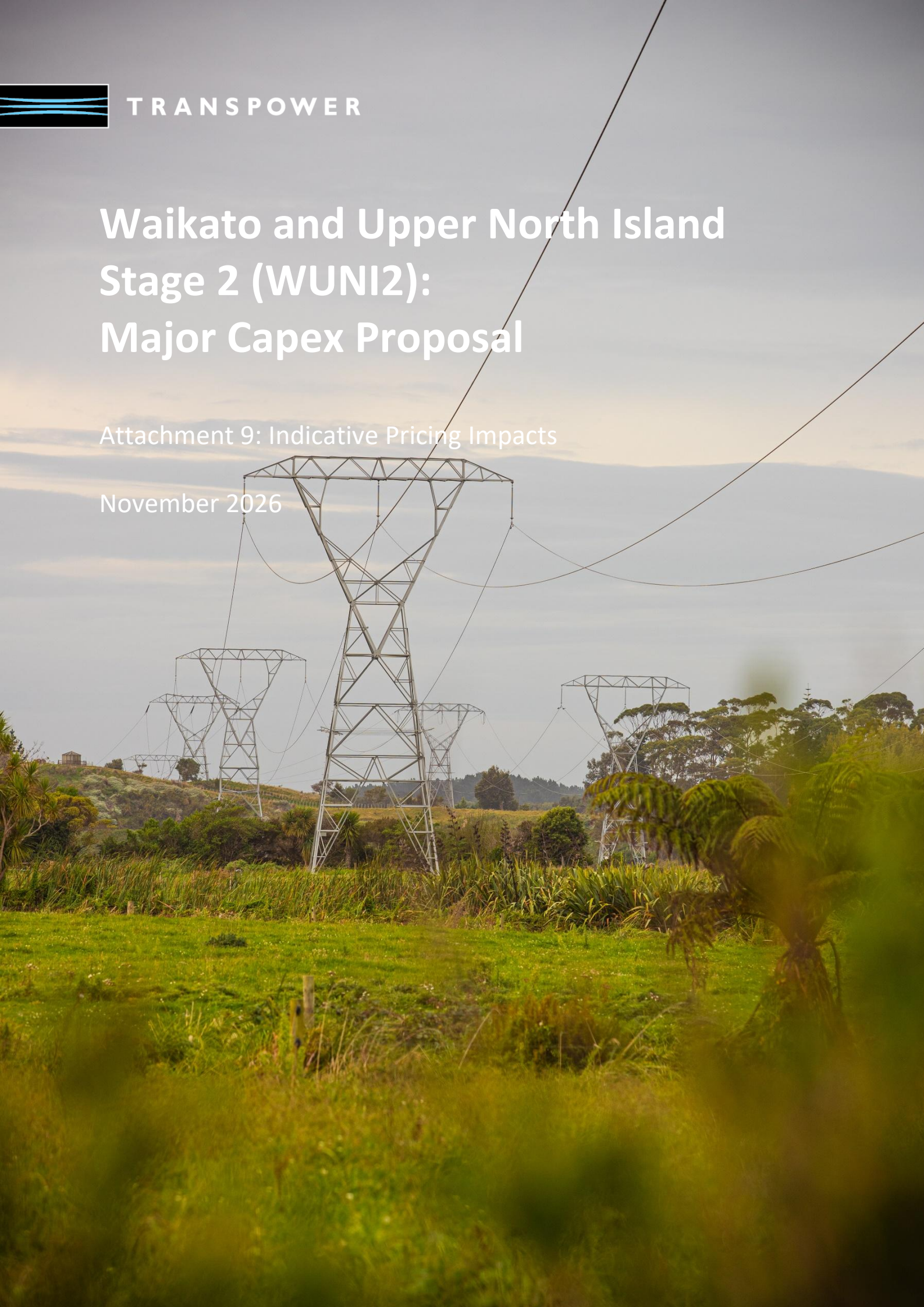


TRANSPOWER

Waikato and Upper North Island Stage 2 (WUNI2): Major Capex Proposal

Attachment 9: Indicative Pricing Impacts

November 2026

Purpose

Under the transmission pricing methodology (**TPM**),[1] the covered costs[2] of post-2019 investments in interconnection assets and interconnection transmission alternatives (post-2019 benefit-based investments or **BBIs**) are recovered from customers identified as beneficiaries. These allocations are based on each customer's expected positive net private benefit (**NPB**) from those investments. The charges through which the covered costs are recovered are called benefit-based charges or **BBCs**. The TPM contains the methods for calculating BBCs.

