TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Attachment 10: Power Systems Analysis Report

August 2025

Purpose

The purpose of this attachment is to:

- provide engineering requirements for the investigation of the Upper South Island (**USI**) Upgrade Project; and
- explain the power systems analysis and assumptions used to develop short-list options.

This attachment forms part of the Upper South Island Upgrade Project Investigation Major Capex Proposal (**MCP**) application and should be read in conjunction with the main report.

Contents

1 Background

Figure 1 shows the geographical area of the Upper South Island. Timaru is included in the USI region, while Twizel is excluded. Studholme is supplied by Timaru in the summer period and is supplied by Waitaki in the winter period, therefore it is included in USI for the summer period only.

Figure 1: Upper South Island geographical region

The USI is experiencing a steady increase in electricity demand as the region is transitioning towards a more electrified lifestyle. Electrification of primary processing in South Canterbury is also anticipated. However, the current electricity generation capacity in the region is insufficient to meet this growing demand. Electricity is supplied from the Waitaki Valley through 220 kV transmission lines. These lines can span over 200 kilometres and transmission requires additional voltage support to ensure a reliable supply. To address this, static Var compensators (SVCs), shunt capacitors, and shunt reactor have been installed at Islington substation to provide voltage support to Christchurch. Despite these measures, transfer to the USI is projected to face voltage stability issues and thermal constraints within the next five years. Therefore, the proposed stage 1 investment options aim to address both these issues and ensure the long-term sustainability of the region's transmission capacity amidst the increasing demand.

2 Modelling assumptions

This section describes the modelling assumptions made as part of developing and evaluating the short-list options. These include the demand forecast, network model, generation, dynamic load model, fault type and reactive support assumptions.

2.1 Demand forecast

Transpower's 2024 USI peak demand data derived from MBIE's 2019 Electricity Demand and Generation Scenarios (**EDGS**) Environmental scenario was used to analyse needs and prepare a short list of options. Given the time and effort required for power system analysis, the calculation of transfer limits was carried out using the 2023 forecast and then updated to the 2024 forecast to determine the investment timings.

Figure 2 displays the prudent (P90) peak demand forecast for the USI region until 2054, with a detailed demand forecast for each grid exit point in Appendix A.1.

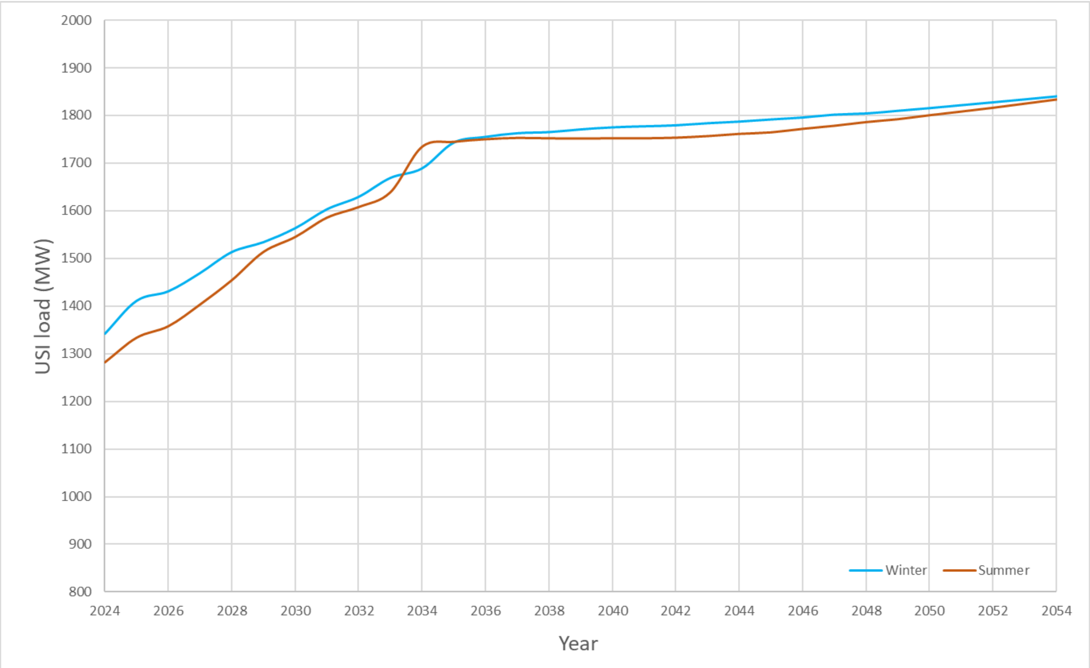

Figure 2: USI region peak – 2024 forecast

As the focus is primarily on upper South Island transmission capacity, load outside the USI region is kept constant throughout this analysis.

