TRANSPOWER

Transmission Pricing Methodology Consultation

Submission by Transpower New Zealand Limited

Date: 2 December 2021

Contents

Attachments:

A. Chapman Tripp letter: Assurance of Transpower's submission

B. Revised proposed TPM (in PDF and Word)

1. Executive summary

1. Transpower welcomes the Electricity Authority's (**Authority's**) consultation on the proposed Transmission Pricing Methodology (**TPM**).

2. We remain of the view that our 30 June proposal, including the amendments and additions made as part of the Authority's refer-back process, (**Proposal**)[1] is consistent with the Authority's 2020 TPM Guidelines (**Guidelines**), the Authority's statutory objective and our regulation under Part 4 of the Commerce Act 1986. We note most of the version of the proposed TPM included in the Authority's consultation paper is unaltered from the version we submitted to the Authority with our Part 2 Refer-Back Response.

3. A particular focus of this submission is on the practical workability of the new TPM. In our view, some of the alternative options included in the Authority's consultation paper, or that may be considered during the consultation process, could adversely impact the workability and durability of the new TPM, as well as add costs associated with developing, administering and complying with the TPM and, potentially, extend the lead time required to implement it.

4. We have provided some targeted recommendations to help improve the drafting of the proposed TPM. As well as minor tidy-ups (corrections of errors etc), our recommendations reflect the development of our thinking on discrete matters since we submitted our Proposal and changes to help achieve a more workable TPM.

5. There are some specific matters where the Authority and Transpower have differing views, or where the Authority is still developing its views, about the best way to apply the Guidelines (noting that for some topics more than one interpretation or option may be available under the Guidelines):

   5.1 **We remain of the view the cost allocation methodology for determining covered costs for benefit-based investments should include a reasonable attribution of overhead opex**. Among other factors, this is necessary to avoid cross-subsidies from load to generation, which would arise under the Authority's alternative option of greater overhead recovery through residual charges/only including directly attributable overheads in covered costs (particularly in the absence of an injection overhead component in connection charges).[2]

   5.2 **We are cautious about the Authority's alternative options for "enhancement" that determine generation/load weighting factors as part of the periodic review of the split in benefit-based charge allocations between generation and load under the simple method.** Some of the enhancements under consideration would blur the separate responsibilities of Transpower in administering the TPM and the Authority in approving it. In our view, our proposed framework and timing for reassessing the weighting factors is appropriate[3] and would not be improved by any of the Authority's alternative options.

   5.3 **We do not support the Authority's proposal to use the simple method allocation factors to recover the costs of anticipatory capacity in connection investments (relating to Type 2 first mover disadvantage).** We remain of the view the "pool and share" approach discussed in the Authority's consultation paper would be a better way to recover the

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1 TPM Proposal Reasons Paper, 30 June 2021 (**Reasons Paper**); TPM Proposal 30 June 2021: Decision Part 1 refer back: Transpower's response, 25 August 2021 (**Part 1 Refer-Back Response**); TPM Proposal 30 June 2021: Decision Part 2 refer back: Transpower's response, 15 September 2021 (**Part 2 Refer-Back Response**).

2 Reasons Paper, chapter 6, section 5; Part 1 Refer-Back Response, pages 3-7.

3 Reasons Paper, chapter 7, section 16.4.

costs of anticipatory capacity in connection investments.[4] In our view, applying the simple method allocation factors to anticipatory capacity in connection investments could not be relied on to produce allocations that are broadly in proportion to expected positive net private benefits (**EPNPB**), and would carry a higher risk of cost-concentration (making anticipatory capacity investments more difficult). Added mechanisms to address the cost-concentration risk would add complexity and cost to the administration of the new TPM.

5.4 **We remain of the view adjustments to residual charges for a new entrant or new large consuming plant should be applied on a step change basis, rather than adopting a lagged approach.** In our view, this is the best way to eliminate, or at least minimise, the competitive disadvantage problem the Authority discusses in its consultation paper.

5.5 **We remain of the view the application of the residual charge to battery storage is a policy matter to be decided by the Authority.** If the Authority decides to deviate from the Guidelines, we agree the final consumption approach would pose the fewest workability issues as it would minimise the information Transpower needs to know about the charging and discharging activity of battery storage.

5.6 **We remain of the view the prudent discount practice manual should be optional and non-binding:** In our view, the framework for developing and implementing a prudent discount manual set out in our Proposal is appropriate. In particular, we consider it would be disproportionate and premature to require the development of a prudent discount practice manual between now and 1 April 2023. The practice manual is intended as an optional tool to be developed as Transpower gains experience with prudent discount applications under the new TPM. All key rules and criteria for prudent discounts are incorporated in the proposed TPM, and applicants will not be disadvantaged by the lack of a manual (but may be disadvantaged by a manual produced too early if it narrows options available to applicants).

6. Transpower's views may develop and change when we consider stakeholder submissions to the Authority's consultation. We appreciated the insights provided by stakeholders during development of our Proposal.

7. We recommend the Authority includes a **technical drafting consultation** step in its process before the new TPM is finalised. This is standard practice for the Commerce Commission in the context of setting Transpower's individual price-quality path. This step could be undertaken towards the end of the Authority's process, between cross-submissions and the Authority's decision on the proposed TPM, and is unlikely to impact the timing of implementation of the new TPM. A final technical drafting consultation would help ensure any remaining TPM drafting issues or anomalies are rectified prior to formal incorporation into the Code.

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[4] TPM Development: Checkpoint 2 submission: First Mover Disadvantage, March 2021, section 6; TPM Development: Checkpoint 2 resubmission: First Mover Disadvantage, May 2021, section 2; Reasons Paper, chapter 5, section 10.2; Part 1 Refer-Back Response, section 3.

2. Introduction

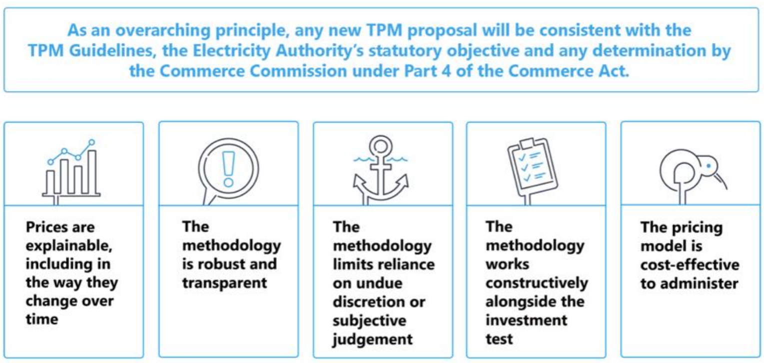
8. Transpower welcomes the Authority's consultation on the proposed TPM.

9. Transpower's views on a number of topics are set out in more detail in our Proposal. Our Proposal should be treated as part of this submission.

10. A particular focus of this submission is the practical workability of the new TPM. In our view, some of the alternative options included in the Authority's consultation paper could adversely impact the workability and therefore durability of the new TPM, as well as add costs associated with developing, administering and complying with the TPM and, potentially, extend the lead time required to implement it (the same may arise for new options considered during consultation). An example is the option presented in the Authority's consultation paper of requiring Transpower to develop a prudent discount practice manual between now and 1 April 2023.

11. We continue to be guided by the principles in the Guidelines and the TPM Design Principles we developed and consulted on at the initial stages of developing our Proposal. These principles have informed our assessment of options.

TPM Design Principles



12. There are some areas where we consider the proposed TPM drafting could be improved, or specific matters clarified. This includes some elements of the proposed TPM where our thinking has developed with the benefit of more time since we submitted our Proposal, and having regard to the matters set out in the Authority's consultation paper and feedback provided in stakeholder workshops.

13. Unless otherwise stated, all TPM clause references in this submission are to the clauses of the revised proposed TPM drafting accompanying this submission.

14. In the time available for cross-submissions, we look forward to considering stakeholder submissions, which may also impact our views on aspects of the proposed TPM.

2.1 Scope of our submission

15. Given that a number of our views are detailed in our Proposal, we have largely limited our submission to areas where the Authority proposal differs from our own or the Authority is consulting on alternative options. Our submission also includes some points of clarification (section 3), and the revised proposed TPM drafting mentioned above.

16. We have not commented on the underlying policy merits of the Guidelines or proposed TPM, or the Authority's cost benefit analysis.

2.2 Next steps - technical drafting

17. Our expectation is further changes will be needed to the consultation version of the proposed TPM to reflect submissions on the proposed TPM drafting (including our own).

18. We recommend the Authority include a technical drafting consultation step in its process before the new TPM is finalised. This is standard practice for the Commerce Commission in the context of setting Transpower's individual price-quality path, and would provide an opportunity for any drafting issues or anomalies to be resolved prior to final approval and implementation of the new TPM.

3. Points of clarification

19. Below we respond briefly to some elements of the Authority's consultation paper by way of clarification.

3.1 Beneficiary-pays versus causer-pays

20. Over the course of the Authority's consultation workshops it became apparent there is some confusion over the distinction between beneficiary-pays and causer-pays (or user-pays). The two concepts are very different, and benefit-based charges (**BBCs**) in the proposed TPM reflect a beneficiary-pays model.

21. A causer-pays transmission charge – such as a congestion or capacity charge – is set on the basis of the cost caused by customers' use of the grid, e.g. the cost of future expected investment in capacity, and does not require the grid owner to identify the benefits customers will receive.[5]

22. A beneficiary-pays transmission charge, on the other hand, is based on the value or benefit customers may receive or be expected to receive from the grid.

23. It may be the case that the beneficiary and causer overlap, though not necessarily, and there may be no particular relationship between a causer-pays charge and a beneficiary-pays charge. By way of example, the need for the HVDC link was largely caused by decisions to invest in more generation capacity in the South Island than needed to meet South Island demand. However, in Schedule 1 of the Guidelines, the Authority has determined the principal beneficiaries of the HVDC link are both South Island generators (the causers) and North Island load.

3.2 Discretion in quantifying market benefits (BBC standard method)

24. In paragraphs 5.14-5.16 of its consultation paper, the Authority summarises its assessment of whether the proposed TPM provides Transpower too much discretion in determining which method to use to quantify market benefits for high-value benefit-based investments (**BBIs**), i.e. a quantities-based or price and quantities-based approach.

25. The Authority notes Transpower's revised approach developed during the refer-back process appropriately limits discretion and provides greater assurance that allocations will be broadly in proportion to expected positive net private benefits (**EPNPB**), but has invited comment on whether any other criteria should be included to limit discretion.