This Attachment presents information to the Commerce Commission (**Commission**) and other stakeholders about the indicative increase in transmission charges (specifically indicative BBCs) due to proposed Stage 2 of the Waikato and Upper North Island (**WUNI**) Upgrade major capex project (**Stage 2**). This document includes indicative starting BBI customer allocations (**starting allocations**) and indicative covered costs for the WUNI Stage 2 BBI, from which we have calculated indicative BBCs.

Following the Commission's final decision, we will undertake a formal consultation on the proposed starting allocations for the BBI, which will be a high-value BBI,[3] as required by the TPM.

We have used the methodologies in the TPM and BBC Assumptions Book v3.0 (**Assumptions Book**)[4] to produce the indicative allocations in this Attachment. However, our calculations have not been at the level of detail we will apply when we calculate proposed starting allocations for the WUNI Stage 2 BBI for consultation under the TPM (as noted above, this will be after the Commission's final decision). Nevertheless, we consider the indicative starting allocations presented in this Attachment provide a reasonable indication of the distribution of NPB from the BBI using the modelling inputs and assumptions set out in this Attachment (which themselves are indicative only).

We emphasise that the indicative starting allocations, covered costs and BBCs in this Attachment are not the proposed or final starting allocations, covered costs or BBCs for the WUNI Stage 2 BBI. Transpower cannot, and does not, accept any liability for the accuracy or completeness of the information provided, nor for any consequences arising from any party's reliance on it. We strongly recommend that stakeholders review the TPM and Assumptions Book themselves and seek independent expert advice before relying on any information in this document.

Unless otherwise stated, all clause references in this document refer to clauses within the TPM.

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1 The TPM is in Schedule 12.4 of Part 12 of the Electricity Industry Participation Code 2010.

2 The cost recovered through the benefit-based charges for a benefit-based investment is referred to in the TPM as the "covered cost".

3 A high-value BBI is a BBI that is expected to involve capital expenditure and/or transmission alternative operating expenditure of more than the base capex threshold under the Capex IM, which is $30m for projects notified to the Commission after 1 April 2025.

4 The Assumptions Book contains detail about how the methodologies in the TPM for calculating and adjusting BBC allocations are applied.

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1 Background

1.1 The proposed Stage 2 investments

The investments that comprise Stage 2 (the proposed Stage 2 investments) are:

- ±150 Mvar STATCOM at Henderson substation ($95.8m)
- 100 Mvar shunt capacitor at Pakuranga substation ($18.2m)
- Ōhinewai switching station upgrade ($24.7m)
- Duplex Ōtāhuhu–Whakamaru A&B circuits (OHW–WKM section) and connect into Ōhinewai ($269.8m).

The proposed Stage 2 investments, which have a nominal cost of $408.4 million, will be comprise a high-value post-2019 BBI because they are interconnection investments, will be commissioned after 23 July 2019,[5] and are forecast to cost more than $30m (being the base capex threshold under the Transpower Capital Expenditure Input Methodology Determination (**Capex IM**)). The proposed Stage 2 investments are expected to be completed and commissioned by June 2035.

The Assumptions Book, at paragraph 291, describes when it may be necessary to break a project into more than one BBI. We have assessed the proposed Stage 2 investments against the criteria in paragraph 291 of the Assumptions Book and determined they should be treated as a single BBI because the investments are occurring in the same area of the grid and address a single need, namely insufficient transmission capacity in the WUNI region to meet the forecast load growth. In this attachment we call this BBI the **WUNI Stage 2 BBI**.

