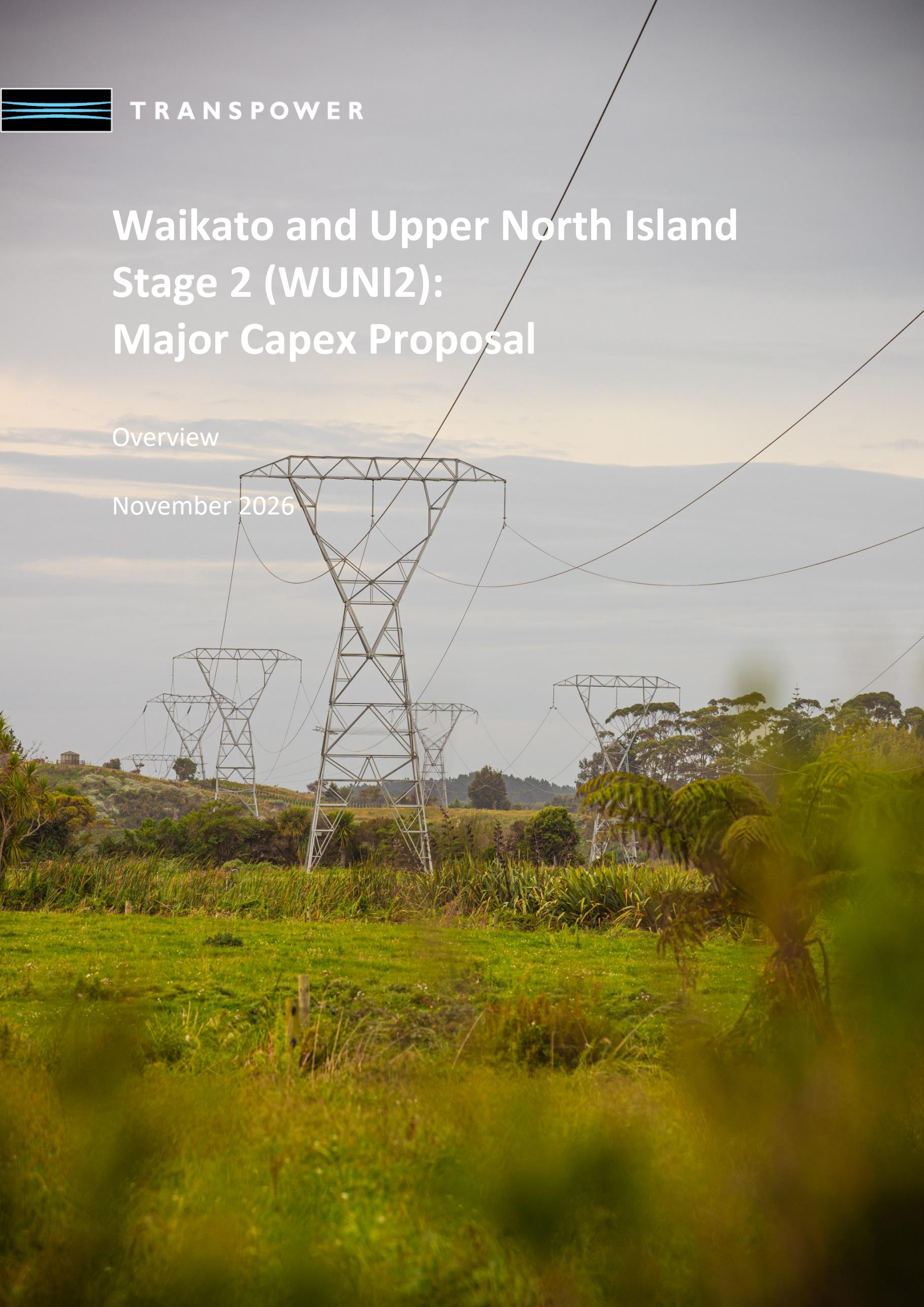
TRANSPOWER

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

Overview

November 2026



Executive Summary

This is a Major Capex Proposal (**MCP**) to the Commerce Commission (**Commission**) under the Transpower Capital Expenditure Input Methodology Determination (**Capex IM**).[1]

The Waikato and Upper North Island (**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 WUNI region has become increasingly reliant on remote hydro-electric and geothermal generation. Alongside this shift, the WUNI region is experiencing considerable electricity demand growth. The increasing load is forecast to exceed the existing thermal limits of the transmission lines supplying the WUNI region, as well as the voltage stability limits of the transmission system in 2034.

This MCP is for the second stage of a multi-stage programme of work aimed at addressing the challenges in the WUNI region. Stage 1 of the WUNI Upgrade major capex project (**Stage 1**), approved by the Commission in 2020,[2] included $144 million in investments to enhance grid stability by installing static synchronous compensators (**STATCOMs**) at Hamilton and Ōtāhuhu substations. This work was completed in 2023 and 2025, respectively. However, continued demand growth in the region means that further investment will be necessary.

