TRANSPOWER

TPM Proposal 30 June 2021 Decision Part 2 refer back: Transpower's response

15 September 2021

Contents

1 Introduction

1. The Electricity Authority (**Authority**) asked Transpower to reconsider some aspects of the proposed TPM that Transpower submitted on 30 June 2021 (**30 June proposed TPM** and **30 June proposal**) relating to the benefit-based charge (**BBC**) allocation methodologies.[1] This document provides our response to the Authority following reconsideration of these matters.[2]
2. The Authority otherwise accepted all other BBC allocation methodology related aspects of the proposed TPM for the purposes of its upcoming consultation. We welcome the Authority's comments about the quality of the work undertaken and level of commitment and constructive engagement from both teams. This is reflected in the limited number of BBC-related matters the Authority has asked Transpower to reconsider.
3. Our role at this step in the process is to reconsider the aspects referred back by the Authority, having particular regard to any new information, analysis or observations supplied by the Authority. The Code requires us to make decisions on each topic having regard to consistency with the Guidelines, the Authority's statutory objective in section 15 of the Electricity Industry Act 2010 and any determination made under Part 4 of the Commerce Act 1986 as applicable, which we have done.
4. We consider the changes we have made to the proposed TPM in response to the Authority's BBC allocation feedback give greater assurance BBC allocations will be broadly in proportion to expected positive net private benefits (**EPNPB**) from the relevant benefit-based investment (**BBI**), consistent with clauses 8 and 21 of the Guidelines. On that basis we consider the changes are also consistent with the Authority's statutory objective. In making the changes we have also taken into account the principles in clause 1 of the Guidelines. Further detail of the changes is provided in sections 2, 3 and 4 below.

[1] Authority, letter to Alison Andrew, [Transpower's proposed TPM](), 18 August 2021.

[2] We responded separately to the Authority's feedback on the other elements of our 30 June proposal on 25 August 2021.

5. The resubmitted TPM also contains some changes aimed at improving drafting clarity and consistency, which are noted and explained in the resubmitted drafting. Further detail of key changes is provided in section 5 below.

6. The Authority also requested we provide an update to our indicative pricing model and a short working paper summarising the updates. We have responded separately to this request. We have updated the indicative pricing to correct minor modelling errors and fill missing data points for the BBC simple method allocators which we noted in the 30 June proposal. We understand the indicative pricing will be released for stakeholders alongside the Authority's consultation package later this calendar year.

7. The resubmitted proposed TPM provided with this response incorporates drafting changes in response to the BBC allocation matters referred back for our reconsideration and the other drafting improvements referred to above.

2 BBC Standard method: Criteria for use of clause 50A (now 52) vs clause 50B (now 53)

8. The 30 June proposed TPM included two methods for determining market benefits:

   8.1 The clause 50A method, which uses the modelled price dimension to define beneficiary regions and groups but not to allocate benefits between benefitting customers.

   8.2 The clause 50B method, which uses the modelled price dimension to define beneficiary regions and groups and also to determine the relative benefits between benefitting customers. As the Authority has identified, this approach results in the modelled price dimension having a materially greater impact on allocations than under clause 50A. Under the 30 June proposed TPM, the clause 50B method would apply only where Transpower determines that using the clause 50A method will not produce customer allocations that are broadly in proportion to EPNPB from the BBI, which will be assessed as part of modelling.

9. In its feedback, the Authority expressed a view "*that the proposed TPM should contain criteria that would clarify when the 50A method is to be used and indicate when the 50B method would be more appropriate ... to the extent practical, the discretion to choose between methods in particular circumstances should be limited*." Consequently, the Authority requested that we "*specify appropriate criteria regarding when the 50A method and the 50B method are to be used*."

10. We have considered the Authority's feedback carefully. We agree, consistent with clause 1(b)(iii) of the Guidelines, it would be preferable to limit Transpower's discretion when choosing between methods to determine market benefits, to the extent reasonably practicable. As part of our reconsideration, we have explored potential ways in which discretion can be limited and more certainty achieved.

11. We have identified two situations where we are confident the TPM can and should include specific criteria about which method applies, which are set out below. In each case we are confident of the method that should be used to produce allocations that are broadly in proportion to EPNPB, such that it is appropriate to incorporate these into the TPM at this time.

12. We expect the inclusion of the two specific situations will limit the need for Transpower to exercise discretion for many BBIs. However, it is not practicable at this time to incorporate additional criteria to remove discretion for all BBIs. Consequently, the resubmitted proposed TPM retains the requirement for Transpower to assess which method is most likely to produce BBI customer allocations that are broadly proportional to EPNPB for other BBIs, consistent with the Guidelines. Over time we expect the assumptions book will help to provide further detail in relation to how we exercise this discretion, to improve transparency, consistency and certainty.[3]

13. We consider this approach achieves an appropriate balance between:

    13.1 providing certainty through limiting the need for Transpower to exercise discretion, in appropriate cases and where it is practicable to do so, consistent with clause 1(b)(iii) of the Guidelines; and

    13.2 ensuring the TPM retains sufficient flexibility to produce allocations that are broadly in proportion to EPNPBs, consistent with clauses 8 and 21 of the Guidelines.

14. The new criteria are in clauses 52 and 53 (previously clauses 50A and 50B) of the resubmitted proposed TPM:

    14.1 Clause 52(1)(a) requires we use the clause 52 method if most of the benefits to supply groups are to new large generating plant.

    14.2 If clause 52(1)(a) does not apply, clause 53(1)(b)(i) requires we use the clause 53 method if most of the benefits relate to consumers avoiding their cost of self-supply during peak demand periods, e.g. due to a lack of transmission and generation capacity to supply load in a region.

    14.3 If clause 52(1)(a) and 53(1)(b)(i) do not apply, we will use the test in the 30 June proposed TPM (now in clause 53(1)(b)(ii)), which requires we use the clause 53 method if we consider that the default clause 52 method will not result in allocations that are broadly in proportion to EPNPB.

