB charges may promote efficiency more than alternatives the impact is undone by making charges largely fixed and unavoidable, and introducing considerable new sources of dispute.

We are unable to agree with the Authority that introducing BB charges would have a significant and beneficial impact upon the Commerce Commission’s grid investment approval processes, resulting in more efficient expenditure. Rather, we consider the Authority’s proposal would put timely, efficient grid investment at risk. We find it difficult to agree with the Authority’s analysis and submit that it is, instead, more likely to create sources of dispute and may incentivise parties to withhold information rather than share it.

It is, instead, more likely to result in the proceedings getting bogged down in private interests and disputes that hinder timely, efficient investment in transmission at the expense of security, reliability and wider economic and social wellbeing considerations (including responding to climate change). We note Axiom’s view that:

if the proposal has any effect on the grid investment approval process, it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information.



Where disputes over price outcomes hinder timely, efficient investment in transmission and generation, higher electricity prices (a disbenefit to consumers) and elevated greenhouse gas emissions are likely consequences.

Customers' BB charges would be based on the benefits that Transpower estimates they will receive over the life of an investment at the time that it is made. Actual benefits will diverge from estimated benefits over time – perhaps dramatically. Moreover, the initial allocations would also apply to any upgrades made many years later. It is hard to see how such a regime could be durable – a problem the Authority itself acknowledged in its First Issues paper. To illustrate some of the challenges with the proposed BB charges we have provided in **Appendix 3** some simplified case studies of how the charge might apply to (hypothetical) grid investment.

See our answers to Q2, Q4, Q44 to Q46, Q54, Q55, Q58 and Q59.

Q14. Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

We agree it is sensible to use a "wash up" charge (such as a residual charge or the current interconnection charge) to recover otherwise unallocated costs.

A pragmatic alternative for recovering the costs of pre-2019 investments would be to use some form of regionalised or tilted postage stamp charge.

Q15. Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

Application of a benefit-based charge to any subset of historical investments, including investments made between 2019 and implementation of the new TPM, would be arbitrary to a degree.

Q16. How should the covered cost of the investment be defined?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 14.)

Q17. How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?

How Transpower recovers the cost of grid investments over time is a function of our regulation by the Commerce Commission. Whether the TPM should use a different time profile should be left to be determined as part of TPM development. Consideration would



need to be given to the impact of the having different price paths for the TPM and under Part 4, e.g. it could result in a more volatile Residual Charge.

Q18. Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

We consider that the Guidelines specifying elements of the benefit-based charge methodology such as this would be overly prescriptive, and could adversely impact on workability. The method by which Transpower determines net private benefits, including the proxies it uses for that, should be left to be determined as part of TPM development (as is currently proposed).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 19 to 24).

Q19. Should the guidelines distinguish between high-value and low-value investments?

We agree that the Guidelines should differentiate between high-value and low-value investments and have simpler requirements for the latter (to the extent the Guidelines have that level of prescription). We agree that the \$20m threshold proposed for a high-value investment is appropriate.

If the Guidelines are to include a high-value investment threshold then that threshold should be applied consistently. The investment value threshold for reassignment (to the extent reassignment is retained) should be \$20m, not \$5m as proposed.

Q20. If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

A pragmatic alternative for recovering the costs of low-value investments would be to use some form of regionalised or tilted postage stamp charge (as also suggested in our answer to Q14 for all pre-2019 investments).

We consider that if the Guidelines include a requirement to apply the benefit-based charge to low-value investments there should be a discretion for Transpower to include a floor, as the administrative cost and effort of applying even a simple method to a very low-value investment is unlikely to be worth it. The costs of very low-value investments (below the floor) would be recovered through the residual charge or through an alternative charge as suggested above.



Q21. What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

See our answers to Q19 and Q20.

Q22. What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 21).

Q23. How should the costs of the investments that are not covered by the benefit-based charge be allocated?

See our answers to Q14 and Q20.

