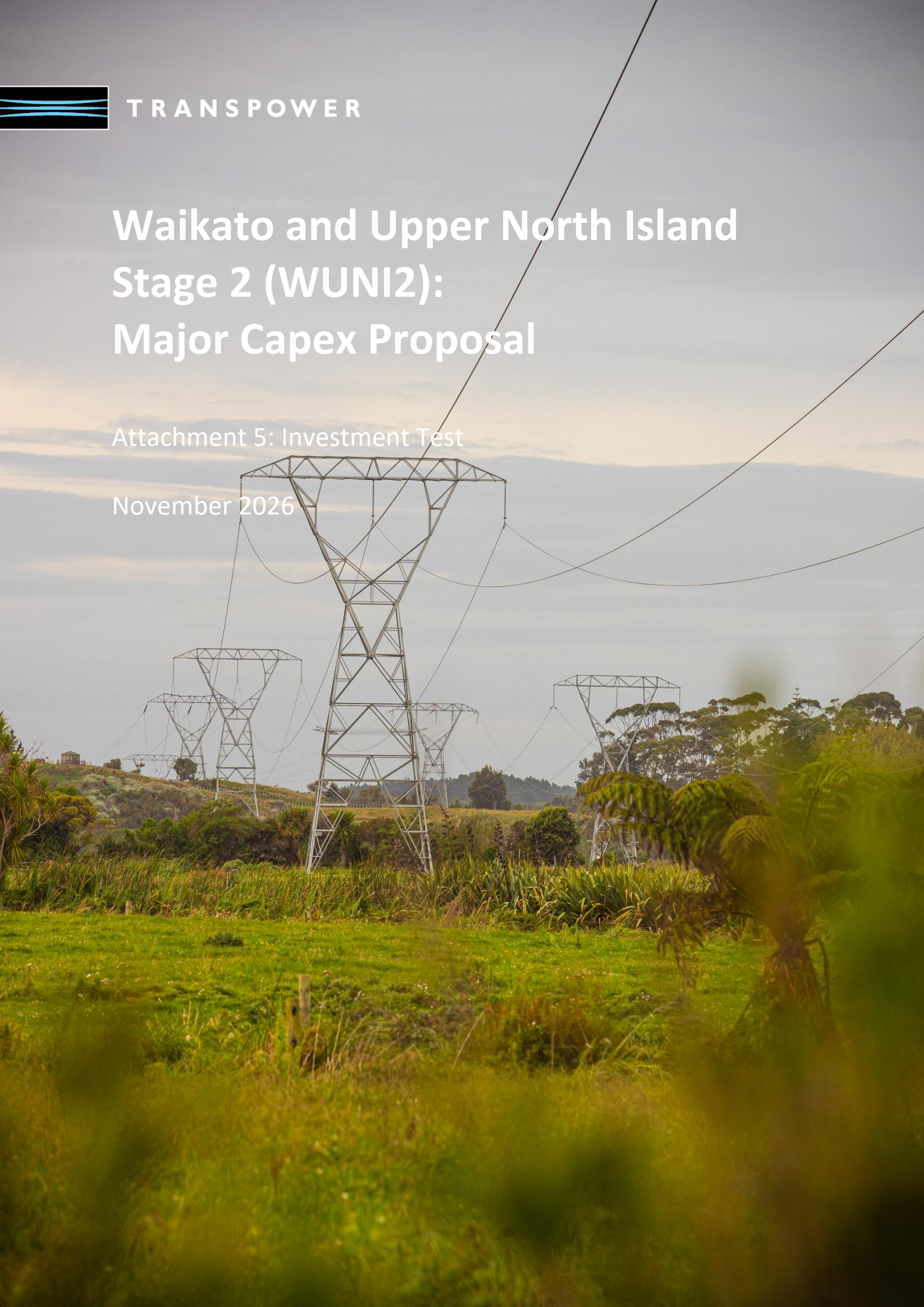
TRANSPOWER

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

Attachment 5: Investment Test

November 2026



Purpose

This Attachment sets out an overview of our investment options analysis for Stage 2 of the Waikato and Upper North Island (**WUNI**) Upgrade major capex project (**Stage 2**) and our approach to the investment test in Schedule D of the Capex IM[1] (**Investment Test**) for this Major Capex Proposal (**MCP**). It includes our application of the Investment Test and identifies our preferred investment option (**Proposed Investment**).