In January 2026, we consulted on the short-listed development plans for Stage 2 of the WUNI Upgrade major capex project (**Stage 2**).[3] After considering stakeholder submissions, the preferred development plan and now **Proposed Investment**, Option 4b, has not changed and is confirmed to be robust under the updated cost-benefit analysis. However, need dates of the proposed Stage 2 investments have been deferred by several years, due to updates in the underlying demand and generation assumptions based on feedback received in the consultation. Due to the later need dates, we have reduced the scope of what is included in the proposed Stage 2 investments. Consequently, the Stage 2 project costs are substantially lower than presented in the short list consultation. Also, the investments happen later which lowers the present value of the costs. The proposed Stage 2 investments preserve future flexibility while delivering the common no regrets investments now.

This MCP focuses on our proposed Stage 2 investments – a STATCOM at Henderson substation, a shunt capacitor at Pakuranga substation and duplexing the Ōtāhuhu–Whakamaru A and B lines south of Ohinewai including a connection into the Ohinewai switching station. We are not proposing any non-transmission solutions (**NTS**) for investment deferral in Stage 2. The investment need dates have been deferred from those set out in the short list consultation as far as possible considering updated demand forecasts and additional project-related factors. These factors include the cost and supply chain risks associated with further deferring procurement of the Henderson STATCOM, and the condition-driven replacement requirements for the Ōtāhuhu–Whakamaru conductors. These factors leave little scope for further economic deferral of the proposed Stage 2 investments, limiting the usefulness of NTS.

---

1 Commission, Transpower Capital Expenditure Input Methodology [2012] NZCC 2

2 Commission, Decision and reasons on Stage 1 of Transpower's Waikato and Upper North Island Voltage Management staged major capex project [2020] NZCC 20

3 Transpower, Waikato and upper North Island (WUNI) stage 2 project short-list consultation, January 2026

The proposed major capex allowance (**MCA**) for Stage 2 is $408.4 million (in nominal dollars) with expected commissioning of the proposed Stage 2 investments between 2030 and 2035. Additional upgrades may be proposed in the future, in one or more potential future stage MCPs, depending on how generation and demand in the WUNI region continue to evolve.

Contents

Executive Summary 2

1 Overview 5

2 WUNI region 8

2.1 Overview of prior investigations and investments 8

2.2 The need for investment 9

3 Options to address the need 11

3.1 Long list of options 11

3.2 Short-listed development plans 11

4 Investment Test inputs and assumptions 13

4.1 Updated demand and generation assumptions 13

4.2 Impact on investment timing and staging 14

5 Application of the Investment Test 16

6 Proposed Stage 2 investments 18

6.1 Revised scope of the proposed Stage 2 investments 19

6.2 Need dates and commissioning dates 20

6.3 Non-transmission solutions (NTS) 21

7 Major Capex Allowance 23

8 Indicative pricing impacts 24

9 Supporting documents 25

10 Next steps 25

1 Overview

The WUNI region accounts 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 have 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 WUNI region, 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. Ongoing investment is required to maintain the transmission network's reliability.

The transmission lines serving the WUNI region are part of the core grid, where Transpower must maintain at least an N-1 reliability standard. This standard ensures that the power system stays stable and continues to supply electricity even if an unplanned outage affects the core grid. Forecast electricity demand growth in the region will soon cause N-1 load limits to be exceeded. Transpower must invest to ensure we continue to meet the needs of consumers in the WUNI region.

Improving our understanding of local needs and opportunities, particularly related to such issues as new electricity generation and commercial and residential developments is critical for getting both the solution and the timing right. We sought input through consultation with our stakeholders. The input provided was useful and has been taken into consideration in the preparation of this MCP.

In January 2026, we consulted on a short list of development plans and our preferred set of investments to reliably meet forecast electricity demand in the WUNI region through to 2055.

This document presents an overview of the updated short list of development plans considered to address the identified voltage stability and thermal capacity needs of the core grid in the WUNI region. These have been evaluated as investment options through the investment test in Schedule D of the Capex IM (**Investment Test**) and we identified the option with the highest expected net electricity market benefit through to 2055 – Option 4b, which is the Proposed Investment. Note that the term Proposed Investment refers to the full Option 4b development plan to 2055; the proposed Stage 2 investments are the subset of these investments that we plan to undertake over the period from 2030 to 2035.

Transpower seeks Commission approval to recover the project costs of the proposed Stage 2 investments (the major capex project outputs for Stage 2), expected to be $408.4 million (MCA, in nominal dollars).[4] This cost is broken down in Table 1 and an overview of our proposal can be found in Table 2.

The proposed Stage 2 investments include upgrading the two lowest-capacity lines serving the WUNI region. This will be achieved by reconductoring the Ōtāhuhu–Whakamaru (OTA–WKM) A and B

[4] The Stage 2 MCA of $408.4 million (in nominal dollars) is larger than the P50 project cost of $322.8 million (in real 2026 dollars) because it includes inflation and interest during construction.

lines[5] south of Ohinewai (OHW) with a duplex configuration to increase the winter rating to 780 MVA and establishing a connection to the Ohinewai switching station. The other elements of the Stage 2 MCP are investments in STATCOM technology and shunt capacitors in the Auckland region.