Q24. Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

If the Authority's proposal were implemented, Transpower would be required to allocate BB charges to customers based on our estimates of the benefits they will receive over the life of an investment at the time that it is made. Our customers' collective utilisation of the grid is constantly changing, and over time that change can be fundamental to what benefits (or disbenefits) are realised by individual customers. Inevitably, any forecast of benefits that will arise over several decades will be wrong. In our considered view, the probability of the benefits estimates proving to be right, or materially right, over the 30 to 50 year life of an interconnected grid investment is low.

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

This is not a reason to never change the TPM. Rather, it is a reason to ensure the TPM can adapt in response to change. BB charges can be designed to adapt. For example, adopting a method consistent with that applied in the United States (**US**) would go some way to achieving this. There, charges are fixed ahead of time to large beneficiary zones and then on-charged to individual parties (in the US context these are generally transmission owners) who themselves on-charge using traditional tariff structures, including peak charges. A



similar approach in New Zealand would, in our view, significantly improve the chances of a successful move to BB charging.

To illustrate some of the problems and challenges with the Authority's proposed BB charges, we have included in **Appendix 3** of our submission some case studies for how the charge might apply to an upgrade of our transmission line between Wairakei and Hawke's Bay (hypothetically).

In our view, the alternative approach reflecting US precedent we have recommended above is likely to prove more workable and reasonably durable. In contrast, a highly granular approach that sought to lock-in charges and seldom – if ever – revisit them would have very little chance of being sustainable in the long-term. The Authority conceded as much in its first issues paper.

Whether or not the Authority adopts this alternative approach, the Guidelines should adopt the principle that the allocation of a benefit-based charge may change whenever there is a material misalignment between net benefits and the allocation, regardless of the cause of that. That would be consistent with the definition of "beneficiaries-pay" in the Authority's DMEF.

The draft Guidelines instead include a series of ad hoc provisions allowing for reallocation, or reassignment, in specific circumstances. The substantial and sustained change in grid use reopener in clause 26 is an example of that.

We note that the clause 26 reopener only applies to high-value investments, which risks significant benefits-to-allocation misalignment over time for low-value investments. We also note that "grid use" is not the only determinant of benefits. For example, the higher wholesale electricity prices over 2018-19 mean that if these dates were selected the proposed Schedule 1 allocations could be substantially different (higher for generators and lower for load) to the allocations the Authority has calculated based on 2014-18 data.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 17, 18, 25, 26, 32(b) and 42 and alternative clauses XA to XC).

Q25. Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

See our answer to Q20.

If the Guidelines apply the benefit-based charge to low-value investments we agree the implementation should be deferred in favour of implementing the charge for high-value investments. We agree that a five-year deferment deadline is appropriate.



Q26. Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

"Reassignment" is optimisation, but without using that word. In our view the Authority has not addressed the principal issues we have raised previously about optimisation of benefit-based investments. Those are:

- we consider the potential efficiencies of optimisation do not justify the administrative burden of it; and
- we are not aware of any established or accepted method of applying optimisation to assets valued on an historical cost basis. We consider this to be a major workability risk with the draft Guidelines.

Our position has not changed from our submission on the Second Issues Paper:

We consider that the [reassignment] provision in the proposed Guidelines should be removed. We recommend that this is replaced by a cap that limits [benefit-based] charges to aggregate positive net benefits.

What is relevant is whether total net private benefits from a benefit-based investment is higher or lower than the total cost of it. There can be situations where, for example, an asset is "gold-plated" (and would be reduced in value under optimisation) but its benefit still exceeds its cost. In that case no optimisation, reassignment or other adjustment is necessary.

As well as avoiding the need for reassignment/optimisation clauses in the Guidelines, a cap on the benefit-based charge at total net private benefits would be consistent with the definition of beneficiaries-pay in the DMEF. This was a core element of the Authority's proposal in the First Issues Paper. We are unclear why the Authority moved away from this.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 33 to 38).

Residual charge

Q27. Should the guidelines provide for a single residual charge or multiple residual charges?