15. In Appendix A we provide simplified examples of the application of the resubmitted proposed TPM to the two situations for which we have proposed new criteria:

    15.1 Example 1 - a BBI that only benefits loads and new generators, which meets the criteria in 52(1)(a) requiring the use of the clause 52 method.

    15.2 Example 2 - a BBI that benefits loads, existing generators, new generators, and avoids scarcity prices, which meets the criteria in 53(1)(b)(i) requiring the use of the clause 53 method.

16. We expand on the rationale for our proposal in the remainder of this section.

2.1 Rationale for clause 52(1)(a)

17. Clause 52(1)(a) requires the use of the clause 52 method for a BBI where most of the benefits to supply groups are to new large generating plant, such as for a BBI that is primarily undertaken to allow lower cost generation to enter the market. BBIs of this type are distinct

[3] Further detail about the role of the assumptions book is in chapter 7 of our TPM Proposal Reasons Paper, 30 June 2021.

because the counterfactual will be an alternative set of generators, with higher capital and/or operating costs, which may mean there is no transmission constraint in the market affecting existing generation.

18. Having considered this matter further in response to the Authority's feedback, and as part of an Authority request for information (**RFI**) in relation to our 30 June proposal, our view is it is appropriate to use the clause 52 method in this scenario. Applying the clause 53 method for this type of BBI would be inconsistent with clauses 8 and 21 of the Guidelines because it is unlikely to produce allocations broadly in proportion to EPNPB:

    18.1 In order to assess the effect of different capital costs on prices, we would need to model how capital costs influence prices in the market in the factual and counterfactual. Clause 53's assumption of prices based on short-run marginal costs, and producer costs based on variable costs (consistent with the assumptions applied in the proposed wholesale market model[4]) would not be appropriate in all situations. For example, prices in the factual and counterfactual will be the same when comparing two marginal generators built at the same time with the same operating costs but different capital costs. Furthermore, as demonstrated in Appendix A, in some cases clause 53 would result in incorrect, and potentially no, private benefits being ascribed to new generators.

    18.2 While clause 50(5) can be used to adjust prices in post-processing to reflect differences in the capital cost of new generation on prices, and the definition of wholesale market model and clause 53 in the proposed TPM drafting could be amended to include capital costs within the assessment of private benefits for new generation, determining the correct allocation between load and generation for a new generating station ultimately requires an assessment of the extent to which the new generating station achieves a return above its cost of capital. As illustrated by the two recent analyses of Meridian's historical returns,[5] determining this value is difficult and contentious.

    18.3 More generally, an assumption of perfect long-run competition represents one extreme, where new marginal generation receives no private benefit and all the benefit of capital cost efficiencies due to a BBI go to loads. At the other extreme, a generator that exercises market power may successfully prevent any capital cost efficiencies from affecting the market price, resulting in all the private benefit going to producers.

19. The resubmitted proposed TPM gives clause 52(1)(a) precedence over clause 53(1)(b)(i) in case the two criteria conflict. However, in practice it is very unlikely a BBI would both (a) primarily benefit new generators compared to existing generators, and (b) primarily benefit load customers compared to generation customers due to the BBI avoiding high prices in the market at their assumed cost of self-supply. BBIs that primarily benefit new (uncommitted) generators will not have significant transmission constraints in the counterfactual (or factual). Rather, they will be BBIs that enable a new generator to connect in a particular region and access the wider market, without which the generator would not exist (because it would not be profitable to do so).

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4 See the definition of "wholesale market model" in the resubmitted proposed TPM (which is unchanged from the 30 June proposed TPM).

5 Energy News, Meridian questions MEUG's analysis and credibility, 24 August 2021

2.2 Rationale for clause 53(1)(b)(i)

20. We consider the clause 53 method, when compared to the clause 52 method, is more likely to produce allocations that are broadly in proportion to EPNPB in a situation where the majority of benefits relate to load customers avoiding their cost of self-supply during peak demand periods. This is because, in a self-supply counterfactual, the price change to loads downstream of the transmission constraint will be greater than the change upstream to generators. The clause 53 method has the ability to account for different price changes either side of a constraint, whereas the clause 52 method does not.

3 BBC Standard method: Number of regions under clause 52 method

21. The Authority has requested we consider whether there is potential to enhance the clause 52 method by taking account of factors in addition to the direction of modelled price changes, such as important constraints elsewhere in the grid when determining the number of regions (i.e. allowing for more than two regions). The Authority considers "*such a potential enhancement is likely to be practicable*" and "*adequately conform with the guidelines and the Authority's statutory objective*." As the Authority has noted, this potential enhancement was identified as part of Transpower's consideration of an Authority RFI in relation to our 30 June proposal.

22. In its refer-back letter, the Authority also requested:

    22.1 Transpower consider whether such an enhancement might create any practical issues such as greater complexity and any implications relating to the clause 52 method, and

    22.2 Transpower set out decision criteria that would help stakeholders understand how Transpower would decide on the number of regions within the 52 method.

23. We have considered the Authority's feedback carefully. We agree with the Authority that the clause 52 method would, in some circumstances, be enhanced by taking account of additional factors, including other important constraints. As above, we consider this enhancement achieves an appropriate balance between certainty (clause 1(b)(iii) of the Guidelines) and flexibility to produce allocations that are broadly in proportion to EPNPB (clauses 8 and 21 of the Guidelines), and in this regard supports the statutory objective.

24. For example, in the CUWLP case study there may be a case for splitting the load regional group into two regions (North Island and Upper South Island) by excluding periods where both the HVDC and CUWLP are fully constrained in the counterfactual from the periods of benefit applied to the North Island.[6] In doing so we would also need to consider if, how and when the HVDC is likely to be upgraded during the analysis period.