2.2 New Timaru grid exit point

Electrification of industrial loads at Timaru is expected to drive a significant step increase in forecast load. We are investigating an upgrade at the request of Alpine Energy. It is assumed a new 220/33 kV grid exit point will be established at Timaru, facilitating the transfer of one–third of the Timaru 11 kV load.

2.3 Clandeboye electrification

Fonterra recently made a commitment to reduce its carbon footprint, announcing a halt to the installation of new coal boilers and any expansion of coal–burning capacity. One expected development resulting from this decision is the electrification of Fonterra's Clandeboye dairy plant, which is currently supplied from the Temuka grid exit point.

From discussions with customers and supported by Alpine Energy's Asset Management Plan 2023, the preferred method for supplying power to Clandeboye is via a new connection to the USI 220 kV circuits. The analysis assumed Clandeboye would be supplied via the 220 kV Ashburton–Timaru–Twizel–1 circuit, with a grid exit point located at Orari (separate to the Orari switching station).

If the Orari switching station is part of a development plan, Orari will potentially be a grid exit point supplying Clandeboye load.

2.3.1 Supply Clandeboye from 220 kV network

Figure 3 illustrates the Clandeboye connection to the 220 kV Ashburton–Timaru–Twizel–1 circuit. It is a loop–in-out configuration with two 220/110 kV 150 MVA, 10% impedance supply transformers, providing N-1 security.

To implement this option, Alpine Energy will need to expand its distribution network to provide power to Clandeboye from the new grid exit point. This expansion involves constructing two 110 kV circuits and installing two step–down 110/33 kV transformers at its Clandeboye substation.

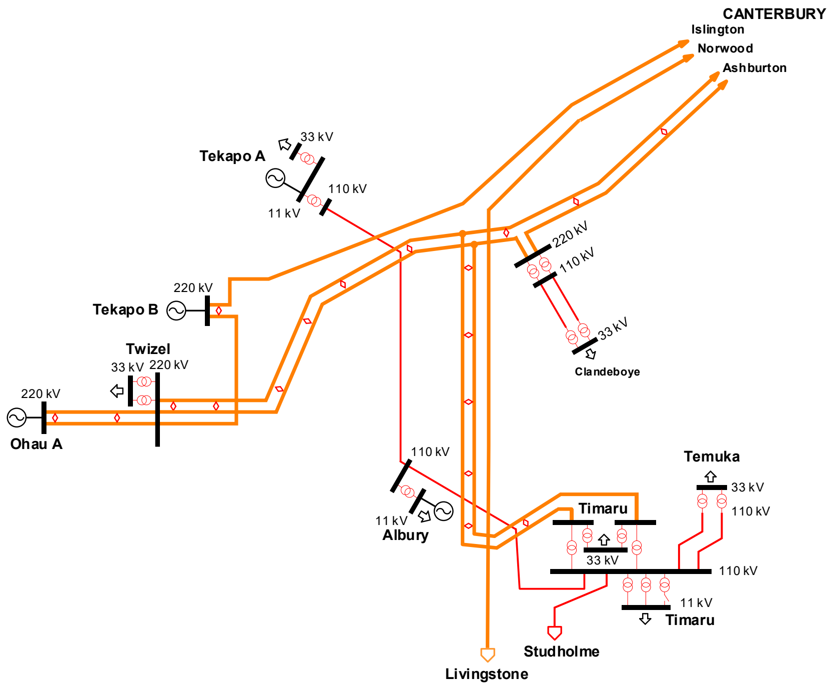

Figure 3: Clandeboye load supplied from 220 kV Ashburton–Timaru–Twizel–1

2.4 Generation assumptions

2.4.1 Existing generation

Most of the generation installed in the USI is comprised of limited storage and run-of–river hydro plants, which means that the amount of available generation is heavily influenced by the prevailing hydrological conditions.

