TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Attachment 4: Application of the Investment Test

August 2025

Purpose

This attachment contains an overview of our Upper South Island Upgrade Stage 1 MCP options analysis and our approach to the Investment Test. It includes our application of the investment test (**Investment Test**) and identifies our preferred option (**Proposed Investment**).

Contents

1 Investigation approach

The short-list options have been analysed using the Investment Test[1]. We have received strong support from our stakeholder consultation for both the project and our application of the Investment Test. This is summarised in Attachment 7.

2 Scenario weightings

The Investment Test is used to determine the expected net electricity market benefit for each short-list option. It does this by calculating the weighted average of the option's net electricity market benefit under each demand and generation scenario. These scenarios are based on the 2019 Energy Demand and Generation Scenarios (**EDGS**) developed by the Ministry of Business, Innovation, and Employment (**MBIE**).[2]

The default scenario weighting assumes equal distribution, meaning with five scenarios, each would typically receive a 20% weighting. However, upon reviewing the growth rates, particularly for the Global and Reference scenarios, these projections appear low. As shown in Attachment 2, the Global scenario forecasts growth of just 0.6% per annum nationally between 2030 and 2050, while the Reference scenario projects 0.8% per annum. The Growth and Environmental scenarios indicate similar levels of demand growth and would likely yield comparable results in our analysis.

The assumptions used in this analysis are consistent with our consultation and supported by submissions. We have adopted the following approach as shown in Table 1:[3]

- *Global Scenario: Weighted at 0%* - We consider the Reference scenario to adequately represent a lower bound for demand growth, rendering the Global scenario unnecessary.
- *Growth Scenario: Weighted at 0%, with the Environmental scenario increased to 60%* – Since the Growth and Environmental scenarios yield nearly identical demand growth, we propose to assign no weight to the Growth scenario. To account for their similarity and the alignment with anticipated outcomes, we increase the Environmental scenario's weighting to 60%.The Environmental scenario has a medium demand growth compared to the other two selected scenario i.e., Disruptive being high and Reference being low.

We have also considered an equal weighting of these three scenarios as a sensitivity. This approach centres our focus on three demand forecasts—low, medium, and high—paired with generation expansion plans based on comparable input assumptions.

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1 The Investment Test is defined in Schedule D of the Capex Input Methodology.

2 Details of the demand and generation scenarios used in this analysis are given in Attachment 2.

3 Schedule D, Division 2 clause D2 (1) of the Capex IM requires that:
"…each relevant demand and generation scenario is accorded the explicit or implicit weighting assigned to it by the party who developed the scenario, unless Transpower considers that alternative weightings should apply and has consulted on these as part of its consultation on the short-list of investment options."
The original scenarios were developed by MBIE, but did not address the issue of how each scenario should be weighted in the context of the Capex IM. The consultation on proposed weightings in our long-list consultation is intended to meet the requirements of the Capex IM in this regard.

Table 1: Scenario weightings

Weighting set	Usage	Global	Reference	Growth	Environmental	Disruptive
1	Standard weighting	20%	20%	20%	20%	20%
2	Proposed weighting	0	20%	0	60%	20%

3 Investment Test parameters

This section describes the Investment Test parameters used in our analysis. The assumptions used in this analysis are mostly consistent with our consultation. We have undertaken additional sensitivities to respond to points raised in consultation submissions.[4,5]

3.1 Calculation period

Our analysis uses a default calculation period of 20 years from 2031 to 2050.

Since the economic lifetime of some options extends beyond 2050, these assets will still retain value at the end of the calculation period. To account for this, we have included a terminal benefit, which effectively reduces the asset's cost by capturing its remaining value. A linear depreciation approach is used to decrease the cost of the asset over its expected lifetime. The terminal benefit for each investment option is the same under each relevant demand and generation scenario.

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

3.2 Discount rate

The Capex IM initially set a real, pre-tax discount rate of 7%, with sensitivities of 4% and 10%, aligned with Transpower's Weighted Average Cost of Capital (WACC) at the time. In the Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination 2023 (for which the changes made are applicable to major capex proposals notified on or after 1

4 Further consultation on our short-list for upper South Island upgrades

5 Transpower Capital Expenditure Input Methodology, Schedule I, I1 and I2 sets out the consultation requirements for major capex projects.