25. This methodology would likely result in a lower allocation to North Island load customers than presented in our CUWLP case study (although we would still expect a significant allocation to be received by North Island load customers, all else being equal). While timelines have not allowed us to provide an addendum to the CUWLP case study reflecting

[6] In accordance with benefits occurring "at different times" from clause 51(c)(ii).

our revised proposal with this response, we are working to do so to support the Authority's consultation later this year, as agreed with the Authority.

26. For the avoidance of doubt, we are not changing our proposal with respect to the constraints we will model for a given BBI (i.e. our proposed definition of "investment grid" has not changed). As explained in Chapter 7, paragraph 93 of our TPM proposal reasons paper, modelling all grid constraints over the course of a 20 year analysis period and resolving these with modelled grid upgrades is not a practical option. The enhancement in the resubmitted proposed TPM allows for the clause 52 method to use more than two regions reflecting the investment grid constraints used in the wholesale market model and the resulting prices and quantities.

27. While this enhancement may add an administrative cost to the clause 52 method,[7] we consider the additional cost is likely to be less than the benefit of increased precision, consistent with clause 1(b)(ii) of the Guidelines. Furthermore, allowing for additional regions to be used under the clause 52 method in appropriate cases decreases the likelihood of Transpower needing to use the more complex (and therefore more costly) clause 53 method to produce allocations that are broadly in proportion to EPNPB.

28. The relevant changes in the resubmitted proposed TPM are as follows:

    28.1 The rules for determining modelled regions (and regional customer groups) have been separated out from clauses 52 and 53 into new clause 51, for clarity. Clause 51 applies to determining the modelled regions (and regional customer groups) for both clauses 52 and 53.

    28.2 Clause 51(1)(c) allows for the larger regions based on the direction of price or quantity changes (clause 51(1)(a) and (b)) to be divided into smaller regions based on the magnitude the changes, the times they occur, and the market scenarios in which they occur.

    28.3 Clause 51(1)(d) confirms that Transpower's region determination must ensure the allocations produced are broadly proportionate to EPNPB, consistent with the Guidelines.

4 BBC Standard method: Flexibility of regional definition

4.1 Regional customer groups for BBIs with significant dynamic efficiency benefits

29. The Authority has requested we "*reconsider the definition of modelled regions in the [52] and [53] methods, specifically to consider the case of a BBI which has significant dynamic efficiency benefits (such as to support the entry of new generation) for which the modelled price changes for the BBI are in the same direction at all nodes (and was justified in the investment proposal to the Commission on the basis of significant dynamic efficiency benefits).*" As noted by the Authority, in response to an RFI we highlighted that in such circumstances the 30 June

[7] In particular, the method will place greater emphasis on the location of new generation, as this may influence the extent to which different regions benefit from the BBI, as well as requiring us to consider if and how the HVDC is upgraded (to the extent it affects the benefits of a BBI elsewhere in the grid).

proposal for the *"[clause 52 and 53] methods would not be sufficiently flexible to appropriately reflect benefits."*

30. As the Authority has noted, since our 30 June proposal we have been considering if the regional definitions for the clause 52 and 53 methods are sufficient in a situation where the driver of a BBI relates to enabling new generation stations to be built to meet demand growth. In such a scenario, the counterfactual to the BBI would likely be an alternative set of generation projects in different locations that do not require the BBI but come at a higher cost. Depending on the specifics of the BBI, this counterfactual may result in a higher price of electricity throughout the market without the BBI (not just in a single region). In this situation, loads throughout the grid would benefit from the BBI due to lower market prices in the factual, and the new generators would benefit by being able to connect to the grid in a particular region that has increased export capacity due to the BBI.

31. Having considered the Authority's feedback carefully, we consider the regional definition in the 30 June proposed TPM can be enhanced by modifying it, in the Authority's words, "*to ensure that a proportionate share of charges, (ie, reflecting their share of benefits) are allocated to the new generators."* We agree with the Authority that *"Given that substantial amounts of new generation are expected to connect as the economy electrifies, this could be a material issue."*

32. The relevant changes in the resubmitted proposed TPM are as follows:

    32.1 We have expanded the clause 51(1)(b) criterion to include changes in quantity (not just price). Therefore, if a region had lower electricity prices due to a BBI but the BBI allowed new generators to enter that region, we could create a region defined by the quantity change from the new generation coming into the market.

    32.2 We have introduced the concept of a "future regional customer group" (an initially empty regional customer group reserved for future customers and plant) and added clause 51(3).

33. We consider these enhancements will help ensure the TPM produces allocations that are broadly in proportion to EPNPB, consistent with clauses 8 and 21 of the Guidelines.

4.2 Allocations for large plant and new customers that do not initially exist

34. Consistent with these enhancements, we have also made drafting improvements to more explicitly state how we propose to set allocations for large plant or customers that do not exist at the time the allocations are first set.

35. When first setting regional allocations, we will remove any calculated benefits associated with future customers or large plant that enter the market after the allocations are first set (clauses 52(3), 53(6), 54(5) and 55(6)).

36. The intent of this change is to prevent future customers and large plant (and the other members of the group the future customers and large plant will enter) receiving an allocation greater than their proportion of EPNPB. This over-allocation would occur if we both counted the benefit of the future customer or large plant in the initial allocation and again later in applying clause 84 or 86 when the customer or large plant connects.

37. We covered this issue in our 30 June proposal through the definitions of "regional customer group" (then in clauses 50A(2), 50B(2), 51(3), 52(4), 53(3), and 56) by referring to "existing"

customers. However, we consider the drafting in the resubmitted proposed TPM more explicitly addresses the issue. The change also avoids an interpretation where any future offtake or injection customer in a modelled region has to be in a separate regional customer group, which is not intended.