26. In our view, it is not possible to produce an ex-ante pricing methodology aligned with a principles-based investment decision-making framework (Transpower's capital expenditure input methodology) without using some discretion in its application. For this reason, we have carefully developed the framework for evaluating market benefits in the proposed TPM, and remain of the view this approach best implements the intent of the Guidelines whilst ensuring there is flexibility to select the method that will best ensure allocations are broadly in proportion to EPNPB for the given investment.

27. As we said in chapter 7, paragraphs 33 and 34 of our Reasons Paper:

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5 Under causer-pays charges, if the benefits the consumer will receive are less than the cost their consumption will impose, they will not consume or will reduce their consumption.

> We are very mindful of the level of discretion Transpower will have to have to apply under a new TPM that complies with the requirements of the Guidelines and that this could result in the application of the BBC being highly contentious amongst our customers given the commercial outcomes and impact on individual customers and, ultimately, on end-consumers. While a more formulaic methodology would reduce discretion, it would also risk resulting in anomalous allocations that are not broadly proportional to EPNPB (e.g. PJM's Artificial Island example) …In order to attempt to mitigate against discretion we are aiming to make the application of the BBC as transparent as practicable, and to enable customers and other stakeholders to engage with us in the pricing determination process.

28. Transpower would prefer to have less discretion when applying the proposed TPM (consistent with our design principles above). However, for some topics we do not consider it possible or appropriate to remove all discretion. Further discussion on this topic, and the criteria we will apply to determine market benefits, is in our Part 2 Refer-Back Response.[6]

3.3 References to "excess capacity"

29. In our view, "anticipatory capacity" is the most appropriate label for additional capacity built into the grid to meet expected future capacity needs. Transpower and the Authority have moved on from the somewhat more pejorative term "excess capacity", although there are still some uses of it in the Authority's consultation paper and we heard it used at times during the Authority's consultation workshops.

30. "Excess capacity" fails to distinguish between investment that is inefficient, unnecessary or excessive, and prudent and efficient investment required in reasonable anticipation of future capacity needs. Type 2 first mover disadvantage (**FMD**) is about the latter - investment in capacity that is expected to be needed at the time it is made - and how the cost of that investment should be recovered.

3.4 Residual charge: large party exit and large plant disconnection

31. The discussion in paragraphs 8.47 to 8.52 of the Authority's consultation paper appears to assume the proposed TPM does not treat a large de-rating the same as large plant disconnection for the purposes of adjusting residual charges. In fact it does, in clause 96(3).[7]

32. We consider this to be the appropriate approach in order to eliminate arbitrarily different treatments under the new TPM of essentially the same event. This also applies to treating a large upgrade the same as large plant connection.

3.5 50/50 split under simple method

33. Paragraph 5.32 of the Authority's consultation paper states *"Transpower has proposed a weighting factor that is broadly 50:50 between load and generation"* under the simple method.

34. To clarify, it is more accurate to say our Proposal does not apply any weighting; the approximate 50:50 split is simply an outcome of the simple method we have proposed. A different outcome would need to be "forced" by applying a weighting factor other than 1 (referred to as a "demand adjustment factor" in the proposed TPM), which is proposed to be reassessed every five years.

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6 Part 2 Refer-Back Response, section 2.
7 And similarly in clause 84(3)(b) for BBC adjustments.

3.6 Exceptional Operating Circumstances

35. Paragraph 13.21 of the Authority's consultation paper states *"The proposed TPM does not define what would be classed as an exceptional operating circumstance"* (**EOC**).

36. For context, our view is it would be inappropriate to define, and therefore limit, the scenarios that may engage the EOC mechanism. However, the proposed TPM does include some criteria for when an EOC will be considered to have occurred,[8] which are consistent with how we apply the EOC mechanism under the current TPM. The EOC provisions in the proposed TPM provide greater clarity as to the circumstances in which the EOC mechanism may apply than those in the current TPM.

3.7 Applying the price cap to intermingled customers

37. Paragraph 12.36 of the Authority's consultation paper may be suggesting clause 5(3) of the proposed TPM (Transpower discretion as to the treatment of customers with intermingled load and generation) is a departure from the requirements of the transitional cap-related clauses of the Guidelines.

38. If that is the Authority's view then we disagree. Clause 5(3) is about classifying an intermingled customer as being either a direct consumer or a grid-connected generator. If we have classified the customer as a direct consumer, the Guidelines (and the proposed TPM) require us to apply the transitional cap.

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[8] Namely, if Transpower determines there are exceptional operating circumstances in the power system caused by a Grid Owner requirement or outage (clause 14). Our submission is that this should extend to exceptional operating circumstances caused by System Operator requirements, as well.

4. Drafting of the proposed TPM

<u>Consultation question (Chapter 13)</u>
Do you have any feedback that would improve the drafting of the proposed TPM?

39. We have provided a tracked changes version of the proposed TPM as part of our submission. The changes are shown against the proposed TPM the Authority released with its consultation paper.

40. We have included embedded comments explaining our recommended amendments to the proposed TPM, which are categorised as follows:

    40.1 **Typo:** Typographical corrections.

    40.2 **Style:** Stylistic changes, including for consistency.

    40.3 **Clarification:** Recommended changes to clarify points that might not otherwise be obvious to the reader.

    40.4 **Change:** Our recommendations for an alternative approach to the drafting without making a substantive change, or where, on further consideration since our Proposal, we consider the drafting should change in a substantive way.

41. The revised proposed TPM accompanying this submission contains alternative drafting for some clauses (highlighted in grey).[9] This drafting illustrates the alternative approaches we support for recovering the capital cost of anticipatory capacity in connection investments (Type 2 FMD) and adjusting residual charges when new customers enter or large consuming plant is connected. These alternative approaches are discussed in sections 5 and 9.2 below.

42. We have also recommended some amendments to the drafting that our alternative drafting would replace. To be clear, we prefer our alternative drafting over the drafting it would replace for the reasons discussed below and in our Proposal, but have provided some suggested amendments to the Authority's drafting for completeness in the event the Authority decides not to adopt Transpower's recommended approach.

43. We consider the revised proposed TPM, including the alternative drafting, is consistent with the Guidelines (except for the departures from the requirements of the Guidelines discussed in sections 4.2 and 4.3 below and in our Proposal), the Authority's statutory objective and our regulation under Part 4 of the Commerce Act 1986.

4.1 Summary of recommended amendments

44. The main amendments Transpower recommends (in addition to the alternative approaches noted above) are as follows:

    44.1 The costs of certain post-2019 investments in respect of pre-2019 interconnection investments would be rolled into the covered cost for the relevant Appendix A BBI or, if the pre-2019 interconnection investment is not comprised in an Appendix A BBI, recovered through residual charges. This would only apply to such post-2019

[9] The alternative drafting shaded grey is identical or very similar to TPM drafting we have previously submitted to the Authority. There may need to be some other consequential changes to the TPM drafting if the alternative approaches are accepted.

investments commissioned before 1 July 2021. This proposal arises from a legacy issue with our asset register functionality, and is discussed further in section 4.2 below.

44.2 Depreciation due to connection asset write-downs would be removed from the connection asset pool and recovered through residual charges instead of connection charges. This is consistent with the proposed approach to calculating covered cost for BBIs. This proposal is discussed further in section 4.3 below.

44.3 Permissible data sources for calculating gross energy, maximum gross demand and total gross energy (referred to in this submission collectively as "gross load") would be listed, and there would be a statement we are not obliged to factor in other data sources. This would help insulate Transpower from potentially recurring disputes about the data sources used to calculate gross load, and would dovetail with any changes the Authority makes to the Code to ensure sufficient embedded generation information is provided to Transpower.

44.4 The partial sale of business adjustment events for connection charges, BBCs and residual charges would be extended to also cover a sale of the entire business. This is so we would not have to go through the steps for the new customer adjustment event when all that needs to happen is to port the vendor's relevant charges to the purchaser. There would also be a consequential apportionment of cap and prudent discount recovery charges when there is a full or partial sale of business affecting BBCs or residual charges.

44.5 Capacity measurement period (CMP) C, which is relevant to calculating simple method allocations, would be pushed back by one capacity year to allow sufficient time for Transpower to obtain the input data and calculate the allocations for the subsequent simple method period.

44.6 To avoid double-counting, the residual charge step adjustment for the disconnection of large plant would phase out as the effect of the disconnection manifests in changes to the customer's lagged residual charge adjustment factor.

44.7 The definition of "embedded" would be amended to accommodate plant that is simultaneously embedded and grid-connected. This would ensure gross load is attributed to the appropriate load customer in this scenario.

44.8 The definition of "investment agreement" would be extended to cover investments in transmission alternatives. To avoid double-recovery, contributions to transmission alternatives made under investment agreements would be carved out of the connection operating costs pool and the covered costs of the BBIs in which the transmission alternatives are comprised.

44.9 Anytime maximum demand (residual) (AMDR) baseline estimates for new or recent load customers would factor in losses for embedded batteries as well as grid-connected batteries. Ignoring losses for embedded batteries may create an inefficient incentive for new batteries to embed (or at least claim to be embedded) or lead to residual charges that are always zero.

44.10 The reverse flow and exceptional operating circumstances (**EOC**) mechanisms would not apply to calculating regional NPB under the simple method (but would still apply to calculating individual NPB, if required). Applying the reverse flow and EOC mechanisms to regional NPB under the simple method would be a difficult task and would not result in significant changes.

44.11 The EOC mechanism would be extended to cover exceptional operating circumstances caused by System Operator requirements as well as Grid Owner requirements and outages. This is consistent with how we apply the EOC mechanism under the current TPM.

44.12 The standard method assumptions and inputs for “tested investments” would not be updated after the final investment date. This is to remove incentives for beneficiaries to change their behavior after a BBI is committed to try to get lower allocations, and is most likely to be relevant to high-value intervening BBIs.

44.13 The method for calculating the asset return rate (**ARR**) for connection charges would stay as in our Proposal, rather than changing to factor in Type 2 FMD adjustments as proposed by the Authority. This avoids the complication of having to estimate notional regulated asset base and depreciation values.

44.14 The wording for the Type 2 FMD adjustment (reduction of replacement cost) would change to avoid any suggestion the replacement cost reduction has to be exactly proportional to the anticipatory capacity and to align with the wording used for reassignment. Economies of scale mean the replacement cost reduction is likely to proportionately less than the anticipatory capacity.

45. Each of these changes is shown as tracked changes in the revised proposed TPM drafting accompanying this submission.

4.2 Post-2019 investment in respect of pre-2019 interconnection assets

46. In the course of preparing to implement the new TPM, we encountered an issue with the ability of our asset register to track some post-2019 investments in respect of pre-2019 interconnection investments.