April 2025), the Commerce Commission reduced this rate to 5%, with a sensitivity range of 3% to 7%.[6] Feedback from our long list consultation supported the use of these revised values.

We have applied a discount rate of 5% per annum (real, pre-tax). Our sensitivity analysis uses discount rates of 3% and 7%.

4 Calculating expected net electricity market benefits

Electricity market costs and benefits

Electricity market costs and benefits refer to those incurred or received by consumers during the calculation period that influence net market benefits. In this analysis we have included the following:

- fuel costs e.g., the cost of generating electricity;
- cost of involuntary demand curtailment i.e., the cost of lost load;
- capital costs of modelled projects e.g., future assets that are likely to exist whose nature and timing is affected by an investment option, for instance new generation;
- relevant operation costs e.g., costs of existing assets, options and modelled projects; and
- cost of losses, including transmission and local losses.

The benefits and the methodologies used to quantify these benefits are discussed in Attachment 6.

Project costs

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

The Upper South Island (**USI**) upgrade study has been undertaken to determine a transmission development plan to 2050 to support a reliable electricity supply into the region. The development plan contains costs associated with those development plan investments.

We have estimated the cost of Transpower's investment options using either concept design reports or internal cost data, depending on the level of information available to us. Costs for options involving modifications to existing assets are more accurate than for options such as new transmission lines, for which the site or transmission routes have not yet been identified.

For new transmission line options, cost estimates are based on our internal experience with similar past projects, which we believe provides an acceptable level of accuracy for this stage of analysis.

To account for cost uncertainty, we have included a range of cost assumptions in our sensitivity analysis to test the robustness of the preferred option.

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6 Transpower-Capital-Expenditure-Input-Methodology-IM-Review-2023-Amendment-Determination-13-December-2023.pdf

While operational expenditure was considered for each short-list option, we found no significant differences across the options. Therefore, operational costs were not factored into the final analysis.

Table 2, Table 3 and Table 4 include cost breakdowns for the three investment options.

The costs for Option 1 were developed following desktop analysis and scope definition by the project team and created by the project cost estimator in Tees. The costs presented are of Class 4 standard.[7]

Table 2: Option 1 project cost breakdown (real 2025$)

Investment	Expected P50 cost ($m)
Switching station at Orari	41.4
Lines turn ins to switching stations	22.6
Thermal upgrades of the NWD-ORI-1 circuit to 90°C	56.0
100 Mvar shunt capacitor banks at Orari 220 kV	11.4
AOVCS	1.0
150 Mvar STATCOM (**STC**) at Ashburton 220 kV	67.2
Thermal upgrades of the OPI-TWZ circuit to 90°C	17.0
New ISL-TWZ line	732.3
Investigation cost	1.5

The costs for Option 2 were developed following an SSR by engineering consultants and scope verification by the project team and created by the project cost estimator in Tees. The costs presented are of Class 3 standard[8].

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7 Class 4 estimates are for study or feasibility purposes and have a project definition certainty of 1-15% and an accuracy range of -30/+50% accuracy.

8 Class 3 estimates are for budget authorisation or control purposes and have a project definition certainty of 10-40% and an accuracy range of -20/+30% accuracy.

Table 3: Option 2 project cost breakdown (real 2025$)

Investment	Expected P50 cost ($m)
Switching station at Orari	41.4
Switching station at Rangitata	29.8
Lines turn ins to switching stations	31.9
Thermal upgrades of the Norwood–Rangitata circuit to 90°C and Orari–Rangitata circuit to 100°C[9]	56.0
2 x 75 Mvar shunt capacitor banks at Orari 220 kV	11.4
AOVCS	1.0
Thermal upgrades of the OPI-TWZ circuit to 90°C	17.0
150 Mvar STC at Ashburton 220 kV	67.2
Thermal upgrades of the RTA-TKB-1 circuit to 90°C	25.3
100 Mvar shunt capacitor banks at Ashburton 220 kV	11.8
Thermal upgrades of the ASB-ORI circuit to 90°C	19.2
150 Mvar STC at Orari 220 kV	62.1
Investigation cost	1.5

The costs for Option 3 were developed following desktop analysis and scope definition by the project team and created by the project cost estimator in Tees. The costs presented are of Class 4 standard.

