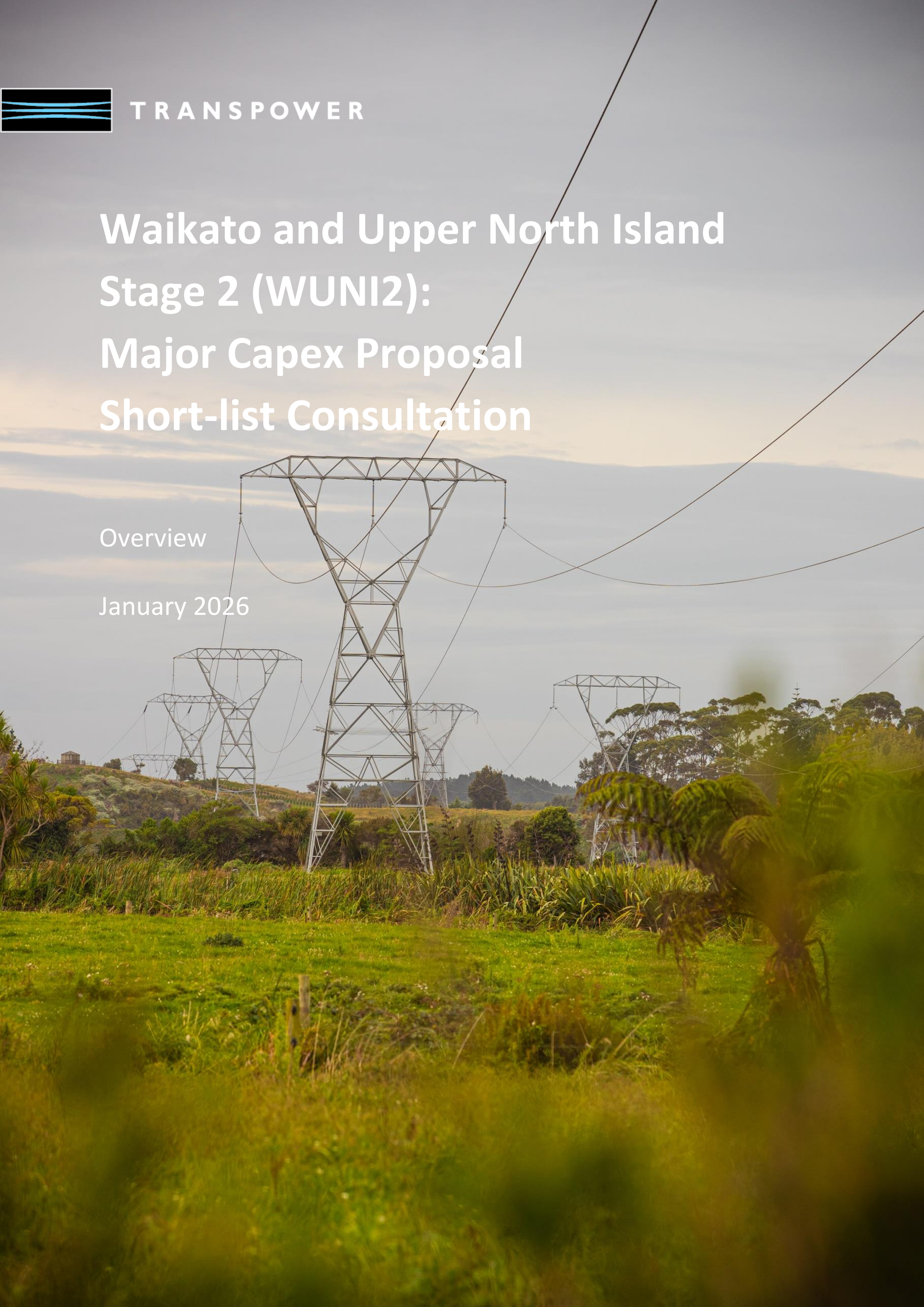
TRANSPOWER

Waikato and Upper North Island Stage 2 (WUNI2): Major Capex Proposal Short-list Consultation

Overview

January 2026



Executive Summary

Transpower is consulting on a short-list of potential electricity infrastructure investments – including its preferred approach – to ensure a reliable electricity supply to the Waikato and Upper North Island (**WUNI**) region.

