TRANSPOWER

NZGP1 shortlist consultation

Indicative covered costs and starting BBI customer allocations

Date: 14 July 2022

Contents

1 Purpose

1. Transpower is currently consulting on its shortlist of investment options for stage 1 of phase 1 of Net Zero Grid Pathways (**NZGP1**).[1] As detailed in the NZGP1 shortlist consultation paper and summarised in section 2.1, the preferred NZGP1 option includes the HVDC, Central North Island and Wairakei Ring investments.

2. Under the new transmission pricing methodology (**TPM**),[2] the covered costs of post-2019 investments in interconnection assets and transmission alternatives (benefit-based investments or **BBIs**) are recovered from customers identified as beneficiaries, in proportion to their expected positive net private benefit (**EPNPB**) from those investments. The TPM contains the methods for calculating charges for BBIs (benefit-based charges or **BBCs**).

3. The purpose of this document is to assist stakeholders responding to our NZGP1 shortlist consultation to understand the possible impact of the preferred NZGP1 option on their transmission charges. It presents indicative covered cost profiles and starting BBI customer allocations for the indicative BBIs comprised in the preferred NZGP1 option, reflecting the requirements of the TPM.

4. This document covers:

   4.1 Section 2: background on the investments and indicative BBIs comprised in the preferred NZGP1 option and future steps under the Transpower Capital Expenditure Input Methodology Determination 2012 (**Capex IM**)[3] and TPM

   4.2 Section 3: indicative covered costs for the indicative BBIs comprised in the preferred NZGP1 option (HVDC/CNI BBI and Wairakei Ring BBI)

   4.3 Section 4: indicative starting BBI customer allocations for the high-value[4] BBI (HVDC/CNI BBI),[5] which are required to be calculated using a standard method under the TPM

   4.4 Section 5: indicative starting BBI customer allocations for the low-value BBI (Wairakei Ring BBI), which are required to be calculated using the simple method under the TPM.

5. At this stage, we are not consulting on the indicative allocations set out in this document. Following the NZGP1 shortlist consultation, we will decide which NZGP1 option to propose and submit a major capex proposal (**MCP**) for it to the Commerce Commission (**Commission**). After submitting the MCP, and ahead of the Commission's draft determination, we will carry out formal consultation on proposed starting BBI customer allocations for the high-value BBI(s) comprised in the NZGP1 option the MCP proposes, as required by the TPM. Further consultation on the starting BBI customer allocations for any low-value BBI(s) is not required

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[1] Net Zero Grid Pathways 1: Major Capex Project (Staged) Investigation: Shortlist consultation, 30 June 2022.

[2] The TPM approved by the Electricity Authority (**Authority**) on 11 April 2022, and effective from 1 April 2023, is published here: https://www.ea.govt.nz/assets/dms-assets/30/New-TPM.pdf.

[3] Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf (comcom.govt.nz)

[4] A high-value BBI is a BBI that is expected to involve capital expenditure and/or transmission alternative opex of more than the base capex threshold under the Capex IM, which is currently $20m. BBIs expected to cost $20m or less are low-value BBIs.

[5] For the purpose of indicative allocations, we have grouped the HVDC and CNI investments into one BBI, as explained in section 2.1.

as we have already done this – we consulted on the simple method modelled regions and allocators for the first simple method period as part of our draft assumptions book consultation.[6]

6. We have applied the methodologies in the TPM and draft assumptions book to produce the indicative allocations for the HVDC/CNI BBI in this document. However, our calculations have not been at the level of detail we will apply when we calculate proposed starting BBI customer allocations for the NZGP1 high-value BBI(s) for consultation under the TPM (as noted above, this will be soon after our MCP to the Commission). Nevertheless, we consider the indicative allocations presented in this document provide a reasonable indication of the distribution of EPNPB from the HVDC/CNI BBI using the modelling inputs and assumptions set out in this document (which themselves are indicative only).

7. We stress that the indicative covered costs and allocations set out in this document are not the proposed or the final covered costs or allocations for the BBIs comprised in the preferred NZGP1 option or any other potential NZGP1 investment. Transpower cannot, and does not, accept any liability for the accuracy or completeness of the information in this document or the consequences of your or others' reliance on it. We recommend you review the TPM itself and seek independent expert advice before relying on anything in this document.

8. Unless otherwise stated, in this document:

    8.1 references to NZGP1 mean stage 1 of NZGP1 (there is a stage 2 contemplated); and

    8.2 clause references are to clauses of the TPM.

[6] https://www.transpower.co.nz/our-work/industry/transmission-pricing-methodology/tpm-consultations-2022. Chapter 4 and Part E of the draft assumptions book relate to the simple method modelled regions and allocation model.

2 Background

2.1 Investments and BBIs comprised in the preferred NZGP1 option

9. The investments and indicative BBIs comprised in the preferred NZGP1 option are as follows:

   9.1 HVDC/CNI BBI (high-value BBI):

   i) New reactive plant at Haywards to enhance the availability of maximum transfer over the HVDC ($182m); and

   ii) Tactical thermal upgrades (**TTUs**) of the Tokaanu-Whakamaru and Bunnythorpe-Tokaanu lines and duplexing of the Tokaanu-Whakamaru lines to enhance the capacity of transfer through the central North Island (CNI) ($128m).

