TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Overview

August 2025

Contents

1 Overview

This is a Major Capex Proposal (**MCP**) to the Commerce Commission.

The Upper South Island (**USI**) region covers most of the South Island north of Twizel. This area lacks sufficient local generation to meet its electricity demand, relying instead on power supplied via transmission lines from the Waitaki Valley to Islington and further north. The region is expected to experience growth as New Zealand transitions to a lower-emissions and more electrified society. Although there are few committed generation projects in the region, there is considerable potential for future intermittent renewable generation.

The transmission lines supplying the USI region are part of the core grid, on which Transpower, the owner and operator of New Zealand's electricity grid, must maintain at least an N-1 reliability standard. This ensures that the power system can remain stable and continue supplying power even if a single significant unplanned grid outage occurs.

As demand in the USI region rises, power flows over the 220 kV lines from the south will increase, leading to capacity constraints. According to our latest demand forecasts (the predicted future need for electricity), the thermal capacity of the existing Waitaki Valley to Christchurch circuits will be sufficient to maintain N-1 security until winter 2028.

Voltage stability has been a recurring issue in this region due to the long distances that electricity must travel from the Waitaki Valley to Christchurch and further north. Maintaining voltage within an acceptable range is crucial, as deviations can cause power surges, outages, and broader system disruptions. Our investigations indicate that based on our prudent demand forecast, voltage stability constraints will begin to limit growth by winter 2028.

To address these challenges, Transpower needs to invest to ensure we can continue to meet the needs of people and businesses in this region.

Transpower has been working on development plans that outline a series of potential investments designed to reliably meet electricity demand for the USI through to 2050 and beyond. Understanding local needs and opportunities, especially regarding electricity generation and developments, is essential for effective solutions and timing. Stakeholder input was gathered and considered in preparing this application (see Attachment 7 for further details of stakeholder consultation).

This document presents an overview of the options considered to address the identified voltage and capacity needs of the core grid in the USI. These options have been evaluated through the investment test[1] (**Investment Test**), and we have identified a preferred option that offers the greatest net benefit for consumers[2] (the **Proposed Investment**). This MCP is for the first stage of the Proposed Investment.

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

2 The Capex IM refers to this as the greatest expected net electricity market benefit.

Our proposal is to undertake a staged investment approach, prioritising the most critical near-term upgrades first (**Stage 1**) as shown in Table 1, with the flexibility to complete the remaining works in later stages.

In Stage 1, we propose constructing two switching stations near Orari and Rangitata, by 2029. Switching stations are substations without transformers. They will interconnect the four Christchurch–Waitaki Valley circuits at a midpoint between the Waitaki Valley and Christchurch and help improve the electrical performance of the grid. In addition, the existing section of the transmission line that will connect the two stations will be upgraded to increase its transfer capacity. To manage voltage stability, we propose installing shunt capacitor banks at the Orari switching station by 2030.

Note that the commissioning year of our first three investments is 2029, which is one year after our 2028 need date. Factors including longer lead times for critical equipment from international suppliers have made it difficult to maintain realistic project timeframes to commission our first investments in 2028. However, our 2028 need date is based on our prudent demand forecast, and consultation submissions also noted our prudent step load assumptions. The thermal upgrades of the Norwood–Rangitata circuit may also finish as late as 2030 due to factors including access and discussions with landowners to ensure under clearance requirements are met (including existing under clearance violations as discussed in Attachment 5).

We consider it is important for us to plan prudently, such that we have sufficient time to implement solutions and avoid placing demand at risk of non-supply. However, we do recognise that future demand is uncertain. While electricity lines businesses and consumers in the USI have informed us of strong expectations of demand growth, we recognise it may not materialise as anticipated. We consider funding for non-transmission solutions will help us to manage risks of delivering too late or to defer investment for several years. However, we need time to develop these solutions and ensure they are available. Until such time as they are available, we consider it is prudent to continue with our investment plans.

This MCP seeks Commerce Commission approval to recover the cost of the first stage of the Proposed Investment, expected to be $193.0m. This cost is broken down in Table 1 and an overview of our proposal can be found in Table 2.

Table 1: Stage 1 outputs and major capex allowance (MCA) breakdown

Project output	Expected cost (real 2025 dollars)	Major capex allowance (MCA) (incl. inflation and interest during construction (IDC))	Planned commissioning year
Switching station at Orari	$41.4m	$47.6m	2029
Switching station at Rangitata	$29.8m	$34.2m	2029
Lines turn ins to switching stations	$31.9m	$36.6m	2029
Thermal upgrades of the Norwood–Rangitata circuit to 90°C and Orari–Rangitata circuit to 100°C[3]	$50.1m	$58.4m	2030
A total of 150 Mvar shunt capacitor banks at Orari 220 kV	$11.4m	$13.4m	2030
Automatic over-voltage shunt capacitor and shunt reactor switching scheme	$1.0m	$1.2m	2030
Investigation cost	$1.5m	$1.6m	-
Total	$167.0m	$193.0m	

Table 2: Proposal at a glance

USI Upgrade Stage 1 MCP at a glance	
What:	*Outcome:* Maintain the grid reliability standards into the USI region by • Constructing two switching stations near Orari and Rangitata on existing Transpower-owned land to connect the four Christchurch–Waitaki Valley circuits halfway between the Waitaki Valley and Christchurch • Thermally upgrading the Orari–Rangitata circuit to 100°C and the Norwood–Rangitata circuit to 90°C • Installing 2 x 75 Mvar shunt capacitor banks at the Orari switching station • Installing automatic over-voltage shunt capacitor and shunt reactor switching schemes • Lines turn ins to switching stations

3 The works involved with these thermal upgrades include fixing existing under clearance violations, which will not be funded from this MCP. The total cost of these thermal upgrades (including fixing existing violations) is $56.0m ($50.1m MCP + $5.9m from other sources).