[9] The works involved with these thermal upgrades include fixing existing under clearance violations, which will not be funded from this MCP. Out of the $56.0m, we have included $50.1m in our Major Capex Allowance. See Attachment 5 for a proposed framework on how costs will be allocated and recovered.

Table 4: Option 3 project cost breakdown (real 2025$)

Investment	Expected P50 cost ($m)
150 Mvar STC at Ashburton 220 kV	67.2
Thermal upgrades of the OPI-TWZ circuit to 90°C	17.0
Thermal upgrades of the LIV-NWD circuit to 90°C	102.2
New ISL-TWZ line	732.3
150 Mvar STC at Ashburton 220 kV	67.2
Investigation cost	1.5

More details on costs and methodologies used to quantify these costs are discussed in Attachment 5.

Passing the Investment Test

To identify a preferred option, we conducted a cost-benefit analysis of the short list of development plans using the Investment Test. As this investment is to meet the GRS N-1 reliability standard on the core grid, for an option to satisfy the Investment Test[10] it must be:

- the option that maximises expected net benefit (although this net benefit may be negative),[11] and
- sufficiently robust under sensitivity analysis.

5 Application of the Investment Test

The Investment Test is an economic cost-benefit test that uses the real value of both costs and benefits over time. To account for the time value of money, future expenditures and costs are discounted at an annual rate of 5%. Table 5 provides an overview of the capital costs for each short-list option, along with their corresponding present value.

10 The net benefit in the Investment Test is the expected electricity market benefit minus the expected electricity market cost. For more detail on terms used in the Investment Test, refer to Division 2 of Schedule D in the Capex IM.

11 For GRS core grid N-1 reliability investments, a proposal must be the option which maximises net benefit, although the net benefit may be negative. This is relevant for the USI Upgrade as this investment is on the 'core grid' of the transmission grid so the net benefit may be negative.

These capital costs reflect the total projected capital cost of each of the three short-list options through to 2050. Although the cost-benefit analysis encompasses the full calculation timeframe, we are currently only seeking approval for investments through to approximately 2030. Any further investments identified in the preferred investment option development plan would require separate approvals (refer section 8.1). As a result, the capital cost values presented in table 3 are higher than those presented in our proposal (refer section 8.2).

Table 5 includes the 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 removes the need to build expensive long-distance transmission lines within our analysis period.

Table 5: Short-list present value project costs

	Option 1 Single switching station path	Option 2 Dual switching station path	Option 3 STATCOM path
Undiscounted capital cost ($m, real 2025)	950.3	375.5	987.5
Discounted capital cost present value ($m, 2025 present value)	748.6	269.5	838.8

Types of benefits have been quantified as part of our analysis include terminal benefits, dispatch benefits and transmission loss benefits.

- **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. This is calculated based on the depreciated value of each investment at the end of our calculation period, assuming that the asset cost decreases linearly over its lifetime. The terminal benefit for each investment option is the same under each relevant demand and generation scenario
- **Modelled benefits**
  I. **Thermal operating benefits** Including savings on fuel costs, variable operating costs and emission costs relative to the Counterfactual.
  II. **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. The magnitude of transmission losses, measured in GWh, have been modelled in a hydro-thermal dispatch optimisation package called

SDDP.[12] These transmission losses are converted to loss costs by multiplying the losses by the Island short run marginal cost.

III. **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 alternatives ways of being supplied with electricity. This electricity shortfall is primarily[13] valued at $600 per MWh.

Details of benefits and the calculation methods are described in Attachment 6.

Table 6: Quantified benefits, at 5% discount rate

Benefit ($m, real 2025)	Option 1 Single switching station path	Option 2 Dual switching station path	Option 3 STATCOM path
Terminal benefit present value	178.7	65.8	180.6
Modelled benefits present value	296.0	211.6	308.1
Total benefit	474.7	277.3	488.7

Option 2 offers the lowest quantified benefits among the short list options.