   9.2 Wairakei Ring BBI (low-value BBI): TTU of the Wairakei-Whakamaru C line to enhance the capacity of the Wairakei Ring ($13m).

10. More detail on these investments is in the NZGP1 shortlist consultation paper.

11. For the purpose of indicative allocations, we have grouped the HVDC and CNI investments together as a single BBI. Our initial view is these investments should be treated as a single BBI because the benefits of the CNI investment are linked to the HVDC investment occurring (and vice versa). This is because the CNI lines and HVDC sit in series configuration;[7] the HVDC moves power from the South Island to the lower North Island (and vice versa) and the CNI lines from the lower North Island to the upper North Island (and vice versa).

12. Before calculating the proposed starting BBI customer allocations for consultation under the TPM, we will consider again whether to treat the HVDC and CNI investments as a single BBI (assuming they are part of the proposed NZGP1 option). A key factor we will consider is whether grouping them is likely to result in allocations that are broadly proportionate to EPNPB, particularly for generation in the lower North Island (see section 4.2.2).

13. We have treated the Wairakei Ring investment as a separate BBI because our analysis indicates its benefits arise mostly from enabling generation development in the Bay of Plenty, Gisborne, and Hawke's Bay regions.

14. At this stage, we have focussed on producing indicative covered costs and allocations for these core elements of the preferred NZGP1 option and have not calculated indicative covered costs or allocations for the approximately $19m of facilitating and preparedness projects that are also part of the preferred option.[8]

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[7] Series configuration means that the electrical current passes through each asset successively.

[8] Which make up the difference between the total estimated cost of the first stage of NZGP1of $342m and the $323m for the HVDC, CNI, and Wairakei Ring investments.

2.1.1 The price-quantity method applies to the HVDC/CNI BBI

15. Because the HVDC/CNI BBI would be a high-value post-2019 BBI, Transpower must use a standard method under the TPM to determine its beneficiary customers and calculate their starting BBI customer allocations.

16. We have used the price-quantity method (one of two standard methods in the TPM) for the HVDC/CNI BBI because it is not a resiliency BBI - its primary investment need is to alleviate, or prevent, transmission constraints that would affect quantities and prices in the wholesale market for electricity, not to mitigate a risk of cascade failure or a high impact, low probability event.

17. Within the price-quantity method there are four types of regional NPB that may be calculated – market regional NPB, ancillary service regional NPB, reliability regional NPB and other regional NPB. For the HVDC/CNI BBI we have calculated market regional NPB only (regional NPB relating to changes in quantities and prices in the wholesale market for electricity). This is because we do not expect the HVDC/CNI BBI to have material reliability or other benefits, and we have not yet assessed the impact of the BBI on ancillary service costs.

18. Within the price-quantity method there are two options for calculating market regional NPB arising from changes in the wholesale market for electricity. The default option is to calculate market regional NPB based on quantities during periods of benefit (clause 51). The alternative option uses both quantities and prices to calculate market regional NPB (clause 52).

19. For the purpose of indicative allocations, we have used the quantity-based option (clause 51) because it is the default method for calculating market regional NPB and the one we expect to use most often. We will reassess this prior to calculating and consulting on the proposed starting BBI customer allocations for the NZGP1 high-value BBI(s).

20. Section 4 contains indicative starting BBI customer allocations for the HVDC/CNI BBI.

2.1.2 The simple method applies to the Wairakei Ring BBI

21. Treating the Wairakei Ring investment as a separate BBI results in it being classified as a low-value BBI. Therefore, its starting BBI customer allocations are calculated using the simple method under the TPM.

22. Section 5 contains indicative starting BBI customer allocations for the Wairakei Ring BBI.

2.2 Interaction with the Capex IM

23. The combined investment value of the preferred NZGP1 option (including the facilitating and preparedness projects) is currently estimated at $342 million and its constituent parts are enhancement investments. This means the option is a major capex project under the Capex IM, for which Transpower must submit an MCP to the Commission for approval.

24. Under clause 7.5.1(1) of the Capex IM, an MCP must include information about the expected increase in transmission charges due to the proposed expenditure. We will include this information in the NZGP1 MCP for whatever NZGP1 option we propose (which we expect will be a major capex project in any event).

25. The NZGP1 MCP will also include the market scenarios and other modelling assumptions and parameters we use to apply the Capex IM investment test to the major capex project. Clause 43(5) of the TPM generally requires consistency in approach with the Capex IM's investment test when we calculate starting BBI customer allocations for a high-value BBI. We may depart from the investment test approach if we determine that approach would not produce allocations that are broadly proportionate to EPNPB from the BBI.