Table 1: Proposed Stage 2 investments and MCA breakdown (Option 4b)[6]

Proposed Stage 2 investments	Estimated P50 cost (in real 2026 dollars)	MCA[7] (incl. inflation and interest during construction, in nominal dollars)	Expected commissioning date
±150 Mvar STATCOM at HEN[8]	$83.3m[9]	$95.8m	2030
100 Mvar shunt capacitor at PAK	$14.5m	$18.2m	2035
OHW switching station upgrade	$20.0m	$24.7m	2033
Duplex OTA–WKM A&B circuits (OHW–WKM section) and connect into OHW	$204.9m	$269.8m	2035
Total	**$322.8m**	**$408.4m**	

Table 2: Stage 2 MCP at a glance

What:	Ensure forecast electricity load growth in the WUNI region can be served by increasing transmission transfer capacity between Whakamaru in Waikato and south Auckland. Major capex project outputs: – Install a ±150 Mvar STATCOM at Henderson substation – Install a 100 Mvar shunt capacitor at Pakuranga substation – Reconductor (duplex) the 220 kV OTA–WKM A&B circuits on the southern OHW–WKM section to achieve a winter rating of 780 MVA – Connect the OTA–WKM A&B circuits to Ohinewai switching station.
When:	Commence work as soon as funding is approved Commissioning date assumption (commissioning date of last investment): 31 December 2035
How much:	Major Capex Allowance: $408.4 million (nominal)
Incentive elements:	Major capex incentive rate: default rate of 15% Exempt major capex: none P30 MCA estimate: $393.4 million (nominal) P70 MCA estimate: $423.7 million (nominal)

5 Each line carries a single 220 kV circuit.

6 Note: values presented in tables throughout this MCP may not sum exactly due to rounding.

7 The assumed inflation is based on the consumers price index (CPI) projection in the Monetary Policy Statement September 2026 - Reserve Bank of New Zealand - Te Pūtea Matua.

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

9 The estimate includes the confirmed STATCOM OEM tender price. This update is not material to the overall P50 estimate for the project nor the P30–P70 range.

Approval expiry date:	31 December 2040 (allowance of five years for any delay in construction that may be caused by unexpected events)

The proposed Stage 2 investments are in interconnection assets[10] on the core grid and will enhance the capabilities of the transmission grid in the region. The costs associated with these assets are recovered by Transpower through transmission charges. For interconnection investments exceeding the base capex threshold that enhance the grid, Transpower must seek approval from the Commission.[11]

Anticipated future stages

While our overall development plan for Option 4b and the Investment Test analysis includes series compensation on the Brownhill–Whakamaru (BHL–WKM) line and further shunt capacitors at various locations in Auckland and Waikato, we do not have sufficiently detailed need dates and cost estimates to be confident enough to include these works in Stage 2. They could be included as part of a potential future stage in the late 2030s, depending on demand and generation developments and evolving system requirements.

We expect a subsequent MCP to include the investments outlined in Table 3, consistent with the analysis underpinning this MCP. However, the proposed staging allows us to reassess the relative benefits of these parts of Option 4b compared to alternative options later, retaining optionality to identify the best solution to address a future need (series compensation versus additional STATCOMs, series reactors or other solutions).

Table 3: Anticipated investments in future stages (Option 4b)

What is likely to be included:	Outputs: – Install series compensation on the BHL-WKM line – Install shunt capacitors at various locations in Auckland and Waikato.

[10] In general, interconnection assets are configured in a loop of continuous nodes and links (the interconnected grid), and connection assets form a link between a transmission customer's plant and the interconnected grid.

[11] The base capex threshold is $30 million for MCPs notified to the Commission on or after 1 April 2025.

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 south Auckland as well as the lines from Stratford in Taranaki via Huntly.



Figure 1: Overview of the WUNI region showing transmission lines and generation locations

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 would affect 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 away from thermal generation and supporting ongoing regional load growth.

We held a long list consultation in July 2016[12] and a short list consultation in June 2019[13] exploring options to address voltage stability and thermal capacity risks.

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, 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.[14]
- **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 increase significantly over the coming decades, with the WUNI region 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 consider a range of scenarios with varying assumptions about future developments. Attachment 3 provides more detail on the electricity demand and generation scenarios that we used in this analysis.

This investment is necessary to maintain N-1 reliability in the core grid, as required under the grid reliability standards (**GRS**).[15] The N-1 reliability standard means the power system must stay stable and supply electricity even with an unplanned outage in the core grid. The transmission lines supplying the WUNI region are listed as core grid assets in Part 12, Schedule 12.3 of the Code.

As the flow of electricity increases, greater demands are placed on the transmission system. 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. Static devices (shunt capacitors and reactors) and dynamic reactive devices (STATCOMs and SVCs)

[12] Transpower, WUNI Long-list Consultation, July 2016
[13] Transpower, WUNI Short-list Consultation, June 2019
[14] Transpower, Waikato and upper North Island (WUNI) Upgrades
[15] Clause 2(2)(b) of Part 12, Schedule 12.2 of the Electricity Industry Participation Code 2010 (**Code**).

across multiple sites maintain voltage stability, especially during outages of grid assets or major generation units in the region.

In addition to the system need, we also consider the condition of the existing transmission assets when determining the timing of investment. Recent condition assessment reports conclude that the conductors on the southern sections of the Ōtāhuhu–Whakamaru A and B lines are approaching end of life due to corrosion and require replacement. This condition-based need is relevant to the timing of the proposed duplexing works, as duplexing would replace the existing conductors while also increasing transmission capacity. Further detail on the proposed timing of the duplexing works is provided in Section 6.2.