The WUNI region, covering Northland, Auckland and Waikato, accounts for nearly 40% of New Zealand's total electricity demand. Following the decommissioning of major thermal power stations at Ōtāhuhu and Southdown, the region has become increasingly reliant on remote hydro-electric and geothermal generation. Alongside this shift, the region is experiencing considerable electricity demand growth, which is placing significant stress on the thermal capacity of the transmission lines that allow the import of electricity into the region and on managing the voltage to ensure stability of the electricity supply during periods of peak demand.

This potential project forms Stage 2 of a multistage programme of work aimed at addressing the challenges in the WUNI region. Stage 1, approved by the Commerce Commission (**Commission**) in 2020, included $144 million in investments to enhance grid stability by installing static synchronous compensators (**STATCOM**s) at Ōtāhuhu and Hamilton substations. However, continued demand growth in the region means that further investment will be necessary. We are exploring development plans to ensure the grid can support the region's growing needs while transitioning to a lower-emissions economy.

This consultation document outlines a short-list of potential development plans, including our preferred Stage 2 option – a STATCOM at Henderson, duplexing the Ōtāhuhu–Whakamaru A and B lines south of Ohinewai, series compensation on the Brownhill–Whakamaru circuits, and series capacitors at various locations (collectively, Option 4b). Additionally, we are considering non-transmission solutions (**NTS**), such as demand response initiatives, as part of our approach.

We invite stakeholders, including local councils and communities, to provide feedback on our short-list and our preferred option. This consultation is a vital step toward preparing a major capex proposal to submit to the Commission for approval, ahead of any works beginning.

Contents

1 Overview

The combined areas of Northland, Auckland and Waikato account for nearly 40% of New Zealand's total electricity demand. Historically this region relied heavily on a mix of remote hydro-electric and geothermal generation from the central North Island, along with significant thermal power stations located at Ōtāhuhu, Southdown and Huntly.

However, over the past decade the decommissioning and capacity reductions of some large thermal generators have significantly altered the operation of the power system in the region. These changes created immediate challenges in maintaining voltage stability, by effectively lowering the static and dynamic voltage stability limits.

These challenges are further compounded by continued demand growth in the upper North Island, particularly residential, commercial and transport electrification. As electricity demand increases, this places pressure on the thermal capacity of the transmission lines that import power into the region. This increasing pressure requires ongoing investment to maintain the network's reliability and resilience in the face of ongoing demand growth.

The transmission lines serving the WUNI region are part of the core grid, where Transpower must maintain at least an N-1 reliability standard.[1] This standard ensures that the power system stays stable and continues to supply electricity even if a major unplanned outage affects the core grid.

Forecast electricity demand growth in the region will soon exceed N-1 transmission limits. Transpower must invest to ensure we continue to meet the needs of local people and businesses in the WUNI region.

We are working on a series of potential investments to reliably meet electricity demand forecasts in the WUNI region through to 2055. Stage 2 investments will be needed starting in 2028.

Stakeholder engagement is vital for this project. Please share your feedback on investment needs, analysis assumptions, and our preferred option to help inform the final proposal.

This consultation paper presents a short-list of development plans for the WUNI region. These options underwent a comprehensive cost-benefit analysis (known as the "Investment Test")[2] and we identified the option with the highest expected net electricity market benefit to consumers through to 2055, our preferred option, Option 4b.

Alongside the preferred option, we have identified an alternative preferred option, Option 4a. The costs and benefits for the full development plans of both 4a and 4b are very similar, but in addition to a marginally superior net benefit, Option 4b provides more opportunity to stage investments, hence Option 4b is recommended as the preferred option.

1 The WUNI network is part of the core grid as defined in Schedule 12.3 of Part 12 of the Code.

2 The "Investment Test" is defined in Schedule D of the Commerce Commission's Transpower Capital Expenditure Input Methodology (**Capex IM**).

Option 4b includes upgrading of the two lowest-capacity lines serving the WUNI region. This will be achieved by duplexing the Ōtāhuhu–Whakamaru A and B lines south of Ohinewai and establishing a connection to the Ohinewai switching station. Series compensation on the Brownhill–Whakamaru circuits increases the thermal capacity into Auckland and improves voltage stability. Additionally, investments in STATCOM technology and shunt capacitors are planned. Subject to feedback from this consultation and further internal investigation, the investment in the series compensation could potentially be deferred into a subsequent stage (Stage 3).

Option 4a reverses the order of the series compensation and duplexing. Option 4a provides more time for duplexing of the Ōtāhuhu–Whakamaru A and B lines to be delivered ahead of the projected condition-based need but has less potential for optionality as the lines are projected to need reconductoring in the mid 2030's even if this project did not proceed. Table 1 in section 5.2 outlines the associated costs, benefits and investment timing in greater detail for Options 4a and 4b.