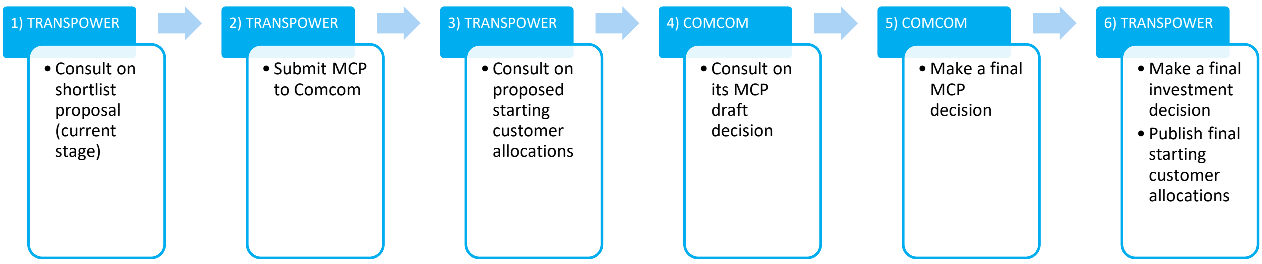
2.3 What happens next for the NZGP1 allocations?

26. Under clause 15 of the TPM, Transpower must consult on the proposed starting BBI customer allocations for each high-value post-2019 BBI. We will therefore consult on the proposed starting BBI customer allocations for any NZGP1 high-value BBI before finalising its BBCs.

27. We plan to consult on the proposed starting BBI customer allocations after we have submitted the NZGP1 MCP and before the Commission consults on its draft decision on the MCP. Following the Commission's final decision, assuming the Commission approves the proposed NZGP1 option, Transpower will make its final investment decision, at which time we will publish the final starting BBI customer allocations for the NZGP1 high-value BBI(s).[9]

28. These planned stages are illustrated in Figure 1 below.

Figure 1: Planned stages to final starting BBI customer allocations



[9] If we amend the proposed investment after consulting on the proposed starting BBI customer allocations we will re-consult on the allocations if the amendment is likely to affect them materially.

3 Covered costs of the BBIs

3.1 TPM requirements for calculating covered cost

29. Under clauses 39 and 40 of the TPM, a BBI's covered cost is calculated annually based on the values of certain capex and opex inputs for the relevant pricing year. A BBI's covered cost is made up of:

    29.1 costs that are directly attributable to the BBI or have a verifiable causal relationship with it. This captures capex costs (depreciation calculated in accordance with the Transpower IMs and a return on investment using our regulated WACC) and some types of opex

    29.2 a portion of our "overhead" opex, which does not have a direct or causal relationship with the BBI but is reasonably attributable to it. This type of opex is attributed to all BBIs in proportion to their depreciation (depreciation multiplied by an attributed opex ratio).

3.2 Latest estimate of covered costs

30. This section summarises the assumptions and results of the indicative covered costs for the HVDC/CNI BBI and Wairakei Ring BBI.

31. We have used the same preliminary costs as on page 10 of the NZGP1 shortlist consultation to estimate the covered costs of the HVDC/CNI BBI and Wairakei Ring BBI. As indicated in the NZGP1 shortlist consultation, these costs will be refined prior to submitting the NZGP1 MCP. Under the TPM, the covered cost of a BBI changes over time based on the final breakdown of assets commissioned as part of the BBI, changes to Transpower's WACC, and depreciation. Therefore, while we expect our covered cost estimates to improve as the cost estimates are refined, they will not be fixed until commissioning.