We do not consider that there should be more than one residual charge, but in our view the Authority should consider an additional regional or tilted postage stamp charge for pre-2019 and/or low-value investments. See our answers to questions 14 and 20.

Q28. Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?

See our answer to Q34.



Q29. Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

See our answer to Q34.

Q30. If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

See our answer to Q34.

Q31. Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

See our answer to Q34.

Q32. If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

See our answer to Q34.

Q33. Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

See our answer to Q34.

Q34. Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

Questions 28 to 34 relate to question 10 in terms of the balance between prescription and flexibility in the Guidelines.

In our view the residual charge allocation methodology should not be determined as part of the Guidelines. We reiterate our submission on the Second Issues Paper that:

it would be better to specify that the Residual Charge is required to be set in a way that, to the extent practicable, is as fixed (unavoidable) and 'incentive-free' as possible, and leave the determination of the allocator to be adopted (be it physical capacity, as currently prescribed, or some other allocator) to the subsequent stage when the methodology itself is designed.

The use of historic AMD the Authority is proposing would rate highly in terms of being fixed and unavoidable, but would benefit regions with high growth rates and discriminate against lower growth regions. If a rolling average AMD were used instead, it would be less fixed and unavoidable, but less prone to substantial changes to demand rendering the charges out-of-date or discriminatory. Historic AMD is not cost-reflective, as it does not differentiate



between maximum demand that is peak (and contributes to capacity requirements) and off-peak (which does not contribute to capacity requirements).

These are examples of the trade-offs and factors that would need to be taken in account in determining an allocator for the residual charge. We consider they are best left to be considered as part of the TPM development process.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 39 to 41).

Q35. Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

In principle we agree the residual charge allocation should respond to demand changes, but the need for a standalone adjustment mechanism depends on the residual charge allocation methodology that is adopted (i.e. it may be "self-adjusting if we are given sufficient flexibility to design it that way – see our answer to Q34).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 41 and 42 and alternative clauses ZA to ZC).

Q36. Should the residual charge apply to both generation and load customers, or only to load customers?

One of the problems with the current TPM identified by the Authority is that generators do not contribute to the costs of interconnection assets they benefit from due to their location. As we have suggested in **Appendix 1** of our submission, one way to address that problem (as an alternative to a benefit-based charge) would be to require generators to pay part of the current interconnection charge or some other residual-type charge.

Other

Q37. Are the proposed provisions relating to adjustments appropriate?

See our answers to Q23 and Q28 to Q34.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 42 and alternative clauses XA to XC and ZA to ZC).

Q38. Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?

The proposal that prudent discounts apply for the life of the relevant asset has not been justified. There is no evidence or assessment of problems with the current prudent discount arrangements.



There should not be a default period of the remaining life of the investment (which investment?) because the conditions that applied when the prudent discount was agreed may not be enduring. As clause 48 is drafted, customers will be able to force inappropriately long prudent discounts. In our view the period should be whatever the parties agree it is.

Q39. Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?

See our answer to Q40.

Q40. Should the price cap be specified as a percentage of electricity bills or in some other way?

We reiterate our submission on the Second Issues Paper Supplementary Consultation:

The process to date has shown the potential for very large transfers, some of which have the potential to affect the viability of enterprise or the economic wellbeing of residential consumers. We consider there to be a need to include or retain transition provisions in the TPM Guidelines. We are open to the inclusion of a price cap. However, we have a number of practical and substantive concerns with the design of the price cap and its expression in the draft Guidelines.

We support the inclusion of transition provisions in the Guidelines. However, our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended. The cap would also have the unusual consequence of increasing the price rises that most load customers would otherwise face in its absence. Price caps normally work by delaying price reductions that customers would otherwise be facing in its absence.

The proposed price cap is not effective because it does not apply to all transmission charges. This means the price cap would not prevent price shocks. We provide, for clarity, some analysis of the proposed price cap mechanism in **Appendix 4** of our submission.

The Authority predicts that some of our distributor customers would face transmission charges increases of 100% or more and predicts large percentage increases for most of our direct-connect industrial customers.