[1] Commission, Transpower Capital Expenditure Input Methodology [2012] NZCC 2 (**Capex IM**).

Contents

Purpose 2

1 Introduction 4

2 Investment Test parameters 5

2.1 Scenario weightings 5
2.2 Calculation period 6
2.3 Discount rate 6

3 Application of the Investment Test 7

3.1 Quantified assessment 7
3.2 Sensitivities 10
3.3 Proposed Investment 12
3.4 Good Electricity Industry Practice 12

4 Proposal to the Commission 13

4.1 Project staging 13
4.2 Updated need dates and proposed Stage 2 investments 13
4.3 The proposed Stage 2 investments 15

1 Introduction

The Investment Test is an economic cost-benefit analysis that uses the expected value of electricity market costs and benefits over time to calculate the expected net electricity market benefits of investment options.[2]

As the investment need in this case relates to maintaining N-1 reliability on the core grid, for an investment option (one of our final short-listed development plans) to satisfy the Investment Test it must be:

- the option that maximises expected net electricity market benefit (although this net benefit may be negative), and
- sufficiently robust under sensitivity analysis.

Electricity market benefits and costs are those received or incurred (ultimately) by electricity consumers. In this analysis we have included changes in the following costs:

- fuel costs - the cost of generating electricity
- cost of involuntary demand curtailment - non-supply of electricity
- capital costs of modelled projects - future assets that are likely to exist whose nature and timing are affected by an investment option, for instance new generation
- relevant operation costs - costs of operating existing assets and modelled projects
- transmission and local losses.

The electricity market benefits and costs (including project costs) and the methodologies used to quantify these can be found in Attachments 6 and 7.

This Attachment summarises our application of the Investment Test.

[2] The expected net electricity market benefit of an investment option in the Investment Test is the weighted average of the option's net electricity market benefit (electricity market benefit minus electricity market cost, including project costs) across a range of demand and generation scenarios.

2 Investment Test parameters

This section sets out key parameters that are critical to the application of the Investment Test.

2.1 Scenario weightings

The Investment Test uses a weighted average of the net electricity market benefits under each demand and generation scenario.[3]

The default position is for scenario weightings to be equal, meaning with five scenarios, each would typically receive a 20% weighting. However, as discussed in Attachment 3, we consider three of the five EDGS 2024 scenarios are sufficient to model a range of high and low demand growth scenarios. Given this, we have adjusted the scenario weightings as follows:

- *Constraint Scenario: weighted at 0%* – We consider the Reference scenario adequately represents a lower bound for demand growth, rendering the Constraint scenario unnecessary;
- *Innovation Scenario: weighted at 0%* – The Innovation scenario is within the range of the three selected scenarios and therefore does not provide additional insights;
- *Environmental, Growth and Reference: weighted equally* – We have adopted an equal weighting for the three other EDGS 2024 scenarios. In the short list consultation, we applied a 60% weighting to the Growth scenario, which was the central scenario in terms of long-term demand growth. In the EDGS 2024 scenarios, Growth has the highest long-term demand forecast (see Attachment 3). To reduce the risk of overestimating benefits in this MCP, and because we have no clear reason to assume that one scenario is more likely to occur than the other, we weight each scenario equally. The net benefit results for each individual scenario are presented as sensitivities.

Table 1: Scenario weightings

Weighting set	Constraint	Environmental	Growth	Innovation	Reference
Default	20%	20%	20%	20%	20%
Proposed	**0%**	**33%**	**33%**	**0%**	**33%**

[3] We have used the Electricity Demand and Generation Scenarios published by MBIE in 2024 (**EDGS 2024**) with variations. See Attachment 3.