To determine the dispatch of generation in the USI, historical generation data from 2021 and 2022 was used. The raw data was then filtered to only include the windows:

- Peak Winter Window (**PWW**), between 1 July and 31 August and the hours of 16:00 – 19:00.
- Peak Summer Window (**PSW**), between 15 January and 28 February and the hours of 14:00 – 18:00.

This process resulted in a realistic dataset of generation that can be employed for dispatch scenarios during summer and winter.

In both the summer and winter seasons, the total dispatch level for the USI was determined as the 50th percentile (average) of the refined generation data. This implies a 50% likelihood that the overall generation in the USI throughout the historical period equalled or exceeded the designated dispatch level. The chosen conservative approach is due to the generation sources in the USI being predominantly limited storage and run-of–river hydro plants. The operational flexibility of these plant is constrained by the natural flow of the river and consent requirements.

Table 1: USI 50th percentile (average) generation dispatch

Station Name	Code	Machines	Station Capacity (MW)	Winter peak window (MW)	Summer peak window (MW)
Amethyst	–	1 x 7.5	7.5	7.5	5.4
Arnold	ALD	2 x 1.5	3	2.9	2.9
Argyle	ARG	1 x 3.2 1 x 7.8	11	10.9	0.0
Cobb	COB	4 x 3	32	32.0	24.1
		2 x 10			
Highbank	–	1 x 25	25	22.7	0.0
Lake Coleridge	COL	1 x 9.5 2 x 12 2 x 3	39.5	30.2	29.1
Kawatiri	–	1 x 5	5	0.0	0.0
Kumara	KUM	1 x 10	10	9.0	5.5
Tekapo A	TKA	1 x 30	30	23.5	16.0
Opuha	OPU	1 x 7	7	3.4	2.6
Generation Total			170	142.1	85.6

2.4.2 Future modelled generation and slack

The commitment of additional generation or other transmission alternatives could defer the need for transmission investment into the USI. However, no new committed[1] generation has been identified in the USI region that can be included in this study. A sensitivity analysis of potential new solar generation has been undertaken (see section 7).

The HVDC at Benmore is used as slack generation.

2.5 Network assumptions

The network model is based upon the 2023 Transmission Planning Report DigSILENT case produced by Transpower.

Future transmission projects, both planned and committed, are considered as modelled projects. Table 2 provides a list of known committed projects and possible modelled projects.

Table 2: Committed and modelled projects

Type	Development	Timing	Description
Modelled	Orari Grid Exit Point	2024	Supply Clandeboye load from Ashburton–Timaru–Twizel–1 (see Table A–1 and Table A–2 for load forecast).
Modelled	Partial Timaru 11 kV load shift to 33 kV	2024	A new 220 kV supply at Timaru (assumed 1/3 of forecast TIM 11 kV load is supplied from the new 33 kV supply).

2.6 Voltage support assumptions

2.6.1 SVC and STATCOM modelling

Table 3 summarises the reactive compensation (static and dynamic) presently installed in the USI region. There is a total of 602 MVAr of capacitors, –130 MVAr of reactors, and +250/–165 MVAr of dynamic compensation presently available. The table does not include reactive compensation within distribution networks.

SVCs and STATCOMs are power electronic devices that can supply dynamic reactive power to the AC system. The USI network has two SVCs (Islington SVC3: +60 / –50 MVAr and SVC9: +150 / –75 MVAr) and one STATCOM (Kikiwa STC2: +/– 40MVAr).

[1] Committed generation is defined in Section D8(1) of the Commerce Commission's Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination2023, 13 December 2023.

Kikiwa STC2 has a 2–second current overload of 2.5 p.u. capacitive or 2.0 p.u. inductive. The increased output capability for short durations provides significant reactive support during voltage dips to re–accelerate stalled motors and to further aid voltage recovery.

The SVCs and STATCOM are dispatched to within ±10% of their rated capacity so the devices can respond to system events.