38. Example 1 in Appendix A presents a situation where all the benefits of a group are associated with large plant or customers that do not exist at the time the allocations are first set. While clause 80(4) of the 30 June proposed TPM contemplated this situation, the changes we have made in the resubmitted proposed TPM have added a more detailed treatment. In particular, and as noted above, we have created "future regional customer groups" which have no members initially and so receive no initial allocation. When a member of the group connects to the grid, their allocation is determined in the same way as for new large plant or customers entering a normal group, except with reference to a notional IRA value set at the time the allocations were first determined (clause 68 of the resubmitted proposed TPM). The notional IRA value is required in order to calculate allocations using clause 84, in the absence of at least one initial member of the future regional customer group.

39. For the avoidance of doubt, this drafting improvement does not prevent us from creating multiple generation groups for existing and new generators. Therefore, the two options referred to in Chapter 7, paragraph 154 of our TPM proposal reasons paper remain open under the clause 53 method.

5 Other changes to proposal

40. This section discusses other changes we have made in the resubmitted proposed TPM, which we identified as part of our consideration of the matters referred back to us by the Authority. As noted above, we have explained less material changes in the resubmitted proposed TPM itself.

5.1 High-value intervening BBIs

41. The Guidelines require BBCs to apply to all BBIs commissioned after 23 July 2019 (clause 14(a) and definition of "post-2019"). As a consequence, there are some BBIs for which we will need to calculate BBCs from the start of the first pricing year.

42. A subset of these BBIs are expected to be high-value and commissioned before 1 July 2022 (referred to in the resubmitted proposed TPM as "high-value intervening BBIs", assuming the new TPM is implemented on 1 April 2023). To support the Authority's aim of the new TPM taking effect in prices from 1 April 2023, we will need to allocate the costs of the high-value intervening BBIs in the annual pricing round commencing July 2022. Our 30 June proposal, consistent with the clause 20(a) of the Guidelines, required these allocations to be calculated using a standard method. Doing so will involve application of one or both of the standard methods for the first time, and set important precedent for future application. It will also involve consultation with our stakeholders, as required under clause 5(b) of the Guidelines and clause 17 of the proposed TPM.

43. As we communicated to the Authority on 1 March 2021:[8]

> The timeline to March 2022 is challenging. Any significant departures from our proposed approach for determining prices is likely to impact our ability to deliver prices under the new TPM that can take effect from April 2023, in addition to any unforeseen developments or impacts from external factors that may occur over this period.

44. We are mindful to ensure that a robust process can be followed to apply the standard methods, particularly the price-quantity method, to high-value intervening BBIs. As we have discussed with the Authority's team, the timeline is challenging and subject to some uncertainty, including because:

    44.1 if the final form of the TPM materially differs from our proposal, potentially as a result of information received as part of the Authority's consultation process, we are likely to have to rework our modelling before we can consult stakeholders; and

    44.2 if Transpower's stakeholder consultations under clause 17 of the proposed TPM provide us with new information or feedback, we will have to revise our modelling, and possibly consult again, before we can calculate final allocations.

45. Based on current forecasts, we expect there to be two high-value intervening BBIs commissioned before 1 July 2022 - the post-2019 CUWLP investment and the reconductoring of the Otara-Flat Bush section of the OTA-WKM A and B lines.

46. In practice, final allocations for these high-value intervening BBIs would need to be available by 31 August 2022 at the latest in order for prices under the new TPM to meet timeframes for our annual pricing round. Consultation with our customers on the inputs to their transmission charges (e.g. assets and capacity measurement) must be completed during September so that calculations and audit can be completed in October for our Board's approval in November. Final transmission charges are communicated to customers in December, at least three months before the start of the pricing year, as required under transmission agreements. This established timeline recognises that transmission charges flow through to distribution tariffs and then to retail tariffs to end consumers. It is important for our distribution customers, in particular, that we meet this timeline because they themselves must determine and communicate their own charges for 1 April 2023 inclusive of transmission charges.

47. If the Authority approves the final form of the new TPM in March 2022 (as indicated by Figure 17 in the 2020 Decision Paper), this would provide five months to produce, consult, and determine final allocations for these two BBIs consistent with the new TPM. We are concerned this may not be sufficient time to complete all relevant modelling and associated consultations to apply the standard methods and ensure allocations are broadly in proportion to EPNPB. This is particularly the case given these would be the first high-value post-2019 BBIs to be subject to the new regime. It is possible we will receive many submissions of a complex nature related to the modelling or input assumptions from affected stakeholders.

48. To help address this, we have added subclauses 43(3) and (4) in the resubmitted proposed TPM. These clauses provide us discretion to delay for one pricing year the start of the

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8 Transpower letter to Authority, 1 March 2021

standard method BBCs for a high-value intervening BBI, where we determine it is necessary to do so to complete a robust process for calculating allocations, including to complete the necessary consultations with our stakeholders.

49. If it is necessary to delay the start of the standard method BBCs for a high-value intervening BBI, we propose to use the simple method to determine allocations for the BBI's start pricing year, and undertake a wash-up in the subsequent pricing year to correct any under or over charging in the start pricing year (subclause 43(4) of the resubmitted proposed TPM).

50. We propose to extend this discretion to high-value intervening BBIs that are commissioned in the period between 1 July 2022 and 30 June 2023 (again assuming the new TPM is implemented on 1 April 2023). We consider the same timing, process and resourcing considerations arise for these BBIs, including because, in parallel to finalising allocations for the high-value intervening BBIs, we must also model allocations to support live investment decision processes consistent with the Capex IM. Based on current forecasts, we expect at least three high-value intervening BBIs to be commissioned in the July 2022-June 2023 financial year - the Pole 2 convertor transformer refurbishment project, the first component of the WUNIVM project, and the Bombay-Otahuhu major capex project.