2.2 Calculation period

The Capex IM specifies that a calculation period should be used that captures significant electricity market benefit or cost elements. The default calculation period for the Investment Test is 20 years following commissioning of the last asset of the proposed investment.[4]

Our analysis uses a 22-year period from 2034 to 2055. This is the same as the calculation period we used in the short list consultation. The start date aligns with the commissioning date of the last asset in Stage 2 of the Proposed Investment (duplexing in Option 4b[5]). The additional two years at the end of the calculation period captured cost elements associated with late-stage investments in Option 3 in the short list consultation.[6]

Assets with economic lives that extend beyond 2055 will retain residual value at the end of the calculation period. To ensure fair comparison across options, we have included a terminal benefit, which effectively reduces the asset's cost by capturing its remaining value. A linear depreciation approach is used to decrease the cost of the asset over its expected lifetime.

We consider this calculation period, and the inclusion of terminal benefits, to be an appropriate trade-off between assessing benefits over the full economic life of an option and the uncertainty regarding far off benefits.

2.3 Discount rate

We have used the standard discount rate (pre-tax, real) of 5%, and a sensitivity range of 3% to 7%. This is consistent with the Capex IM and our proposed approach stated in the short list consultation.

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4 Consistent with our approach in the Upper South Island and HVDC Link Upgrade MCPs, we have interpreted "proposed investment" in this context as meaning "stage" and aligned the start of the calculation period to the assumed commissioning date of the last asset to be commissioned in Stage 2. If we were to align with the assumed commissioning date of the last asset to be commissioned in the Proposed Investment, the calculation period would not start until 2050. We do not consider that approach would appropriately value the expected net electricity market benefits of the investment options.

5 The need date for the duplexing is now 2035 based on the updated peak load forecast, but the Investment Test assessed the investment options with the timing set out in Attachment 4.

6 Option 3 in Attachment 4 has the latest investments occurring in 2050, but for computational efficiency we have retained the 2055 end date for the calculation period. This does not impact materially the outcome of the Investment Test.

3 Application of the Investment Test

Our Investment Test analysis incorporates electricity market benefits and costs associated with each investment option. By including these costs and benefits, we ensure that the option delivering the highest expected net electricity market benefit is identified.

Electricity market benefit and cost elements are those received or incurred (ultimately) by electricity consumers during the calculation period relative to the base case, and that will affect expected net electricity market benefits.

Project costs are those costs reasonably incurred prior to or during the calculation period in undertaking a major capex project.

We estimated the cost of the investment options using concept design reports, budgetary offers, or internal cost data, depending on the level of information available. The estimation process incorporated benchmarking against historical projects, utilisation of our cost library, and inclusion of budgetary equipment pricing. Where information was incomplete or unclear, reasonable assumptions were applied. An appropriate cost classification was assigned to each option based on the accuracy, confidence level, and quality of information available for this analysis.

While operational expenditure was considered for each investment option, we found no significant differences across the options. Therefore, operational costs were not factored into the application of the Investment Test, other than allowances for the mid-life refurbishment of the STATCOM and series compensation assets after 20 years of operation.

The electricity market benefits and costs and the methodologies used to quantify these can be found in Attachments 6 and 7.

3.1 Quantified assessment

The Investment Test is a cost-benefit analysis that uses the expected aggregated value of electricity market benefits and costs over time. To account for the time value of money, future costs and benefits are discounted at an annual rate of 5%.

Although the cost-benefit analysis encompasses the full calculation period, we are only seeking approval for the proposed Stage 2 investments. Any further investments identified in the Proposed Investment would require separate approvals.

Table 2 includes the total discounted cost for each investment option over the calculation period.

Table 2 incorporates the project costs for each investment option, which comprise the project costs of all stages of the option including future stages.[7] Further details of the investment options, their components and timings can be found in Attachment 4.