47. The issue arose because such post-2019 investments commissioned before 1 July 2021 (which we have called “exempt post-2019 investments” in the revised proposed TPM drafting) were not preserved as stand-alone investments in our asset register.[10] As a result, after the financial year during which an exempt post-2019 investment was commissioned, it became indistinguishable from the underlying pre-2019 interconnection investment to which it relates. It is therefore not possible to track depreciation and capital return separately for the exempt post-2019 investment without a complex manual work-around to our FMIS.[11] We have since modified our FMIS so that this issue does not affect interconnection investments commissioned from 1 July 2021, including the post-2019 CUWLP investment.[12]

48. As a consequence:

48.1 We have revised our original proposal to treat all post-2019 investments in respect of the Appendix A BBIs as separate post-2019 BBIs. Instead, we propose to treat an exempt post-2019 investment in respect of an Appendix A BBI as part of the underlying Appendix A BBI. As a result, the covered cost of the Appendix A BBI would increase and the relevant Appendix A allocations would apply (subject to any future adjustments). This may be a departure from clause 26(b)(ii) of the Guidelines, to the extent the post-2019 investment is “upgrading expenditure”, because we do not propose to calculate separately EPNPB for the post-2019 investment.

10 This issue arose because our asset register was designed principally for revenue-setting rather than transmission pricing.

11 FMIS stands for financial management information systems and refers to the systems that collectively constitute our asset register and other financial and regulatory records and registers.

12 Some parts of the post-2019 CUWLP investment were commissioned before 1 July 2021. These assets will be tagged to the post-2019 CUWLP investment when it is fully commissioned, which is expected to be this financial year.

48.2 We also propose the new TPM departs from the requirements of clause 14(a) of the Guidelines by not treating exempt post-2019 investments in respect of other (non-Appendix A) pre-2019 interconnection investments as BBIs. This proposal means the costs of such exempt post-2019 investments would be recovered through residual charges.

49. In the revised proposed TPM drafting accompanying this submission, these proposals are captured in the new definition of "exempt post-2019 investment", the change to the definition of "post-2019 BBI", and the changes to clause 39. We note the post-2019 CUWLP investment is not an exempt post-2019 investment, meaning that investment will be treated as a post-2019 BBI.

50. We consider the departure and potential departure from the requirements of clauses 14(a) and 26(b)(ii) of the Guidelines are justified under clause 2 of the Guidelines:

50.1 We consider the departures are not inconsistent with the intent of the Guidelines. All post-2019 investments in the interconnected grid will be treated as BBIs apart from a small selection commissioned during a window of less than two years after 23 July 2019. We estimate the total commissioned value of the exempt post-2019 investments to be in the vicinity of $11-$12m.[13] This is very small in the context of our current interconnection asset base of approximately $3b.

50.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective. In our view, the cost of implementing and maintaining a complex manual FMIS work-around for the life of the exempt post-2019 investments (potentially 50+ years) to avoid a very small recovery of costs through residual charges instead of BBCs and a very slightly different overall allocation for some Appendix A BBIs would be disproportionate and would not provide any material efficiency benefit, especially as the investments are already committed and commissioned. The principle in clause 1(b) of the Guidelines requires the new TPM to balance the economic benefits of precision with practical considerations, including the costs of administering the TPM.

4.3 Allocation of depreciation due to connection asset and BBI write-downs

51. Our Proposal excluded accelerated depreciation of an asset comprised in a BBI from the BBI's covered cost (clause 40(1) of the proposed TPM, variable D_a). This proposal was motivated by clause 32 of the Guidelines, which requires BBCs to be adjusted if there is material damage to the relevant BBI, the adjustment in this case being the removal of the part of the covered cost of the BBI attributable to the accelerated depreciation arising from the damage.[14]

52. In the revised proposed TPM accompanying this submission we have extended this concept as follows:

52.1 For added clarity, "write-down" is now a defined term, meaning a reduction in an asset's value due to damage to, or destruction, stranding or decommissioning of, the asset before the end of its economic life. The phrase "depreciation due to write-down" is now used instead of "accelerated depreciation".

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13 The contribution of these investments to our annual recoverable revenue will be much smaller.

14 Clause 85 also allows for RAB values used in the calculation of covered cost to be adjusted as necessary to reflect any material damage.

52.2 Depreciation due to write-down is now also removed from the calculation of the depreciation tax loss or gain component of covered cost (clause 40(3)).

52.3 For consistency with the treatment for covered cost and BBCs, depreciation due to write-down is now also removed from the connection pool for the purposes of calculating the ARR for connection charges (clause 27(2), variable D_{total}).

53. These changes mean that depreciation due to write down of both BBIs and connection assets would be allocated to residual charges rather than BBCs and connection charges. This is consistent with Transpower's current practice whereby depreciation due to write-downs is allocated to interconnection charges under the current TPM (which was another motivating factor for the treatment of accelerated depreciation in covered cost in our Proposal).

54. We now consider the exclusion of depreciation due to write downs from both covered cost and the connection pool to be departures from the requirements of the Guidelines. Specifically:

54.1 clause 15 requires the covered cost of a BBI to include the capital cost of the BBI based on its commissioned value or (in the case of the historic BBIs) its depreciated value at the start of the first pricing year, and clause 16 requires the "full present value" of the covered cost to be recovered through BBCs (subject to some exceptions that do not include excluding depreciation due to write-downs); and

54.2 clause 11 requires the costs of connection investments, including capital costs, to be recovered from the connected customers.

55. We consider these departures are justified under clause 2 of the Guidelines:

55.1 We consider the departures are not inconsistent with the intent of the Guidelines. In our view, the intent of the Guidelines is that transmission charges targeted to specific groups of customers based on the benefits they receive from a connection or interconnection investment (including by reason of being connected to it) should only apply if, and to the extent, those specific customers are receiving those benefits. This intent is express throughout the Guidelines for BBIs and, in our view, implied for connection investments, including in clause 7. For BBIs, excluding depreciation due to all forms of write-down is also consistent with the intent behind clause 32.

55.2 We consider the departures promote the efficiency limb of the Authority's statutory objective (although only marginally) by avoiding the need for Transpower to make changes to its current practice for allocating depreciation due to write-downs. We do not consider there would be any countervailing downside in respect of either the efficiency, reliability or competition limb of the Authority's statutory objective.

56. An option for connection investments is to pool and share depreciation due to write-downs through the asset component of connection charges, which was the approach in our Proposal. However, on further consideration, we do not prefer that option because:

56.1 pooling and sharing through the asset component of connection charges would not result in allocations in respect of connection assets provided under investment agreements, which are deemed to have a replacement cost of zero. This would result in a relative concentration of the write-down costs, which may get worse over time as we expect an increasing proportion of connection assets to be provided under investment agreements; and

56.2 we consider it generally desirable to have a consistent treatment of depreciation due to write-downs across both connection and interconnection investments.

5. Type 2 FMD

<u>Consultation question (Chapter 4)</u>

Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on:

- **the proposed FAC mechanism for Type 1 FMD**
- **the alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD**
- **the approach to applying 'above-limit costs' under this alternative option?**

57. We agree with the Authority that *"Having to carry the full cost of anticipatory capacity would create uncertainty and cost for the first mover that may discourage it from agreeing to anticipatory capacity, even if building this now would be efficient over the longer term (because building one bigger asset now is usually cheaper than building two smaller assets that add up to the same capacity - one now, one later)."*[15]

58. We also agree with the Authority that *"This FMD could lead to inefficiently undersized connection investments or deter connection by first movers. These effects would lead to higher transmission costs overall and could lead to businesses slowing down their electrification, or to generation investment being delayed"*.[16]

5.1 Transpower continues to support a "pool and share" approach to Type 2 FMD

59. We remain of the view that the Authority should address the Type 2 FMD problem by accepting the solution in our Proposal, which is labelled as *"Alternative: pool and share the costs relating to anticipatory investments"* in the Authority's consultation paper. Our detailed reasons are set out in our Proposal.[17]

60. In summary, we consider Type 2 FMD should be dealt with by pooling (spreading the risk) of investment in prudent and efficient capacity investment over a large group of customers. There are several ways the pooling could be done including, for example, through the connection charges to other customers (our Proposal), the residual charge, or a pro-rata increase in transmission charges.

61. Under our proposed Type 2 FMD solution:

    61.1 The connection charge for the first mover customer would be based on the replacement cost of the capacity they need (C), rather than the "anticipatory capacity" (C+X) that is additionally provisioned to prudently and efficiently meet future demand.

    61.2 The part of the asset component of the connection charge for the discounted connection asset that is attributable to the incremental capital cost of the additional anticipatory capacity (X) would be allocated to other connection assets (including

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15 Authority's consultation paper, paragraph E.2.

16 Authority's consultation paper, paragraph E.3.

17 See footnote 4.

investment contract assets) in proportion to their replacement costs, and recovered from all connected customers accordingly.

62. We agree with the Authority's analysis that our preferred approach *"would address the Type 2 FMD issue and has the advantage of simplicity of implementation (it does not require benefit-based allocation or tracking)"* and *"address[es] many of the issues that the Authority is concerned about, i.e., it removes disincentives to connect, and incentives to undersize the connection asset"*.[18]

63. The objection raised in the Authority's consultation paper is that the Authority considers this approach *"risks leading to inefficient investment … due to a lack of any real incentives for scrutiny of proposed investments in anticipatory capacity"* and this could result in *"Inefficient investment"* and *"relatively higher electricity prices"*.[19]

64. We do not consider our Proposal generates a risk of inefficient investment. In particular, any connection investments provisioned with anticipatory capacity will be subject to scrutiny, and incentives, in accordance with Transpower's usual capital expenditure decision-making framework and overseen by the Commerce Commission (whether they constitute "base capex" or "major capex" proposals).

65. We do not consider the Authority's proposal to charge a smaller subset of customers a larger amount should be assumed to be more efficient or result in more efficient investment outcomes than a "pool and share" approach. Based on the reasoning for beneficiaries-pay, the Authority proposal could result in the small subset of customers opposing efficient investment in transmission capacity because the amount they pay would be disproportionate to, or in excess of, the benefits they would receive. We consider this to be a bigger risk than hypothetical "over-investment" risk. The cost of under versus over-investment is also shaped by the future transmission network requirements for decarbonisation/electrification.

5.2 We do not support the Authority's benefit-based approach

66. We do not support the Authority's benefit-based approach to allocating the cost of anticipatory connection investments using Additional Component C.

67. Having carefully considered this alternative approach, we consider the Authority's proposed approach to be problematic on several counts.