Figure 2: HVDC/CNI indicative covered cost

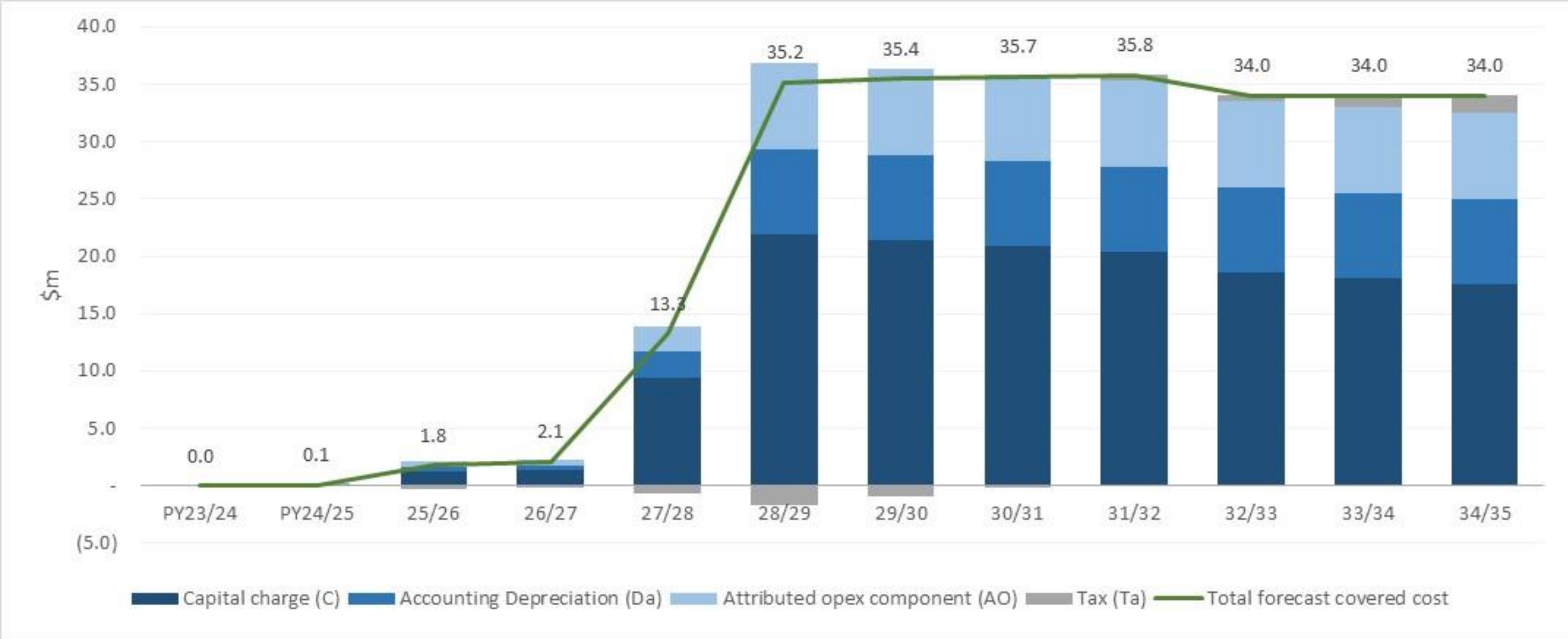


Table 1: HVDC/CNI indicative covered cost

Pricing year, PY (ending 31 March)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Accounting Depreciation (Da)	-	0.4	0.4	2.2	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Capital charge (C)	0.1	1.2	1.4	9.5	21.9	21.4	20.9	20.4	18.5	18.0	17.6
Attributed opex component (AO)	-	0.4	0.4	2.2	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	0.0	(0.3)	(0.2)	(0.7)	(1.7)	(0.9)	(0.2)	0.5	0.5	1.1	1.5
Total forecast covered cost	0.1	1.8	2.1	13.3	35.2	35.4	35.7	35.8	34.0	34.0	34.0