Analysis shows 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 depend heavily on the assumptions about available generation in the region, particularly at Huntly, and its capacity during winter peak periods. These assumptions were updated following the short list consultation and are discussed in Section 4.1. More details around the limits and underlying assumptions are presented in Attachment 2.

The schematic in Figure 2 shows the main transmission corridor in the WUNI region and the existing winter ratings of the relevant 220 kV lines.

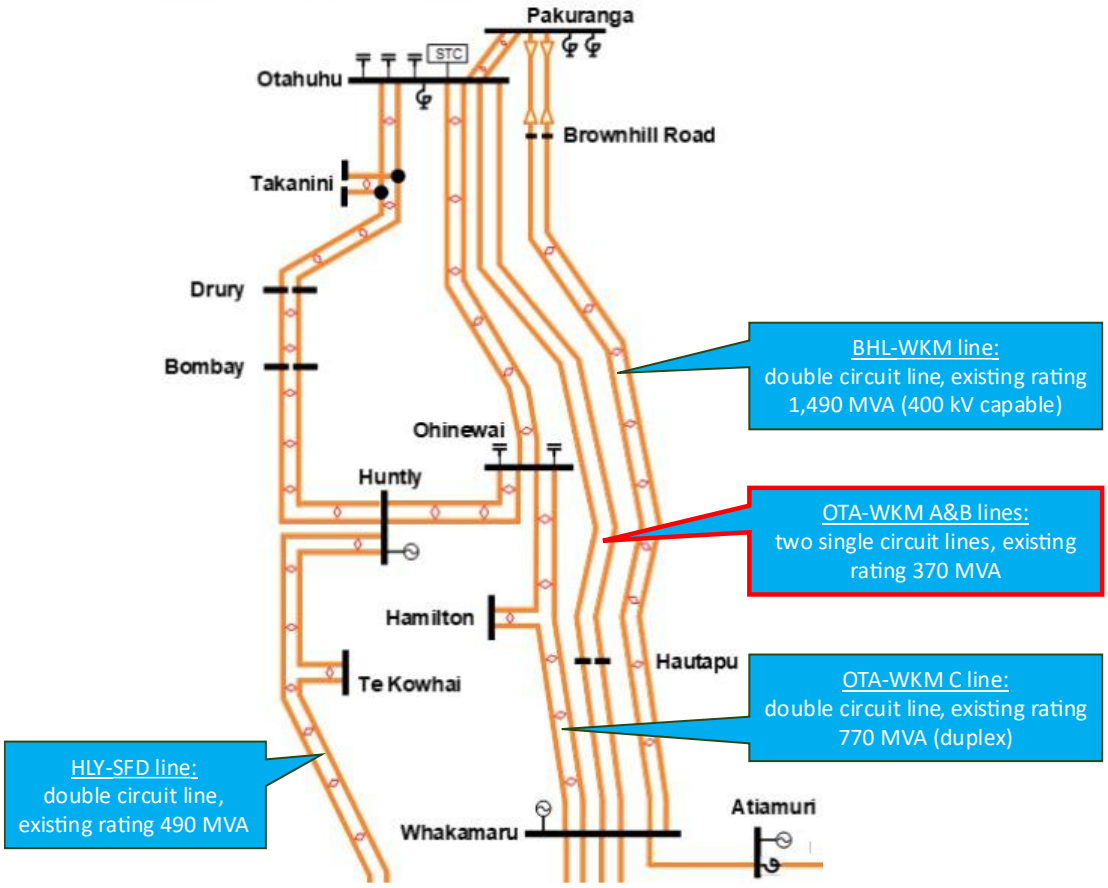


Figure 2: Schematic of the main WUNI transmission corridor and existing winter line ratings

3 Options to address the need

3.1 Long list of options

During Stage 1, a long list of options was considered to address the identified investment need.[16] These options included:

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

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 developing our investment options and meeting the investment need.

Each long-listed component was assessed on its ability to address the investment need, using our short-listing criteria. Further detail on the process is provided in Attachment 4.

3.2 Short-listed development plans

Just as we did in Stage 1, we have combined various components of the long list to create short-listed development plans for Stage 2 and beyond, in this case extending out to 2055. Each plan consists of several 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 investment need.

Following the short list consultation,[17] we removed Option 1 (series compensation and a tee connection at Ohinewai) from the final assessment in this MCP due to technical issues with the series compensation in combination with the tee connection of the Brownhill–Whakamaru line (creating a three-terminal circuit).

We also removed the alternative variant 4a of Option 4, which was included to address anticipated challenges in delivery timeframes, particularly with respect to duplexing. Changes to input assumptions resulted in the investments being deferred, removing the need for this variant. Consequently, only Option 4b is considered in this MCP, keeping the naming consistent with the short list consultation.

[16] These components were considered and consulted on during our Stage 1 investigation.

[17] Transpower, Waikato and upper North Island (WUNI) stage 2 project short-list consultation

The final short-listed development plans (now investment options) are summarised below. Common to all development plans is the installation of a STATCOM at Henderson substation and a shunt capacitor at Pakuranga substation.