In this consultation, we are also seeking feedback on the availability of generation in the region, and demand growth, which are important in determining the need dates for the various investments. We are also continuing to evaluate our ability to carry out the duplexing by 2030, which is a challenging timeline.

The outcome of these factors and the consultation feedback will influence whether Option 4a or 4b is the preferred option for any major capex proposal (**MCP**) to the Commission. If Option 4b remains the preferred option, Transpower will request the Commission's approval to recover the Major Capex Allowance (**MCA**),[3] estimated at $607 million for Stage 2. If Option 4a becomes the preferred option, we will look to recover an MCA of $605 million in Stage 2. However, opportunities to defer approval for some part of this expenditure to a Stage 3 may emerge during the course of this consultation and further investigation, in which case we will revise our Stage 2 MCA request downwards.

See sections 5.5 and 5.6 for the cost details and the calculation method. These costs will be recovered through transmission charges.

This document summarises the short-listed development plans and sets out our preferred option, and alternative preferred option, with further details on the comparison covered in section 5.4. Further details are available in the Attachments, which include option descriptions, electricity demand and generation scenarios, modelling assumptions and preliminary Investment Test results.

2 WUNI Region

The WUNI region is illustrated in Figure 1. The transmission lines relevant to supplying power to the WUNI region are the 220 kV (and the 400 kV capable) lines between Whakamaru in Waikato, and Auckland.

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[3] The Major Capex Allowance (MCA) includes inflation and interest during construction.

Figure 1: Overview of the WUNI geographical region showing transmission lines

2.1 Overview of Prior Investigations and Investments

We have been actively monitoring the evolving power system challenges in the WUNI region for several years. In 2015, we began studies on how retiring thermal generation affects the system, with immediate concerns about voltage management during peak demand and longer-term issues from thermal constraints.

To address these challenges, we developed a staged investment programme to manage voltage and thermal constraints, enabling a gradual shift from thermal generation and supporting ongoing regional load growth.

We held a long-list consultation in July 2016[4] and a short-list consultation in June 2019[5] exploring options to address voltage stability and thermal capacity risks.

4 Waikato and Upper North Island Voltage Management long-list consultation, July 2016

5 WUNIVM Short-list Consultation, June 2019

We evaluated several long-term development plans to ensure future demand remains within voltage and thermal N-1 limits. To manage risk, and align investment timing with evolving system needs, the programme was structured into multiple stages:

- **Stage 1 Investments – Voltage Stability:** Stage 1 of the WUNI programme, approved by the Commission in September 2020, focused on improving voltage stability. The Stage 1 investment involved installing two STATCOMs at the Hamilton and Ōtāhuhu substations. These works were successfully completed in 2023 and 2025.[6]
- **Future Stages – Thermal and Voltage:** As demand in the WUNI region was forecast to continue growing, some future investments – potential Stages 2 and 3 – were identified as necessary to support ongoing regional demand growth and to ensure a reliable, resilient transmission network through 2030 and beyond.

2.2 The Need for Investment

New Zealand's electricity demand is expected to continue increasing significantly over the coming decades, with the Northland, Auckland and Waikato regions already experiencing substantial growth. The current increase is driven by expanding residential, commercial and industrial sectors, the growth of agriculture-related industries and the ongoing electrification of industry and transport.

Beyond residential growth, future electricity demand is being driven by the electrification of transport, the transition from coal to electricity in the process heat sector, and the replacement of gas and other thermal fuels usage with electric alternatives. To account for alternative futures, we have developed a range of scenarios based on varying assumptions about future developments.

Attachment 3 provides more detail on the electricity demand and generation forecasts that we used in this analysis.

This investment is necessary to maintain N-1 reliability in the core grid under Grid Reliability Standards (**GRS**). The transmission lines supplying the WUNI region are listed as core grid assets in the Electricity Industry Participation Code 2010.

The GRS requires Transpower to uphold an N-1 reliability standard on the core grid, meaning the power system stays stable and supplies electricity even with one unplanned outage.

As the flow of electricity increases, greater demands are placed on the transmission line capacity. Thermal constraints limit power transmission to prevent conductors and equipment from overheating. These thermal capacity limits may be mitigated by constructing additional transmission lines or upgrading the capacity of existing ones.