	Potential non-transmission solution (NTS) *Outcome: Economic deferral of any of the above investments* <u>Outputs</u> • Specific NTS (if any) not yet scoped
When:	Commence work as soon as funding is approved. Commissioning date assumption (commissioning date of last investment assuming no NTS): 31 December 2030
How much:	MCA (excluding potential NTS): $193.0 million[4] Maximum recoverable costs (for potential NTS): $7.0 million
Incentive elements:	Major capex incentive rate: default rate of 15% Exempt major capex: none
Approval expiry date:	31 December 2040[5]

The Proposed Investment involves "interconnection assets[6]" on the core grid and will enhance the capabilities of the transmission network (grid) in the region. The costs associated with these assets are recovered by Transpower through transmission charges. For interconnection investments exceeding $20 million that enhance the grid, Transpower must seek approval from the Commerce Commission.[7]

Additional upgrades may be implemented later, during Stage 2, depending on demand and generation growth and evolving system requirements. These are outlined in the Proposed Investment's overall development plan. We will seek approval from the Commerce Commission for any future staging projects. The investments outlined in Table 3 are anticipated for Stage 2, based on the analysis conducted to support our Stage 1 Proposal.

4 Breakdown of inflation and financing costs are available in Attachment 5.

5 We propose the approval expiry date be 31 December 2040, being ten years after the commissioning date assumption. We have proposed this extra period because this allows for both demand fluctuations and the potential use of NTS. In addition, a major generation announcement post-approval but before we have committed to expenditure could defer the need for some of the grid outputs for Stage 1 for several years. If this happens it will be efficient to have a reasonable window during which we will not have to re-apply for investment approval.

6 According to the Transmission Pricing Methodology – at Schedule 12.4 of the Electricity Industry Participation Code (2010) – an interconnection asset is a transmission asset that is not a connection asset. That is, 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.

7 The Commerce Commission has updated the Capex IM and the threshold is increased to $30 million for major capital expenditure proposals notified on or after 1 April 2025.

Table 3: Anticipated investments in USI Upgrade Stage 2

Anticipated for USI Upgrade Stage 2	
What is likely to be included:	Outputs • *Thermal upgrade of Opihi–Twizel circuit sections to 90°C* • *150 Mvar STATCOM at Ashburton 220 kV* • *Thermal upgrade of Rangitata–Tekapo B–1 to 90°C* • *100 Mvar of shunt capacitor at Ashburton 220 kV* • *Thermal upgrade Ashburton–Orari–1 and 2 to 90°C* • *150 Mvar STATCOM at Orari 220 kV*

This document provides an overview of our Proposal. For more detail, a set of supporting attachments offers in-depth information (see section 7 for a list of the supporting documents). These attachments cover detailed descriptions of the options considered, our scenarios and demand modelling assumptions, and the application of the Investment Test.

2 Upper South Island region

The USI region comprises all of the South Island north of Twizel. Figure 1 shows a map of the USI, and a schematic of the 220 kV circuits within the region.

Electricity is supplied to the USI by four 220 kV circuits that connect Christchurch to generation in the lower South Island and North Island (via the HVDC link). These circuits include:

- a single circuit line from Twizel to Islington
- a single circuit line from Livingstone to Islington
- a double circuit line from Twizel to Islington and Bromley.

Three 220 kV circuits from Islington to Kikiwa supply the entire Nelson-Marlborough region and part of the West Coast. The West Coast is also supported by two smaller 66 kV circuits from Islington to Hororata, though their contribution is minimal compared to the 220 kV lines.

From Kikiwa, two 220 kV circuits and two 110 kV circuits continue north to Stoke, supplying power to the Nelson-Marlborough region.