The WUNI Stage 2 BBI is a high-value post-2019 BBI. Under the TPM, Transpower must use a standard method under the TPM to determine its beneficiary customers and calculate their starting allocations.

We have used the price-quantity method[6] for the WUNI Stage 2 BBI. The price-quantity method must be used for all high-value post-2019 BBIs that are not resiliency BBIs. There are no material resiliency risks being mitigated by the proposed Stage 2 investments.

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 WUNI Stage 2 BBI, we have calculated market regional NPB only (regional NPB relating to changes in quantities and prices in the wholesale electricity market). This is because we expect most of the benefits of the WUNI Stage 2 BBI to be derived from market benefit.

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

[5] 23 July 2019 is the date the TPM uses to distinguish between pre- and post-2019.

[6] The price-quantity method is detailed in clauses 44 to 55 of the TPM.

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).

We have used the quantity and price-based option (clause 52) to calculate the indicative starting allocations and BBCs for the WUNI Stage 2 BBI because our initial assessment is that using the clause 51 method would not produce allocations that are broadly proportionate to positive NPB from the BBI. We will consult over the method applied when we formally consult on the proposed starting allocations following the approval of Stage 2.

1.2 Interaction with the Capex IM

The WUNI programme is estimated at approximately $750 million (in real 2026 dollars) and will be delivered in stages. The programme comprises enhancement investments and is therefore a major capex project (staged) under the Capex IM. Transpower must submit an MCP to the Commission for each stage seeking approval to recover the costs of the stage from Transpower customers.

Under the Capex IM, an MCP must include information about the expected increase in transmission charges due to the proposed expenditure.

The MCP also includes the generation and demand scenarios and other modelling assumptions and parameters we use to apply the investment test in Schedule D of the Capex IM (**Investment Test**). Clause 43(5) of the TPM generally requires consistency in approach with the Investment Test when we calculate starting allocations for a high-value post-2019 BBI. We may depart from the Investment Test approach if we determine that approach would not produce allocations that are broadly proportionate to NPB from the BBI. Refer to Section 3.1 for more details.

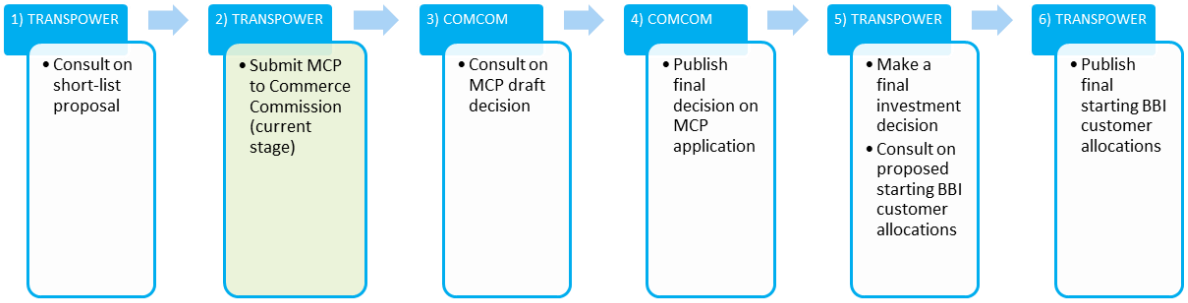
1.3 What happens next?

Under clause 15 of the TPM, Transpower must consult on the proposed starting allocations for each high-value post-2019 BBI.

Assuming the Commission approves Stage 2, Transpower will make its final investment decision whether to proceed with the project. If we decide to proceed, we will consult on the proposed starting allocations for the WUNI Stage 2 BBI under the TPM. After considering submissions in response to that consultation, we will finalise the starting allocations and publish them.

These planned stages are illustrated in Figure 1 below.

Figure 1: Planned stages up to publishing starting allocations



2 Indicative covered costs

This section summarises the assumptions used in calculating the indicative covered costs for the WUNI Stage 2 BBI and provides the results of those calculations.