68. As part of the refer-back process, the Authority asked us to consider an approach conceptually the same as the approach proposed for this consultation. In our view, the following considerations noted at that time remain relevant:[20]

> 41. We have considered the suggestion that the balance can be struck by applying a benefits-based approach to allocating the cost of the anticipatory connection capacity. Our practical challenge with that approach is that, at the time of the investment, *we* will not know who the future beneficiaries are. The future beneficiaries may not even exist at the time of investment. We will only have a prediction as to the type of future beneficiary, which may not transpire.
>
> 42. In places, the choice comes down to socialising the cost across a subset of customers that have been selected on the basis of necessarily poor information, or socialising the cost across all customers. In our view the latter is more efficient. It avoids concentrating the socialisation on certain customers in an arbitrary and unfair way, when they are unlikely to represent all future beneficiaries, or possibly be future beneficiaries at all.

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[18] Authority's consultation paper, paragraph, 4.50.

[19] Authority's consultation paper, paragraph, 4.52.

[20] Part 1 Refer-Back Response, section 3.1.

In these circumstances, the additional investment scrutiny hoped for when concentrating the socialisation is less likely.

43. Another way of looking at this issue is to ask which customers should bear the risk that the anticipatory connection capacity is not needed or not fully needed? We consider pooling the risk over all customers rather than exposing a single customer or subset of customers to the risk is the most efficient approach, and avoids Transpower being put in a position of picking winners and losers based on poor information.

69. The Authority has indicated its view that the question of whether proposed benefit-based charges are consistent with the statutory objective requires that *"they can be expected to result in cost allocations that are broadly in proportion to benefits"*.[21] In our view, there would be an inherent difficulty in adopting Additional Component C *"to use a method substantially the same as for benefit-based charges"* for recovering the cost of anticipatory capacity, given the fundamental tenet of benefit-based charges that they *"must result in an allocation between designated transmission customers that is broadly in proportion to their expected positive net private benefits"*.[22]

70. Under the Authority's proposal the subset of customers that would be charged for the anticipatory capacity:

    70.1 may not necessarily be the expected majority or principal beneficiaries of the anticipatory capacity (X); and/or

    70.2 may not necessarily be expected to benefit from the anticipatory capacity (they could incur net disbenefits).

71. The subset of customers would simply be charged because they are there first. Any or all of the above outcomes would mean that the cost allocations under the Authority's benefit-based proposal cannot reasonably be expected to be broadly in proportion to benefits (which would be inconsistent with the benefits-based principle inherent throughout the Guidelines, for example in clause 8).

72. It is worth stressing it does not follow that because the simple method is suitable for allocating the cost of certain (low-value) BBIs – and can be relied on to result in allocations broadly in proportion to EPNPB – that the same allocation factors should be applied to connection investments, as the Authority is proposing. The Authority proposal is a modified version of the simple method which uses the allocation factors for only generation or only load.

73. The simple method was developed to allocate the cost of low value BBIs in the interconnected grid. It was not intended to allocate costs associated with connection assets. The simple method is designed to produce allocators that reflect the benefits from the interconnected grid, including the lower-voltage sections of the interconnected grid, based on historical patterns of load, generation, and interconnection branch flows. These are to be reviewed every five years to capture changing power flow patterns over time.

74. This issue is demonstrated by one of illustrative examples in Appendix E of the Authority's consultation paper: "*Figure 27 illustrates how costs relating to [anticipatory capacity] X would be allocated for an anticipatory capacity BBI in the Hawkes Bay low voltage region made in*

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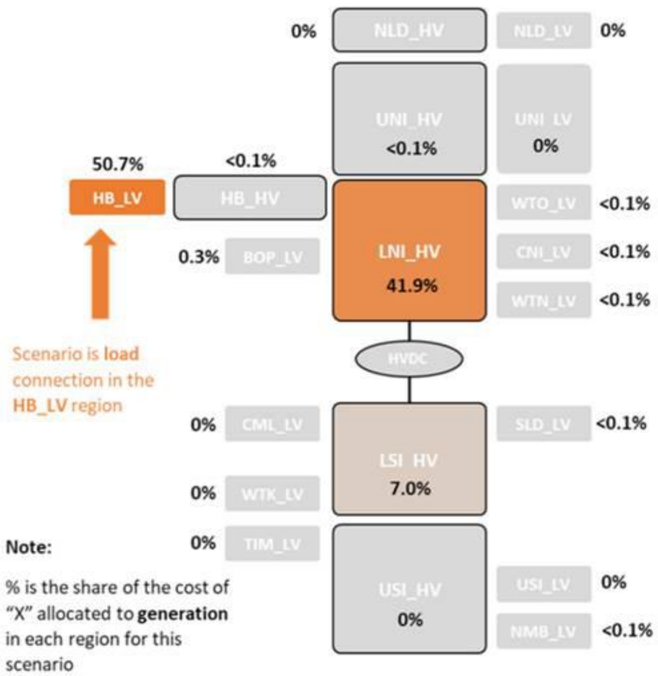
[21] Authority's consultation paper, paragraph 5.5

[22] This is compounded by clause (iv) of the Guidelines which states *"The purpose of the benefit-based charge is to ensure that the costs … are … recovered in accordance with the positive net private benefits that each designated transmission customer is expected … to receive from the investment"*. Clause viii(c) of the Authority's Intent links back to clause iv specifying *"Charges for connection investments to use a method substantially the same as for benefit-based charges. The purpose of this component is to allocate the charges for each connection investment in substantially the same way as the charges for each benefit-based investment"*.

anticipation of a new load connection, with costs allocated to local and upstream generation". The Authority considers "*This situation illustrates an investment for which the benefit-based approach would identify beneficiaries as widely spread. Beneficiaries are generators that would supply the new load. Benefiting generation is mostly spread across the lower North Island high voltage and Hawkes Bay low voltage regions, with some allocation also to the South Island.*"

Figure 27 The BB approach for anticipated capacity for load in the Hawkes Bay low voltage region.



75. This example shows that applying the simple method to connection assets would yield allocations that are demonstrably not in proportion to expected EPNPB because it concentrates 50.7% of the incremental cost of the anticipatory capacity on generation within the HB_LV simple method region (currently only Genesis' generation at Waikaremoana).

76. Waikaremoana is a small generator in a fairly large zone. It is not plausible to suggest Genesis receive 50.7% of the benefit of enabling new load to connect more easily in Hawkes Bay.

77. Using the simple method allocations for connection assets and anticipatory capacity for new load assumes the proportion of within region and outside region generation used to supply the existing HB_LV region load is also used to supply the new load connecting in the HB_LV region. However, in this example, it is likely most of the generation to supply the new load will come from generation outside the HB_LV simple method region. Using the existing simple method factors would thus allocate a greater proportion of the connection costs to the within region generation (currently Waikaremoana generation).

78. Over time (in this example), the increased proportion of the HB_LV region network load (including the additional connected load) would be supplied with an increased proportion of generation from outside the HB_LV region. In subsequent simple method periods this would be reflected by updated simple method allocation factors to broadly reflect the increased benefits outside region generators get from the interconnected grid in the HB_LV region.

79. We expect this type of pricing outcome, where a subset of customers would pay for a disproportionate share of the anticipatory capacity, will arise in many situations under the

Authority's proposed approach. In practice, it is unlikely to be tenable for Transpower to make efficient anticipatory investment when this does arise.

80. Charging a select sub-group of customers more than their share of benefits from an investment could result in poor incentives on participants to make sure grid investments are the best solution to improve the capacity of that part of the electricity system. The sub-group of customers that would pay would be over-incentivised to object even if it is an efficient investment.

81. Our view is the harm from inefficient investment is asymmetric, and the detriment from "under-investment" can be greater than any detriment from "over-investment", particularly given projected trends of increased electrification and grid use in future. This is consistent with the New Zealand's climate change goals, and the Authority's observation that *"decarbonisation objectives rely on significant new investment in process heat and transport electrification and new renewable generation, much of which may require additional connection assets or capacity"*.[23]

82. It also reflects that the risks of under-investment are much greater/costlier for consumers than the risks of over investment e.g. a constrained grid and/or delayed investment in generation leads rapidly to high prices.

83. This is consistent with the emphasis of dynamic efficiency over static efficiency in the Authority's interpretation of its statutory objective,[24] and the reasoning the Commerce Commission relied on to set WACC for regulated electricity and gas network businesses above mid-point.

84. The Commerce Commission's view of the relative importance of dynamic efficiency, which it equates with incentives to invest, is reflected in its commentary on its decisions to set WACC above the mid-point. The Commission's preference has been to err towards incentivising efficient investment:[25]

> That is, the Commission is acknowledging that where there is potentially a trade-off between dynamic efficiency (i.e. incentives to invest) and static allocative efficiency (i.e. higher short-term pricing), the Commission will always favour outcomes that promote dynamic efficiency. The reason is that dynamic efficiency promotes investment over time and ensures the longer term supply of the service, which thereby promotes the long-term benefit of consumers (consistent with outcomes in workably competitive markets).

5.3 We do not support the other alternatives the Authority has raised

85. The Authority has raised other alternatives, including charging the first mover for anticipatory capacity above a certain cap, "Temporary socialisation" and "Brownfield-only". Having carefully considered each alternative (including for some of them as part of the development of our Proposal), we consider each of these options would not be appropriate, including because they do not resolve, or only partly resolve, the Type 2 FMD problem, and could result in the TPM producing outcomes inconsistent with the outcomes in workably competitive markets.

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[23] Authority's consultation paper, paragraph 4.31.

[24] The Authority states: *"In regard to long-term benefit, the Authority considers that its primary focus is to promote dynamic efficiency in the electricity industry"*.

[25] Commerce Commission, Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, paragraph H1.31. A more fulsome discussion of this can be found in Commerce Commission, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services: Reasons paper, 30 October 2014.

86. The problems with the Authority's alternatives are highlighted by the Appendix E Northland scenario.

87. Appendix E provides a plausible scenario where Northland switches from an importing region to an exporting region, and this is due to large transmission investment which enables substantial new generation.

88. In this scenario the principal beneficiaries of transmission investment in Northland would switch from load customers in the region to future generators (who are unknown and not current customers) and customers in other regions who can access the additional generation supply.

89. The Authority's proposed application of a benefit-based approach would result in load customers in Northland being treated as the principal (majority) beneficiaries until the anticipated future generators arrive. This would result in load customers paying transmission charges for the new capacity disproportionate to the benefits they may receive, both initially and over time. While the possible option of a cap may mitigate the extent of this, it could result in a large first mover disadvantage acting as a substantial barrier or delay to the generation investment going ahead and (efficiently) utilising the new capacity.