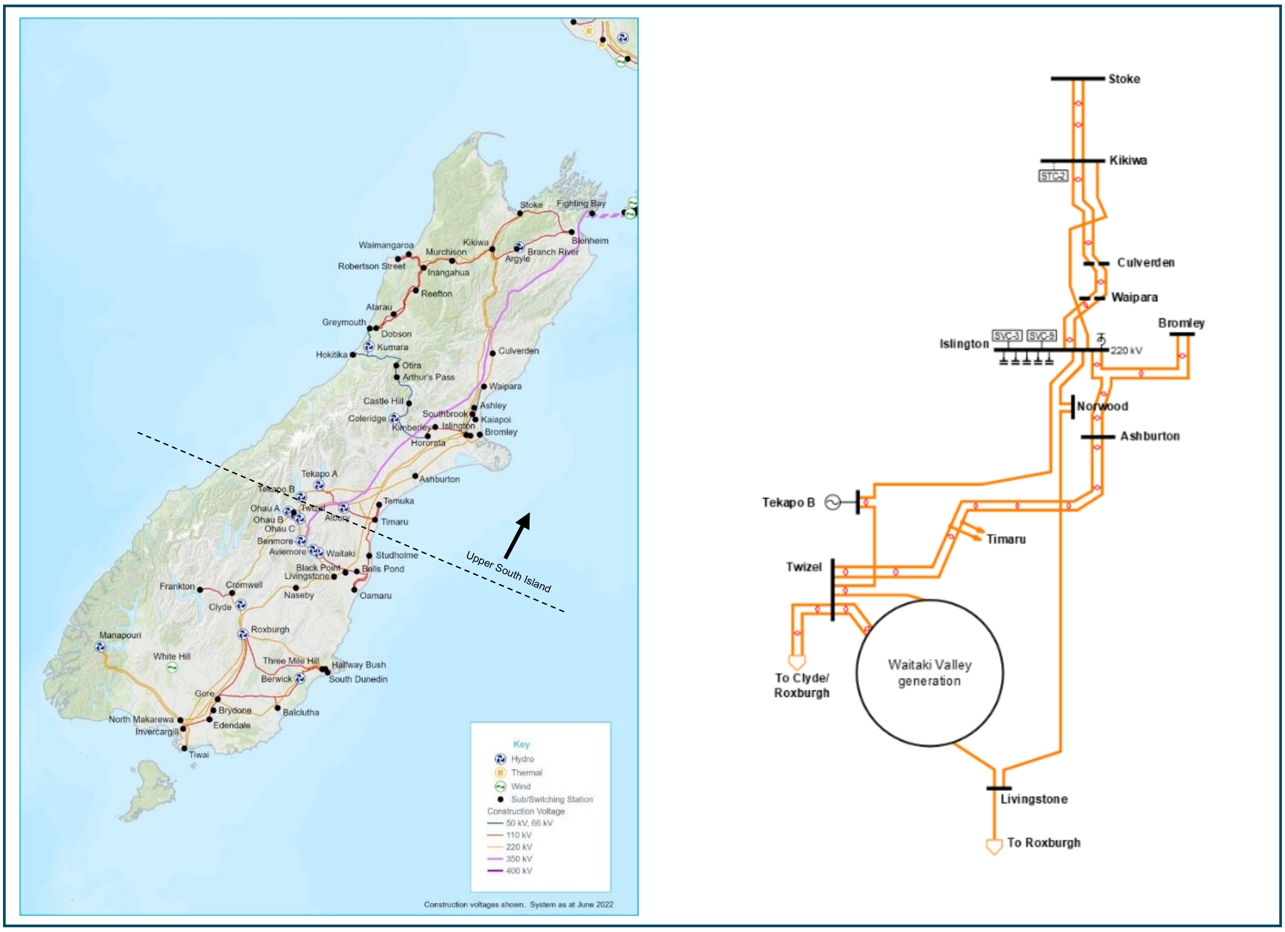

Figure 1: USI map and 220 kV transmission network

2.1 The need for investment

This investment is required to meet the deterministic limb of the grid reliability standards (**GRS**), being N-1 reliability on the core grid.[9] The transmission lines supplying the USI region are part of the core grid, which is defined in the Electricity Industry Participation Code 2010 (**Code**) as a specific list of transmission assets.

The GRS requires Transpower to maintain at least an N-1 reliability standard on the core grid. N-1 ensures that the power system can remain stable and continue supplying power even if a single significant unplanned grid outage occurs.

[9] The USI circuits are part of the core grid as defined in Schedule 12.3 of the Code (220kV Tekapo B-Islington, 220kV Twizel-Opihi-Timaru-Ashburton and 220kV Livingstone-Islington). The GRS in Schedule 12.2 of the Code require us to maintain at least an N-1 reliability standard on the core grid. This ensures that the core grid remains stable without a loss of supply following a single significant unplanned outage in the grid.

Forecasts indicate that within the next three years – without significant new (non-intermittent) generation and/or transmission investment – the transmission constraints on the core grid in the USI region will begin to impact our ability to ensure a reliable electricity supply.

2.2 Demand growth and new generation

New Zealand's electricity demand is expected to increase significantly over the next decade, with the USI region experiencing strong growth, particularly in residential, commercial and agricultural related industries.

Key drivers of future electricity demand include the electrification of transport, the transition from coal to electricity within the process heat sector, and the replacement of gas and other thermal fuels usage with electric alternatives. To account for alternative futures, we have considered a range of scenarios based on varying assumptions about future developments. Each scenario incorporates different potential developments, ensuring a range of possible future outcomes are considered.