2.1 TPM requirements for calculating covered cost

The cost recovered through the BBCs for a BBI is referred to in the TPM as the BBI's 'covered cost'.[7]

Under 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:

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

2.2 Indicative covered costs

We have used the same cost estimates as in Attachment 6 to calculate the indicative covered costs for the WUNI Stage 2 BBI.

The annual covered cost of a BBI is confirmed as part of calculating transmission charges for each pricing year after the BBI is commissioned. Our calculation of the WUNI Stage 2 BBI's indicative covered cost relies on a number of estimates including final asset composition and asset values, which we will not know until after the BBI is fully commissioned.

While this MCP does not seek approval for operating and maintenance expenditure, we have estimated the opex reasonably attributable to the investment as part of our indicative covered cost. This opex will be recovered through our base expenditure allowances approved for each regulatory control period (**RCP**) and allocated under the TPM as appropriate.

[7] For more information see also Transpower's TPM Information Sheet - BBC Covered Cost v2.pdf.

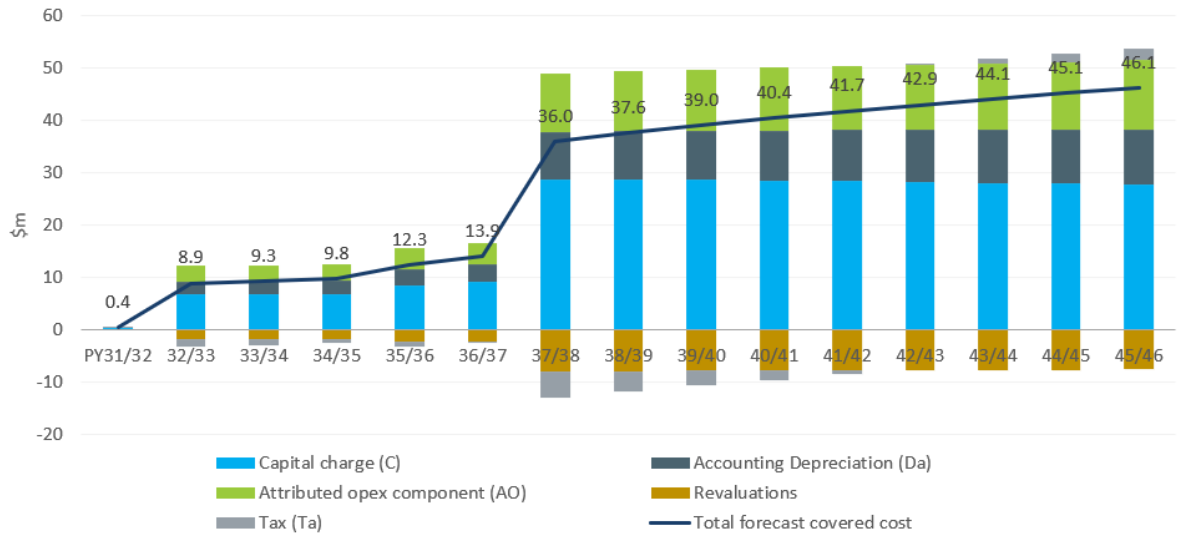


Figure 2: WUNI Stage 2 BBI indicative covered costs

Table 1: WUNI Stage 2 BBI indicative covered costs

Pricing year (PY), starting 1 April	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39	39/40	40/41	41/42	42/43	43/44	44/45	45/46
Accounting depreciation (Da)	-	2.4	2.4	2.5	3.2	3.2	9.0	9.2	9.4	9.6	9.7	9.9	10.1	10.3	10.5
Capital charge (C)	0.3	6.8	6.8	6.8	8.4	9.2	28.7	28.7	28.6	28.5	28.4	28.2	28.1	27.9	27.7
Revaluations	-	(1.9)	(1.9)	(1.8)	(2.3)	(2.3)	(7.9)	(7.9)	(7.9)	(7.8)	(7.8)	(7.7)	(7.7)	(7.6)	(7.6)
Attributed opex component (AO)	-	3.0	3.1	3.1	3.9	4.0	11.2	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	0.1	(1.4)	(1.1)	(0.8)	(0.9)	(0.2)	(5.1)	(3.9)	(2.7)	(1.7)	(0.8)	0.1	0.9	1.6	2.3
Total forecast covered cost	**0.4**	**8.9**	**9.3**	**9.8**	**12.3**	**13.9**	**36.0**	**37.6**	**39.0**	**40.4**	**41.7**	**42.9**	**44.1**	**45.1**	**46.1**