51. Overall, our proposal can be summarised as follows:

Commissioning date of high-value intervening BBI	Start pricing year	Pricing year from which standard method BBCs apply (if delay required)
before 1 July 2022	2023/24	2024/25
1 July 2022 to 30 June 2023	2024/25	2025/26

52. This proposal is a departure from the requirements of clause 20(a) of the Guidelines. We consider this departure is justified under clause 2 of the Guidelines:

52.1 We consider the departure is not inconsistent with the intent of the Guidelines. Clause 21 requires a standard method to produce allocations "in proportion to the expected positive net private benefit to [the beneficiaries of the high-value post-2019 BBI]". In our view this outcome will be best achieved by ensuring the necessary processes for completing modelling and consultation requirements for the standard methods can occur. As per the requirements of the Guidelines, these allocations will then be locked in, subject to limited adjustments, for the remaining life of the BBI. We consider the intended outcome of the standard method is more likely to be achieved by, if required, delaying the standard method BBCs for a high-value intervening BBI by one year and using simple method BBCs for a limited transition period, with a wash-up being later applied (noting that the simple method is also a benefit-based allocation methodology).

52.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective by providing greater assurance that the enduring BBCs for a high-value intervening BBI will be in proportion to EPNPB, as required by the Guidelines.

53. We note this proposal is consistent with the precedent provided by the Commerce Commission's implementation of the fibre price control regime under Part 6 of the Telecommunications Act 2001. Under that regime the Commission has to introduce price control for Chorus' fibre business no later than 1 January 2022. The Commission is going to

do so by adopting a "transitional" RAB (effectively a draft RAB) for the first regulatory period, with application of wash-up in the 2nd regulatory period after the RAB value is finalised.[9]

5.2 Calculation of embedded electricity and gross energy

54. In its feedback on the 30 June proposed TPM, the Authority asked us to "*consider whether the following scenario is captured (if feasible): Injection by a distributed generator passes through the load customer to the grid. In this scenario, would the load customer be considered a load customer to the extent of that distributed generation?*"

55. In our response to this comment, we confirmed clause 28(a) of the Guidelines and the definition of "gross" requires the load customer's embedded electricity, and therefore gross energy, to include all of the embedded generator's injection.

56. We have carefully considered the scenario raised by the Authority, and the implications for residual charge calculations. Having considered this matter further, we consider it would be appropriate, and consistent with the Authority's intent and statutory objective, to net-off from embedded electricity any coincident electricity that is injected into the grid. This change is described and illustrated in clause 5 of the resubmitted proposed TPM.

57. This proposal is a departure from the requirements of clause 28(a) of the Guidelines and the definition of "gross", which do not contemplate netting off coincident grid injection. We consider this departure is justified under clause 2 of the Guidelines.

    57.1 We consider the departure is not inconsistent with the intent of the Guidelines. The Guidelines do not treat grid-injected electricity as part of the gross energy of a grid-connected generator because it is not a substitute for grid offtake. By the same logic, we do not consider grid-injected electricity from an embedded generator should count as part of the gross energy of the relevant grid-connected consumer or distributor. If it were, we consider that would be contrary to the intent of the Guidelines.

    57.2 We consider the departure promotes all three limbs of the Authority's statutory objective by removing a potentially inefficient disincentive for the development or full use of embedded generation, which could also have adverse reliability consequences, and protecting competitive neutrality between grid-connected and embedded generation.

58. We confirm the indicative pricing model submitted as part of the 30 June proposal was consistent with the above approach of netting off coincident grid injection, as is the updated indicative pricing submitted in response to the Authority's feedback. This has now been clarified in the resubmitted proposed TPM.

[9] Commerce Commission, Chorus' initial regulatory asset base as at 1 January 2022 – Draft Decisions - Reasons paper, 19 August 2021 at paragraphs 1.12 to 1.14.

Appendix A – clause 52 and 53 criteria worked examples

59. We have assessed the use of the clause 52 and 53 methods for a BBI that meets the criterion in clause 52(1)(a) and a BBI that meets the criterion in clause 53(1)(b)(i), using two simplified examples. The purpose of these two examples is to support understanding of the approach in the resubmitted proposed TPM, and our rationale for it.

Example 1 – a BBI that only benefits loads and new generators, which meets the criterion in clause 52(1)(a) requiring the use of the clause 52 method

60. Example 1 is based on the following assumptions:
    - The market consists of two nodes (A and B) both with load and generation.
    - Node A has constant demand of 350 MW from January-March, and constant demand of 250 MW from April-December.
    - Node B has constant demand of 250 MW from January-September, and constant demand of 350 MW from October-December.
    - The nodes are connected by an existing transmission line with a capacity of 50 MW from Node A to B, and 100 MW from B to A.
    - Each node has a 250 MW baseload generator with an SRMC of $100/MWh. Node B also has a 100 MW peaking generator with an SRMC of $150/MWh.
    - Node A has a potential new 100 MW peaking generator with an SRMC of $120/MWh, and a capital cost of $120m (equal to an annualised capital cost of $10.5m p.a. assuming a 6% cost of capital and a 20-year life).
61. With this existing generation, the two baseload generators run at full output all the time, and the peaker at Node B runs at full output from January to March, and October to December. From April to September the peaker at Node B does not run.
62. Ignoring transmission constraints and assuming least-cost system dispatch and offers at SRMC, if the peaking generator at Node A was built it would be dispatched instead of the peaker at Node B, saving $13.1m p.a. in operating costs (100 MW × 24 hours/day × 182 days/year × ($150/MWh - $120/MWh)). Therefore, the peaker at Node A would be built because this operating cost saving is higher than its annualised capital cost. However, a transmission upgrade is also needed to increase transmission capacity from Node A to B from 50 to 100 MW to allow the peaker at Node A to be fully utilised.
63. Given these assumptions, the transmission upgrade would pass the investment test (which assesses changes in costs, not private benefits) if it has an annualised capital cost lower than $2.6m p.a. ($13.1m - $10.5m).[10]

[10] For the purpose of this example we are ignoring that under the proposed TPM this BBI would use the simple method because it is less than $20m.