Table 3: Static and dynamic reactive compensation in the USI

Substation	Voltage (kV)	Capacitors (MVAr)	Reactors (MVAr)	Dynamic support (MVAr) SVC	STATCOM
Islington	220	4 x 60		+150/–75	
	220			+60/–50	
	220		1x80		
	220	1 x 75			
	66	3 x 37			
Kikiwa	11		50		+40/–40
Stoke	33	4x10			
Blenheim	33	4 x 5			
Bromley	11	2 x 30			
Greymouth[1]	11	1x1, 1x2 & 1x4			
Hokitika[1]	11	1x2, 1x4 & 1x8			
Southbrook	66	1 x 35			
	TOTALS	**602**	**–130**	**+210/–125**	**+40/–40**

[1] Binary switched capacitor

There are several capacitors in the USI planned for replacement within the next 10 years (see Table 4). For this analysis, we assume that these capacitors will be replaced with like–for–like capacitors.

Table 4: Planned capacitor retirement/replacement date[2]

USI capacitor	Voltage (kV)	Reactive (MVAr)	Scheduled retirement/replacement date
BLN C1, C2, C3, C4 replacement	33	4 x 5	Mid 2029

[2] Internal Integrated Works Plan report on 12/7/2024

GYM C1, C2, C3 replacement	11	1x1, 1x2 & 1x4	End 2031
ISL–C14 replacement	66	1x37	Start 2033
ISL–C15 replacement	66	1x37	Start 2034
ISL–C16 replacement	66	1x37	Start 2035

2.7 On-load tap changers

All 220/110 kV and 220/66 kV interconnecting transformers have on-load tap changers. The auto–voltage regulation mode is set to manual for all interconnectors in the USI region and adjusted manually to meet voltage criteria.

2.8 Load modelling

Analysis of voltage stability in the USI region requires knowledge of the make-up of voltage-sensitive load in the region. The following sections describe the load model used in the analysis.

In the studies the load model is based on our load survey of motor load data conducted in 2023[3]. The load model consists of:

- induction motor load
- static "non-rotating" load
- electronics load
- known distribution capacitors.

[3] We periodically survey lines companies and major customers in the region to gather information on load characteristics to support voltage stability analysis.

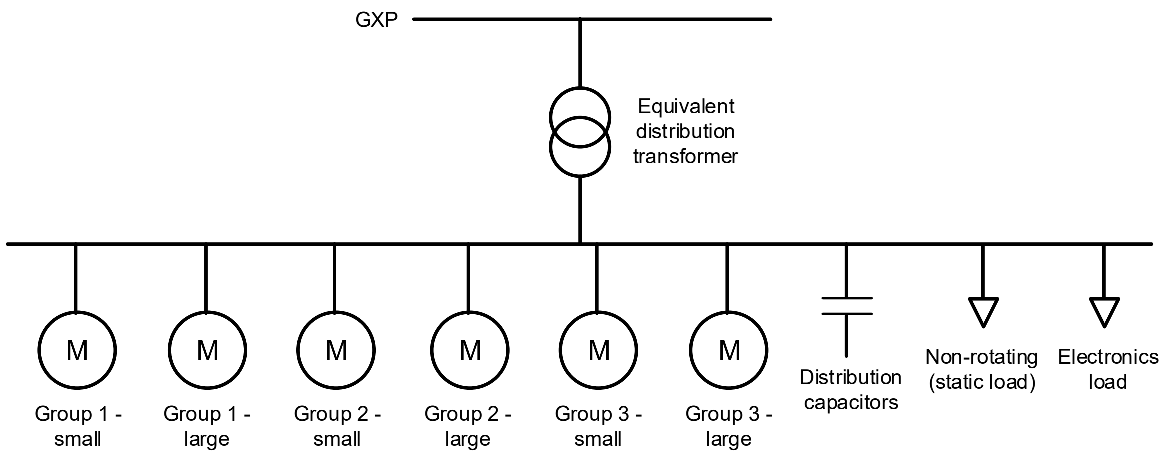

Figure 4: Load model for each upper South Island grid exit point

2.8.1 Induction motors

When subjected to voltage dips or disturbances, induction motors draw more reactive power from the electrical power system, leading to a further drop in voltage, potentially lead to voltage instability. In our study, these motors are split into three protection groups (Group 1, 2, and 3). Each group is further divided into large and small motor size (see Figure 4).

Note that motors connected via variable frequency drives are considered as Electronics load.