- **Option 2 – Series compensation and Brownhill–Ōtāhuhu cable:** This path strengthens the transmission corridor with a new 220 kV underground cable between Brownhill Road and Ōtāhuhu, combined with series compensation on the Brownhill–Whakamaru line to optimise power flow. Reactive power support is provided by shunt capacitors at various locations. At a later stage, series reactors are considered to balance power flow on circuits into Auckland.
- **Option 3 – Ōtāhuhu–Whakamaru duplexing and STATCOM:** 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 a second STATCOM and shunt capacitors at various locations. At a later stage, series reactors are considered to balance power flow.
- **Option 4b – Ōtāhuhu–Whakamaru duplexing and series compensation:** This path also upgrades the two lowest-capacity lines supplying the WUNI region, by duplexing the Ōtāhuhu–Whakamaru A and B lines as in Option 3. Subsequently, series compensation on the Brownhill–Whakamaru line optimises the power flow across the available circuits in the WUNI region and increases the overall transmission limit. Reactive power support is provided by shunt capacitors at various locations.

Options 3 and 4b are identical through to 2035 and include the same Stage 2 investments proposed in this MCP. The options only differ in the later stages of the development plans, where Option 3 uses an additional STATCOM and series reactors, while Option 4b uses series compensation. Further details on the final short-listed development plans can be found in Attachment 4.

Alignment with condition-based reconductoring

A related consideration is the modelled project[18] 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). The condition assessment reports conclude that the southern section (between Ohinewai and Whakamaru) will require reconductoring during the 2030s.[19] However, under Options 3 and 4b these works – and the associated costs – could be avoided, as these options include duplexing the lines to increase capacity in place of the condition-based replacement.

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

[19] Condition assessment reports indicate that the OHW–HTU sections of the OTA–WKM A and B lines require replacement by 2034-35. The HTU–WKM sections are expected to require replacement by 2037-40. Updated conductor surveys over the next few years will provide greater confidence in the replacement need dates for the HTU–WKM sections.

4 Investment Test inputs and assumptions

We conducted a cost-benefit analysis of the final short-listed development plans (now investment options) using the Investment Test. As the investment need in this case is to provide N-1 reliability on the core grid, for a proposed investment to satisfy the Investment Test it must be the investment option that maximises the expected net electricity market benefit relative to the other investment options considered,[20] although the expected net electricity market 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 relative benefits of alternative investment options relative to the base case.[21] Costs and benefits are discussed in greater detail in Attachments 6 and 7.[22]

Applying the Investment Test requires several key assumptions. These include assumptions about electricity demand growth and future generation capacity (demand and generation scenarios). Attachment 3 provides more detail on the demand and generation scenarios that we used in this analysis. We also make assumptions in calculating the present value of future cash flows. Attachment 5 provides more detail about the assumptions used in our application of the Investment Test and the results.

4.1 Updated demand and generation assumptions

In the short list consultation, we asked specifically for feedback regarding our generation assumptions in the region and the contribution of generators and battery energy storage systems (**BESS**) during the crucial winter peak periods. These assumptions are highly relevant for the calculation of the load limits (thermal capacity and voltage stability) in the WUNI region. Together with the peak load forecast, this informs the need dates for required grid upgrades.

Based on the short list consultation feedback received, we have updated our assumptions regarding available generation at Huntly and the contribution of existing and future grid-scale BESS to cover peak load.[23] Specifically, out to 2035, we now assume:

---

20 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.

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

22 These costs and benefits reflect the real aggregate electricity market costs and benefits of each of the investment options 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 2035 (Stage 2). Any further investments that are part of the Proposed Investment would require separate approvals.

23 The submissions to our short list consultation and a summary of these submissions are available on the WUNI project website: WUNI Stage 2 Short-list Consultation

- all three Huntly Rankine units (240 MW each) and the peaking unit 6 (50 MW) are available during peak load periods
- as a prudent assumption and reflecting the uncertain gas availability, we do not consider the combined-cycle gas turbine (unit 5, 400 MW) in the power system modelling, and
- in terms of BESS, we now assume 635 MW of grid-scale BESS operational by 2029 (235 MW existing, 400 MW under construction or committed) with an expected contribution during peak load of 15% of the nominal capacity.

The updated generation and BESS assumptions increase the initial load limit (i.e., the limit before any grid upgrades in the region are required) by approximately 170 MW.

As proposed in our short list consultation document and reinforced by the feedback received, we have also updated our peak load forecast by lowering it. The forecast update adopts MBIE's EDGS[24] as of July 2024 on a national level and incorporates inputs from electricity distribution businesses regarding local demand growth that we received and consolidated in early 2026. Also, the starting point of the updated forecast is lower, reflecting the most recent historical peaks. More details of the underlying demand and generation assumptions are provided in Attachment 3.

4.2 Impact on investment timing and staging

The resulting impact of the updated demand and generation assumptions on the need date for the first required grid upgrade can be derived from the intersection of the peak load forecast and the initial load limit, as shown in Figure 3. In the short list consultation, the peak load forecast exceeds the initial load limit in 2028 (orange lines in chart, labelled as SLC). With the updated higher load limit and lower peak load forecast (blue lines), this point is now reached in 2034, hence deferring the need date for the first required grid upgrade by six years compared to the short list consultation.