The Commerce Commission tends to cap regulated price increases at between 5% and 10% to fulfil its statutory obligation to minimise undue financial hardship for suppliers and price shocks for consumers. Most of our customers who are predicted to face increases in their transmission charges would incur increases far in excess of 10%.

The choice to base the price cap on a percentage (3.5% initially) of the total consumer bill would not have the effect of capping increases in consumers' bills at that percentage, not only because the price cap does not apply to all transmission charges but also because the TPM does not control how distributors pass transmission costs onto their customers. The



total consumer bill approach also introduces complexity and estimation error into the calculation.

Another choice, to use transmission charges for the 19/20 pricing year as the comparator for the price cap regardless of when any new TPM takes effect in prices, means the year-to-year price impact on our customers would be different to the indicative effect modelled by the Authority.

We submit that a better approach would be to apply the cap to all transmission charges and base the cap on a percentage of final year of transmission charges under the current TPM. Alternatively, the new transmission charges could be phased in in combination with the existing ones, similar to the transition from HAMI to SIMI for the current HVDC charge.

Another option is to remove the prescription about the price cap from the Guidelines and allow a suitable transition mechanism to be designed during TPM development.

We encourage the Authority to liaise with the Commerce Commission to ensure any TPM and Part 4 Commerce Act price cap and transition mechanisms are well co-ordinated and complementary. The Commission has recognised the potential for TPM change to be an issue in its price reset consultations.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 49 to 53 and alternative clauses Y and YA to YH).

Q41. Should the price cap apply only to load customers, or to generators as well?

See our answer to Q40.

Q42. How should the price cap be funded?

See our answer to Q40.

Q43. Are the proposed additional components appropriate? If not, what changes should be made?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 54 to 65).

Q44. Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

Transpower's view on this matter is well known. In our view, a peak price signal is needed for an efficient TPM. It should be a core component of the Guidelines.

The Authority's proposal appears to be unsympathetic towards retaining a peak pricing signal in the TPM. We submit that a peak price signal for transmission saves consumers



money by deferring new transmission investment. Real-time nodal energy prices cannot do this job – as the Authority has acknowledged in the past. Opportunities to incentivise peak-demand management through the design of transmission charges should not be passed up in favour of more expensive alternatives, such as paying for demand response as a transmission alternative or through the wholesale energy market.

We agree with the Authority there might be benefits to be obtained from reforming the current (RCPD) peak pricing signal in some way, (such as ‘weakening’ the strength of the signal and/or making it more targeted). However, our analysis strongly reinforces our belief that the long-term risks associated with removing entirely all peak price signalling from the TPM far outweigh any potential near-term benefits. We believe that dynamic efficiency benefits from peak-pricing outweigh any allocative efficiency benefits from their removal. Put another way, the potential long-term economic costs from having a peak signal that is ‘too weak’ outweigh the near-term costs associated with a signal that is ‘too strong’.

We also do not accept the Authority’s claim that nodal prices alone can result in efficient short-term grid usage decisions *and* the right long-term investment outcomes, thereby obviating the need for a peak price signal in the TPM. This contention is not only at odds with widely accepted economic theory (as Axiom details in its report), it is also inconsistent with what the Authority has said in the past (when it supported unambiguously the economically orthodox position) and what it continues to say in the context of distribution pricing (where it is encouraging peak pricing).

Even if there are some parts of the grid with excess capacity at present, it does not follow that all peak pricing signals should be removed permanently. We would be open to modifying the existing signal. But removing it in all locations would, in time, spur peak demand growth and bring forward generation, distribution and transmission investment costs. Without a peak signal, we would not be able to efficiently defer those costs, or the increased greenhouse gas emissions that they would bring.

We are firmly of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry’s climate change response.

Q45. Should the peak charge be applied only where the grid would otherwise be congested?

As noted in our answer to Q44, we support consideration of options to target the current RCPD peak pricing signal to areas where transmission investment is most likely to be needed. This could include having varying strengths of peak-pricing signal for different areas.