The Investment Test identifies is satisfied if the option with the highest net electricity market benefit is the preferred option. Table 7 below outlines the quantified net benefits for each of the short list options.

Table 7: Quantified net benefits, at 5% discount rate

($m, real 2025)	Option 1 Single switching station path	Option 2 Dual switching station path	Option 3 STATCOM path
Net benefit	-273.9	7.8	-350.1

The results indicate that Option 2 provides the highest quantified net benefit of the three options. Our analysis ultimately concludes that Option 2 delivers the greatest overall net benefit for consumers.

12 SDDP is an electricity market modelling tool used to determine economic benefits, see Attachment 6.

13 Deficit cost has been valued using cost tranches (described in Section 2.3.1 in Attachment 6).

6 Sensitivities

Our sensitivity analysis examines how variations in parameter values impact net benefits, unless such analysis for a parameter is impractical or (due to the parameter not contributing to net benefit) unnecessary. The sensitivities considered are outlined in Table 8.

Table 8: Sensitivities considered

Sensitised parameters	Comment
Forecast demand	Net benefits are reported for each of the three EDGS demand scenarios under consideration.
Size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question	Either reflected in scenarios or included in +/- 30% cost sensitivity.
Capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects	Scenarios where capital costs are increased or decreased by 30% are considered to evaluate the impact on net benefits.
Timing of decommissioning, removing or de-rating decommissioned assets	Not relevant.
Value of expected unserved energy	Not relevant. We have not included reliability benefits in our Investment Test.
Discount rate	Sensitivities of 3% and 7% discount rates are considered.
Range of hydrological inflow sequences	Reflected in scenarios.
Relevant demand and generation scenario probability weightings	Results are presented using both the preferred weighting (20% Reference, 60% Environmental, 20% Disruptive) and an equal weighting across these scenarios.
In relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies	Not relevant.
Any other variables that Transpower considers to be relatively uncertain	Sensitivities to account for the possibility of new generation. They assume the following additional generation capacity in the USI (over our base assumptions). The sensitivities are based on the Environmental scenario.

Sensitised parameters	Comment
	• Sensitivity 1: Around 200 MW solar and 100 MW Battery Energy Storage System (**BESS**). • Sensitivity 2: Around 300 MW solar and 150 MW BESS. • Sensitivity 3: Around 300 MW solar. • Sensitivity 4: Around 300 MW solar, 150 MW BESS and 300 MW wind.

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

Table 9: Quantified expected net electricity market benefits, sensitivity analysis (2025 $m)

	Option 1 Single switching station path	Option 2 Dual switching station path	Option 3 STATCOM path
Reference	-501.1	-196.8	-580.6
Environmental	-255.8	16.3	-331.2
Disruptive	-101.1	186.9	-176.4
Low discount rate (3%)	-104.2	109.9	-156.3
Base discount rate (5%)	-273.9	7.8	-350.1
High discount rate (7%)	-364.4	-52.3	-463.1
Capital increase (130% of base)	-498.5	-73.1	-601.7
Capital decrease (70% of base)	-49.3	88.7	-98.5
Equal scenario weighting	-286.0	2.1	-362.7
Generation Sensitivity 1	-402.1	-117.8	-479.1
Generation Sensitivity 2	-426.5	-138.3	-503.8
Generation Sensitivity 3	-498.5	-195.9	-579.7
Generation Sensitivity 4	-371.9	-89.3	-447.9

The sensitivity analysis indicates that Option 2 consistently delivers the highest expected net electricity market benefit across a wide range of assumptions. In the base case – representing the weighted average across the scenarios – Option 2 produces the highest overall net benefit. The sensitivity analysis reveals that Option 2 achieves both positive and negative results under varying future energy scenarios.

Consequently, we consider Option 2 is robust to uncertainties in the key input parameters and remains a robust choice under diverse future energy scenarios.

7 Preferred option

Our net-benefit analysis identified Option 2 as having the highest net benefit to meet the GRS N-1 reliability standard on the core grid.