Figure 2 summarises the electricity peak demand forecasts that we considered in our analysis. To inform the timing of investment we have used the EDGS Environmental (prudent) peak forecast. The Environmental (prudent) peak forecast is the same as the Environmental peak forecast except it includes a prudency factor to account for the year-to-year variability of peak demand that is not otherwise accounted for in the forecasts. Figure 3 illustrates the components that make up the Environmental (prudent) forecast. The main components of the forecast are:

- Base demand – this relates to underlying business-as-usual growth and is informed by the scenario assumptions.
- Prudent component – this accounts for year-to-year variability in peak demand. For example, demand may be abnormally high due to a very cold weather pattern. It contributes approximately 5-8% of the forecast and is based on an analysis of historical peak demand variability.
- New step loads – these are based on feedback from electricity lines businesses and other consumers.
- New electrified heat demand – this has been informed by scenario assumptions and information from surveys of boiler and heat demand. If some of this demand is captured by a step load, we adjust these figures down to avoid double-counting.
- Residential and business solar, EV and batteries – this has been informed by scenario assumptions. Their effect on peak demand is relatively modest in the near term.

As with any forecast, there are uncertainties. We have used a prudent forecast in our planning to ensure we have time to invest without putting demand at risk of non-supply. It is a higher forecast and includes most new step loads that we have been informed about through this process. Our forecast was first produced for the long-list consultation in August 2023, and we recognise that updated information regarding step loads is continually emerging. We have reviewed our assumptions about step loads against our latest step load information and consider that while there appears to have been nearer term deferral and reduction in likelihood of some steps, expectations of step load growth in the USI by the early 2030s is still similar. On that basis we consider it is reasonable and prudent for us to continue to plan based on our current forecast.

As noted above, we consider there is significant potential for NTS to be able to play a role in managing risks associated with demand and to potentially defer investment given there is adequate time provided for them to be developed.

Electricity demand in the USI region far exceeds the region's current electricity generation capacity. We are not aware of any significant committed generation or battery storage projects that could reduce the need for additional electricity transmission into the region. There is considerable potential for intermittent generation. However, we would require dispatchable generation or battery solutions with sufficient capacity to inject power into the grid on demand during peak load periods. Intermittent generation cannot achieve this.

Our base analysis assumes only committed future generation projects are commissioned in the USI. Since our consultation, we added several sensitivities that consider the impact of additional generation capacity in the USI. Attachment 4 and Attachment 6 present the results of applying alternative assumptions regarding future generation in the region.

Attachment 2 provides more detail on the electricity demand and generation forecasts that we used in this analysis. These forecasts build upon the ones we consulted on in August 2023 during our long-list consultation, incorporating any relevant information received[10].

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10 It's important to note that demand forecasts are snapshots in time and are regularly updated through our planning process in collaboration with electricity distribution businesses in the USI region. Changes since our long-list consultation have not materially affected the long-term need, timing, or preferred option for this project. Note that the Global and Growth scenarios have been given a zero weighting in the Investment Test.