Q46. Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

See our answer to Q44. We consider it very important that a peak price signal is retained in the TPM indefinitely. We note that:

- The type and level of responses to a temporary peak charge can be expected to be weaker than for an indefinite peak charge as market participants would be less willing to make investments with only a short pay-back period.
- It is incorrect to describe the proposed transitional peak charge option as a “phase out” of the current peak charge. Clauses 58 to 61 of the draft Guidelines would require us to develop a new peak mechanism and then phase it out. Regardless of the merits of peak-pricing, we question whether the cost of doing this would be a good use of Transpower’s resources, particularly given the many other challenges we will face in developing the new TPM in line with the draft Guidelines.

If transitional peak pricing arrangements were applied it should be on a pragmatic basis that reflects the limited timeframe they would apply for. This could include, for example, continuation and phase-out of the RCPD charge but on a more targeted basis.

Q47. Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

See our answers to Q14 and 15.

Q48. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission.

Appendix C: Material change in circumstances

Q49. Do you have any comments on the matters covered in this appendix C?

Appendix D: Elaboration of decision-making and economic framework

Q50. Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?

We do not consider the content of Appendix D of the 2019 Issues Paper to be an “Elaboration of [the] decision-making and economic framework”. It appears the Authority has effectively replaced the DMEF with new tests that the TPM be “cost-reflective” and “service-based”.



Q51. Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

We agree with this in principle, but do not consider the Authority's proposal to be analogous with workably competitive markets.

In Appendix D the Authority correctly states that:

in workably competitive markets, prices paid by customers are typically no more than the benefit the customers get from the service and on average equal to the cost of providing the service.

However, this does not mean or require that prices are set on the basis of estimated benefits.

In workably competitive markets, if the (cost-based) price of a good or service exceeds the benefit to the consumer they will not buy it. If a firm tries to engage in first degree price discrimination, which the Authority's proposal would require Transpower to do, and they get it wrong they lose customers to alternative suppliers. For example, if Air New Zealand misjudges the scarcity value of seats on peak-time flights it risks flying with an excess of empty seats, but is able to adjust its pricing to minimise the risk of repeating the same mistake for future flights.

This is not Transpower's situation. As a provider of a natural monopoly service, if Transpower gets it wrong (or the Authority with Schedule 1) and sets prices higher than net private benefit, the transmission customer would bear the cost. The only thing certain about setting charges on the basis of individual customer expected net private benefit over the life of an investment is that Transpower will get it wrong.

The divide between workably competitive markets and the Authority's proposal is highlighted vividly by the Authority's comment on its website that:

If the owner of the generation asset was continuing to be a transmission customer, then closing down one of its generation assets wouldn't generally lead to a change in charges. The owner would continue to be liable for the same level of charges for which it was previously liable. The reason for this is to avoid distorting the owner's incentives: the intention is that the owner should not have an incentive to shut down a generation asset arising due to the avoidance of the benefit-based charge or the residual charge. These are intended to be fixed charges that do not vary based on a party's use of the grid.

In a workably competitive market, a firm would not be able to continue to charge for a service the customer is no longer using. Only a monopoly could do that.

Q52. Do you agree with the conclusions of appendix D?

See our answers to Q50 and Q51.

Q53. Do you have any comments on the matters covered in this appendix D?

See our answers to Q50 and Q51.

**Appendix E: Assessment of alternatives****Q54. Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?**

No. As noted in our answer to Q44, the analysis we presented in our report strongly reinforces our belief that the long-term risks associated with removing all peak price signalling from the TPM far outweigh any potential near-term benefits.

Q55. Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

We do not agree this is the correct question to ask in relation to whether the TPM should retain peak pricing signals. The purpose of peak pricing in the TPM is not to efficiently constrain grid use to capacity.

Nodal pricing and administrative demand control can be useful for managing short-term demand and capacity constraints only. Transpower does not see the principal role of the TPM as managing short-term demand fluctuations. In our view, the focus of peak pricing signals in the TPM is longer-term (dynamic efficiency) on future investment and capacity requirements.