As mentioned in Attachment 4, the anticipated need for condition-based reconductoring of the Ōtāhuhu–Whakamaru A and B lines (southern section between Ohinewai and Whakamaru) can be avoided in Options 3 and 4b. We have assumed this like-for-like (simplex) reconductoring would happen between 2034 and 2037. The present value of these avoided costs is shown in Table 2.

Table 2: Cost estimates, 2026 present values at 5% discount rate[8]

	Option 2 Series Compensation + Cable	Option 3 Duplex + STATCOM	Option 4b Duplex + Series Compensation
Stage 2 investments	$479.6m	$271.5m	$271.5m
Future stages and modelled projects	$112.5m	$162.6m	$193.5m
Avoided reconductoring cost	-	-$88.4m	-$88.4m
Total cost	**$592.1m**	**$345.6m**	**$376.6m**

The Stage 2 investments in Options 3 and 4b are the same. However, Option 3 (Duplex + STATCOM) incurs the lowest total costs. Option 3 avoids series compensation on the Brownhill–Whakamaru A and B lines but requires later investments in an additional STATCOM, shunt capacitors and series reactors. Option 2 (Series Compensation + Cable) has the highest cost because of the costly investments in series compensation and a new underground cable between Brownhill and Ōtāhuhu.

The types of benefits quantified as part of our analysis are generation dispatch benefits and terminal benefits:

- **Generation dispatch benefits:** calculated by applying a hydro-thermal dispatch optimisation package called SDDP[9]:
  - **Thermal operating benefits:** represent fuel costs, variable operating costs and emission costs of electricity generation. With transmission investment, more efficient generation can be dispatched leading to a benefit compared to the dispatch in the counterfactual.
  - **AC loss benefits:** represent the reduced electricity needed to be generated due to lower electrical losses over the transmission network under different asset

[7] The Investment Test contemplates project costs being treated separately to other electricity market costs. Our practice is to combine project costs and some other electricity market costs as shown in Table 2. This does not affect the quantum of expected net electricity market benefits for the investment options, which are the key values in the Investment Test.

[8] Discounted costs, including mid-life refurbishment costs for STATCOM and series compensation assets after 20 years of operation.

[9] SDDP is an electricity market modelling tool used to determine electricity prices and resulting economic benefits, see Attachment 7.

configurations of the grid. Transmission loss costs are calculated by multiplying the losses by the average North Island short-run marginal generation cost.

- **Deficit benefits:** if no transmission investment is made, we will be unable to supply all forecast electricity demand. In this situation consumers will be forced to curtail demand or find alternative ways of being supplied with electricity. This electricity shortfall is primarily valued at $700 per MWh.[10]

- **Terminal value benefits:** the economic lifespan of some options considered extend beyond the calculation period, meaning that the assets will retain value at the end of 2055. We have accounted for this as a terminal benefit, which effectively reduces the overall asset cost. It is assumed that the asset value decreases linearly over its lifetime.[11]

Further details of the generation dispatch benefits and the modelling approach are in Attachment 7.

Table 3 outlines the quantified benefits for each of the investment options.

Table 3: Quantified benefits, 2026 present values at 5% discount rate

	Option 2 Series Compensation + Cable	Option 3 Duplex + STATCOM	Option 4b Duplex + Series Compensation
Generation dispatch benefit	$416.3m	$385.2m	$406.2m
Terminal value benefit	$101.1m	$91.3m	$105.6m
Total benefit	**$517.4m**	**$476.5m**	**$511.7m**

Option 2 (Series Compensation + Cable) offers the highest quantified benefits among the investment options due to the early investments in series compensation and the high-capacity cable connection. Option 4b offers a slightly lower generation dispatch benefit but a higher terminal value benefit than Option 2 due to the investment in series compensation happening late in the calculation period.

The Investment Test identifies the investment option with the highest expected net electricity market benefit as the proposed investment. Table 4 outlines the expected net electricity market benefits (total benefits minus total costs) for each of the investment options.

[10] Deficit costs have been valued using cost tranches, see Attachment 7.