64. Assuming this is the case, this is a highly simplified example of a transmission project that has benefits arising solely from new generation investment – i.e. the project has no benefits in the market as it exists today, and only has benefits if the peaker at Node A is built.

65. Based on the price outputs of the market model shown in the graph below, the beneficiaries of this transmission project are:

- Loads throughout the grid who benefit from reduced prices in Jan-Mar and Oct-Dec
- The new generator at Node A, which would not exist if the transmission investment did not occur (or alternatively, would have its output curtailed and would not be profitable).

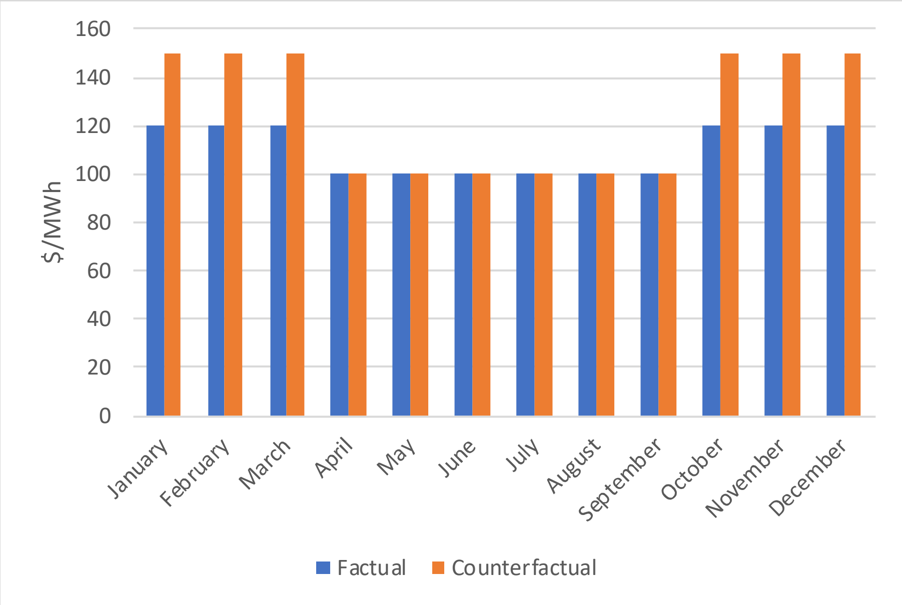

Figure 1: Node A and B prices with and without BBI

66. The existing baseload generators do not benefit because they receive less revenue due to prices being lower throughout the grid. The existing peaker at Node B also does not benefit because its output is displaced by the new peaker at Node A.

67. This example highlights the practical limitations of using the clause 53 method to quantify the benefits to new generation:

- Because prices are based on SRMC, they are not high enough to recover the capital cost of the new peaker in this example. In reality, prices would at least be sufficient to recover operating and capital costs.
- Even if prices were adjusted to reflect the LRMC of the new peaker (using clause 50(5) and if the definition of wholesale market model was expanded to include capital costs) prices would only be enough to recover costs (including capital costs), and the peaker will be economically agnostic to entering the market. Therefore, the peaker would not be identified as a beneficiary.

68. As a result, and as discussed in section 2.1, we have specified that where most of the benefits to supply groups are to new large generating plant, we will use the clause 52 method to calculate market benefits and disbenefits as the resulting BBI customer allocations will better (than the clause 53 method) meet the requirement in clauses 8 and 21 of the Guidelines to be broadly in proportion to EPNPBs.

69. In this example, the 52 method identifies the peaker at Node A as a beneficiary and produces the following allocations:
    - Loads benefit by the quantity of offtake in the periods where prices are lower in the factual than the counterfactual – equal to 2620 GWh p.a. (600 MW × 182 days/year × 24 hours/day).
    - The peaker at Node A benefits from the BBI during all periods it is operating – equal to 440 GWh (100 MW × 182 days/year × 24 hours/day).
70. Because we cannot charge a customer that does not exist today, load customers will be allocated 100% of the charge until the new peaker (or another generator) connects at Node A. When the new peaker connects, it will be the first member of the future regional supply group and its allocation will be calculated under clause 84 using the notional IRA value for the group (clause 84(4)).
71. Therefore, in this example, once the peaker at Node A connects, loads have an allocation of 86% and the peaker at Node A has an allocation of 14%. If additional peaking generation connects at Node A, the allocation to generation will increase further as per clause 84.

Example 2 – a BBI that benefits loads, existing generators, new generators, and avoids scarcity prices, which meets the criterion in 53(1)(b)(i) requiring the use of the clause 53 method

72. Example 2 has the same assumptions as example 1, except:
    - In the counterfactual, the transmission enhancement from example 1 has occurred (i.e. 100 MW capacity in both directions). The transmission line connecting Nodes A and B can be enhanced further to increase capacity from A to B by 150 MW (250 MW total) – this is the factual in this example.
    - After 5 years, a 100 MW load with constant demand connects at Node B.
    - Demand at Node B begins growing at 4% p.a. from year 6.
    - The following peakers are available to be commissioned when market conditions justify investment:
        - 100 MW peaker at Node A with SRMC $125/MWh and capital cost $100m
        - 50 MW peaker at Node A with SRMC of $130/MWh and capital cost $50m
        - 100 MW peaker at Node B with SRMC $150/MWh and capital cost $100m
        - 50 MW peaker at Node B with SRMC of $150/MWh and capital cost of $50m
73. Transmission capacity provided by the BBI is sufficient in the factual to enable the lowest cost new generation at Node A to be built. In the counterfactual, transmission capacity from Node A to B is insufficient for generation to be commissioned at Node A and access the growing load at Node B, so the more expensive generation at Node B is commissioned later in the analysis period, resulting in higher prices at Node B until the generation is commissioned.
74. The below graphs show the change in price at Node A and B due to the BBI.