90. In figure 29, the existing load customers pay "too much" relative to their share of benefits until such time as the second mover enters the market (if at all), and so bear the risk of whether (and when) the second mover enters the market. This is both inconsistent with the intent of benefit-based charges and efficient risk management.

91. If Transpower's "pool and share" option is adopted the risk that the second mover does not arrive (either at all or later than anticipated) is spread over a wider group of customers (figure 30).

92. Figure 31 shows the FMD allocations under temporary socialisation and illustrates that the first mover will pay too much – the efficient stand-alone cost of the connection asset is $17,915 but the first mover will pay $25,168 if the second mover does not arrive.

93. Using the Authority's bus analogy, under the Authority's preferred options, Northland load customers end up paying for a bus trip they will not use, and generation customers could be discouraged by the upfront initial ticket cost from getting on the (near empty) bus and may instead wait to see if a bus with more occupants arrives later so they can pay less.

A complementary alternative: Limit how much benefit-based charges can increase

94. The problems with this approach are highlighted by the need to identify a limit on how much benefit-based charges should increase with respect to anticipatory capacity. Adding this "complementary alternative" to the Authority's primary proposal would involve an arbitrary and difficult decision as to at what level to impose the cap. Under the Authority's proposal, "above cap" costs would either be borne by the first mover (perpetuating the same FMD problem) or broadly socialised (as per Transpower's proposal).

95. In principle, if charges are allocated in a way that is broadly in proportion to EPNPB then the quantum of the charges should not need to be capped. This is reflected in the Guidelines framework for the BBC allocation methodologies, which do not involve the use of a cap. A cap "fix" would only be attractive in the event the Authority's proposal was adopted and resulted in a subset of customers incurring charges for anticipatory capacity which are not broadly in

proportion to EPNPB.[26] In our view, this illustrates why the Authority's approach is not an adequate response to the FMD problem, particularly if it requires the need for complex "bolt-ons".

96. It is unclear why the Authority considers it might be efficient for "above cap" costs to revert to "*falling on the first mover*"[27]. This would perpetuate the type of situation a Type 2 FMD solution is intended to resolve.

Alternative: Temporary socialisation

97. In our view, the "Temporary socialisation" option would reduce the size of the FMD problem in the short term but would not remove it. The Authority recognises this problem in its statement *"A challenge for this option is that it does not eliminate second-mover risk for the first mover, so may leave the FMD issue unresolved"*.[28]

98. We also do not consider it would be efficient for the first mover to face the risk of ultimately bearing the full cost of the anticipatory investment.

99. As we said in our Part 1 Refer-Back Response:[29]

> Our concern is that an option that does not eliminate that risk will not be an effective solution to the Type 2 FMD problem. If the second and subsequent customers do not come on board within 10 years, the first mover will bear the cost of the anticipatory capacity, albeit in 10 years' time and not immediately. There remains a significant risk that, faced with the risk of ultimately bearing the full cost of "C+X", a customer would agree to pay for "C" (noting again the customer always has the option to build its own assets).

Alternative: Brownfield-only

100. Under "Brownfield-only", FMD would not be resolved for greenfield investments e.g. investment in capacity to meet future generation needs in a region where the renewable energy options have not been developed. We commented on this in our Part 1 Refer-Back Response:[30]

> 44. As we have said previously, Type 2 FMD is a potential problem that extends beyond brownfields connection investments. Unfortunately, the fact that greenfields (and brownfields) connection investments are funded under investment agreements, with capital costs recovered outside the TPM, does not make Type 2 FMD a non-issue. The fact remains that it may be prudent and efficient to build more connection capacity than the funding customer wants or needs. Making a distinction between greenfields and brownfields connection investments risks creating a boundary issue for the application of any mechanism to address Type 2 FMD.
>
> 45. We have considered whether competition from non-Transpower providers for greenfields connection investments addresses this dynamic. [It] is not clear that private connection investments would always be in the long term interests of consumers if they result in connection capacity being built without an eye to future capacity needs, the creation of private property rights in connection capacity or inefficient duplication of connection assets.

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[26] Similarly, the variation where the Authority *"would propose 'above limit' costs could revert to falling on the first mover"* would mean (i) the FMD problem would not be resolved; and (ii) the first mover would incur charges that are out of proportion to their EPNPB.

[27] Authority's consultation paper, paragraph 4.46.

[28] Authority's consultation paper, paragraph 4.56.

[29] Part 1 Refer-Back Response, paragraph 52.

[30] Part 1 Refer-Back Response, section 3.2.

> 46. Transpower operates an open access grid and recovers the costs of new connections required by customers outside the TPM. A customer has the option to build its own new connection assets, or seek an alternative supplier to build them, if it does not consider Transpower's price to do so is competitive (or perhaps because it considers it is better able to mitigate timeline or financing risks). It is not unusual for our customers to do so. That competitive tension is healthy and our proposal would not change it.

101. The Authority considers this alternative *"would mean excluding investments in new connection capacity ('greenfields' investments), the building of which is potentially subject to competition"*.[31]

102. This statement is incorrect. The "Brownfield-only" option would not exclude anticipatory capacity in relation to greenfield investments from having their costs recovered through the TPM. Under this approach, the costs would still need to be recovered in some way.

103. It is not the role of the TPM to determine whether an investment is permitted or goes ahead.

104. The role of the TPM is to determine how the costs of transmission investment are recovered. Arguably the price signals under the TPM may *influence* what investment goes ahead. But the TPM (and the Code more broadly) does not have jurisdiction to *determine* what investment, including greenfields investment, may go ahead.

105. On the basis of the assumption this option would exclude Transpower from making greenfields investments, the Authority suggests *"alternative commercial providers are able to make appropriate risk-return trade-offs in agreements with connecting customers, so there are incentives to invest efficiently. That is, such a provider would have a commercial incentive to build the additional capacity if additional customers were likely to connect in future but would not have such an incentive where future connections were unlikely. This is efficient"*.[32]

106. The basis for these statements is unclear. We note, for example, that operating as a generation business (which requires a capacity of C, not C+X) is a very different business model, with different investment costs and risks, to operating as a transmission grid operator. We also note the Authority's observation it *"is also aware of the risk that potential commercial providers, if closely aligned to the connecting party, might have incentives not to build capacity that competitors of the connecting party might use (particularly competing generation)"*.[33]

107. Where the "alternative commercial provider" is a generator, it would need to consider the impact of providing access to its competitors and would have incentives to consider the benefits of foreclosing supply options for its competitors. Analogous issues have arisen in supermarkets and in retail fuel supply.

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31 Authority's consultation paper, paragraph 4.58.

32 Authority's consultation paper, paragraph 4.59.

33 Authority's consultation paper, paragraph 4.61.

6. Overhead opex and covered cost

<u>Consultation question (Chapter 6)</u>
Do you have any comment on the proposed approach to covered costs, including on:

- **whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view?**
- **the recovery of opex on fully depreciated assets through the residual charge?**

6.1 Transpower supports the proposed approach for allocating overhead opex to covered cost

108. The Authority has accepted (for consultation purposes) Transpower's proposed approach of recovering a share of overhead opex through BBCs. We support this approach, for the reasons set out in our Proposal.[34] We elaborate on some of those reasons below.

6.2 The requirements of the Guidelines

109. The Guidelines require that BBCs recover the covered cost of BBIs, with prescriptive rules about how covered costs are to be determined.

110. Clause 15 of the Guidelines specifies a BBI's covered cost must include:

110.1 the capital cost of the BBI;

110.2 a return on capital for the BBI, based on its capital cost and WACC;

110.3 an amount of opex "reasonably attributable" to the BBI based on an allocation of the opex allowance for the pricing year as set in the IPP; and

110.4 any other costs attributable to the BBI.

111. The cost allocation methodology used to determine the covered cost of BBIs will impact, amongst other things, the distribution of transmission costs (in aggregate) between generation and load, because it determines whether transmission costs will be recovered through BBCs or residual charges.

112. The less cost attributed to the covered cost of a BBI the lower the proportion of Transpower's allowable revenue that will be recovered through BBCs, which are payable by both generation and load. Accordingly, more cost would be recovered through residual charges and paid by load only. This would result in a higher contribution to transmission costs from load relative to generators. In this respect, it should be noted the injection overhead component of connection charges in the current TPM was designed to ensure generators pay a contribution towards overhead opex.

113. As set out in our Proposal, we consider there is a potential range of "reasonably attributable" cost allocation approaches available to meet the criteria for covered cost imposed by the Guidelines, in-between incremental or avoidable cost and stand-alone cost. In our view, the closer the allocation is to 0% (incremental cost) or 100% (stand-alone cost) the less likely the allocation will be reasonable. This range is narrower than that suggested in the Authority's

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[34] See footnote 2.

consultation paper, which starts the potential range below incremental cost and instead at directly attributable costs.

114. The approach of attributing costs to both BBIs and non-BBIs, rather than solely to non-BBIs, is consistent with regulatory precedent for how "reasonably attributable" is applied under Part 4 of the Commerce Act 1986 and Part 6 of the Telecommunications Act 2001. We also note, by way of precedent, that under the Telecommunications Act, Total Service Long Run Incremental Cost (**TSLRIC**) is defined as including "*a reasonable allocation of forward-looking common costs*",[35] i.e. the TSLRIC pricing principles in the Telecommunications Act treat incremental costs and a contribution to common costs as a "reasonable allocation".

115. There is nothing we have gleaned from the different purposes of the legislation that would mean costs that are reasonably attributable for pricing under the Commerce Act or Telecommunications Act are not, or should not be considered, reasonably attributable for pricing under the Electricity Industry Act or in relation to the TPM.

6.3 Transpower does not support the Authority's alternative option

116. Under the Authority's alternative option, covered costs would only include costs (including overhead opex) that are directly attributable to the BBI. This issue was considered extensively as part of the development of the TPM, including through the Checkpoint and Refer-Back processes. Having carefully considered the matters set out in the Authority's consultation paper, our view remains that this alternative approach is not appropriate, and does not advance the Authority's statutory objective.

117. We consider this approach is not reasonably available on a plain reading of the Guidelines which require allocation of "reasonably attributable" opex and other costs that are "attributable". In our view, when read in the context of economic regulation, a direct attribution approach would fall outside the range of alternatives available, and would therefore require a departure from the requirements of the Guidelines.

118. We are concerned, on efficiency grounds, that the Authority's alternative option would result in outcomes that are inconsistent with outcomes in workably competitive markets and would result in cross-subsidies from load to generation. We also consider a cost allocation approach to opex that results in cross-subsidies would not satisfy the requirement to allocate "reasonably attributable" opex, and therefore is not within the spectrum of options that are consistent with the Guidelines.