Voltage stability is a persistent issue in the region, requiring ongoing investment as demand grows. Currently static capacitors, shunt reactors and dynamic reactive devices (STATCOMs and SVCs) across multiple sites support voltage levels, especially during outages affecting Auckland or major generation units nearby.

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6 Waikato and Upper North Island (WUNI) Upgrades | Transpower

Forecasts show that, without additional investment to meet growing electricity demand, thermal and voltage transmission constraints in the WUNI region will soon threaten supply reliability as capacity limits are reached.

The calculation of the transmission limits and the resulting need dates for the required investments heavily depend on the assumptions of available generation in the region, particularly at Huntly, and its capacity during winter peak periods. More details around the limits and underlying assumptions are presented in Attachment 1. We invite feedback on these assumptions to refine our analysis after the consultation.

After this short-list consultation, we will evaluate all feedback and determine whether adjustments to our assumptions and analysis are necessary before submitting our (potential) proposal to the Commission.

3 Options to Address the Need

3.1 Our Long-list of Options

During Stage 1, a long-list of options was considered to address the identified need.[7] These options include:

- Reactive power devices (e.g., capacitor banks, shunt capacitors, STATCOMs)
- Transmission assets (e.g., series capacitors, new transmission lines and upgraded existing lines, 400 kV conversion, grid reconfigurations)
- Non-transmission solutions (e.g., battery storage, demand-side participation, special protection schemes).

No single component alone is sufficient to provide a complete solution; therefore, a combination of these components is required, added progressively over time, to meet the investment need and ensure a reliable electricity supply for the region.

As part of this Stage 2 investigation, we have reviewed these components and determined that they remain appropriate for building our investment options and meeting our identified need.

Each long-listed component was assessed on its ability to address the identified need, using our short-listing criteria. Further detail on the process is provided in Attachment 2.

3.2 Short-list of Development Plans

Just as we did in Stage 1,[8] we have combined various components of the long-list to create a Stage 2 short-list of development plans, in this case extending out to 2055. Each plan consists of several

[7] These components were considered and consulted on during our WUNI Stage 1 MCP. The long-list consultation document with further detail, can be found here.

[8] Our WUNI Stage 1 Short-list Consultation can be found here.

specific components and their proposed commissioning timelines. These development plans were designed to address both voltage stability and thermal capacity constraints, collectively forming a technically feasible solution to meet the region's core grid investment need.

The short-listed development plans are summarised below. Common to all short-listed development plans is the installation of a shunt capacitor at Pakuranga substation in 2028 and a STATCOM at Henderson substation in 2029.

- **Option 1 – Series Compensation and Ohinewai Tee:** An investment path integrating reactive power support (shunt capacitors and another STATCOM), series compensation on the Brownhill–Whakamaru circuits, and a new hard tee connection of the Brownhill–Whakamaru circuits at Ohinewai to enhance thermal transfer capacity. Series reactors are considered to redirect power flow after 2040.
- **Option 2 – Series Compensation and Brownhill–Ōtāhuhu Cable:** A new 220 kV underground cable between Brownhill Road and Ōtāhuhu, combined with series compensation on the Brownhill–Whakamaru circuits to optimise power flow. Reactive power support is provided by shunt capacitors at various locations. At a later stage, series reactors are considered on the new cable and on other circuits.
- **Option 3 – Ōtāhuhu–Whakamaru Duplexing and STATCOMs:** This path upgrades the two lowest-capacity lines supplying the WUNI region, by duplexing the Ōtāhuhu–Whakamaru A and B lines south of Ohinewai and connecting to the Ohinewai switching station. This increases thermal capacity of the lines while voltage stability is increased with two additional STATCOMs and various shunt capacitors. Series reactors are used to redirect power flow.
- **Option 4 – Series Compensation and Duplexing:** An investment path integrating reactive power support (shunt capacitors), series compensation on the Brownhill–Whakamaru circuits, and upgrades of the two lowest-capacity lines supplying the WUNI region, by duplexing the Ōtāhuhu–Whakamaru A and B lines south of Ohinewai and connecting to the Ohinewai switching station. This optimises the power flow across the available circuits into the WUNI region and increases the overall transmission limit.

We have considered two variants of Option 4, varying the order of series compensation and duplexing, to acknowledge the challenging timeline for delivering the duplexing by the specified need date (2030). The implications of these variants are presented in section 5.