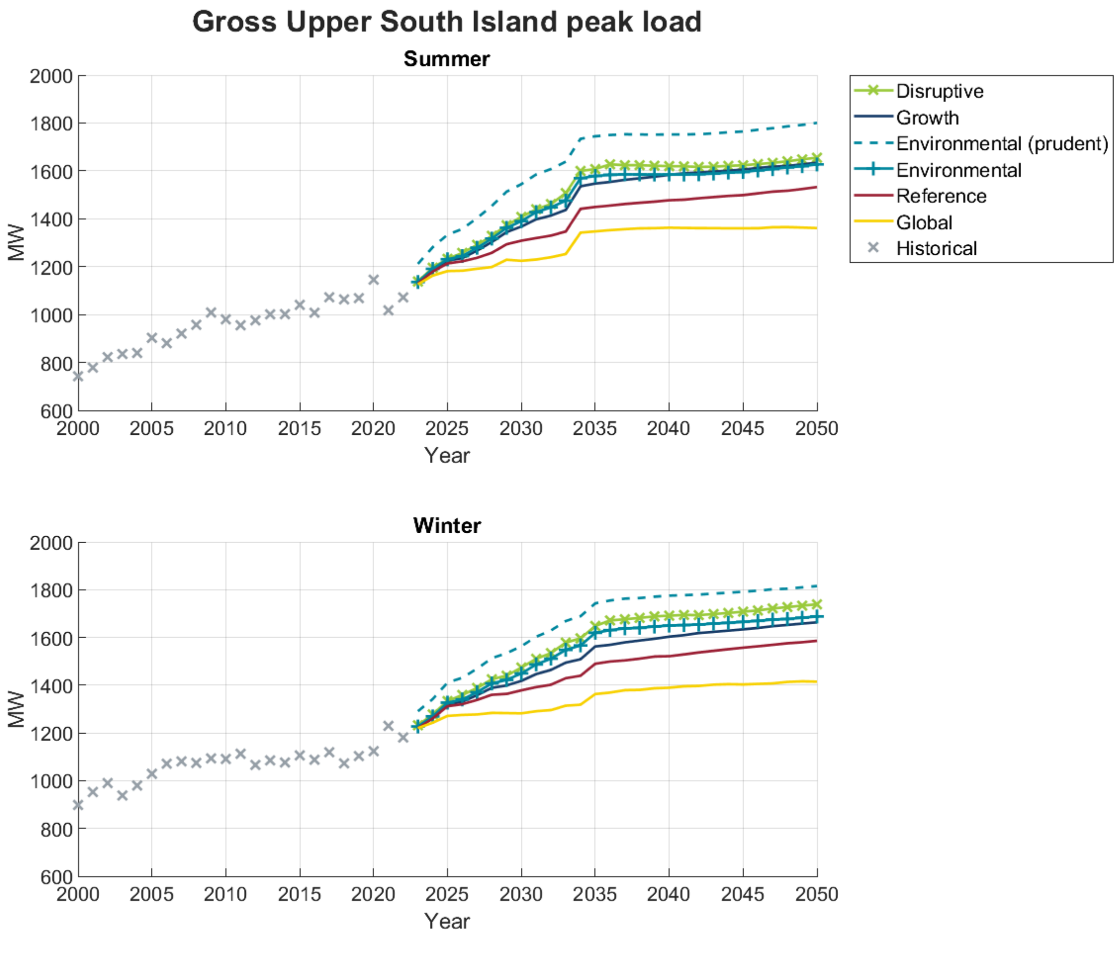

Figure 2: USI peak demand forecast, in MW

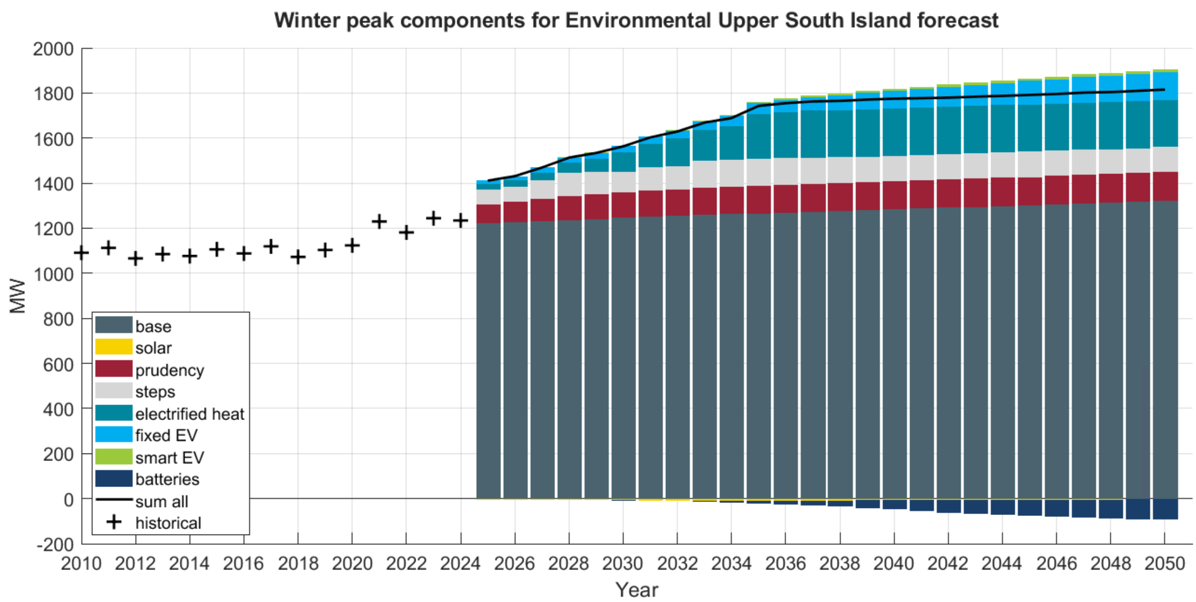

Figure 3: Winter prudent forecast by component, in MW

2.3 Transmission capacity and constraints

With insufficient local generation in the USI region, increasing demand will result in greater reliance on the 220 kV transmission lines from the south, leading to binding capacity constraints. Based on our Environmental (prudent) demand forecasts, the Ashburton–Timaru–Twizel circuits' thermal capacity will maintain N-1 security through winter 2028.

Voltage stability is another ongoing challenge in the region, as power must be transmitted over long distances from the Waitaki Valley to Christchurch and further north to the top of the South Island. It is important that we maintain voltage within an acceptable range. Voltage outside of the acceptable range can cause power surges, power cuts, and severe impacts across the power system. Our investigations indicate that based on our prudent demand forecast, voltage stability constraints will begin to limit growth by winter 2028. Beyond 2028, as demand continues to increase, additional constraints are expected to emerge.

3 Options to address electricity transmission grid capacity constraints

We published a long-list consultation document in August 2023[11] in which we outlined a detailed list of option components that could help address the transmission challenges identified in the USI region.[12] These option components include:

1. upgrading existing high-voltage transmission lines;
2. establishing new switching station(s) and installing specialised equipment or devices;
3. constructing new high voltage transmission lines; and
4. exploring non-transmission solutions, such as demand response initiatives.[13]

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

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11 The long-list consultation document, as well as submissions and Transpower's response to submissions can be found here.

12 Attachment 2 discusses details of the identified investment need, which were consulted on in the long-list and short-list consultations.