Some key assumptions and inputs we have applied to calculate the BBI's indicative covered cost are as follows:

- The accounting and tax depreciation rates used are the weighted average rates applicable to the assets that make up the proposed Stage 2 investments.
- Vanilla WACC (7.10%), cost of debt (5.74%) and leverage (41%) approved for Transpower's current RCP, being RCP4, are used in the calculation for all later RCPs.
- The attributable opex ratio for RCP4 is used in the calculation for all later RCPs.

Note, we have limited our modelling of covered cost to 15 years - BBCs for the WUNI Stage 2 BBI will continue for pricing years after 2045/46.

3 Indicative Starting Allocations

This section summarises our application of the price-quantity method in the TPM to calculate indicative starting allocations for the WUNI Stage 2 BBI.

3.1 Market scenarios and other key modelling assumptions

The indicative starting allocations primarily use the modelling assumptions and inputs from the Stage 2 Investment Test, which are generally consistent with chapter 2 of the Assumptions Book. The indicative starting allocations have been derived from the proposed investment's overall development plan, including investments associated with potential future stages of the WUNI Upgrade major capex project.[8] Should the Commission approve Stage 2 and Transpower decide to go ahead with it, we will calculate and consult on the proposed starting allocations for the WUNI Stage 2 BBI in accordance with the TPM.

For the purpose of calculating indicative starting allocations, the counterfactual and factual scenarios are as follows:

- The counterfactual is the existing grid without any of the proposed Stage 2 investments.
- The factual is the grid after the proposed investment (Stage 2 and potential future stages).

3.2 Modelled regions and market regional NPB

3.2.1 Modelled regions

We have calculated indicative starting allocations for the following modelled regions:

- Waikato and Upper North Island (**WUNI**)
- Rest of North Island (**RNI**)
- South Island (**SI**).

3.2.2 Market regional NPB

Under clause 52 of the TPM, market regional NPB is calculated based on:

[8] For the purpose of calculating the indicative starting allocations presented in this Attachment, we have used existing modelling runs from the Investment Test that include investments associated with potential future stages. If Stage 2 is approved by the Commission and Transpower consults on proposed starting allocations for the WUNI Stage 2 BBI under the TPM, the modelling will be updated to reflect only the proposed Stage 2 investments.

- For load customers, the difference in consumer surplus between the factual and counterfactual scenarios, where consumer surplus is the difference between the cost of self-supply and the modelled price, multiplied by load supplied.
- For supply customers, the difference in generator surplus between the factual and counterfactual scenarios, where generator surplus is the price times generation, minus fuel and emission costs.

In modelling the market regional NPB, we have not included the change to loss and constraint excess (**LCE**) payments as per clauses 52(3)(b) and 52(4)(b). We will include these LCE impacts when consulting on proposed starting allocations.

The following table shows the indicative share of positive regional NPB to regional customer groups for the WUNI Stage 2 BBI.

Table 2: Indicative allocations of positive regional NPB to regional customer groups

Regional customer groups	Indicative regional NPB share
WUNI Demand	65.3%
SI Supply (Hydro)	15.8%
RNI Supply (geothermal and wind)	9.7%
RNI Supply (hydro storage and run-of-river)	8.9%
RNI Supply (thermal peaker)	0.2%
RNI Supply (solar)	0.04%

3.2.3 Individual NPB

To calculate individual NPBs for the purpose of indicative starting allocations we used the intra-regional allocator values for each benefitting customer based on their mean historical annual injection and mean coincident peak offtake[9] (as appropriate) from 1 September 2020 to 31 August 2025 with adjustments for more recent large plant connections. This calculation will be updated for more recent years' offtake and injection after there is a final investment decision date for Stage 2 and prior to consulting on the proposed starting allocations for the WUNI Stage 2 BBI under the TPM.