A related consideration is the modelled project[9] involving the planned reconductoring works on the Ōtāhuhu–Whakamaru A and B lines. These lines are approaching the need for condition-based reconductoring (i.e., replacing the conductors due to corrosion). A recent condition assessment indicates that the southern section (between Ohinewai and Whakamaru) will require reconductoring during the 2030s. However, under our short-listed Options 3 and 4 this work – and its associated costs – could be avoided, as these options include the duplexing of the lines to increase capacity ahead of the condition-based replacement.

Further details on the short-listed development plans can be found in Attachment 2 of this consultation document.

[9] Modelled projects are not part of the investment option, but their likelihood, nature and timing are affected by an investment option proceeding, see Capex IM clause D8(4).

3.3 Non-transmission Solutions

Non-transmission solutions (**NTS**) may have the potential to defer transmission investment in the WUNI region.

We have worked closely with the Commission to develop an approach that allows us to fund economic NTS that provide a net benefit by deferring transmission investments – using the financial value of up to 12 months' deferred transmission capital expenditure.

Given the scale of electricity demand growth in the WUNI region and the requirement for us to meet the GRS, NTS are unlikely to eliminate the need for investment (or any alternative development plan). However, NTS could help to defer transmission investment until the early 2030s and assist in managing risks from potential delays in constructing transmission assets.

We are seeking a maximum recoverable cost allowance for potential future NTS, determined by its estimated deferral value. Any decision to proceed depends on meeting the net benefit test at that time. This approach aligns with our recent Western Bay of Plenty and Upper South Island MCPs.

4 Investment Test Inputs and Assumptions

To identify our preferred option, we conducted a cost-benefit analysis of the short-list of development plans using the Investment Test. As the investment need is to provide N-1 reliability on the core grid, for an option to satisfy the Investment Test, it must be the option which maximises expected net electricity market benefit,[10] although the net benefit may be negative. This is because the N-1 reliability standard takes precedence as a 'safety net' that underpins the core grid's operation.

The costs considered in the Investment Test include capital expenditure and allowances for mid-life refurbishment. Benefits are calculated using models of the New Zealand electricity system to estimate the benefits of alternative transmission options relative to the base case.[11] Costs and benefits are discussed in greater detail in Attachments 4 and 5.

Applying the Investment Test requires several key assumptions. These include assumptions about electricity demand growth and future generation capacity, as mentioned earlier. Additional assumptions are made in calculating the present value of future cash flows.

Attachment 5 provides more detail of the assumptions used in our preliminary application of the Investment Test.

Following this short-list consultation, we will review all feedback and consider if we should vary our assumptions and analysis before submitting our potential proposal to the Commission.

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[10] The expected net electricity market benefit in the Investment Test is the expected electricity market benefit minus the expected electricity market cost (including project costs).

[11] The types of costs and benefits we consider in the Investment Test are specified in the Capex IM.

5 Preliminary Application of the Investment Test

Our preliminary application of the Investment Test has considered the costs[12] and benefits of each option. The preferred option provides the highest expected net electricity market benefit.

5.1 Electricity Market Benefits

All electricity market benefits are calculated relative to the base case where no new transmission investment occurs. The types of benefits considered include:

- **Terminal 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.
- **Modelled market benefits:** calculated by applying a hydro-thermal dispatch optimisation package called SDDP.[13]
  - **Transmission loss benefits:** represent the reduced electricity needed to be generated due to lower electrical losses over the transmission network under different asset configurations of the grid. These transmission losses are converted to loss costs by multiplying the losses by the Island short-run marginal 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 $600 per MWh.[14]

5.2 Cost-benefit Analysis

Table 1 presents the total discounted project costs and benefits for each option out to 2055. To account for the time value of money, we present total costs and benefits as present values, discounted at an annual rate of 5%.

As mentioned in section 3.2, we have considered two variants of Option 4:

- In Option 4a we set the commissioning date for the series compensation to 2030 and for the duplexing to 2033.
- In Option 4b these timings are reversed.

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12 These costs reflect the real aggregate project costs of each of the short-listed development plans through to 2055. Although the cost-benefit analysis encompasses the full calculation period to 2055, we are currently only seeking approval for investments through to 2033 (Stage 2). Any further investments that are part of the preferred development plan would require separate approvals, see Attachment 5.

13 SDDP is an electricity market modelling tool used to determine economic benefits, see Attachment 4.

14 Deficit costs have been valued using cost tranches, see Attachment 4.

The quantified market benefits for the Option 4 variants in the calculation period from 2034 to 2055 (after the duplexing and series compensation investments are made), are identical. However, the difference in the timing of individual investments leads to small variations in the discounted costs and the terminal values.