[11] Example: In 2036, an investment of $100m is made in an asset with 40 years of economic lifespan. At the end of 2055, 50% of the lifespan remains, resulting in a terminal value of $50m. This translates to a present value of $11.6m. The terminal values consider all components of the investment options, their commissioning years and economic lifespans.

Table 4: Expected net electricity market benefits, 2026 present values at 5% discount rate

	Option 2 Series Compensation + Cable	Option 3 Duplex + STATCOM	Option 4b Duplex + Series Compensation
Total benefit	$517.4m	$476.5m	$511.7m
Total cost	$592.1m	$345.6m	$376.6m
Expected net electricity market benefit	-$74.7m	$130.9m	$135.2m

The cost-benefit analysis shows that Option 4b (Duplex + Series Compensation) delivers the highest expected net electricity market benefit among the investment options. However, Option 3 (Duplex + STATCOM) delivers a similar expected net electricity market benefit and therefore unquantified benefits can be considered.[12] As the Stage 2 investments for Options 3 and 4b are identical, we have not differentiated the options based on unquantified benefits. The differences between Options 3 and 4b only emerge from 2049. Option 4b is the Proposed Investment based on having the highest expected net electricity market benefit of the investment options.

3.2 Sensitivities

Sensitivity analysis considers the impact of certain parameter variations on the quantum of electricity market benefits and costs, and consequently expected net electricity market benefits, except when not reasonably practicable nor reasonably necessary. The variations we considered are set out in Table 5.

Table 5: Sensitivities considered

Sensitised parameters	Comment
Forecast demand	Net benefits are reported for each of the selected scenarios used in the Investment Test (100% weighting).
Size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question	Reflected in selected scenarios.
Capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects	Sensitivities of +/- 30% of capital costs are considered.

[12] Capex IM clause D1(2)(a) states that a similar expected net electricity market benefit is one where the difference in quantum is 10% or less of the aggregate project costs of the investment option with the highest expected net electricity market benefit. If that is the case, unquantified costs and benefits can be taken into account to choose the proposed investment. Here, the $4.3m difference in expected net electricity market benefit between Options 3 and 4b is less than 10% of the project cost for just Stage 2 of Option 4b ($271.5m, before factoring in the project cost for the later stages of Option 4b) so Options 3 and 4b clearly have similar expected net electricity market benefit.

Sensitised parameters	Comment
Timing of decommissioning, removing or de-rating of decommissioned assets	Not relevant.
Value of expected unserved energy	Not relevant. We have not included reliability benefits in our application of the Investment Test.
Discount rate	Sensitivities of 3% and 7% discount rates are considered.
Range of hydrological inflow sequences	Reflected in hydro dispatch modelling.
Relevant demand and generation scenario probability weightings	Results are presented using both the proposed equal weighting and individually for each of the selected scenarios.
In relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies	Not relevant.

The results of the sensitivity analysis are presented below, with green highlights indicating the investment option with the highest expected net electricity market benefit for each sensitivity scenario.

Table 6: Expected net electricity market benefits, sensitivity analysis, 2026 present values ($m)

	Option 2 Series Compensation + Cable	Option 3 Duplex + STATCOM	Option 4b Duplex + Series Compensation
Low discount rate 3%	119.8	340.9	352.7
High discount rate 7%	-178.9	7.3	8.2
Capex increase (130% of base)	-252.4	27.2	22.2
Capex decrease (70% of base)	102.9	234.6	248.2
Environmental scenario only	-101.3	104.1	108.3
Growth scenario only	138.9	339.8	348.2
Reference scenario only	-261.8	-51.1	-50.9

The sensitivity analysis shows that Option 4b consistently delivers the highest expected net electricity market benefit across a wide range of assumptions. In the sensitivity case with increased capex, Option 3 delivers a slightly higher net benefit than Option 4b. In the Reference scenario with a low demand increase, the net benefit is negative for all investment options but is still highest for Option 4b.

Consequently, we consider Option 4b robust to uncertainties in key input parameters and under diverse future energy scenarios.