The sensitivity analysis reinforces the robustness of Option 2, showing that it maintains the highest net benefit across a wide range of input uncertainties and diverse future energy scenarios, particularly in scenarios characterised by high levels of electrification.

Based on our application of the Investment Test, we conclude that Option 2 is our preferred option. This MCP application is for approval of the first stage of Option 2.

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.

Option 2 effectively addresses these challenges by enabling a robust transmission network that supports the integration of intermittent generation while ensuring a reliable and stable electricity supply for consumers as demand for electrification grows. Although the value of this firming capability and enhanced stability is not fully reflected in our benefit calculations, these factors strongly support the case for Option 2 as a necessary and forward-looking investment to meet the N-1 reliability standard on New Zealand's core electricity transmission grid.

7.1 Good electricity industry practice

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

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

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

8 Our proposal

8.1 Project staging

We have a high level of confidence in the immediate investment horizon, but this confidence diminishes as we look further into the future due to the inherent uncertainties in demand and generation forecasting. While we are certain about the near-term investment needs and expect continued demand for reactive devices and other investments into the mid to late 2030s and beyond, there is still some uncertainty regarding the exact timing, location, and nature of future components.

For this MCP application, our focus is primarily on the investments required in the near term, within the immediate investment horizon (between now and 2030), while keeping in mind the longer-term development path extending to 2050. Any additional investments in thermal and voltage management that may be needed after the early 2030s will be addressed either in a subsequent stage of this major capex project or through separate major or base capex projects.

The proposed Stage 1 investments included in this application are outlined in Table 10.

Table 10: Proposed Stage 1 investments (real 2025$)

Investment	Expected 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[14]	50.1	2030
2 x 75 Mvar shunt capacitor banks at Orari 220 kV	11.4	2030

14 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 (including fixing existing violations) is $56m. See Attachment 5 for a proposed framework on how costs will be allocated and recovered.

Investment	Expected P50 cost ($m)	Expected commissioning date
Automatic over-voltage shunt capacitor and shunt capacitor switching scheme	1.0	2030
Investigations cost	1.5	-
Total	**167.0**	

Additional upgrades outlined in the overall development plan may be implemented during a potential Stage 2, at a later date, depending on demand and generation growth and evolving system requirements. We will seek approval from the Commerce Commission for any future projects. The investments outlined in Table 11 are anticipated for Stage 2, based on the analysis conducted in preparation of this Stage 1 Proposal.

Table 11: Anticipated investments in USI Stage 2

Anticipated for USI 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*

8.2 Proposal to the Commerce Commission

This section describes our proposal. Transpower can submit staged major capex project applications. We intend to treat the USI project as a staged major capex project, and propose to approach the USI project in two stages:

- Stage 1: This is the MCP that we are submitting for approval at this stage. It covers the recovery of costs associated with constructing two switching stations and other necessary components in the immediate investment horizon, while also preserving flexibility for future investments.
- Stage 2: A second or subsequent MCP would address future investments, should they become necessary. We do not anticipate submitting the next MCP for some years, unless significant changes in market conditions occur.

[15] We may submit as sub-stages, to ensure timely delivery of projects, given the need dates may vary.

This is an application to the Commerce Commission for approval for the USI Stage 1 Project to recover the costs of undertaking the proposed Stage 1 investments to address the identified need. Table 12 indicates our proposal.

Table 12: Proposal at a glance

Proposal at a glance	
What:	Maintain the grid reliability standards into the USI region through investing in: • 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
When:	Commence work as soon as funding is approved. Commissioning date assumption 31 December 2030
How much:	Major capex allowance (**MCA**) (excluding potential NTS): $193.0 million Maximum recoverable costs (for potential NTS): $7.0 million
Incentive elements:	Major capex incentive rate: 15% Exempt major capex: none
Approval expiry date:	31 December 2040

In addition, Transpower has worked closely with the Commerce Commission to develop an approach that allows us to fund economic non-transmission solutions (**NTS**) that provide a net benefit by deferring transmission investments. A 12-month deferral of all transmission investments in Stage 1 of the Proposed Investment is estimated to save $7.0m. See Attachment 8 for further details.

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