Figure 3: Wairakei Ring indicative covered cost

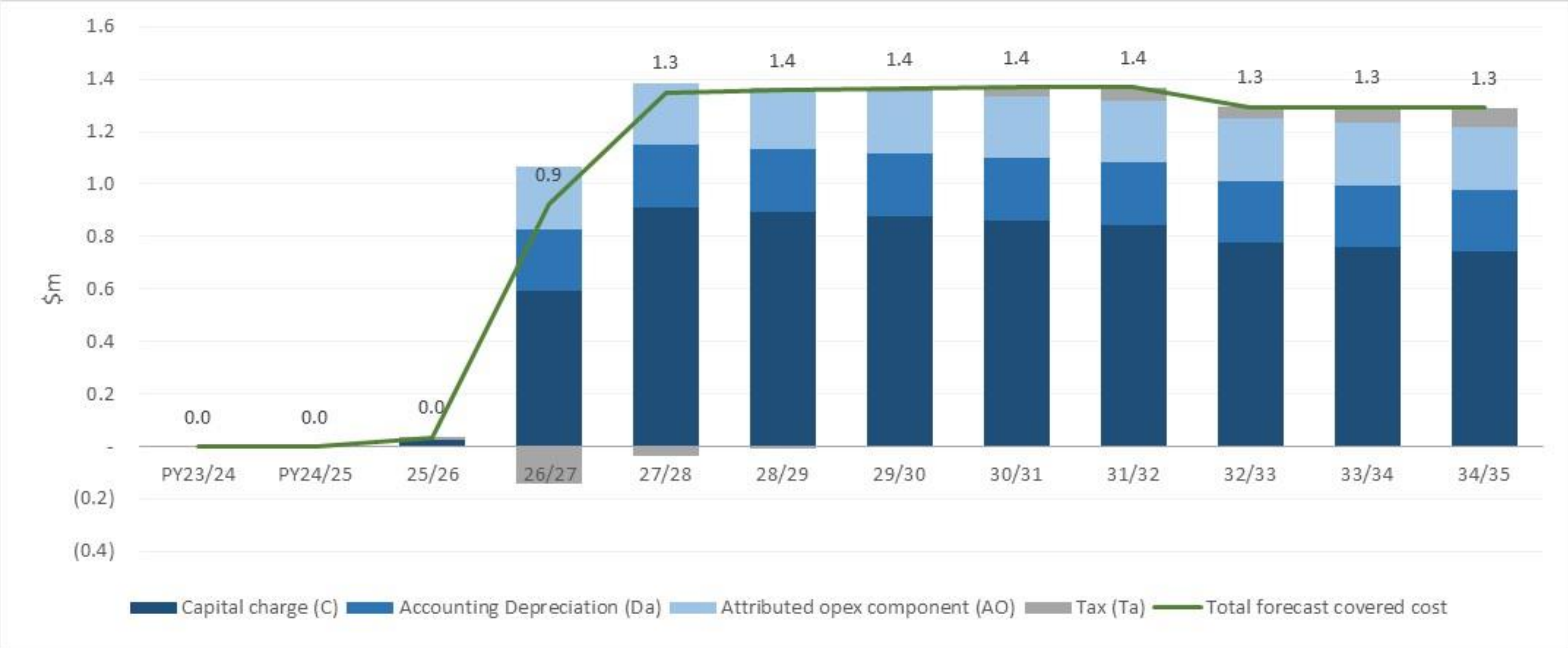


Table 2: Wairakei Ring indicative covered cost

Pricing year, PY (ending 31 March)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Accounting Depreciation (Da)	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Capital charge (C)	-	0.0	0.6	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.7
Attributed opex component (AO)	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	-	0.0	(0.1)	(0.0)	(0.0)	0.0	0.0	0.1	0.0	0.1	0.1
Total forecast covered cost	-	0.0	0.9	1.3	1.4	1.4	1.4	1.4	1.3	1.3	1.3

32. As shown in figures and tables above, the annual covered costs initially increase reflecting progressive asset commissioning, before stabilising once the assets that make up the BBI are fully commissioned. Covered cost for PY 2027/28 to PY 2032/33 includes a forecast increase in Transpower's regulated WACC for the regulatory control period commencing on 1 April 2025 (**RCP4**), reflecting expected higher inflation.[10]

33. The key assumptions and inputs we have applied to estimate the BBIs' covered costs are as follows:

    33.1 Commissioning is assumed to be in June of each financial year.

    33.2 Nominal WACC is forecast to increase from 4.57% in RCP3 to 7.15% in RCP4 reflecting forecast higher inflation. The RCP4 WACC first takes effect in pricing for PY 2027/28. RCP5 nominal WACC is forecast to decrease slightly to 6.69% which impacts covered costs from PY 2032/33.

    33.3 The attributed opex ratios for RCP4 and RCP5 are calculated based on Transpower's opex allowances for RCP3.

    33.4 We assume no material change to HVDC insurance costs and to reserve costs attributable to the HVDC as a result of the HVDC/CNI BBI, but will consider this further and update stakeholders when we consult on the proposed starting BBI customer allocations.

[10] The Commission's determination of Transpower's RCP4 WACC will have effect for revenue-setting purposes for the five pricing years commencing PY 2025/26.

4 Indicative allocations for the HVDC/CNI BBI

34. This section summarises our application of the price-quantity method to the HVDC/CNI BBI and presents indicative starting BBI customer allocations.

4.1 Market scenarios and other key modelling assumptions

35. The key modelling inputs we have used in our application of the price-quantity method to the HVDC/CNI BBI are as follows:

35.1 Expected market benefits and disbenefits have been discounted at a rate of 7% per annum (the standard method discount rate in the TPM), which is the same rate as used in the application of the investment test in the NZGP1 shortlist consultation.

35.2 For the purpose of indicative allocations, we have used a single market scenario – the Growth scenario used in the application of the investment test in the NZGP1 shortlist consultation. We chose this scenario because it is the middle of the five scenarios used in the NZGP1 shortlist consultation with respect to electricity demand.

35.3 We have used the same assumptions to produce indicative allocations as used in the Growth scenario in the application of the investment test in the NZGP1 shortlist consultation, with the following exceptions:

i) All facilitating projects that make up part of the preferred option but are not part of the HVDC/CNI BBI are assumed to occur in both the factual and the counterfactual, whereas they are assumed to occur in the factual but not the counterfactual in the application of the investment test. We have done this because the price-quantity method is trying to identify the private benefits associated with the BBI rather than with other transmission projects, whereas the investment test often assesses the costs and benefits of a development path of projects over a number of years to ensure the preferred option is least cost over time.

ii) We have not modelled upgrades to the HVDC/CNI BBI associated with stage 2 of NZGP1, because these will be the subject of a future investment proposal if and when that occurs.

36. We note, in general, the modelling assumptions used in the NZGP1 shortlist consultation are consistent with chapter 2 of the draft assumptions book. However, there are several assumptions that are different which are discussed in the shortlist consultation document. For example:

36.1 The inclusion of a number of additional generation units as possible new wind, solar, and battery generation projects associated with new connection enquiries.

36.2 In the Environmental scenario carbon price projections are based on the IEA's 2021 World Energy Outlook. Specifically, the IEA's carbon prices for their "Net Zero" scenario and for "advanced economies".[11] All other market scenarios use the Climate Change Commission's projections for carbon prices.

36.3 The use of a conservative cost decline for wind generation in the Disruptive scenario to achieve a balance of new wind and solar that better reflects the large number of proposed solar projects.

36.4 A different timing for the HVDC upgrade, reflecting the proposed timing of the HVDC investment in the major capex project.