As this investment is a core grid reliability investment, the proposed investment must be the option which maximises expected net electricity market benefit, although the net benefit may be negative. The expected net electricity market benefit is calculated as the difference between total benefits and total costs as shown in Table 1.

Table 1: Summary of quantified costs and benefits for the short-listed development plans, 2025 present values at 5% discount rate[15]

	Option 1 Series Comp + Tee	Option 2 Series Comp + Cable	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
Stage 2 investments ($m)	276.8	494.1	274.1	404.0	403.7
Future stages and modelled projects ($m)	139.9	95.5	161.3	60.1	60.1
Avoided reconductoring cost ($m)	-	-	-64.7	-64.7	-64.7
Total costs ($m)[16]	**416.7**	**589.7**	**370.8**	**399.4**	**399.2**
Terminal value benefits ($m)	84.0	107.6	81.9	71.7	72.9
Modelled market benefits ($m)	318.7	365.1	335.3	422.1	422.1
Total benefits ($m)	**402.7**	**472.8**	**417.2**	**493.9**	**495.0**
Net benefits ($m)	**-14.0**	**-116.9**	**46.4**	**94.5**	**95.8**

The cost-benefit analysis indicates that Option 4b (Duplex + Series Compensation) delivers the highest quantified positive net benefit among all options. However, Option 4a (Series Compensation + Duplex) delivers a similar net benefit and can therefore be considered as an alternative preferred option.[17]

A sensitivity analysis of the cost-benefit calculations can be found in Attachment 5. The sensitivity analysis reinforces the robustness of Options 4a and 4b, showing that both maintain the highest net benefit across a wide range of input uncertainties.

15 Future costs and benefits have been calculated out to 2055 and discounted back to a present value using a real pre-tax discount rate of 5%.

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

17 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.

5.3 Comparison of Option 3 and Option 4 Variants

Table 2 presents the near-term investments out to 2038 for the three highest net benefit options, Options 3, 4a and 4b, highlighting the main differences.

Table 2: Near-term investments in Options 3, 4a and 4b, main differences highlighted

Year	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
2028	Shunt capacitor	Shunt capacitor	Shunt capacitor
2029	STATCOM	STATCOM	STATCOM
2030	**Duplex OTA–WKM circuits, connect at OHW**	**Series compensation BHL–WKM**	**Duplex OTA–WKM circuits, connect at OHW**
2031	Shunt capacitors x2	Shunt capacitors x2	Shunt capacitors x2
2032	Shunt capacitors x3	Shunt capacitors x3	Shunt capacitors x3
2033	Shunt capacitors x2	**Duplex OTA–WKM circuits, connect at OHW**	**Series compensation BHL–WKM**
2034	**STATCOM**	-	-
2035	Shunt capacitors x2	Shunt capacitors x2	Shunt capacitors x2
2038	Shunt capacitors x2 Series reactors	Shunt capacitors x2	Shunt capacitors x2
...	...	...	...

The initial investments between 2028 and 2032 are the same for Options 3 and 4b. The series compensation in Option 4b is included in the proposed Stage 2, however, as the STATCOM in Option 3 is only needed by 2034, we have considered that for a future Stage 3.

Subject to feedback from this consultation and further investigation, there may be an opportunity to defer the series compensation in Option 4b into a future Stage 3 also. In comparison, Option 4a require both the series compensation and the duplexing to be included in Stage 2.[18] An advantage of Option 4a is that this variant allows more time to deliver the duplexing.

Further details of the development plans, their components and timings can be found in Attachment 2.

5.4 Risk Trade-offs Between Option 4 Variants

The total costs, benefits and net benefits of the full development plans for the Option 4 variants are very similar, however there are different risk trade-offs for each of them.

[18] The timing of the duplexing is driven by the condition-based replacement of the conductor on the OTA–WKM A and B circuits between Ohinewai and Whakamaru and therefore is unable to be deferred beyond 2033. Because of this, and as duplexing has a relatively long lead time, it is not practical to defer that investment into a subsequent stage.

There are two key constraints with the Option 4 variants:[19]

- the duplexing must be completed by 2033, which is the condition-based replacement date of the existing simplex conductor, and
- duplexing by 2030 is very challenging for a section of over 100 km.

Option 4a (duplexing by 2033) provides more time for duplexing to be delivered because it builds series compensation in 2030. However, the duplexing cannot be deferred further even if the forecast load growth does not eventuate. This option commits us to the full cost of both the series compensation and duplexing by 2033.