13 A non-transmission solution is a solution where the transmission grid can meet electricity demand without building new transmission assets. An example of this is contracting with electricity users to reduce electricity demand at peak times. This is commonly referred to as demand response.

3.1 Short-list of development plans

Following our consultation on the long-list, we consulted on a short-list in December 2024 and April 2025.[14] We combined various option components from our long-list to create a short-list of development plans that extend from now through to 2050. Each plan consists of several specific components and their proposed commissioning timelines. These development plans are 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.

Our short-list had three options to manage the transmission constraints:

- **Option 1** involves constructing a single switching station on existing Transpower-owned property where our existing transmission lines converge, transmission lines upgrades, the installation of shunt capacitor banks, and a new line from Twizel to Islington.
- **Option 2** involves constructing dual switching stations on existing Transpower-owned property where our existing transmission lines converge, transmission lines upgrades and the installation of shunt capacitor banks.
- **Option 3** relies on a combination of static synchronous compensator (**STATCOM**) technology, line upgrades to manage the various transmission constraints, and a new line from Twizel to Islington.

Options 1 and 3 require a new line from Twizel to Islington, resulting in significantly higher costs. Further details on the short-list of development plans can be found in Attachment 3.

3.2 Non-transmission solutions

Non-transmission solutions (**NTS**) may have the potential to defer transmission investment in the USI. Following our long-list consultation, we sought NTS options from the market in February 2024 to support the USI needs. However, market responses indicated limited available capacity and uncertain pricing, leading us to pause NTS procurement at that time. Despite this, we believe NTS could play a valuable role supporting the future needs of the USI.

Transpower has worked closely with the Commerce Commission to develop an approach that allows us to fund economic NTS solutions that provide a net benefit by deferring transmission investments – using the financial value of up to 12 months' deferred transmission capex.

A 12-month deferral of all the transmission investments included in the proposed Stage 1 investment would result in an estimated maximum deferral value of approximately $7.0m. We have used this as an estimate of the value of NTS to manage peak capacity for one year. See Attachment 8 for further details.

Given the scale of electricity demand growth in the USI and the requirement for Transpower to meet the GRS, NTS are unlikely to eliminate the need for the Proposed Investment (or any alternative development plan). However, NTS may play a role in deferring transmission investment to the early 2030s, and/or managing or mitigating risks of delays in constructing transmission assets. The commissioning year of our first investment is 2029, which is one year after our 2028

14 Upper South Island upgrade project - short-list consultation

need date. Increased lead times for critical equipment from international suppliers have made it difficult to maintain realistic project timeframes to commission our first investment in 2028. However, our 2028 need date is based on our prudent demand forecast and consultation submissions also noted our prudent step load assumptions.

For this reason, we have applied for a NTS allowance (maximum recoverable costs) of $7.0m as part of this application. We have not included this allowance in our application of the Investment Test because it is contingent on a later economic deferment test.

4 Application of the Investment Test

To identify our preferred option, we conducted a cost-benefit analysis of the short-list of development plans using the Investment Test. As components of this investment will provide improved 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,[15] 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. [16]

All three options have electricity market benefits. All benefits are calculated relative to an option where no new transmission investment occurs. The benefits considered are:

- **Thermal operating benefits** Including savings on fuel costs, variable operating costs and emission costs relative to the counterfactual.
- **AC loss benefits** represent the reduced electricity needed to be generated due to lower electrical losses over the transmission network due to different asset configurations of the grid.
- **Deficit benefits**. If no investment occurs, we will not be able 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.
- **Terminal benefits.** The economic lifespan of some options considered extend beyond the calculation period, meaning that the assets will retain value in 2050. We have accounted for this as a terminal benefit, which effectively reduces the overall asset cost. It is assumed that the asset cost decreases linearly over its lifetime.

Benefits are discussed in greater detail in Attachment 6.

Applying the Investment Test requires several key assumptions. These include assumptions about electricity demand growth and future generation capacity, as mentioned earlier. We also use assumptions in calculating the present value of future cash flows.[17] Attachment 4 provides more detail of the assumptions used in our application of the Investment Test.

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15 The net benefit in the Investment Test is the expected electricity market benefit minus the expected electricity market cost. Costs and benefits are discussed in greater detail in Attachments 5 and 6.

16 As written in the Capex IM, Schedule D, D1(1)(b).

17 We consulted on the discount rate as part of the long-list consultation and have used 5% and the associated sensitivity range (3% and 7%) in this analysis. The costs and benefits have been discounted to 2025.

Table 4 presents the total discounted capital cost for each short-listed option over the period to 2050. Options 1 (Single Switching Station) and 3 (STATCOM) incur the highest costs, primarily due to the need to construct new, expensive transmission lines within the next decade.

In contrast, Option 2 (Dual Switching Station) has a lower discounted capital cost, as the immediate development of two switching stations and cost-effective thermal upgrades defer the need to build expensive long-distance transmission lines.