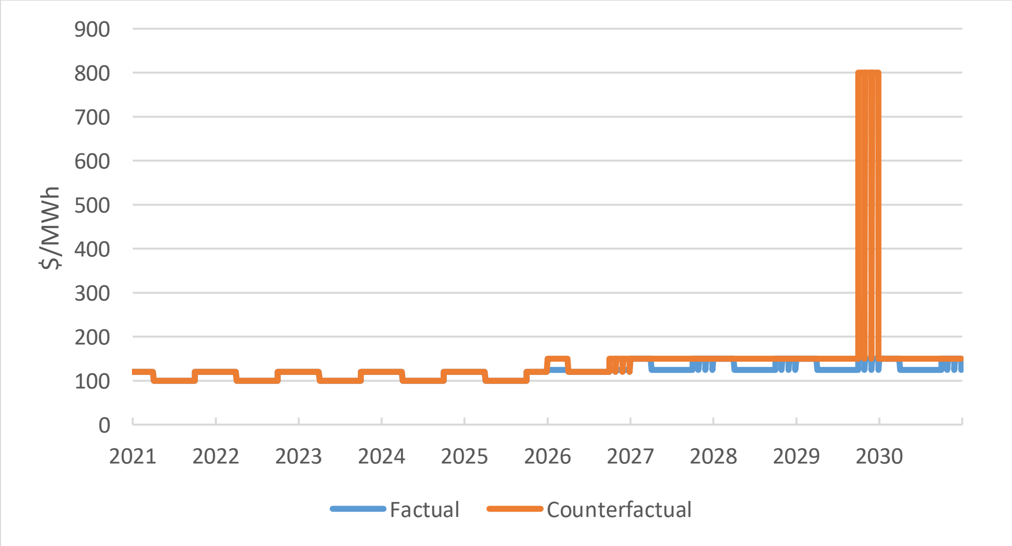

Figure 2: Node B prices with and without the transmission investment (pre-adjustment)

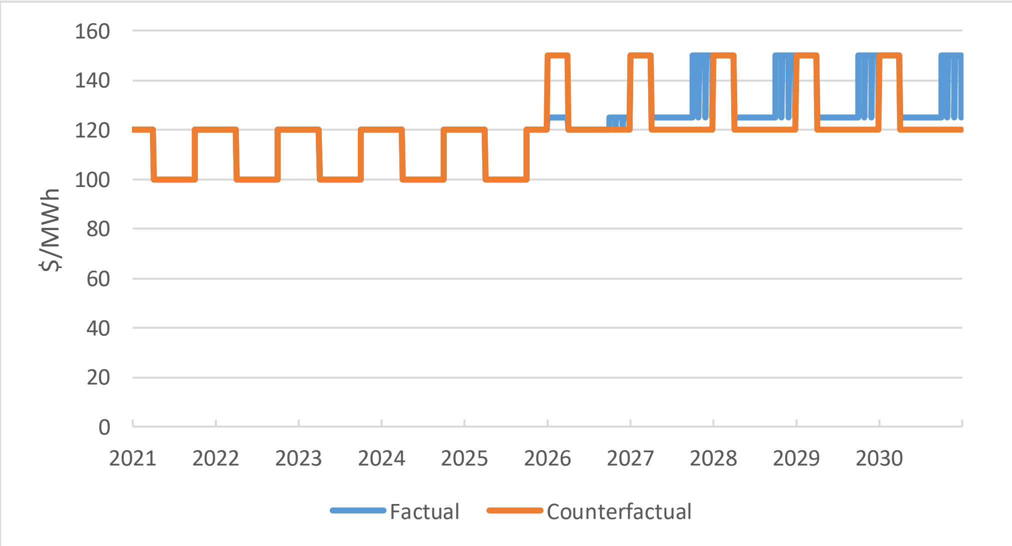

Figure 3: Node A prices with and without the transmission investment (pre-adjustment)

75. The prices from the market model do not reflect the capital costs for the new peakers built in the factual and counterfactual. Therefore, we have adjusted up the prices to the LRMC of the new generation during the periods it is generating and marginal using clause 50(5)[11], and applied these adjusted prices for determining benefits and beneficiaries in both the clause 52 and 53 methods. The resulting prices are shown in the below graphs.

76. We note that we do not necessarily expect to need, or intend, to adjust prices in this manner for every BBI in order to produce allocations that are broadly in proportion to EPNPB – price adjustments are particularly relevant in this simplified example, and prices are comparably straightforward to adjust in a transparent manner, because the generators being commissioned are often marginal.

[11] If the new generator is only marginal at the node it is connected to, prices are only adjusted for that node. If the new generator is marginal at both nodes, prices are adjusted for both.