Option 4b (duplexing by 2030) provides future optionality and possible staging opportunities, as the investment in series compensation can potentially be delayed if the forecast load growth does not eventuate. However, as mentioned above, there are risks with the deliverability of duplexing by 2030. This option therefore brings risk if, for example, high demand growth eventuates or if generation is on the lower side of our assumptions (particularly at Huntly). This is discussed further in Attachment 1.

Deliverability of duplexing by the 2030 need date will be further considered, and along with consultation feedback on demand growth and generation, will feed into our final option selection.

5.5 Our Preferred Option

Based on our preliminary application of the Investment Test, we conclude that Option 4b is our preferred option, subject to feedback from this consultation and further investigation into possible staging. Option 4a is considered as an alternative preferred option.

Option 4b consists of a series of successive investments designed to accommodate continued demand growth in the WUNI region through to 2055. While we have a higher level of confidence in the immediate investment horizon, this decreases over time due to forecasting uncertainties. For this proposed project, our primary focus is on the near-term investments required between 2028 and 2033 (Stage 2).

In this Stage 2 investment, we propose to invest in the core grid to meet the N-1 reliability standard, including:

- ±150 Mvar STATCOM at Henderson
- Connect the Ōtāhuhu–Whakamaru A and B circuits to the Ohinewai switching station and duplex the sections between Ohinewai and Whakamaru
- Series compensation on the Brownhill–Whakamaru circuits at Hangawera Road
- Shunt capacitors at various locations.

Further investments outlined in the broader development plan may be undertaken as part of a potential Stage 3, depending on how electricity demand and system need evolve over time. This staged approach allows us to address immediate capacity and reliability concerns while retaining flexibility to deliver additional improvements later.

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[19] The duplexing constraints also apply to Option 3.

Table 3 outlines the Stage 2 investments included in the preferred development plan (Option 4b), in real 2025 dollars (undiscounted). Any additional investments needed after the early 2030s will be addressed in a subsequent stage or project. Table 3 contrasts with the cost presented in Table 1, which are for the entire development plan, and are discounted to a 2025 present value.

Table 3: Proposed WUNI Stage 2 investments (in real 2025 dollars)

WUNI Stage 2 investments (Option 4b)[20]	Estimated P50 cost (real 2025 $m)	Expected commissioning date
100 Mvar shunt capacitor (PAK)	13.3	2028
±150 Mvar STATCOM (HEN)	80.3	2029
Duplex OTA–WKM A&B circuits (OHW–WKM section) and connect at OHW	174.9	2030
100 Mvar shunt capacitor (Auckland region)	13.3	2031
100 Mvar shunt capacitor (Auckland region)	13.3	2031
100 Mvar shunt capacitor (Auckland region)	13.3	2032
2x75 Mvar shunt capacitors (OHW)	21.3	2032
Series compensation on BHL–WKM circuits at Hangawera Road	185.9	2033
Total	515.6	

These transmission investments are assets known as “interconnection assets”, owned and operated by Transpower. Should this consultation result in an MCP, the WUNI Stage 2 MCP will seek Commission approval to recover the cost of the preferred development plan. If approved by the Commission, the cost will be recovered via transmission charges calculated in accordance with the Transmission Pricing Methodology (**TPM**) upon commissioning of the relevant assets.

5.6 Major Capex Allowance

Transpower will seek an allowance from the Commission to recover project costs associated with “interconnection” investments; this is referred to as the Major Capex Allowance (**MCA**). The draft MCA for our preferred option, and alternative preferred option are provided in Table 4.

Table 4: Expected projects costs and draft MCA

WUNI Stage 2 Investments	Expected P50 cost (real 2025 $m)	Draft MCA (nominal $m)
Option 4b (preferred option)	515.6	606.7
Option 4a (alternative preferred option)	515.6	605.0

[20] Substation acronyms: Henderson (HEN), Brownhill Road (BHL), Whakamaru (WKM), Ōtāhuhu (OTA), Ohinewai (OHW), Pakuranga (PAK)

The draft MCA of $606.7 million (in nominal dollars) for the preferred option is larger than Transpower's expected project cost because it includes inflation and interest during construction. Note that the expected cost and draft MCA presented in Table 4 are not discounted.

If our preferred option remains unchanged following this consultation, and the Commission approves our investment proposal, interconnection transmission charges will increase. The Commission determines the revenue Transpower can recover from its customers, while the TPM determines how this revenue is allocated among Transpower's customers each pricing year.