3.2.4 Indicative starting allocations

As required under the TPM, we calculated each benefitting customer's indicative starting allocation for the WUNI Stage 2 BBI as the customer's individual NPB divided by the sum of all benefitting customers' individual NPBs. This results in the following indicative starting allocations.

[9] These are the intra-regional allocators for the WUNI Stage 2 BBI because it will be a peak BBI - a post-2019 BBI for which the investment need is primarily attributable to meeting peak demand.

Table 3: Indicative starting allocations

Customer Code	Customer Name	Indicative Starting Allocation
VECT	Vector Ltd	43%
MERI	Meridian Energy Ltd	11%
CTCT	Contact Energy Ltd	7%
WELE	WEL Networks Ltd	6%
MRPL	Mercury NZ Ltd	5%
POCO	Powerco Ltd	4%
GENE	Genesis Energy Ltd	4%
NPOW	Northpower Ltd	4%
COUP	Counties Power Ltd	3%
WAIP	Waipa Networks Ltd	2%
NAPA	Nga Awa Purua Joint Venture	1%
NZST	New Zealand Steel Ltd	1%
NTRG	Ngatamariki Geothermal Ltd	1%
TRUG	Manawa Energy Ltd	1%
KWGL	Kawerau Geothermal Ltd	1%
MSVP	Mercury SPV Ltd	1%
WTOM	The Lines Company Ltd	1%
TAOM	Eastland Generation Ltd	1%
UNIS	Unison Networks Ltd	1%
MELW	MEL (West Wind) Ltd	0.4%
WAV1	Waverly Wind Farm Ltd	0.4%
TARW	Tararua Wind Power	0.4%
TOPE	Top Energy Ltd	0.3%
TRNZ	KiwiRail Holdings Ltd	0.3%
MELT	MEL (Te Apiti) Ltd	0.2%
CHHE	Oji Fibre Solutions (NZ) Ltd	0.2%
TBOP	Nova Energy Ltd	0.2%
SOU2	Southern Generation Ltd	0.1%
RUAK	Ruakura EDB Limited Partnership	0.1%
DUNE	Aurora Energy Ltd	0.04%
WPOW	Westpower Ltd	0.03%
LODS	Lodestone Solar Ltd	0.03%
DSFL	Dannevirke Solar Farm Limited	0.01%
ALPE	Alpine Energy Ltd	0.01%
SHPK	Southpark Utilities Ltd	0.002%

4 Indicative increase in transmission charges

We have calculated the total indicative increase in transmission charges (specifically BBCs) for each affected GXP/GIP by multiplying the indicative covered cost of the WUNI Stage 2 BBI by the indicative starting allocations from Table 3 above.

Note that Tables 4 and 5 show the indicative increase in BBCs associated with the WUNI Stage 2 BBI, but not the decrease in residual charges. There are two reasons for this decrease. First, decommissioning the replaced assets will reduce the costs recovered through residual charges. Second, the BBI's covered cost will include an attribution of some of Transpower's operating costs (in proportion to the BBI's depreciation), shifting recovery of these costs from residual charges to BBCs. The decrease in residual charges will be shared across all Transpower's load customers, not just those in the modelled regions.

In Table 4, the c/kWh rate is the same for all load customers when peak kWh—the intra-regional allocator—is used as the denominator, as shown in the last column. However, because this project is a peak BBI, the rate differs across load customers in the relevant modelled region when total kWh measured at the GXP is used instead. This reflects differences in customer load factors, defined as the ratio of average load to peak load: a higher load factor results in a lower c/kWh rate, while a lower load factor results in a higher rate. EDBs with embedded generation generally have lower load factors at the GXP and therefore appear to have higher c/kWh rates. In practice, their rates would be lower if the kWh supplied by embedded generation were included. This applies to Top Energy which have particularly high rates as shown in the fifth column.