[24] Ministry of Business, Innovation & Employment (**MBIE**), Electricity Demand and Generation Scenarios (**EDGS**)

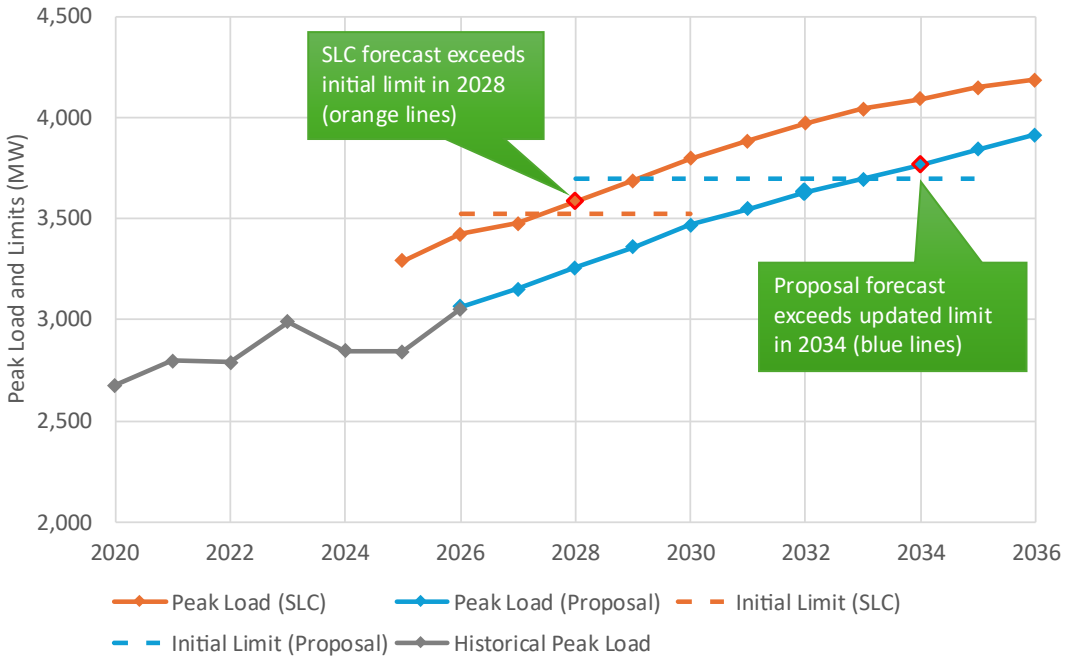


Figure 3: WUNI winter peak load (prudent forecast) and initial load limits

Note that the final short-listed development plans presented in Attachment 4, which are the investment options assessed in the Investment Test, are based on the short list consultation peak load forecast but reflect the updated load limits. Using the updated load limits means the investment years for the components of the final short list development plans in Attachment 4 are different to those in the short list consultation.

The market benefit modelling in the Investment Test uses the updated peak load forecast[25] and updated load limits. The final need dates for the proposed Stage 2 investments are also based on the updated peak load forecast and updated load limits.

[25] In the market benefit modelling, we have used an earlier version of the demand and generation scenarios which is also based on the 2024 EDGS.

5 Application of the Investment Test

Our application of the Investment Test has considered the electricity market costs and benefits of each investment option to calculate the expected net electricity market benefits.

Table 4 presents the total discounted costs and benefits for each investment option out to 2055. To account for the time value of money, we present total costs and benefits as present values, incorporating the phasing of investment and the benefits expected over time.

We considered electricity market benefits for the three investment options. The benefits considered are:

- **Generation dispatch benefits:** calculated by applying a hydro-thermal dispatch optimisation package called SDDP[26]:
  - **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 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.[27]
- **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.

As this investment is a core grid reliability investment, to satisfy the Investment Test, the proposed investment must be the option that maximises expected net electricity market benefit, although the expected net electricity market benefit may be negative. The expected net electricity market benefit is calculated as the difference between total benefits and total costs, as shown below.

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

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

Table 4: Summary of quantified costs and benefits for the investment options, 2026 present values at 5% discount rate[28]

	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**
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**
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.[29] 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 the two options only emerge after 2049. Option 4b is the Proposed Investment based on having the highest expected net electricity market benefit of the investment options.

A sensitivity analysis of the cost-benefit calculations can be found in Attachment 5. The analysis reinforces the robustness of Option 4b, showing that this option maintains the highest expected net electricity market benefit across a wide range of input uncertainties.

[28] 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%, the default value from the Capex IM.

[29] 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.

6 Proposed Stage 2 investments

Based on the application of the Investment Test, we have concluded that Option 4b is the Proposed Investment. This conclusion was also supported by stakeholders during the short list consultation process.

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 MCP, our primary focus is on the near-term investments required between 2030 and 2035 (Stage 2).

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

- A ±150 Mvar STATCOM at Henderson substation
- A 100 Mvar shunt capacitor at Pakuranga substation
- Connecting the circuits of the Ōtāhuhu–Whakamaru A and B lines to the Ohinewai switching station and duplexing the sections between Ohinewai and Whakamaru.

Figure 4 shows the single line diagram of the regional 220 kV transmission system with two of the proposed Stage 2 investments (i.e., duplexing of the OTA–WKM A and B lines and connecting the circuits to the Ohinewai switching station) highlighted in blue.