Group 1 motors

Group 1 motors are connected with electromagnetic contactors. These contactors may open and a proportion of motors will stay open when subjected to a fault. This is modelled by assuming that some of Group 1 USI motor loads will trip instantaneously when the voltage falls below 0.75 p.u. In our simulation analysis, the amount of Group 1 motors that trip was assumed to range from 25% to 50%. The remaining 50% to 75% of Group 1 motor capacity is then split into Group 2 and Group 3 motors in proportion to their ratios. We also assume that 50% of power factor correction capacitors will trip due to the contactors opening.

Group 2 and 3 motors

These motors are assumed to remain connected during and immediately after the fault. They have over–voltage and over–current protection.

The remaining Group 2 and Group 3 motor loads are assumed to remain connected during and immediately after the fault. The Group 2 motors and Group 3 motors have a combination of over–voltage and over–current protection, but only the Group 3 motors have undervoltage protection.

These motors are assumed to trip if the:

- motor current is greater than 6 times the rated current (6 p.u.) for more than 2 seconds or greater than 3 times the rated current (3 p.u.) for more than 8 seconds.
- voltage at the motor terminals is below 0.8 p.u. after 4 seconds or below 0.9 p.u. after 60 seconds.
- voltage at the motor terminals is above 1.4 p.u.

- voltage at the motor terminals is above 1.1 p.u. for more than 2 seconds.

Static load

The static load is assumed to stay connected during the fault. It is modelled as having PIQZ characteristics. PIQZ load has a constant real current and constant reactive impedance characteristic to variations in voltage.

Distribution capacitor banks

Distribution capacitor banks are needed to support voltage in the distribution network and meet distribution companies' power factor obligations. Known distribution capacitors are explicitly modelled.

Electronics load

The electronics load includes Variable Frequency Drives (VFDs), computers, LED lighting, inverter fridges and heat pumps. It is assumed that capacitance on the DC side allows the load to continue operating at constant power through small dips. When the voltage recovers, additional power to recharge the capacitor is drawn. For larger voltage dips, the inverters stop operating but reconnect immediately when the voltage recovers.

Directly connected induction motors draw large amounts of reactive current (~9 times normal) when reaccelerating after a large fault. This extra reactive current draw holds the voltage down, which can exacerbate the problem. For this reason, Transpower has historically modelled induction motors separately.

However, many modern induction motors are connected via a variable frequency drive (VFDs), which is an AC-DC-AC device. This does not have this MVAR draw phenomenon and, from a Grid perspective, behaves similarly to a normal AC-DC for, say, electronic equipment. The Load Survey now asks explicitly about VFDs to avoid this confusion. Thus, with a single model we can clear up the VFD ambiguity and model the increasing use of power electronics.

The model itself is based on research by NERC/EPRI: Modeling the Aggregated Response of Variable Frequency Drives (VFDs) for Power System Dynamic Studies | IEEE Journals & Magazine | IEEE Xplore.

Distribution network

The distribution network is modelled as a transformer between the grid exit point and the load. The network impedance is assumed to be 10% (with load MVA as base) for each grid exit point in USI.

USI load proportions

The motor load composition in the USI region is determined based on the regional coincident peak demand. This peak demand occurs during different time periods: the evening peak in winter and the afternoon peak during summer.

The USI load model is summarised in Table 5. Our analysis assumed these motor load percentages do not change over the duration of the study.

Table 5: USI average load composition summary (regional coincident peak demand)

Region	Period	Static	Elect-ronic	Induction motors					
				Group 1		Group 2		Group 3	
				Large	Small	Large	Small	Large	Small
Upper South Island	Summer peak	22.0%	30.3%	5.0%	20.5%	0.7%	18.3%	1.7%	1.6%
	Winter peak	38.1%	36.6%	3.4%	7.6%	0.6%	11.9%	0.9%	0.8%

3 Analysis criteria

This section explains the key criteria that were applied in this analysis.

3.1 Security criteria

The Electricity Industry Participation Code (EIPC) dictates that N-1 security is required for core–grid assets.

3.2 Voltage performance criteria

3.2.1 Steady–state voltage performance

The analysis uses the voltage criteria that at all:

- 220 kV and 110 kV buses, voltage is maintained between 0.9 p.u. and 1.1 p.u. for both normal operating condition and for a contingent event; and
- 66 kV and 33 kV buses, voltage is maintained between 0.95 p.u. and 1.05 p.u. for both normal operating condition and for a contingent event, except where a wider voltage agreement applies.