Waipa HTU is a new GXP that now supplies some load previously served through CBG. Combining the HTU and CBG charges and supplied kWh provides a complete view, resulting in a rate of 0.23 cents per kWh.

Table 4: Indicative increases in transmission charges – regional demand groups

Customer	GXP/GIP	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied in 45/46 (c/kWh)	Indicative increase in transmission charges per peak kWh in 45/46 (c/kWh)
Counties Power Ltd	BOB	WUNI	1,025.59	0.22	2410.41
Counties Power Ltd	GLN	WUNI	357.63	0.22	2410.41
Northpower Ltd	BRB	WUNI	178.46	0.17	2410.41
Northpower Ltd	MPE	WUNI	1,234.06	0.21	2410.41
Northpower Ltd	MTO	WUNI	219.71	0.34	2410.41
Powerco Ltd	ARI	WUNI	184.89	0.41	2410.41
Powerco Ltd	HIN	WUNI	304.42	0.19	2410.41
Powerco Ltd	KPU	WUNI	492.34	0.28	2410.41
Powerco Ltd	PAO	WUNI	368.71	0.17	2410.41

Customer	GXP/GIP	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied in 45/46 (c/kWh)	Indicative increase in transmission charges per peak kWh in 45/46 (c/kWh)
Powerco Ltd	WHU	WUNI	265.34	0.15	2410.41
Powerco Ltd	WKO	WUNI	396.05	0.20	2410.41
Ruakura EDB Limited Partnership	HAM	WUNI	35.94	0.24	2410.41
Vector Ltd	ALB	WUNI	2,281.25	0.24	2410.41
Vector Ltd	HEN	WUNI	1,391.97	0.25	2410.41
Vector Ltd	HEP	WUNI	1,541.91	0.25	2410.41
Vector Ltd	HOB	WUNI	484.18	0.19	2410.41
Vector Ltd	MNG	WUNI	1,299.71	0.20	2410.41
Vector Ltd	OTA	WUNI	647.93	0.21	2410.41
Vector Ltd	PAK	WUNI	1,564.50	0.24	2410.41
Vector Ltd	PEN	WUNI	4,406.08	0.21	2410.41
Vector Ltd	ROS	WUNI	1,769.41	0.26	2410.41
Vector Ltd	SVL	WUNI	1,026.84	0.25	2410.41
Vector Ltd	TAK	WUNI	1,365.30	0.25	2410.41
Vector Ltd	WEL	WUNI	420.68	0.24	2410.41
Vector Ltd	WIR	WUNI	978.70	0.20	2410.41
Vector Ltd	WRD	WUNI	850.55	0.27	2410.41
Waipa Networks Ltd	CBG	WUNI	478.43	0.20	2410.41
Waipa Networks Ltd	HTU	WUNI	113.63	1.02	2410.41
Waipa Networks Limited	TMU	WUNI	446.53	0.22	2410.41
WEL Networks Limited	HAM	WUNI	1,871.04	0.24	2410.41
WEL Networks Limited	HLY	WUNI	296.71	0.29	2410.41
WEL Networks Limited	TWH	WUNI	802.93	0.25	2410.41
The Lines Company Ltd	HTI	WUNI	273.01	0.17	2410.41
New Zealand Steel Ltd	GLN	WUNI	465.36	0.10	2410.41
Southpark Utilities Limited	PEN	WUNI	0.79	0.19	2410.41
KiwiRail Holdings Limited	HAM	WUNI	1.47	0.13	2410.41
KiwiRail Holdings Limited	PEN	WUNI	45.01	0.31	2410.41
KiwiRail Holdings Limited	SWN	WUNI	70.28	0.46	2410.41
Top Energy Ltd	KOE	WUNI	153.17	1.47	2410.41