36.5 A reduced discount rate for solar projects to either 5% or 6% (depending on the market scenario) to reflect the wider pool of capital that is available given solar is simpler to consent, construct, and maintain than other generation technologies.

36.6 A 50% reduction in the capital cost of geothermal generation to reflect that exhaust steam can be used for industrial processes (thereby reducing the revenue required to be recovered from the electricity market).

37. Where the investment test in the NZGP1 shortlist consultation uses a different assumption than in the draft assumptions book, we have used the assumption from the investment test (if relevant) to produce indicative starting BBI customer allocations for the HVDC/CNI BBI. This is so that the indicative allocations are consistent with the application of the investment test, which, as noted above, is a general requirement of the TPM.

4.2 Modelled regions and market regional NPB

4.2.1 Modelled regions

38. To determine the modelled regions for the HVDC/CNI BBI we analysed prices in the counterfactual at each modelled node in the network. We calculated the correlation coefficient between all pairs of nodes, and grouped nodes into a region if they had a high correlation. This resulted in the following modelled regions:

38.1 Upper North Island (UNI) including Bay of Plenty and Hawke's Bay

38.2 Lower North Island (LNI) including Taranaki and Manawatu-Whanganui

38.3 South Island (SI).

4.2.2 Market regional NPB

39. Under clause 51 of the TPM, market regional NPB is calculated based on:

39.1 the volume of load or generation exposed to a transmission constraint alleviated by the BBI, which effectively produces allocations that are consistent with an equal change in market price to each beneficiary either side of the constraint; plus

[11] For further details see: https://www.iea.org/reports/world-energy-model/macro-drivers

39.2 any additional volume of generation or load enabled by the BBI.

40. As illustrated in the diagrams below, load customers downstream of a transmission constraint alleviated by a BBI benefit because prices downstream of the constraint are elevated in the counterfactual. Prices are elevated downstream of a transmission constraint because downstream loads cannot access lower cost resources upstream of the constraint.

41. Generation customers upstream of a transmission constraint alleviated by a BBI benefit because prices are depressed upstream of the constraint in the counterfactual. Prices are depressed upstream of a transmission constraint because there is a surplus of generation which would otherwise be transmitted to other regions via the transmission network.

42. Conversely, load customers upstream and generation downstream of a transmission constraint alleviated by a BBI disbenefit.

Figure 4: Prices with circuit at less than capacity

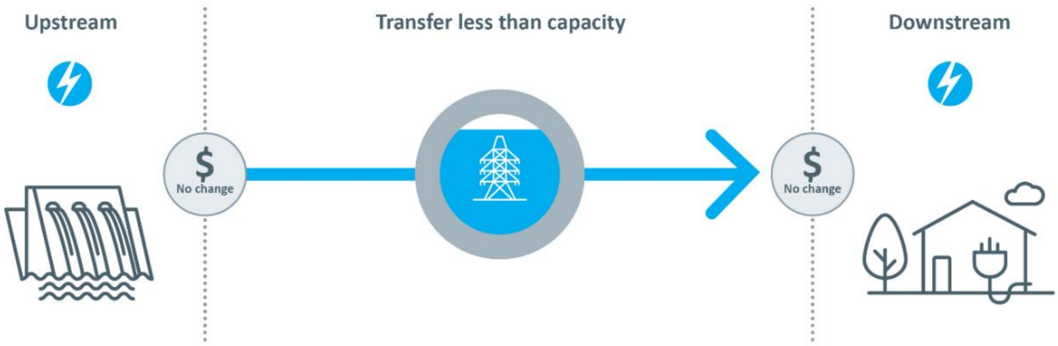
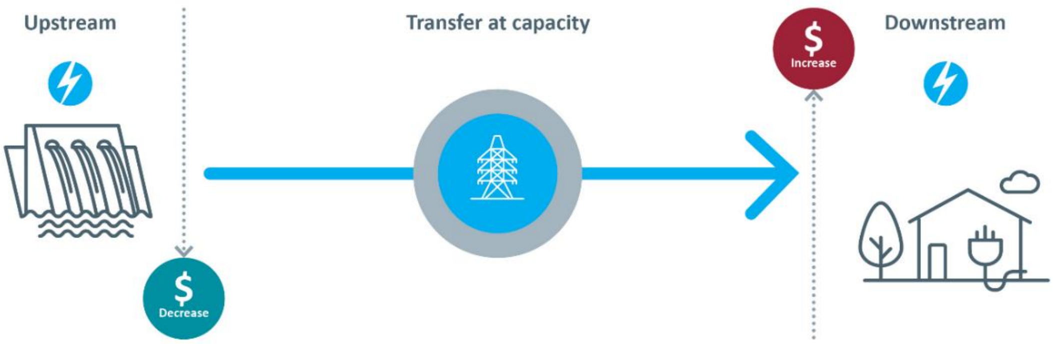


Figure 5: Prices with circuit at capacity



43. As applied to the HVDC/CNI BBI, UNI load and SI generation benefit if either or both of the HVDC and CNI constraints are binding north (and disbenefit if they are binding south).