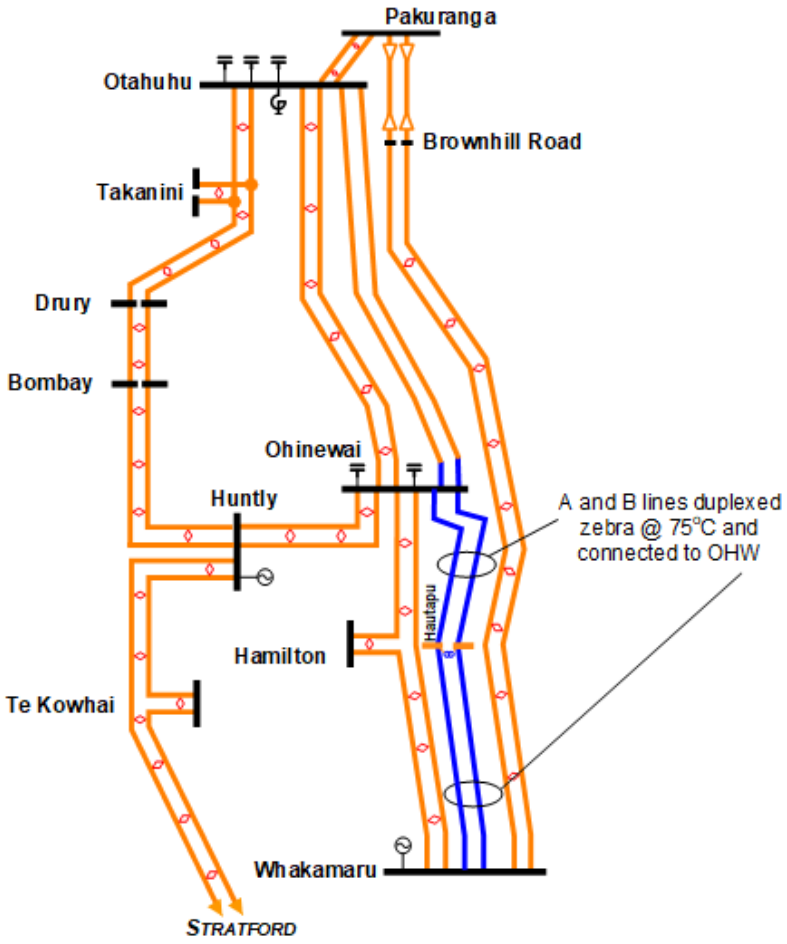


Figure 4: Single line diagram of Option 4b (Stage 2 excluding Henderson STATCOM)

6.1 Revised scope of the proposed Stage 2 investments

Table 5 summarises the changes to the proposed Stage 2 investments from the short list consultation to this MCP.

Table 5: Changes to Option 4b since the short list consultation

Year	Short List Consultation (based on 2019 EDGS with 2024 inputs)	MCP (based on 2024 EDGS with 2026 inputs)
2028	Shunt capacitor at PAK	-
2029	STATCOM at HEN	-
2030	Duplexing OTA-WKM	STATCOM at HEN
2031	Shunt capacitors x2	-
2032	Shunt capacitors x3	-
2033	Series compensation on BHL-WKM	OHW switching station upgrade[30]
2034	-	-
2035	Shunt capacitors x2	Duplexing OTA-WKM[31] Shunt capacitor at PAK

Because of the updated demand and generation assumptions discussed in Section 4.1, the proposed Stage 2 investments are now required later than assumed in the short list consultation. Accordingly, we have removed series compensation and further shunt capacitors from the scope of the proposed Stage 2 investments. This reduces the real project costs by $247 million (in 2025 dollars, based on the costing as per the short list consultation). This reduction is partly offset by an approximately $54 million increase in project costs following solution study design and an update in our cost database to real 2026 dollars, including service provider resource rates for the new contract year.[32]

Reasons for the proposed staging

Consistent with the later need timing, further investments identified in Option 4b – including the previously considered series compensation on the Brownhill–Whakamaru line and additional shunt capacitors – have been deferred. These investments may be undertaken as part of one or more potential future stages beginning in the late 2030s, depending on how electricity demand and

[30] The upgrade of the Ohinewai switching station to accommodate the new connection of the Ōtāhuhu–Whakamaru lines is now reported as a separate project. It was included in the scope and cost of the duplexing project in the short list consultation.

[31] The 2035 date referred to here is driven by the condition-based replacement need date for the OTA–WKM conductors. Further information on system need dates, condition-based replacement need dates and proposed commissioning dates is provided in Section 6.2.

[32] The cost estimate for duplexing the OTA–WKM A and B lines has increased by approximately $50 million since the short list consultation. The estimate has been updated following completion of the solution study design, additional site investigations and incorporation of learnings and updated cost information from recent duplexing projects. We consider the updated estimate provides a more accurate expected cost of duplexing the OTA–WKM A and B lines and upgrading the Ohinewai switching station. Further detail is provided in Attachment 6.

system need evolve over time. Taking a staged approach allows us to address immediate thermal capacity and voltage stability concerns now, while reducing uncertainties and retaining flexibility to deliver additional improvements later. It also allows us to reassess the relative benefits of Option 4b compared to Option 3 (or another option) later, retaining optionality to identify the best solution to address a future need.