3.2.2 Dynamic voltage stability performance

Transpower's transient voltage criteria are derived from the requirements set out in the EIPC reliability standard for the New Zealand power transmission system. The overriding criteria is that the power system remains stable during and following a fault. In addition, to ensure the power system does not recover too slowly or stabilise at an unacceptable voltage, the voltage recovery trajectory must also be within the following criteria.

Voltage recovery criteria

For major (220 kV and 110 kV) buses with no generators connected the recovery criteria are:

- Voltage must be greater than 0.5 p.u. following a single credible contingency event which removes an item of equipment from service without a transmission system short circuit fault. For modelling purposes, all load is assumed to stay connected during and following the event.
- Voltage must recover to above 0.8 p.u. in less than 4 seconds and above 0.9 p.u. in less than 60 seconds following a credible contingency event.
- Voltage overshoot must be limited to below 1.3 p.u.
- Voltage overshoot must not be above 1.1 p.u. for more than 2 seconds.

For generator buses[4] the recovery criteria follow the generator voltage fault ride through criteria in the Code. If only a single generator is connected to the bus and the fault is the loss of this single generator, then the criteria for a bus with no generators connected applies.

The voltage recovery criteria depicted under Transpower's Grid Planning Guidelines and the EIPC's generator fault ride through criteria are shown in Appendix C.

3.3 Thermal criteria

The analysis assumed that transmission lines are limited to 100% of their respective winter and summer branch or thermal ratings, with no short-term overload capability, as shown in Appendix D. This is to provide a margin to allow for small changes such as minute-to-minute fluctuations in load that occur naturally in power systems or changes in voltage setpoints.

4 Methodology

The purpose of this section is to explain the process that was followed to calculate load limits to define the need and the impact of possible short-list options.

The methodology includes steady-state voltage stability analysis, thermal analysis and dynamic analysis that was used to create and review transmission development paths for the planning horizon out to 2050.

4.1 Steady-state voltage stability analysis

PV analysis is conducted to find the relationship between transmitted power and receiving voltage. PV curves are obtained through load flow analysis.

PV calculations are done with a fictitious infinite voltage source on the load side to lock the voltage, which allows the load flow algorithm to be more stable near the nose-point. The load is

4 The generator bus for the USI investigation refers to Ashburton 220 kV, Stoke 66 kV bus, Argyle 110 kV, Dobson 33 kV, Kumara 66 kV, Hokitika 66 kV, Albury 110 kV, and Coleridge 66 kV, Inangahua 110 kV, Tekapo A 11 kV, Tekapo B 220 kV.

then adjusted until the voltage source produces 0 MVAR so there is no artificial reactive power contribution into the grid from the voltage source. The voltage level setpoint of the voltage source is then adjusted, the USI load is adjusted, the voltage source MVAR is re-adjusted to 0 MVAR, etc, until the entire PV curve and nose point is found. This method also allows the reverse side of the nose point to be found, which increases confidence in the nose point calculation.

As shunt capacitors are added, the PV curve flattens, and the nose point rises. At some point the voltage collapse point becomes untenably high and starts to look like a normal operating point. Furthermore, the operators have the Voltage Stability Analysis Tool (VSAT) which calculates how many shunt capacitors need to be in service so that a contingency does not cause a PV collapse. There is a limit on the number of shunt capacitors which can be installed before the pre-contingent voltage becomes too high.

One option to resolve this issue is to use dynamic plant instead of capacitors, which can be at 0 MVAR during normal operation, but still provide reactive power post-contingency. However, this becomes extremely expensive and at some point, it becomes cheaper to lower the impedance to the load, by building more lines, or series capacitors, etc.

The characteristics of a PV curve (also illustrated in Figure 5) are:

- near the 'nose' of the PV curve, voltage drops rapidly with a small increase in power transfer.
- the PV nose point is the maximum power transfer into a region and the load at PV nose sets the voltage stability limit.
- operation at or near the voltage stability limit risks a widespread voltage collapse. A satisfactory operating condition is ensured by allowing a sufficient power margin. A margin of 5% from the nose point is applied throughout the investigation.