44. Because the LNI sits between the HVDC and CNI constraints, load benefits if the HVDC constraint is binding north, and disbenefits if the CNI constraint is binding north (and vice versa for generation in the LNI).

45. The following table shows the indicative allocations of positive regional NPB to regional customer groups for the HVDC/CNI BBI. For the purpose of indicative allocations, we have not split regional customer groups in the same region into more discrete groups (e.g. distributors and industrial load), as is permissible under the TPM.

Table 3: Indicative allocations of positive regional NPB to regional customer groups

Modelled region	Regional customer group	Regional NPB share
UNI	Load	50.6%
LNI	Load	4.2%
SI	All generation	44.2%
LNI	Wind Generation	1.0%

46. A high-level summary of the results of our application of the price-quantity method to the HVDC/CNI BBI is as follows:

46.1 SI generation and UNI load receive the majority of the allocation of positive regional NPB because the CNI and HVDC constraints primarily bind north, rather than south. Because the HVDC and CNI constraints are – collectively – approximately half-way up the core grid, this results in an allocation that is fairly even between these groups.

46.2 LNI load receives an allocation of positive regional NPB because the HVDC constraints bind north (during which this group benefits) more frequently than the CNI constraints bind north (during which this group disbenefits). This results in an allocation that is smaller on a volume-weighted basis than UNI load.

46.3 LNI wind generation receives only a small allocation of positive regional NPB, in part because this region has a relatively low volume of generation, but also because we have treated the HVDC and CNI projects as a single BBI. If we were to treat them as separate BBIs, we expect LNI wind generation would receive a larger allocation for the CNI BBI and no allocation for the HVDC BBI – which may result in a larger allocation overall.[12] Unlike other generation in the LNI, wind generation receives an allocation because it tends to have a higher capacity factor when the CNI constraints are binding north (during which this group benefits) than when the HVDC constraints are binding north (during which this group disbenefits).

[12] Splitting the HVDC/CNI into two BBIs may also result in other generation in the LNI receiving an allocation of positive regional NPB for the CNI BBI (e.g. thermal generation in Taranaki).

46.4 All other groups disbenefit from the HVDC/CNI BBI more than they benefit and therefore receive no allocation of positive regional NPB.

4.3 Indicative starting BBI customer allocations

47. As required under the TPM, we calculated each customer's indicative starting BBI customer allocation for the HVDC/CNI BBI as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the following allocations (to two decimal places).

48. To calculate individual NPB for the purpose of indicative allocations we used the same intra-regional allocators as we used for the proposed starting BBI customer allocations for the CUWLP BBI[13] (i.e. mean offtake or injection from 1 September 2014 to 31 August 2019). This will be updated prior to calculating and consulting on the proposed starting BBI customer allocations for the NZGP1 high-value BBI(s).

Table 4: Indicative starting BBI customer allocations for the HVDC/CNI BBI

Customer Code	Customer Name	Starting BBI customer allocation (%)[14]
MERI	Meridian Energy Limited	30.58%
VECT	Vector Limited	25.24%
CTCT	Contact Energy Limited	9.78%
POCO	Powerco Limited	8.35%
UNIS	Unison Networks Limited	3.84%
NPOW	Northpower Limited	3.18%
WELE	WEL Networks Limited	2.85%
GENE	Genesis Energy Ltd	2.55%
UNET	Wellington Electricity Lines Limited	1.80%
COUP	Counties Power Ltd	1.64%
PANP	Pan Pac Forest Product Limited	1.47%

[13] https://www.transpower.co.nz/our-work/industry/transmission-pricing-methodology/tpm-consultations-2022.

[14] In this table, a "-" indicates a zero allocation, and "0.00%" indicates a very small non-zero allocation.

NZST	New Zealand Steel Limited	1.45%
WAIP	Waipa Networks Limited	1.19%
CNIR	Manawa Energy Limited	1.18%
HRZE	Horizon Energy Distribution Ltd	1.10%
EAST	Eastland Network Limited	0.86%
WTOM	The Lines Company Ltd	0.57%
TOPE	Top Energy Ltd	0.48%
HORO	Electra Limited	0.26%
WNST	Winstone Pulp International	0.19%
MSVP	Mercury SVP Ltd	0.27%
TRNZ	KiwiRail Holdings Limited	0.12%
MELW	MEL (West Wind) Limited	0.23%
TARW	Tararua Wind Power	0.20%
DUNE	Aurora Energy Limited	0.10%
CHBP	Centralines Limited	0.09%
WAV1	Waverly Wind Farm Ltd	0.16%
SCAN	Scanpower Limited	0.07%
MELT	MEL (Te Apiti) Limited	0.10%
KUPE	Beach Energy Resources NZ (Holdings) Ltd	0.05%
METH	Methanex New Zealand Ltd	0.04%
OMVP	OMV NZ Production Ltd	0.04%
SHPK	Southpark Utilities Limited	0.001%
MRPL	Mercury NZ Limited	-
NAPA	Nga Awa Purua Joint Venture	-