119. We note the Authority's comments on the benefits of generators facing higher transmission costs and how this would result in greater scrutiny of transmission investment. The investment scrutiny argument is a key basis for the Guidelines:[36]

> It is likely that generators would seek to pass the charge on to consumers by raising their wholesale offers. To the extent that some generators face higher transmission costs than others (which is likely under the proposed approach) there will be a constraint on how much these generators can pass on in their charges. In other words, the situation is likely to be analogous to the ability of a potato farmer from Oamaru seeking to pass on the costs of transport of their potatoes to Auckland when they face competition from potatoes produced in Pukekohe. If generators face the charge they would have greater incentives to scrutinise the costs of transmission investment recovered through the charge, which would help promote more efficient transmission investment.

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35 Telecommunications Act 2001, Schedule 1, clause 1.

36 Authority, Transmission Pricing Methodology: issues and proposal: Consultation Paper, 10 October 2012, paragraph 5.6.74.

6.4 Consistency with outcomes in workably competitive markets

120. We consider the proposal that overheads be treated as attributable to both BBIs and non-BBIs, including investments in non-grid assets, historic investments whose costs are recovered through residual charges and fully depreciated assets, is consistent with workably competitive market outcomes.

121. In its 2019 issues paper, the Authority stated "*Our view is that the recovery of overheads should reflect how* they *would be recovered in a workably competitive market*".[37] The Commerce Commission considered this matter when it reviewed the previous avoidable cost allocation methodology (**ACAM**) rules which allowed allocation of all shared and common costs to the regulated business under Part 4 of the Commerce Act regulation, and when considering cost allocation under Part 6 the Telecommunications Act.

122. In both decisions, the Commerce Commission concluded a workably competitive market would result in common costs (including overheads) being shared and not allocated to one particular service or group of customers, e.g.:[38]

> … in the longer-term, all services are expected to recover some proportion of shared costs.
>
> Experts advising EDBs and GPBs (as well as Airports) unanimously agreed that in workably competitive markets firms would expect to recover some proportion of shared costs from all services in the longer-term.
>
> … The Commission does not consider that an approach which allocates all shared costs to the regulated businesses will produce outcomes which are consistent with those occurring in workably competitive markets.

and:[39]

> We consider that in most cases, ACAM would not lead to outcomes consistent with those produced in workably competitive markets. Under ACAM, shared costs would be allocated to regulated FFLAS to the extent that they would be non-avoidable if services that are not regulated FFLAS were no longer supplied. Axiom has previously recommended that ACAM should not be an allowable option in the cost allocation IM, as the ACAM approach would allocate a disproportionate share of shared costs to regulated FFLAS. We agree with the view expressed by Axiom, that "firms in workably competitive markets would expect to recover some portion of their common costs from all services in the long-term.

6.5 Requirements for subsidy-free pricing

123. From an economic stand-point, prices need to be equal to or above incremental/avoidable cost, and equal to or below stand-alone cost to be subsidy free and avoid economic rents. This is reflected in the Guidelines' provisions relating to stand-alone cost prudent discounts.

124. An allocation of directly attributable costs only would fall below these bounds and requires that BBIs are subsidised through residual charges, i.e. load customers would subsidise generators.

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37 Authority, 2019 issues paper: Transmission pricing review: Consultation paper, 23 July 2019, paragraph B.222

38 Commerce Commission, Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, paragraphs 3.5.52 to 3.5.56.

39 Commerce Commission, Fibre input methodologies: Draft decision - reasons paper, 19 November 2019, paragraph 3.392.

125. It is important to note directly attributable costs and overheads are accounting concepts and do not directly translate to incremental/avoidable costs or what the Commerce Commission refers to as “economic common costs”.

126. The incremental/avoidable costs of providing a service or, in the TPM context, a particular BBI will include directly attributable costs and also a share of overheads where the size of the overhead depends in part on the provision of that service or asset.

127. This is illustrated in the following Commerce Commission example:[40]

Electricity lines and fibre (broadband)

Services provided separately

Service	*Total asset base*	*Poles*	*Other assets*
Electricity lines	100	25	75
Fibre	100	25	75

Services provided together

<table>
<tr><th>Service</th><th>Total asset base</th><th>Poles</th><th>Other assets</th></tr>
<tr><td>Electricity lines</td><td rowspan="2">180</td><td rowspan="2">30</td><td>75</td></tr>
<tr><td>Fibre</td><td>75</td></tr>
</table>

128. The electricity lines and fibre services the Commerce Commission uses in this example are not important and could be interchanged with BBIs and non-BBIs and have the same implications for subsidy-free pricing.

129. In the example, the directly attributable cost of each service is $75. Shared costs when the services are provided together (poles) are $30.

130. The incremental/avoidable cost of each service is $80 and more than the directly attributable cost of $75. This is because if the fibre service, for example, was not provided the electricity lines business would avoid $5 of the $30 in shared pole costs:

> Incremental cost = directly attributable cost + the avoidable/incremental component of the shared costs (the poles) = $75 + $5 = $80.

131. What this means is that a BBI’s covered cost needs to include directly attributable costs and an allocation of overheads to satisfy the economic efficiency requirement to be subsidy-free.

40 Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289, from paragraph [1807].

7. Allocation between generators and load under the simple method

<u>Consultation question (Chapter 5):</u>
Do you have any comment or additional evidence on the proposed weighting of benefits between load and generation customers under the simple method, or with respect to the proposed review of the allocation?

132. The proposed simple method, as described in chapter 7, section 16 of our Reasons Paper, results in (but does not assume) a broadly equal split between injection and offtake groups, which is subject to review (for future BBIs) every 5 years.

133. The proposed simple method allows for an adjustment of the allocation between injection and offtake customer groups based on a "demand adjustment factor" which *"means a factor by which individual NPB under the simple method for offtake customers is scaled relative to individual NPB under the simple method for injection customers"*.

134. The determination of the proportion of EPNPB derived by load and generators could result in substantial wealth transfers. The higher the proportion of benefits that are deemed to be derived by load (and therefore the lower the proportion for generators) the higher (lower) the share of BBCs they will incur.

135. The way that wealth transfers could change over time is illustrated in paragraphs 5.42 to 5.45 of the Authority's consultation paper.

136. As part of TPM development, Transpower considered a number of different approaches to determining the allocation of BBCs between load and generation, including benchmarking against allocations of interconnection charges in different jurisdictions (initially proposed by Meridian) and basing the allocations on the Schedule 1 allocations in the Guidelines. These options are considered in chapter 7, section 16.4 of our Reasons Paper.

137. Our assessment of these different approaches was that they supported a range of different potential allocations and our proposal was comfortably within these ranges. We agree with the Authority there is not strong evidence for moving away from Transpower's proposed weighting factor, which has an initial value of 1 and results in a roughly 50:50 split between load and generation.

7.1 Weighting factor review mechanism in the proposed TPM

138. The Authority is proposing to adopt Transpower's proposed review mechanism. Under this mechanism, we will review the weighting factor at least every 5 years and update its value based on the average aggregate generation/load splits as determined from post-2019 standard method BBCs provided there are at least 10 of them.

139. The Authority has additionally raised for consideration some options that would apply to the future reviews of the weighting factor.

140. We do not support the options the Authority has raised, for the reasons set out below.

    140.1 *"Requiring Transpower to consult early on a review methodology, (e.g., to be included in the assumptions book in year three of the proposed TPM) which is then applied in year four of a simple method period"*: We are uncertain what the Authority has in mind when it refers to a "review methodology" or what the potential benefits of consulting separately on it would be. The proposed TPM already contains an empirical basis for the review (the outcome of at least 10 standard method allocations) and already requires us to consult on any material update of the assumptions book (the demand adjustment factor is published in the assumptions book).

140.2 *"Transpower could be required to formally consult with the Authority on the weighting factors"*: This is unnecessary because Transpower would consult all stakeholders and interested parties (including the Authority) on the assumptions book update anyway.

140.3 *"Transpower could commission (by itself or jointly with the Authority) an independent reviewer of weighting factors (with a duty of care to both Transpower and the Authority) to review and provide recommendations"*: This proposal, which we understand to be based on the Commerce Commission price path application requirements, is in our view disproportionate for this discrete aspect of the proposed TPM, especially in view of the empirical basis for the review in the proposed TPM itself. Transpower has no vested interest in the weighting factor so the involvement of an independent third party seems unnecessary and an avoidable cost of administration.

140.4 *"The weighting factor could be for the Authority to determine (based on a proposal by Transpower)"*: In our view, this re-allocation of responsibilities would be out of step with the framework for implementation of the TPM which leaves operational aspects to Transpower, including all determinations and calculations. This option would blur the separate responsibilities of Transpower in administering the TPM and the Authority in approving it. We also note the Authority has previously said, in relation to prudent discounts, *"The Authority does not agree that it should take an active role in deciding on prudent discount applications and considers that Transpower is better suited to making such a decision, given its operational role and expertise"*.[41]

[41] Authority, Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM: Decision, 10 June 2020, paragraph 12.40.

8. Residual charge and battery storage

<u>Consultation question (Chapter 7):</u>
Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?

141. We remain of the view – having closely considered the Authority's consultation paper – that gross load would be a problematic allocator for batteries.

142. The submissions we received on this topic are relevant to the Authority's consultation. Stakeholder views were fairly binary. Legitimate arguments were raised both in favour of and against departing from the Guidelines to address potential problems associated with applying the gross load allocator to battery storage .[42]

143. Both Transpower's stakeholder engagement during TPM development and the Authority's consultation paper demonstrate a full exemption for battery storage would overshoot the problem, shifting the residual charge from a potential barrier to investment in battery storage to creating an artificial advantage for it. It would not be competitively neutral or efficient to charge other generators for electricity they consume but not batteries.

144. The Authority's proposed partial exemption for battery storage has a practical advantage over the other options as it would mean Transpower would not need ongoing information about what the battery storage is actually doing, including if the battery is part of hybrid plant or co-located with a generator. On an ongoing basis, all we would need to know is grid offtake and non-battery embedded generation (albeit the latter presents a non-trivial information challenge).

[42] Some submitters commented that the impact of the residual charge on batteries can be seen as an example of a wider competition/distortion problem not limited or specific to batteries.

9. Adjustments

9.1 "Whole-of-life" approach to BBC adjustments

> <u>Consultation question (Chapter 8):</u>
> **Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:…**
>
> - **the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines…**

145. We support the Authority's proposal not to implement a "whole-of-life" approach to BBC adjustments that is backward-looking, for the reasons set out in chapter 10, paragraphs 63 to 69 of our Reasons Paper.