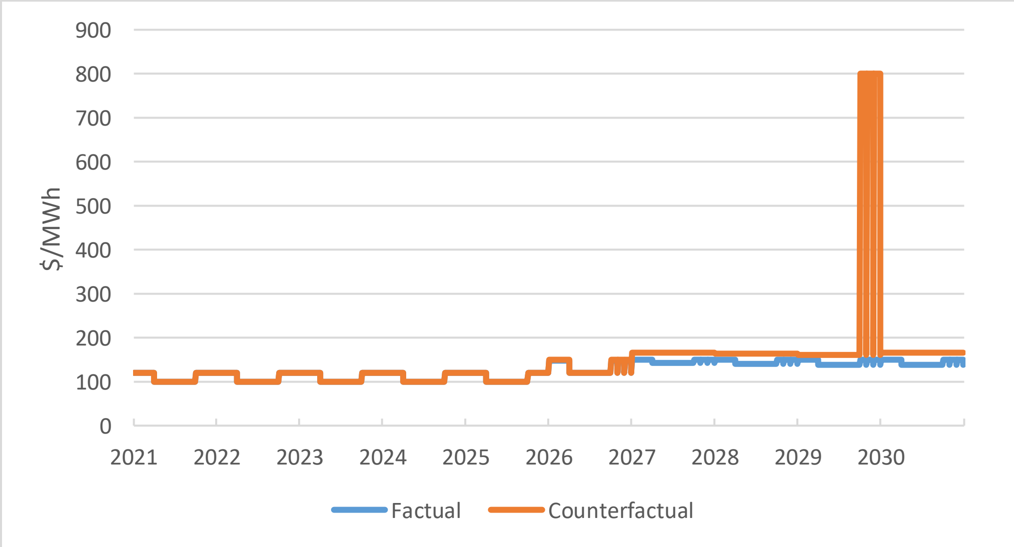

Figure 4: Node B prices with and without the transmission investment (post-adjustment)

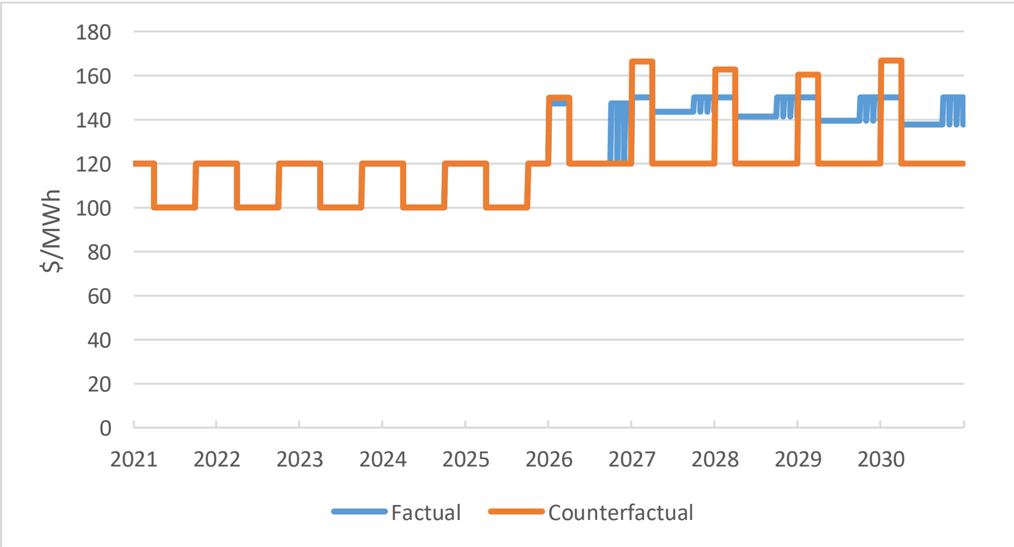

Figure 5: Node A prices with and without the transmission investment (post-adjustment)

77. The tables below show the expected net-private benefits allocations using the clause 52[12] and 53 methods. Unlike example 1, the majority of private benefits result from loads avoiding high prices when there is not enough generation to supply load at Node B (at an assumed long-run cost of self-supply of $800/MWh), which results in a higher allocation to load customers at Node B under the clause 53 method than the clause 52 method.

78. This example also results in the majority of benefits to generation customers being received by existing generators at Node A, who benefit from accessing higher Node B prices. We note, unlike example 1, the benefits to new generators are significantly less than for existing generators so clause 52(1)(a) would not apply. Furthermore, because benefits to new generators are less significant in this example, the issues described in section 2.1 – while still present – are a less material factor than the avoided cost of self-supply for determining

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[12] Under clause 52, for the purpose of this example, we have defined the periods of benefit and disbenefit as those in which the price changes in the factual compared to the counterfactual (with a price increase being a benefit to generation and disbenefit to load and vice versa).

beneficiaries and allocations that are broadly in proportion to EPNPB. Therefore, we consider clause 53 is the correct method to use to produce allocations that are broadly in proportion to EPNPB, and hence we have added the 53(1)(b)(i) criterion to the resubmitted proposed TPM, as described in section 2.2.

Table 1: Example 2 expected net-private benefits and allocations using 52 method

	Node A - load	Node B - load	Node A - existing generation	Node B - existing generation	Node A - new generation	Node B - new generation
Expected net-private benefit	-1,962 GWh	9,814 GWh	3,699 GWh	-7,606 GWh	1,653 GWh	-1,056 GWh
Proportion of total EPNPB[13]	0%	72.6%	27.4%	0%	0%	0%

Table 2: Example 2 expected net-private benefits and allocations using 53 method

	Node A - load	Node B - load	Node A - existing generation	Node B - existing generation	Node A - new generation	Node B - new generation
Counterfactual	$12,036m	$13,725m	$328m	$731m	$0m	$49m
Factual	$11,962m	$14,233m	$443m	$382m	$36m	$0m
Expected net-private benefit	-$74m	$509m	$115m	-$349m	$36m	-$49m
Proportion of total EPNPB[13]	0%	81.5%	18.5%	0%	0%	0%

79. Given the limitations of the clause 53 method for quantifying benefits to new generators, in a situation such as this example we intend to group the new generator with the existing generation group so it receives the same allocation (in proportion to its size) under clause 84 when it connects to the grid. As discussed in paragraph 25 of our Checkpoint 2B resubmission: adjustments, by grouping new and existing generation customers together we ensure new generators receive the same allocation as existing generators in the same region. This approach avoids creating a competitive advantage to an existing generator compared to a new generator where the two are otherwise identical.

80. Therefore, as per clause 53(6), we have removed the benefits of new generators from the generation group when determining the final allocations, rather than creating a separate future regional supply group for new generators.

[13] After removing benefits from new large plant as per clause 53(6).