Table 4: Summary of discounted[18] costs and quantified benefits for the short list options

	Option 1 Single switching station path	Option 2 Dual switching station path	Option 3 STATCOM path
Capital cost (2025 $m)	748.6	269.5	838.8
Quantified benefit (2025 $m)	474.7	277.3	488.7
Net quantified benefit (2025 $m)	-273.9	7.8	-350.1

These costs reflect the total projected capital cost of each of the three short-listed options through to 2050. Although the cost-benefit analysis encompasses the full calculation timeframe, we are currently only proposing to seek approval for investments through to approximately 2030. Any further investments identified in the preferred investment option development plan would require separate approvals (refer Attachment 4 section 8.1).

As the USI is a core grid reliability investment, a proposal must be the option which maximises net benefit, although the net benefit may be negative. Table 4 indicates that Option 2, which includes the dual switching stations and targeted thermal upgrades, has the highest net benefit at $7.8m.

Notably, the net benefit for Option 2 is positive in scenarios characterised by increased adoption of electric vehicles and solar PV systems, and increased electrification of process heat.

In a future with increasing electrification, Option 2 represents a prudent investment for Transpower to ensure the reliability of the core grid in the USI region. While new generation could reduce the need for transmission infrastructure, the most likely sources – such as wind and solar – are intermittent and cannot consistently meet regional peak energy demands. Moreover, voltage stability challenges cannot always be addressed through generation alone due to technical and locational constraints. By enabling a robust transmission network, Option 2 facilitates a reliable electricity supply, and supports growing electrification needs, making it a forward-looking and prudent investment in New Zealand's core electricity transmission grid.

18 Future costs and benefits have been calculated out to 2050 and discounted back to present value using a discount rate of 5%.

5 Preferred option

Based on our application of the Investment Test, we conclude that Option 2 (via a staged investment approach) is our preferred option.

Option 2 consists of staged investments designed to accommodate continued demand growth in the USI region through to 2050 (as illustrated in Figure 4). While we have a higher level of confidence in the immediate investment horizon, this confidence diminishes as we look further into the future due to inherent uncertainties in demand and generation forecasting. For this MCP, our primary focus is on the near-term investments required between now and 2030 (Stage 1).

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

- Constructing two new switching stations near Orari and Rangitata (north of Timaru) by 2029. These stations will improve the grid's electrical performance by interconnecting the four Christchurch–Waitaki Valley circuits at a critical midpoint.
- Thermal upgrades of the Norwood–Rangitata to 90°C and Orari–Rangitata circuits to 100°C.
- Installing equipment to manage voltage stability - Install a total of 2 x 75 Mvar shunt capacitor banks at Orari 220 kV and an automatic over-voltage shunt capacitor and shunt reactor switching schemes.

The further investments outlined in Table 3 may be undertaken as part of Stage 2 (or potentially a later stage) of the Proposed Investment, depending on how demand and system needs evolve over time. This staged approach allows us to address immediate capacity and reliability concerns while retaining flexibility to deliver additional improvements later.

In addition to the quantified benefits, we believe that Option 2 is a prudent investment for Transpower to ensure the reliability and resilience of the core grid in the USI 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.