146. We differ from the Authority in that we do not consider this is a departure from the requirements of clause 33(b) of the Guidelines, which contains the important qualifier *"to the extent possible"*. As we said in chapter 10, paragraph 69 of our Reasons Paper:

> We consider a backward-looking adjustment will not increase our levels of confidence that BBCs reflect the share of net private benefits each customer is expected to receive from a BBI across the whole of its life. For this reason, the proposed TPM reflects a forward–looking approach to reallocating BBCs when a new customer enters (clause 80 of the proposed TPM). We have concluded the proposed TPM complies with clause 33(b) of the Guidelines, to the extent it is possible to do so, without including a backward-looking adjustment.

9.2 Residual charge adjustment for new entrant and expanding customer

> <u>Consultation question (Chapter 8):</u>
> **Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:…**
>
> - **the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed…**

147. The Authority has proposed to ramp up the residual charge for a new customer to mimic the outcome under the lagged residual charge adjustment mechanism for an existing customer connecting new plant. We do not support this proposal.

148. While we agree the Guidelines create a competitive neutrality problem, in terms of how the residual charge applies to new versus existing customers, we do not consider the Authority's

proposal adequately addresses this problem. As we said in our Part 1 Refer-Back Response,[43] and illustrated in the accompanying worked example, the Authority's proposal leaves existing customers with existing plant at a competitive disadvantage compared to existing customers with new plant and new customers.

149. We remain of the view the proposed new TPM should provide for a step adjustment to an existing customer's residual charge if the customer connects new large consuming plant. In our view, this is the best way to eliminate, or at least minimise, the competitive disadvantage problem. We have suggested revised proposed TPM drafting to achieve this, which is substantively the same as the TPM drafting we proposed in our Checkpoint 2B submission.[44]

150. We do not consider our Proposal would defeat the purpose of the lagged adjustment mechanism (paragraph 8.46 of the Authority's consultation paper). The lagged adjustment would still apply to increases in gross load not arising from new plant or upgrades and would still operate to avoid inefficient actions to avoid the charge (noting that any avoidance behaviour would involve the customer reducing, not increasing, its gross load). The lagged adjustment would also capture increases in gross load attributable to new plant or upgrades that are not large, i.e. not grid-connected and not at least 10 MW embedded.

151. Another problem we see with the Authority's proposal is that extending the lagged residual charge adjustment mechanism to new customers and applying it to new large consuming plant would make it less likely a customer or embedded party would bear the full transmission charges cost of their decision to enter or expand. That cost will be borne eventually by whoever owns the relevant consuming plant four to eight years later, which may not be the original customer or embedded party. For embedded consuming plant that no longer exists at that time, the cost may be borne exclusively by parties who never had an interest in the plant.

9.3 Residual charge adjustment for customer exit and large plant disconnection

Consultation question (Chapter 8):
Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter…

152. The TPM drafting the Authority has proposed to make the step adjustment for large plant disconnection (clause 97) would result in double-counting of the reduction when the lagged adjustment mechanism "catches up". This would mean the disconnecting customer would ultimately under-pay residual charges. We have suggested a fix for this in the revised proposed TPM drafting accompanying this submission.

153. We note the adjustment provisions in the proposed TPM treat embedded plant changes, including large consuming plant disconnection or de-rating, as analogous to the same change

43 Part 1 Refer-Back Response, section 5.
44 Checkpoint 2B proposed TPM drafting. We removed step adjustments from our 30 June proposal because the Authority indicated in response to our Checkpoint 2B submission that it did not intend the Guidelines to be departed from in that way.

happening at the grid interface. In all cases, the adjustment falls on the transmission customer, not the embedded plant owner (who will typically not be a transmission customer or pay transmission charges directly). We therefore do not understand the issue/problem the Authority discusses in paragraph 8.51 of its consultation paper relating to the proposed TPM's treatment of embedded party downsizing.

10. Prudent discounts

10.1 Prudent discount practice manual

Consultation question (Chapter 9):
Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:

- **Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower**

154. We consider the prudent discount practice manual should be an optional tool to be developed as we gain experience with prudent discount applications under the new TPM.

155. We do not support making the prudent discount practice manual mandatory, for the following reasons:

155.1 The prudent discount practice manual is not a pre-requisite for prudent discount applications. The key information required to enable prudent discount applications (in addition to the fundamental prudent discount conditions in the proposed TPM itself) are the application fees and application requirements. Under the proposed TPM these are required to be published on our website, whether there is a prudent discount practice manual or not (definitions of “application fee” and “application requirements”). We intend to publish the application fees and application requirements for prudent discounts before the first pricing year under the new TPM so that prudent discount applications can start straight away.[45]

155.2 Developing, consulting on and finalising a useful prudent discount practice manual containing all of the information contemplated in paragraph 9.12 of the Authority’s consultation paper would take time and require the application of considerable Transpower and stakeholder resource. In our view, this is not warranted at this time. We are mindful of the need to prioritise critical tasks while we are preparing to implement, or are in the early stages of implementing, the new TPM. We expect most of our customers would be of the same view. We are also mindful there is a reasonable chance we will never receive a prudent discount application, or at least not during the first pricing year, in which case the effort to produce the manual before the first pricing year (or at all) would be wasted.

155.3 We do not consider it axiomatic applicants would benefit from a prudent discount practice manual if prepared prematurely. Applicants may find it beneficial not to be constrained by our views about alternative project options, for example. Absent prescriptive prudent discount rules, applicants will have the benefit of more flexibility in how they construct their business and technical cases for a discount.

155.4 We consider it would be optimal to develop the manual in the context of real applications. Setting (even on a non-binding basis) particular prudent discount

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45 Noting, however, our ability to process early applications in a timely way, especially if there are several of them, may be affected by the need to prioritise matters essential to bedding in the new TPM.

assumptions or methodologies in the absence of at least one application is potentially inefficient, especially for SACPDs which are a new concept introduced by the Guidelines. We consider attempting to do so is likely to result in re-work, both for Transpower and applicants. In the early stages of the new TPM, applicants are as likely as Transpower to make valuable contributions to prudent discount "jurisprudence".

156. We do not consider the prudent discount practice manual should be binding, for the reasons set out in paragraph 9.20 of the Authority's consultation paper.

157. The above points apply equally to the development of the reassignment practice manual.

10.2 Duration of prudent discount agreements

Consultation question (Chapter 9):
Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:…

- **15 years should be the default maximum period with a longer term possible on proof…**

158. In our view, it would be appropriate for the default duration for a prudent discount agreement to be 15 years in cases where the parties are unable to agree on a different duration.

159. While we consider there are potential inefficiencies with this approach because it introduces an unnecessary negotiating dimension, our principal concern is (and always has been) to ensure the default duration for a prudent discount agreement is not unreasonably long. A maximum duration of 15 years is consistent with the current prudent discount policy, and we do not see a strong justification for changing that.

160. We do not agree limiting the duration of a prudent discount agreement to 15 years could risk inefficient outcomes due to uncertainty about whether the agreement will be renewed. If the conditions for renewal are satisfied, then the agreement must be renewed; it is not discretionary. If the conditions are not satisfied, then it would be inefficient to renew the agreement and so it should not be. In any event, a customer would normally much rather have a prudent discount agreement than build the alternative project[46] because the prudent discount agreement avoids all project execution risk.

161. Whatever the duration of a prudent discount agreement, we consider there has to be a sensible limit on the prudent discount calculation period so that we are not required to assess discounted costs many decades into the future. We do not consider the prudent discount calculation period should be any longer than 20 years (matching the proposed maximum duration of the standard method calculation period).

10.3 Customer termination of prudent discount agreements

Consultation question (Chapter 9):
Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:…

[46] Assuming the alternative project can be built, which is not necessarily the case for a SACPD.

- **customers should be able to terminate a prudent discount agreement before the end date of the agreement?**

162. We consider the customer should be able to terminate a SACPD agreement, as we have proposed.

163. If a SACPD agreement no longer provides a discount, and therefore the customer's transmission charges no longer exceed the efficient stand-alone cost of the interconnection services the customer receives, why should the customer be forced to continue with the agreement? In that situation the SACPD agreement, if it continued, would have the effect of artificially raising the customer's transmission charges, the opposite of what it is intended to do.

164. The Authority's comment on page 84 of its consultation paper that *"the commercial discipline on a customer applying for an SACPD should reflect reality as closely as possible"* appears not to acknowledge the hypothetical nature of the alternative project underlying a SACPD (clause 47(a) of the Guidelines and clause 136(2) of the proposed TPM).

165. A SACPD should act as a ceiling for transmission charges and should not act as a floor as well. If a SACPD acts as a floor for transmission charges, that may act as a disincentive for customers to apply for one. A customer would not only have to assess that its current transmission charges exceed efficient stand-alone cost but would also have to make a judgement about whether that will continue to be the case for the duration of the SACPD agreement.

11. Commencement date

<u>Consultation question (Chapter 15):</u>
Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM?

166. We are committed to delivering the new TPM by the implementation date set by the Authority.

167. The proposed 1 April 2023 date will be challenging to achieve, especially as there are only a few months between the Authority's planned approval date for the new TPM (31 March 2022) and our effective deadlines for consulting on transmission charges for pricing year 2023 (1 September 2022) and producing audit-ready transmission prices (1 October 2022).

168. By various dates between now and 1 April 2023 we would need to carry out the following tasks, at a minimum:

168.1 Produce transmission prices for pricing year 2023 and have them audited, approved by our Board and notified to customers.[47] This includes:

- developing, consulting on and finalising the initial assumptions book, which will specify key inputs to the calculation of BBI customer allocations and factors for the standard and simple methods;
- calculating, consulting on and finalising standard method allocations, and then BBCs, for the two high-value post-2019 BBIs expected to be commissioned during financial year 2021;[48]
- calculating, consulting on and finalising the simple method allocations (regional and individual) for the first simple method period, and then BBCs for the low-value post-2019 BBIs commissioned before the end of financial year 2021;
- calculating, consulting on and finalising the residual charge allocations and residual charges for the first pricing year;
- obtaining all the inputs for the above calculations, using new Code information-gathering powers if necessary and available, consulting on those inputs[49] and finalising them; and
- working with our audit and assurance service providers to assist them to understand and prepare our Board for certifying transmission charges for pricing year 2023.

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[47] Transmission agreements allow transmission charges for a pricing year to be notified to customers as late as 1 January, but we routinely notify earlier than that due to the Christmas/New Year break and to provide sufficient time for our customers and retailers to factor transmission charges into their price-setting processes.