Table 5: Indicative increases in transmission charges – regional supply groups

Customer	GXP/GIP	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied in 45/46 (c/kWh)
Alpine Energy Ltd	ABY	SI	6.49	0.043
Contact Energy Ltd	CYD	SI	870.04	0.043
Contact Energy Ltd	ROX	SI	698.01	0.043
Aurora Energy Ltd	CYD	SI	18.57	0.043
Genesis Energy Ltd	TKA	SI	63.23	0.043
Genesis Energy Ltd	TKB	SI	392.12	0.043
Meridian Energy Ltd	AVI	SI	442.42	0.043
Meridian Energy Ltd	BEN	SI	1,069.18	0.043
Meridian Energy Ltd	MAN	SI	1,947.71	0.043
Meridian Energy Ltd	OHA	SI	519.18	0.043
Meridian Energy Ltd	OHB	SI	435.91	0.043
Meridian Energy Ltd	OHC	SI	432.94	0.043
Meridian Energy Ltd	WTK	SI	226.29	0.043
Manawa Energy Ltd	BWK	SI	44.24	0.043
Manawa Energy Ltd	COL	SI	104.56	0.043
Westpower Ltd	KUM	SI	15.58	0.043
Oji Fibre Solutions (NZ) Ltd	KAW	RNI	87.06	0.042
Contact Energy Ltd	OKI	RNI	130.15	0.042
Contact Energy Ltd	PPI	RNI	129.71	0.042
Contact Energy Ltd	TAB	RNI	580.71	0.042
Contact Energy Ltd	THI	RNI	558.31	0.042
Kawerau Geothermal Limited	KAW	RNI	345.71	0.042
Nga Awa Purua Joint Venture	NAP	RNI	497.91	0.042
Ngatamariki Geothermal Ltd	NAP	RNI	460.35	0.042
Eastland Generation Ltd	KAW	RNI	258.21	0.042
Unison Networks Limited	TAB	RNI	178.93	0.042
Unison Networks Limited	WRK	RNI	67.83	0.042
Genesis Energy Ltd	TUI	RNI	356.79	0.072
Mercury NZ Ltd	ARA	RNI	245.93	0.072
Mercury NZ Ltd	ATI	RNI	204.31	0.072
Mercury NZ Ltd	MTI	RNI	650.16	0.072

Customer	GXP/GIP	Region	Indicative increase in annual transmission charges in 45/46 ($k)	Indicative increase in transmission charges per kWh of energy supplied in 45/46 (c/kWh)
Mercury NZ Ltd	OHK	RNI	291.13	0.072
Mercury NZ Ltd	WKM	RNI	882.46	0.072
Mercury NZ Ltd	WPA	RNI	167.93	0.072
Genesis Energy Ltd	RPO	RNI	404.42	0.072
Genesis Energy Ltd	TKU	RNI	526.05	0.072
Southern Generation Ltd	MAT	RNI	67.91	0.072
Manawa Energy Ltd	MAT	RNI	209.63	0.072
Manawa Energy Ltd	OHG	RNI	77.16	0.072
MEL (Te Apiti) Limited	WDV	RNI	101.19	0.042
MEL (West Wind) Ltd	WWD	RNI	199.77	0.042
Meridian Energy Ltd	HRP	RNI	224.87	0.042
Mercury SPV Ltd	LTN	RNI	321.80	0.042
Tararua Wind Power	TWC	RNI	164.61	0.042
Waverley Windfarm Limited	WVY	RNI	170.83	0.042
Contact Energy Limited	SFD	RNI	40.24	0.016
Contact Energy Ltd	WHI	RNI	1.37	0.016
Nova Energy Ltd	JRD	RNI	44.81	0.016
Nova Energy Limited	MKE	RNI	27.28	0.016
Dannevirke SF Limited Partnership	DVK	RNI	6.71	0.020
Lodestone Solar Ltd	WAI	RNI	14.01	0.020
Manawa Energy Ltd	ARG	SI	18.25	0.043

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