6.2 Need dates and commissioning dates

Commissioning dates may differ from need dates. The proposed commissioning dates for the proposed Stage 2 investments reflect the updated demand and generation assumptions discussed in Section 4.1 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 with the selected supplier;
- Due to strong global demand and potential for further high cost escalation for this type of equipment and associated power electronics (currently approximately 10% p.a. which is in line with observed historic cost escalation), the cost and supply chain risk of any delay likely offsets the costs of early commissioning;
- Due to increasing global demand for this type of equipment, timely procurement is likely to get increasingly difficult if the purchase is further deferred;
- With a 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 proposed timing of the duplexing works is primarily driven by the conductor condition. Recent 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[33] rather than splitting the programme into separate stages for the OHW–HTU and HTU–WKM sections for the following reasons:

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

- 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 up to 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 project 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 Ōtāhuhu–Whakamaru 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 provides sufficient reactive support to defer the need for the Pakuranga shunt capacitor until 2035.

6.3 Non-transmission solutions (NTS)

Transpower has considered the potential for NTS to defer the proposed Stage 2 investments but do not propose an NTS allowance for investment deferral in Stage 2.

Updated demand and generation assumptions have moved the investment need dates out relative to the short list consultation and further economic deferral is constrained by procurement considerations and asset condition.

For the Henderson STATCOM, Transpower has completed a competitive RFP process and secured a competitive price. Given market and supply-chain pressure, Transpower considers that proceeding with procurement now, at the price secured through the RFP process, is the most efficient path. Also, the effectiveness of the STATCOM unit to manage voltage stability is very location dependent. The investigations in Stage 1 showed that the STATCOM installations were the most cost-effective approach to meet the regional grid requirements.

The replacement of the OTA–WKM conductors is driven by asset condition and the need to manage the risks of continued operation of the transmission network in the region. NTS would not address these condition-related issues or provide a practical basis for further deferral. The targeted

commissioning date reflects both the need for replacing the conductors and the need to increase the transmission capacity in the region and is therefore a cost-effective and future-proof solution.

The Pakuranga shunt capacitor provides a material increase in transmission capacity and reactive support at relatively low cost. Given the capacity benefit relative to the investment required, Transpower considers that deferral through NTS is unlikely to be practical or economic. The shunt capacitor increases the relevant voltage stability limit by approximately 100 MW, while the deferral value of the investment for one year is around $0.5 million.

7 Major Capex Allowance

Stage 2 is a staging project of a major capex project (staged) under the Capex IM. The Capex IM requires us to submit a MCP to the Commission seeking approval to recover the costs of Stage 2.

Table 6 outlines Transpower's proposal for Stage 2. Any additional investments needed after 2035 will be the subject of one or more future MCPs for subsequent stages. Transpower is seeking an MCA to recover the costs associated with the proposed Stage 2 investments.

Table 6: Proposed Stage 2 investments MCA breakdown

Proposed Stage 2 investments	Estimated P50 cost (in real 2026 dollars)	MCA (incl. inflation and interest during construction, in nominal dollars)	Expected commissioning date
±150 Mvar STATCOM at HEN	$83.3m	$95.8m	2030
100 Mvar shunt capacitor at PAK	$14.5m	$18.2m	2035
OHW switching station upgrade	$20.0m	$24.7m	2033
Duplex OTA–WKM A&B circuits (OHW–WKM section) and connect into OHW	$204.9m	$269.8m	2035
Total	**$322.8m**	**$408.4m**	

The MCA of $408.4 million (in nominal dollars) is larger than Transpower's estimated P50 project cost because it includes inflation and interest during construction. Note that the estimated P50 cost and MCA presented in Table 6 are not discounted. More detail about the costing of the proposed Stage 2 investments is provided in Attachment 6.

8 Indicative pricing impacts

The Commission determines how much revenue Transpower can recover from its customers. The Transmission Pricing Methodology (**TPM**)[34] determines how revenue is recovered from each of Transpower's customers in each pricing year. If approved, cost recovery will occur through transmission charges.

Once commissioned, the proposed Stage 2 investments will be classified as a high-value post-2019 benefit-based investment (**BBI**) under the TPM. The costs of the BBI will be recovered through benefit-based charges (**BBCs**) from customers who are expected to benefit from the BBI. The BBCs will be allocated to customers in proportion to their expected positive net private benefits.

If the Commission approves Stage 2 and we make a final investment decision to go ahead with it, transmission charges, specifically BBCs, will increase. Transpower will calculate expected net private benefits and proposed starting allocations for the BBI using a standard method[35] under the TPM (in particular, the price-quantity method) and consult on them. Indicative starting allocations and indicative BBCs are presented in Attachment 9.

[34] Electricity Industry Participation Code 2010, Part 12, Schedule 12.4

[35] Transpower, Information sheet on benefit-based charges: Standard methods

9 Supporting documents

The MCP comprises:

- This MCP overview document
- A series of attachments providing more detailed information on key elements of the MCP:
  - Attachment 1 – Compliance with the Capex IM
  - Attachment 2 – Need
  - Attachment 3 – Demand and Generation Scenarios
  - Attachment 4 – Short list of investment options
  - Attachment 5 – Investment Test
  - Attachment 6 – Costing
  - Attachment 7 – Benefits modelling
  - Attachment 8 – Stakeholder consultation
  - Attachment 9 – Indicative pricing impacts
  - Attachment 10 – CEO Certification.

10 Next steps

This MCP marks a significant milestone in the regulated process for proposing major investments in New Zealand's electricity transmission network. The next step is for the Commission to review and consider this MCP and determine whether to approve the project outputs and cost recovery for the proposed Stage 2 investments.



TRANSPOWER