Although we are not yet consulting on proposed starting benefit-based investment (**BBI**) customer allocations, we have included indicative starting BBI customer allocations for the preferred option in Attachment 6.

Should we proceed with submitting an MCP to the Commission following this consultation, we will formally consult on the proposed starting BBI customer allocations for that investment after the Commission's final decision and Transpower's final investment decision on the MCP.

6 Consultation Process and Scope

6.1 Consultation Information Provided

The information provided for this consultation comprises:

- This short-list consultation overview paper
- A series of Attachments providing more detailed information on key elements of the process:
    - Attachment 1 – Need for Investment
    - Attachment 2 – Short-list of Development Plans
    - Attachment 3 – Demand and Generation Scenarios
    - Attachment 4 – Benefits Modelling
    - Attachment 5 – Investment Test and Intended Proposal
    - Attachment 6 – Indicative Starting Allocations.

The Attachments contain information and questions to guide feedback. The questions are also summarised in the final section of this document.

6.2 Consultation Process

We invite written feedback for this consultation from 15 January 2026 to 25 February 2026. Please send your submissions or queries to grid.investments@transpower.co.nz. We will acknowledge submissions by return email.

Once the consultation period ends, we will make all submissions available on our website. Any contact details you have included in your document will be included. In addition, we will share these submissions with the Commission as part of our discussions on this project.

If you want to keep your contact details or any part of your submission confidential, please submit a redacted version. We will publish that version to our website, but relevant confidential information may still be shared with the Commission if this investigation results in an MCP, as Transpower is subject to the Official Information Act.

7 Next Steps

This short-list consultation is a significant step in the regulated process for proposing major investments in New Zealand's electricity transmission network. The next steps include:

- Considering the feedback and information received in submissions.
- Refining our application of the Investment Test, including taking account of the information received in response to this consultation, and obtaining more detailed cost estimates.
- Submitting a proposal to the Commission (should the expected cost of the final preferred option exceed $30 million).

8 Specific Feedback We Are Seeking

This consultation document includes specific questions to guide your feedback. You are not obliged to answer all or any of these questions, and you are welcome to raise other relevant issues.

Attachment 1 discusses the need for investment and seeks feedback. Attachment 1 poses the following questions:

Q1. Are there any additional factors we should consider regarding our identified investment need in the Waikato and Upper North Island region?

Q2. Do you agree with our approach that the prudent Environmental forecast is the appropriate forecast to inform the investment need?

Q3. Do you agree with our assumptions on availability and type of generation at Huntly during winter peak periods? Are there other relevant generation projects we should consider in our analysis?

Q4. There is now a grid-connected battery energy storage system (BESS) in the WUNI region, with more projects committed. Based on very limited data available we are proposing an assumption that average BESS output is 15% of nominal capacity during peak load periods. Do you consider this to be appropriately conservative?

Attachment 2 provides details on the development plans formed by combining option components, as well as the short-listing of these plans to meet the identified need. Attachment 2 poses the following questions:

Q5. Do you agree with the components we have short-listed? Are there any additional considerations you believe should be included?

Q6. Do you agree with the development plans we have short-listed?

Q7. Do you support the proposed NTS approach?

Attachment 3 outlines the generation and demand scenarios we are using for our analysis. Attachment 3 poses the following question:

Q8. Do you have any additional information that could materially affect our electricity demand forecast or generation assumptions?

Attachment 4 outlines our approach to modelling the benefits of options. We have no questions associated with this attachment.

Attachment 5 outlines our preliminary application of the Investment Test, including the parameters that are used in our analysis. Attachment 5 asks:

Q9. Do you consider our proposed weighting of the scenarios to be appropriate?

Q10. Do you consider our use of a calculation period of 2034-55 and a standard discount rate of 5% to be appropriate?

Q11. Do you have any feedback on our cost-benefit analysis for this project?

Q12. Do you agree that our preferred option remains robust under sensitivity analysis?

Q13. Is our selection of the preferred option (4b) reasonable? How do you view the benefits of the potential for staging in the context of the delivery challenges of duplexing by 2030? Do you support the consideration of an alternative preferred option (4a), as the feasibility of 4b is dependent on consultation feedback and further consideration of duplexing deliverability by 2030?

Attachment 6 provides an indicative range of starting BBI customer allocations for the preferred option. These indicative ranges are included for information purposes only, and we are not seeking feedback on them at this stage. No specific questions are associated with this attachment.

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