3.3 Proposed Investment

Our cost-benefit analysis identified Option 4b as having the highest expected net electricity market benefit among the investment options to meet the N-1 reliability standard on the core grid. The sensitivity analysis reinforces the robustness of Option 4b, showing that it maintains the highest net benefit across a range of input uncertainties and diverse future energy scenarios.

Based on our application of the Investment Test, we conclude that Option 4b is our preferred option and the Proposed Investment. This MCP seeks approval of Stage 2 of Option 4b.

In addition to the quantified net benefits, we believe that Option 4b is a prudent investment for Transpower to ensure the reliability and resilience of the core grid in the WUNI region. In a future likely to see increased electrification, new generation could potentially reduce the need for transmission infrastructure investment. However, the most likely future generation sources in the region are inherently intermittent and cannot consistently meet regional energy requirements. Moreover, voltage stability challenges cannot always be addressed through new generation alone, due to technical and locational constraints.

Option 4b effectively addresses these challenges by enabling a robust transmission network that supports the integration of intermittent generation while ensuring a reliable and stable electricity supply for consumers as demand for electricity grows. These factors strongly support the case for Option 4b as a necessary and forward looking investment to meet the N-1 reliability standard on the core grid.

3.4 Good Electricity Industry Practice

The Capex IM requires Transpower to comply with Good Electricity Industry Practice (**GEIP**). We have ensured that the planning and performance standards used to determine the investment options and the Proposed Investment reflect GEIP. GEIP is defined in the Electricity Industry Participation Code as:

> "… the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."

No issues were raised by stakeholders during the short list consultation, or otherwise, about the Proposed Investment not being consistent with GEIP.

4 Proposal to the Commission

4.1 Project staging

We have a high level of confidence in the immediate investment horizon, but this confidence diminishes as we look further into the future due to the inherent uncertainties in demand and generation forecasting. While we are certain about the near term investment need into the mid-2030s, there is higher uncertainty regarding the exact timing, location, and nature of future components.

In this MCP, our focus is on the investments required in the immediate investment horizon (between 2030 and 2035), while keeping in mind the longer term development plan extending to 2055. Any additional investments in thermal capacity and voltage management that may be needed after 2035 will be addressed either in a subsequent stage of the WUNI major capex project (staged) or through separate major or base capex projects.

4.2 Updated need dates and proposed Stage 2 investments

As mentioned in Attachments 2 and 4, for the updated development plans we considered the peak load forecast as presented in the short list consultation but revised the load limits, leading to a deferral of the required investments by two to three years. For the proposed Stage 2 investments, we additionally consider the latest available peak load forecast (based on 2024 EDGS with 2026 customer inputs, as introduced in Attachment 3). This lower forecast pushes the need dates further out.

Commissioning dates may differ from need dates. The proposed commissioning dates for the proposed Stage 2 investments reflect the updated demand and generation assumptions as well as asset condition and project delivery considerations.

Henderson STATCOM

While the revised need date for the STATCOM at Henderson substation is 2034/35, we propose targeting a commissioning date in 2030. Procurement for the STATCOM was initiated to ensure delivery in sufficient time to meet the short list consultation need date (2029), reflecting long lead times and a tight global market for this type of equipment. The project is continuing with the well advanced procurement process (and therefore early commissioning) for the following reasons:

- Transpower has completed a competitive RFP process and secured a competitive price;
- Due to the global demand and potential for further high cost escalation for this type of equipment and associated power electronics (currently approximately 10% p.a.), the cost and supply chain risk of any delay likely offsets the costs of early commissioning;
- Due to increasing global demand for this equipment, timely procurement is likely to get increasingly difficult if the purchase is further deferred;

- With another similar STATCOM unit to be purchased for another project, joint procurement and a common set of spares can reduce the cost to the WUNI project;
- Commissioning of the STATCOM in 2030 provides some headroom and flexibility in case of an unexpectedly large demand increase.