[48] The two investments are post-2019 CUWLP and the reconductoring of the Otara-Flat Bush section of OTA-WKM A&B. We have suggested a change to the proposed TPM that would allow us to delay the commencement of standard method BBCs for these investments by a year if necessary, but our intent is to try to have the standard method BBCs ready to start from the first pricing year

[49] We are planning to start consultation on the inputs to residual charge allocations, intra-regional BBC allocations and the transitional cap in February 2022.

168.2 Develop and publish application requirements and application fees for prudent discount and reassignment applications, and the list of BBIs eligible for reassignment.

168.3 Complete development and testing of our tools, systems and processes for the first pricing round under the new TPM, including our core transmission pricing system and FMIS.

168.4 Continue to engage with the Authority on the development of the new TPM, including responding to questions and participating in the Authority's consultation and any post-consultation interactions.

168.5 Engage with the Authority on TPM-related Code changes, including participating in the Authority's consultations.

168.6 Potentially develop, consult on and publish a new loss and constraint excess (**LCE**) allocation methodology.

168.7 Continue to engage with our customers and other stakeholders on their transmission pricing enquiries, a backlog of which is beginning to build up.

168.8 Develop collateral to support our customers to understand the new TPM and their transmission charges under it, including to assist customers to develop and communicate their methodologies for passing through their new transmission charges.

168.9 Support our New Zealand Grid Pathways consultation processes and investment proposals with indicative pricing under the new TPM.

168.10 Support our RCP4 consultation processes and base capex and opex proposals with indicative pricing under the new TPM.

169. This represents a considerable body of work to complete within the limited timeframe that is proposed. Further, any unforeseen or material delay to the transmission charge calculation or systems development work stream could put the proposed 1 April 2023 implementation date at risk.

170. We urge the Authority to closely consider the potential implications from a timing perspective of including in the new TPM any additional complication (such as "bolt-ons" to the proposed method for addressing Type 2 FMD) or additional, or intensified, pre-implementation work streams for Transpower (such as a mandatory prudent discount or reassignment practice manual).

171. In our view, the Authority should only include additional complication or additional pre-implementation work streams in the new TPM if the Authority is confident the new requirements will produce benefits to consumers that outweigh the administrative cost and risk of delay those new requirements may represent.

12. Potential supporting Code amendments

<u>Consultation question (Other):</u>
Is there anything else in relation to the proposed Code amendment that you wish to comment on?

172. Our views on the potential supporting Code amendments outlined in paragraphs 2.18(a), (b) and (d) of the Authority's consultation paper are set out in chapter 16 of our Reasons Paper. In short, we support those potential Code amendments in principle.

173. In relation to the potential Code amendment relating to the availability of behind-the-GXP[50] data, we note any new Code obligations should require customers to not only provide that data to Transpower but also to record and retain it so it can be used by Transpower for transmission pricing purposes.

174. In the absence of these additional obligations, a rational approach for some customers may be to simply not capture behind-the-GXP data or, if they do, to get rid of it as soon as possible. In our view, this potential incentive supports incorporating this amendment into the Code sooner rather than later. In any event, the amendment is required in good time before the start of the first pricing year to which the new TPM applies so we have access to the data necessary to calculate the initial residual charge allocation.

175. Related to this, we would support a further Code amendment to provide a "safe harbour" for our calculation of the baseline residual charge allocation metrics for existing customers. We consider this important because historic embedded electricity data going back to 2014 is likely to be relatively patchy and in some cases may need to be extrapolated from SCADA data. Any Code amendment requiring customers to record, retain and provide embedded electricity data would not resolve data gaps that already exist. Provided we consult on our calculation of those baseline metrics (as we are required to under clause 17(1) of the proposed TPM) and act reasonably in calculating them, we consider this calculations will be robust.[51]

176. We do not have a view on the potential supporting Code amendment outlined in paragraph 2.18(c) of the consultation paper (ACOT changes). We note however that removing a regulatory right to be paid ACOT (as is currently the case for all new embedded generation) is not the same as stopping ACOT payments where they have been agreed in a contract (either before or after the Code amendment).[52]

177. There is another Code amendment we think the Authority should consider. It would be useful if the System Operator were expressly able to disclose to the Grid Owner information about matters that may be relevant to the calculation or adjustment of transmission charges. For example:

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50 The consultation paper refers to behind-the-GXP data, but behind-the-GIP data is also relevant to the calculation of gross load and residual charges. The issue really relates to data about activity behind points of connection to the grid.

51 Related to this, the revised proposed TPM drafting accompanying this submission includes a recommended new subclause to specify the data Transpower may use to calculate gross load (subclause 5(7)).

52 Even without a peak charge, distributed generation can help offtake customers avoid transmission charges because the individual allocations of future BBCs will be based on grid offtake.

177.1 We may need to use SCADA data to calculate gross load for some customers in some situations. SCADA data is provided by participants to the System Operator under Part 8 of the Code and therefore resides with the System Operator.

177.2 It is possible the System Operator will know about proposals to connect large embedded generating plant, or even that large embedded generating plant has already been connected, before the Grid Owner does.

178. Currently, clause 3(2) of Technical Code A of Schedule 8.3 of the Code prohibits the System Operator disclosing "*information about an asset, supply or demand of…asset owners*" except in limited situations which do not include assisting the Grid Owner to calculate or adjust transmission charges.

179. The Authority should also consider what changes may be required to the benchmark transmission agreement to align with the new TPM. Our initial view is the following clauses will or may need to be amended:

179.1 Clause 4.3 (benchmark agreement reviews) – This clause still refers to the Authority making recommendations to the Minister for amendments to the benchmark agreement.

179.2 Clauses 9.2, 9.3 and 12.1 (information from customers) – There may need to be consequential changes to these clauses arising from the new Code provisions about the availability of behind-the-GXP data.

179.3 Clause 10.3(e) (charges by connection location) – Not all of the new transmission charges are amenable to being assigned to particular connection locations as required by this clause. This is certainly the case for prudent discount and cap recovery charges.

179.4 Clauses 10.1 and 11.2 (date for invoicing and payment of invoices) – These clauses do not reflect the actual invoicing date (typically during and towards the end of the month being billed) or the actual due date for payment (20th of the month after the month of invoice).

179.5 Part D (LCE) – This Part may need to be amended depending on what LCE-related Code amendments the Authority decides to make.

179.6 Clause 4.4 of the Connection Code (minimum power factor) – The customer's obligations in this clause are linked to regional peak demand periods, which will not need to be determined under the new TPM.[53]

180. Generally, we consider the benchmark agreement is overdue for review[54] and the advent of the new TPM would be a good opportunity to bring it up to date.

181. If there are changes to the benchmark agreement, there should be a corresponding Code amendment to make those changes effective in existing transmission agreements. Changing the benchmark agreement will not automatically have that effect in all cases.[55]

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53 To amend the connection code the Authority would need to initiate a review of it under clause 12.18 of the Code.

54 As far as we are aware, the benchmark agreement has not been reviewed since it was amended in October 2007 by the Electricity Commission, shortly after it was added to the former Electricity Governance Rules.

55 Clause 4.3 of the benchmark agreement only carries through benchmark agreement changes for default transmission agreements deemed to apply under clause 12.10 or 12.13 of the Code. Most transmission agreements on benchmark terms are entered into by agreement and are therefore not covered by clause 4.3. Clause 4.3 does not cover legacy forms of transmission agreement either. There is also the arguable point that clause 4.3 can never now apply because the condition in subclause (a) (recommendation to the Minister) cannot be satisfied.

TRANSPOWER

chapman tripp

Memorandum

Date: 2 December 2021

To: Transpower

by email

From: Lucy Cooper / Penelope Ward
Direct: +64 4 498 2406 / +64 4 498 6304
Mobile: +64 27 948 1748 / +64 22 476 4939
Email: lucy.cooper@chapmantripp.com / penelope.ward@chapmantripp.com
Ref: 100420261/4819721.1

Confidential and Privileged

ELECTRICITY AUTHORITY CONSULTATION ON THE PROPOSED TPM: ASSURANCE OF TRANSPOWER'S SUBMISSION

Introduction

1 Transpower intends to make a submission to the Electricity Authority (**Authority**) in response to its consultation on the proposed transmission pricing methodology proposal (**TPM**).

2 The Authority is required to consult on the proposed TPM under clause 12.92 of the Electricity Industry Participation Code (**Code**) and has indicated that it will accept initial submissions by **2 December 2021**, and cross-submissions by **23 December 2021**.

3 Transpower intends to include in its submission:

3.1 comments in response to select questions raised by the Authority in relation to key TPM topics;

3.2 comments on the material changes made by the Authority to the drafting of the proposed TPM; and

3.3 revised TPM drafting, which builds on the changes made by the Authority and which are primarily intended to ensure workability of the proposed TPM, and/ or address additional issues identified by Transpower.

4 In making its submission, Transpower is guided by the matters set out in clause 12.89(1) of the Code, which require that the proposed TPM be consistent with:

4.1 the Guidelines published under clause 12.83(b);

4.2 the Authority's statutory objective in section 15 of the Act; and

4.3 any determination made under Part 4 of the Commerce Act 1986.

5 You have asked Chapman Tripp to provide assurance in relation to Transpower's submission, including its proposed TPM drafting, with a particular focus on compliance with the Guidelines and the Code, as applicable.

Assurance

6 In our opinion, and subject to any assumptions, qualifications and limitations noted below:

6.1 Transpower's revised TPM to be included as part of the submission is consistent with the requirements of the TPM Guidelines in all material respects, in that the revised TPM:

(a) addresses the scope and boundaries set in the TPM Guidelines;

(b) addresses any tests or criteria in the TPM Guidelines;

(c) is consistent with the content requirements of the TPM Guidelines (except where clause 2 departures have been clearly identified and documented); and

(d) addresses any process requirements in the TPM Guidelines;

6.2 Transpower has addressed the requirements of clause 12.89(1) of the Code, as applicable.

Assumptions, qualifications and limitations

7 Our assurance in paragraph 6 above is subject to the following:

7.1 our assurance is based on the information made available to us;

7.2 our assurance role addresses legal requirements and legal form, and does not address economic or engineering effects; and

7.3 Transpower has satisfied itself that the revised TPM contains the structural and fundamental aspects of the proposed methodologies.

Reliance

8 This opinion may be relied on by Transpower and its Directors. Except to the extent (if any) required by law, no other person may, without our written consent, use this letter, either directly or indirectly, or enable this letter to be relied upon by any other person, or allow this letter to be quoted or referred to in any document, whether public or private, or filed with any regulatory authority.

9 We are aware that Transpower may intend to disclose this letter when providing its submission to the Authority. We understand the disclosure of this letter is not intended to waive privilege in any advice we have given to Transpower, in this or any other process.

Lucy Cooper / Penelope Ward
Partner / Senior Associate