The Authority has articulated well, in the context of distribution pricing, that what is important is the impact absence of peak pricing signals could have on peak demand and the need to bring forward/increase investment in network capacity.

We consider the impacts and risks of removal of peak pricing on long-term grid investment and price levels, not short-term demand, should be the primary focus of the Authority. This would be consistent with the Authority's position that dynamic efficiency is more important than short-term efficiency.

Q56. Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

No. See our answers to Q54 and Q55.

Q57. Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

No. See our answers to Q54 and Q55.

Q58. Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?



No. We instead agree with the views the Authority expressed in its LPMC Working Paper.

In the LPMC Working Paper, the Authority explained in an orthodox and non-contentious manner that "... charges based on LPMC could promote dynamic efficiency" and "... nodal prices are likely to under-signal LPMC so LPMC charges could potentially promote more efficient investment". The Authority detailed why nodal pricing was not adequate and would under-signal:

Some authors, such as Associate Professor James Bushnell of the University of California, Davis, who provided advice to Trustpower on the beneficiaries-pay working paper, suggest that nodal pricing is all that is required to promote efficient investment in relation to transmission. This appears to be based on a view that nodal pricing provides price signals that reflect both the SRMC and the LPMC for transmission. However, nodal pricing is likely to result in price signals systematically below LPMC for the following reasons:

- (a) the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices do not reflect the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network. While scarcity pricing has been introduced in New Zealand, its application is limited to separate scarcity prices for the North and South Island, so the value of lost load at a more disaggregated level is still not priced. This means within-island price differences, at least, send a muted price signal below the true marginal cost of the network
- (b) transmission planners err on the side of caution in determining the transmission capacity required to meet future demand
- (c) the grid reliability standards (e.g. the N-1 standard for the core grid) are independent of economic costs. To the extent the core grid extends to remote locations, the same reliability standards are applied to remote and centrally located customers
- (d) lack of competition may lead to overbuilding transmission in an attempt to address competition problems
- (e) over-building of transmission may be justified for reasons of national security
- (f) economies of scale in transmission mean transmission is commonly overbuilt, and the amount by which overbuilding reduces SRMC below LPMC is considerable. This means it is impossible to match transmission capacity precisely with transmission requirements at all times.

Since most of these reasons apply in New Zealand nodal prices are likely to under-signal LPMC so LPMC charges could potentially promote more efficient investment. However, while LPMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted.

Q59. Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

In our view the Authority should address the problems it has identified with the current TPM through incremental reform.

The table in **Appendix 1** of our submission provides some examples of incremental reform options that could address the problems the Authority has identified with the current TPM.

In our view, this type of reform has significant advantages over the "root and branch" type reform of the Authority's proposal. It is faster and less expensive to implement, bringing the reforms to the market more quickly, and there is a lower risk of unintended consequences.



The Authority has previously noted (most recently in response to the EPR's hedge market reform proposals) that major regulatory changes carry a risk of unintended consequences and should be approached cautiously. For example, in the context of the Authority's proposal, there is a risk that the BB charge could inefficiently distort the wholesale electricity market and generation investment decisions. One concern we have is that the BB charge would send a signal to delay potential new generation until spot prices are not only high enough to cover the cost of the generation but also the new, and potentially uncertain, transmission charges. This would create windfalls (higher price benefits) for generators operating in areas that are subject to lower BB charges.

Q60. Do you have any comments on the matters covered in this appendix E?

See our answers to Q54 and Q59.

Appendix F: Potential changes to the Code

Q61. Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

As we submitted in response to the Authority's RTP Remaining Elements Proposal (April 2019), given that the FTR grid is an increasingly close approximation of the whole grid, we do not think the administrative cost of having Transpower allocate residual LCE (the part of total LCE not required for the settlement of FTRs) is justified. The task of allocating residual LCE should go to the clearing manager, who could allocate it to wholesale market purchasers in proportion to their payments as part of the normal monthly clearing process.