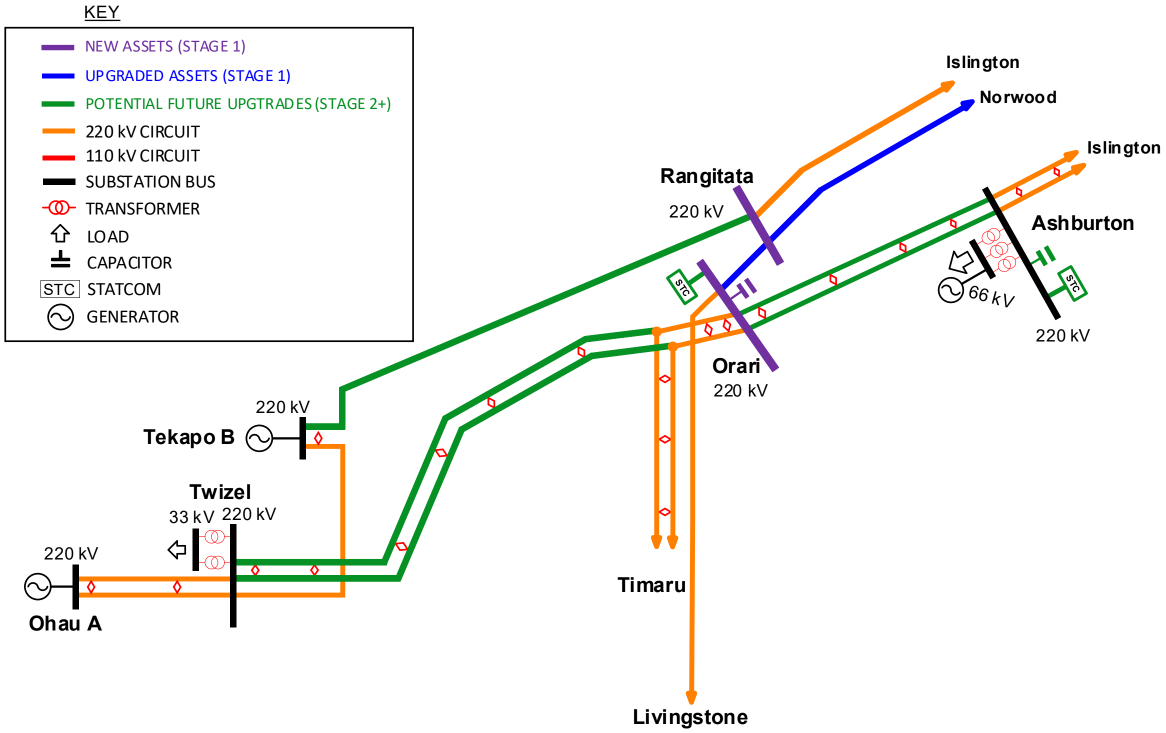

Figure 4: Diagram of the Proposed Investment (Option 2, Orari and Rangitata development plan)

6 Application to the Commerce Commission

The Proposed Investment is a major capex project under the Capex IM.[19] The major capex project status means that we need to submit an MCP to the Commerce Commission seeking approval to recover the costs of the Proposed Investment (or, as in this case, the first stage of it).

The table below outlines Transpower's proposal for USI Upgrade Stage 1. Any additional investments needed after the early 2030s will be the subject of one or more future MCPs for subsequent stages.

[19] The relevant version of the Capex IM is Transpower-Capital-Expenditure-Input-Methodology-Determination-consolidated-as-of-29-January-2020.pdf .

Table 5: Investments in our USI Upgrade Stage 1 Proposal ($2025)

USI Upgrade Stage 1 investments	Estimated P50 cost($m)	Expected commissioning date
Switching station at Orari	41.4	2029
Switching station at Rangitata	29.8	2029
Lines turn ins to switching stations	31.9	2029
Thermal upgrades of the Norwood–Rangitata circuit to 90°C and Orari–Rangitata circuit to 100°C[20]	50.1	2030
2 x 75 Mvar shunt capacitor banks at Orari 220 kV	11.4	2030
Automatic over-voltage shunt capacitor and shunt capacitor switching scheme	1.0	2030
Investigations cost	1.5	-
Total	**167.0**	**-**

These proposed transmission investments are 'interconnection' assets. These would be owned and operated by Transpower, and costs would be recovered via transmission charges under the Transmission Pricing Methodology (**TPM**).

The expected cost of Stage 1 in $2025 is $167.0m and the commissioned cost is forecast to be $193.0m as explained in the next section.

6.1 Major Capex Allowance and Maximum Recoverable Costs

Transpower seeks allowances from the Commerce Commission to recover costs associated with the proposed Stage 1 investment; these are the MCA (for capital costs) and the Maximum Recoverable Costs (for the costs of any NTS).

20 The works involved with these thermal upgrades include fixing existing under clearance violations, which will not be funded from this MCP. The total project cost of these thermal upgrades (including fixing existing violations) is $56.0m. The costs of existing violations will not be funded by the MCA sought in this MCP, and therefore the expected cost of the thermal upgrades to be funded from the MCA is $50.1m. See Attachment 5 for a proposed framework on how costs will be allocated, and recovered.

The proposed MCA and Maximum Recoverable Costs for the proposed Stage 1 investments are shown in Table 6.

Table 6: Stage 1 MCA and Maximum Recoverable Costs for Stage 1

	Expected capital cost ($m)	Major Capex Allowance ($m)	Maximum Recoverable Costs ($m)
Transpower Capital Projects	167.0	193.0	-
Potential NTS	-	-	7.0

The MCA is larger than Transpower's expected capital cost because it accounts for inflation and interest during construction costs.

More detail about the costing of the Proposed Investment is in Attachment 5.

Stage 1, when commissioned, will be a benefit-based investment (**BBI**) under the TPM. The costs of the BBI will be recovered from our customers who are expected to benefit from the BBI through benefit-based charges (**BBCs**) under the TPM. The BBCs will be allocated to customers in proportion to their expected positive net private benefits.

If the Commerce Commission approves cost recovery for Stage 1, Transpower will calculate expected net private benefits and proposed starting allocations for the BBI using a standard method[21] under the TPM (in particular, the price-quantity method) and consult on them.

Indicative starting allocations and BBCs for the BBI are in Attachment 9.

7 Supporting documents

This MCP comprises:

- This MCP overview document
- A series of attachments providing more detailed information on key elements of the MCP application:
    - Attachment 1 – Compliance with the Capex IM;
    - Attachment 2 – Need, Demand and Generation Scenarios;
    - Attachment 3 – Short list of investment options;
    - Attachment 4 – Application of the Investment Test;
    - Attachment 5 – Costing;
    - Attachment 6 – Benefits modelling;

21 Information sheet on benefit-based charges: Standard method

- Attachment 7 – Stakeholder consultation;
- Attachment 8 – Approach to non-transmission solutions;
- Attachment 9 – Indicative pricing impacts;
- Attachment 10 – Power Systems Analysis Report; and
- Attachment 11 – CEO Certification.

8 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 Commerce Commission to review and consider this MCP and determine whether to approve the project outputs and cost recovery for the proposed Stage 1 investment.

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