BOPD	Southern Generation Ltd	-
ORON	Orion New Zealand Limited	-
ALPE	Alpine Energy Ltd	-
MPOW	Mainpower New Zealand Limited	-
TASM	Network Tasman Limited	-
EASH	EA Networks	-
MARL	Marlborough Lines Limited	-
WATA	Network Waitaki Limited	-
OTNT	OtagoNet	-
WPOW	Westpower Limited	-
NELS	Nelson Electricity Ltd	-
BUEL	Buller Electricity Ltd	-
ESLL	PowerNet Limited	-
SKOG	Norske Skog Tasman Limited	-
TOD3	Todd Generation Taranaki Limited	-
KIWI	Whareroa Cogeneration Limited	-
TBOP	Nova Energy Limited	-
KRGL	Kawerau Geothermal Ltd	-
NZAS	NZ Aluminium Smelters Limited	-
POWN	Powernet Ltd	-
RAYN	Daiken Southland Limited	-
SOLE	GTL Energy New Zealand Ltd	-

5 Indicative allocations for the Wairakei Ring BBI

49. As noted above, and as required under the TPM, we have calculated indicative starting BBI customer allocations for the (low-value) Wairakei Ring BBI using the simple method modelled regions and allocators for the first simple method period in chapter 4 and Part E of the draft assumptions book.

50. We note:

50.1 We have applied the modelled regions and simple method allocators for the first simple method period because the Wairakei Ring BBI is expected to be commissioned during the first simple method period, .

50.2 The Wairakei-Whakamaru C line is in the Lower North Island High Voltage (LNI_HV) simple method modelled region. Accordingly, we have used the simple method regional NPB allocations that relate to the LNI_HV investment region.

Table 5: Indicative starting BBI customer allocations for the Wairakei Ring BBI

Customer Code	Customer Name	Starting BBI customer allocation (%)[15]
VECT	Vector Limited	28.8%
GENE	Genesis Energy Ltd	11.4%
CTCT	Contact Energy Limited	9.1%
POCO	Powerco Limited	6.7%
UNET	Wellington Electricity Lines Limited	5.9%
MRPL	Mercury NZ Limited	5.4%
MERI	Meridian Energy Limited	4.2%
NPOW	Northpower Limited	3.7%
WELE	WEL Networks Limited	3.3%
UNIS	Unison Networks Limited	3.0%

[15] In this table, a "-" indicates a zero allocation, and "0.00%" indicates a very small non-zero allocation.

NAPA	Nga Awa Purua Joint Venture	2.3%
PANP	Pan Pac Forest Product Limited	1.5%
NTRG	Ngatamariki Geothermal Ltd	1.4%
NZST	New Zealand Steel Limited	1.4%
COUP	Counties Power Ltd	1.3%
SKOG	Norske Skog Tasman Limited	1.2%
MSVP	Mercury SPV Limited	1.1%
HRZE	Horizon Energy Distribution Ltd	1.0%
HORO	Electra Limited	1.0%
TARW	Tararua Wind Power	0.8%
WAIP	Waipa Networks Limited	0.8%
WNST	Winstone Pulp International	0.8%
WAV1	Waverley Wind Farm	0.7%
EAST	Eastland Network Limited	0.5%
WTOM	The Lines Company Ltd	0.5%
TOPE	Top Energy Ltd	0.5%
ORON	Orion New Zealand Limited	0.4%
NZAS	NZ Aluminium Smelters Limited	0.2%
CHBP	Centralines Limited	0.2%
TRNZ	KiwiRail Holdings Limited	0.1%
SCAN	Scanpower Limited	0.1%
ALPE	Alpine Energy Ltd	0.1%
KUPE	Beach Energy Resources NZ (Holdings) Ltd	0.1%

DUNE	Aurora Energy Limited	0.1%
KWGL	Kawerau Geothermal Limited	0.1%
MPOW	Mainpower New Zealand Limited	0.1%
TASM	Network Tasman Limited	0.1%
OMVP	OMV New Zealand Production Ltd	0.1%
METH	Methanex New Zealand Ltd	0.1%
EASH	EA Networks	0.1%
POWN	Powernet Ltd	0.1%
MARL	Marlborough Lines Limited	0.0%
TOD3	Todd Generation Taranaki Limited	0.0%
WATA	Network Waitaki Limited	0.0%
CNIR	Manawa Energy Limited	0.0%
WPOW	Westpower Limited	0.0%
MELT	MEL (Te Apiti) Limited	0.0%
SOU2	Southern Generation GP Limited	0.0%
KIWI	Whareroa Cogeneration Limited	0.0%
TBOP	Nova Energy Limited	0.0%
NELS	Nelson Electricity Ltd	0.0%
SCGL	Southdown Cogeneration Ltd	0.0%
BUEL	Buller Electricity Ltd	0.0%
MELW	MEL (West Wind) Limited	0.0%
SHPK	Southpark Utilities Limited	0.0%
RAYN	Daiken Southland Limited	0.0%
SOLE	GTL Energy New Zealand Ltd	0.0%

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