If Transpower is to continue to allocate residual LCE, we recommend the following changes to proposed clause 14.35A (assuming the draft Guidelines are issued):

14.35A Allocation of loss and constraint excess

- (1) A **grid owner** must allocate any **loss and constraint excess** (including **residual loss and constraint excess**) it receives in a pricing year:
 - (a) amongst grid assets investments in proportion to the **loss and constraint excess** generated by each grid asset investment (including investments whose cost is recovered through the residual charge); and
 - (b) in respect of each grid asset that is a connection asset or part of a benefit-based investment (other than grid assets whose cost is recovered through the residual charge), amongst **designated transmission customers** in proportion to the transmission charges they pay in that pricing year in respect of that grid asset investment; and
 - (c) in respect of each other grid asset investments whose cost is recovered by the residual charge, amongst **designated transmission customers** in proportion to the residual charge they pay in that pricing year.



- (2) This allocation methodology is deemed to be the prevailing methodology for distribution of loss and constraint excess payments for the purposes of the **benchmark agreement and every transmission agreement**.
- (3) In this clause, "pricing year", "grid asset", "connection asset", "benefit-based investment", "transmission charges" and "residual charge" have the meanings set out in the **transmission pricing methodology**.

We note:

- Transpower allocates residual LCE on an asset basis, not an "investment" basis. A single investment may involve more than one grid asset.
- The benchmark agreement is not itself a transmission agreement (i.e. the contract for connection to and use of the grid between Transpower and its customer).

Q62. Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?

We note that:

- the proposed change to clause 2(a)(i) refers to an area-of-benefit charge instead of the benefit-based charge; and
- it should be clarified that the charges referred to in clause 2(a)(i) are defined in the TPM.

We support the proposed revocation of clauses 2A to 2C of schedule 6.4 and the consequential changes.

Q63. Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

In our view, any post-implementation workability issue would be better dealt by way of a Transpower operational review rather than a review by the Authority under proposed clause 12.86(b)(i).

Operational reviews are already available under clause 12.85, although the 12-month interval rule would be problematic if the issue were discovered within a year of implementation of the new TPM. That problem could be eliminated by adding the following words to the end of clause 12.85:

(unless otherwise approved by the Authority, having regard to the reason for the proposed variation)

Proposed clause 12.86(b)(ii) goes beyond workability and is not discussed in the 2019 Issues Paper. In our view, a new right for the Authority to re-open the TPM on vague "policy



objective” grounds would introduce too much uncertainty into transmission pricing, affecting both Transpower and its customers. The Authority needs to consider its policy objectives when it is preparing the Guidelines and when it is deciding whether to approve the proposed TPM, in each case within the confines of its statutory objective. Proposed clause 12.86(b)(ii) should not be added to the Code.

Q64. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

No.

Appendix G: Response to some criticisms

Q65. Do you have any comments on the matters covered in this appendix G?

None beyond those covered in answer to the other questions and in our submission more generally.

Appendix H: Method and assumptions: impact modelling and proposed benefit allocation

Q66. Over what period should we undertake the vSPD modelling?

See our answer to Q70.

Q67. Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

See our answer to Q70.

Q68. Do you agree with the approach we have taken to net distributed generation? Do you agree with the application of our netting policy for particular generator(s)? If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.

See our answer to Q70.

Q69. Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.

See our answer to Q70.



Q70. In addition to the specific questions above, do you have any other comments on the matters covered in chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A)?

We consider questions 66 to 70 to be matters most appropriately responded to by our customers who will be directly impacted by the Schedule 1 allocations for the historical investments.

We are aware that issues were raised with the Authority's vSPD method in response to the First Issues Paper, many of which would still be relevant and should be considered.

Subsequent to the First Issues Paper, the Authority withdrew its proposal to mandate the vSPD methodology as part of the Guidelines, so subsequent Authority indicative prices (and the methodology used to produce them) did not receive significant focus in submissions.

See our clause-by-clause comments on the Guidelines in Attachment B to our submission (clause 21).