OTA–WKM duplexing

The timing of the duplexing works is primarily driven by the conductor condition. Condition assessments conclude that the Ohinewai–Hautapu (OHW–HTU) sections of the OTA–WKM A and B lines require replacement by 2034-35, while parts of the Hautapu–Whakamaru (HTU–WKM) section may not require replacement until 2037-40. However, we propose completing the duplexing works by 2035[13] rather than splitting the programme into separate stages for the OHW–HTU and HTU–WKM sections for the following reasons:

- Duplexing the OTA–WKM A and B lines is a very large body of work (over 110 km, two circuits), involving 3-4 stringing seasons, and 5-6 years of enabling works, property agreements, consents and stakeholder engagement;
- Partial upgrades (with higher capacity and lower resistance conductors) reduce the effective load limit in the WUNI region by approximately 100 MW and could result in the remaining sections overloading earlier;
- Several other large transmission line projects are expected to be delivered during regulatory control period 5 (RCP5, from 2030 to 2035); completing the duplexing works as a single programme reduces programme and resource risks across the wider transmission line portfolio, while providing delivery and cost efficiencies.

The duplexing will be coordinated with Transpower's wider reconductoring programme, including the planned condition driven reconductoring of the OTA–WKM A and B lines north of Ohinewai, also being planned for RCP5. The final OTA–WKM A and B lines duplex commissioning date will consider the sequencing and alignment of these works within the wider transmission line portfolio.

The upgrade of the Ohinewai switching station to accommodate the new connection of the circuits of the OTA-WKM A and B lines is now reported as a separate project to be commissioned in 2033. Establishing this connection ahead of the reconductoring work will reduce circuit outage impacts during the delivery phase.

Pakuranga shunt capacitor

The commissioning date for the Pakuranga shunt capacitor aligns with the updated system need date of 2035. This is later than the need date presented in the short list consultation. Early commissioning of the Henderson STATCOM ahead of the system need provides sufficient reactive support to defer the need for the Pakuranga shunt capacitor until 2035.

Summary of changes to Option 4b

The changes since the short list consultation to the investments in Option 4b and their targeted commissioning dates are summarised in Table 7. The series compensation on the Brownhill–

[13] The reconductoring works will commence with the sections in worst condition, aiming for completion by winter 2035.

Whakamaru line that was considered as part of Stage 2 in the short list consultation is now only required in the 2040s.

Table 7: Changes to Option 4b since the short list consultation

Year	Short List Consultation (based on 2019 EDGS with 2024 inputs)	Updated Development Plan (see Attachment 4)	MCP (based on 2024 EDGS with 2026 inputs)	What sets commissioning dates?
2028	Shunt capacitor at PAK[14]			
2029	STATCOM at HEN			
2030	Duplexing OTA-WKM	Shunt capacitor at PAK	STATCOM at HEN	Procurement process, cost escalation
2031	Shunt capacitors x2	STATCOM at HEN		
2032	Shunt capacitors x3	Shunt capacitors x3		
2033	Series compensation on BHL-WKM	Duplexing OTA-WKM	OHW switching station upgrade	Duplexing delivery process
2034				
2035	Shunt capacitors x2	Shunt capacitor	Duplexing OTA-WKM Shunt capacitor at PAK	Asset condition of conductors System need (reactive support)

4.3 The proposed Stage 2 investments

The proposed Stage 2 investments included in this MCP are outlined in Table 8. The details of the cost estimates are presented in Attachment 6.

Table 8: Proposed Stage 2 investments (Option 4b)

Stage 2 Investments	Estimated P50 cost (in real 2026 dollars)	Expected commissioning date
±150 Mvar STATCOM at HEN	$83.3m	2030
100 Mvar shunt capacitor at PAK	$14.5m	2035
OHW switching station upgrade	$20.0m	2033
Duplex OTA–WKM A&B circuits (OHW–WKM section) and connect into OHW	$204.9m	2035
Total	**$322.8m**	

[14] Acronyms: Henderson (HEN), Ohinewai (OHW), Ōtāhuhu (OTA), Pakuranga (PAK), Whakamaru (WKM), Brownhill (BHL), Hautapu (HTU).

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