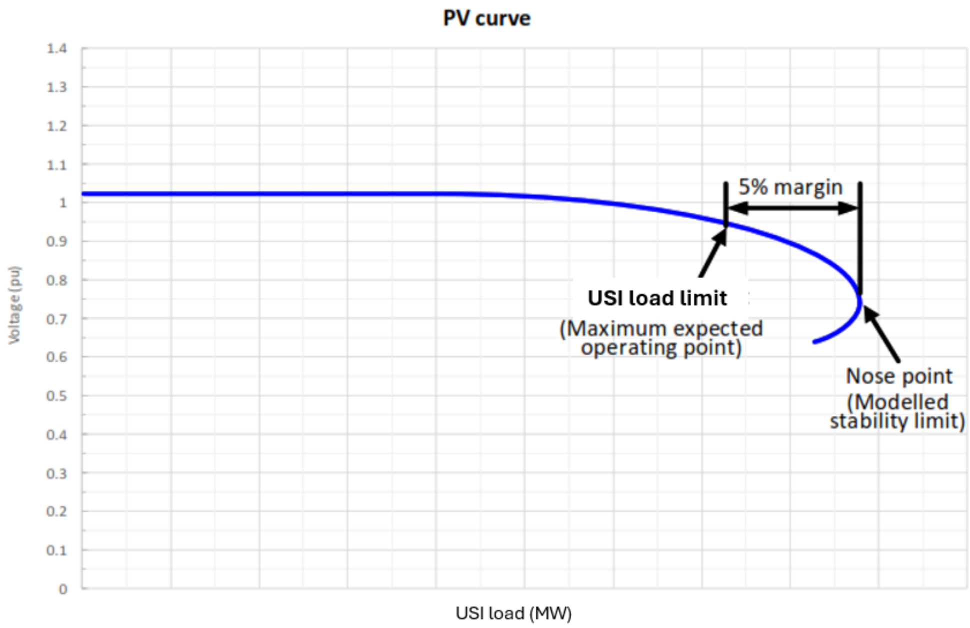

Figure 5: PV curve

4.2 Thermal analysis

For thermal analysis, load flow contingency analysis is used to identify if there are any thermal issues on the network.

4.3 Dynamic voltage stability analysis

Dynamic analysis is conducted to find the relationship between USI load and transient voltage recovery of the transmission system.

First, we convert the static load model in our power systems analysis tool to the dynamic load model representation as mentioned in Section 2.8.

We define the faults being tested as mentioned in Appendix B.2 Fault type.

Faults are implemented as follow:

- Circuits: Permanent single phase (1f) to ground faults are individually applied at both ends of a circuit. Fault is tested with 25% and 50% Group 1 motor load tripping.
- Transmission bus: Loss of transmission bus with no fault e.g., incorrect disconnector switching performed. This assumes 0% Group 1 motor load tripping.
- Transformers: Permanent 1f to ground faults are applied to transformers on their HV terminals. Fault is tested with 25% and 50% Group 1 motor load tripping.

The faults are mostly cleared in the main protection time of 100 ms, except for the four terminal Islington–Waipara–Culverden–Kikiwa circuits where the fault is cleared in 130ms. The auto–reclose time for transmission circuits varied from 1.5 sec to 4.5 sec.

We conducted dynamic RMS analysis while scaling the USI load. If the voltage recovery is:

- within the permissible voltage recovery envelope as mentioned in Appendix C, dynamic simulations continue with increased USI load.
- outside the permissible voltage recovery envelope for 0%, 25% and 50% Group 1 motor load tripping, we will scale back USI load until it is just within the voltage recovery envelope. This sets the dynamic load limit for the USI region.

5 Identifying the system need

This section describes the system needs that were identified using the assumptions outlined in Sections 2 and 3.

Our analysis shows that without additional investment, the load in USI will exceed the thermal and PV limits starting in 2028. Table 6 shows the system need date for the worst N-1 contingency in USI.

Table 6: System need date

Season	Thermal MW (N-1)	Contingency	Need date
Summer	1420	Ashburton–Timaru–Twizel–2	2028
Summer	1430	Clandeboye–Timaru–Twizel–1	2028
Winter	1640	Ashburton–Timaru–Twizel–2	2033
Winter	1650	Clandeboye–Timaru–Twizel–1	2033

Season	Static PV MW (N-1) – 5% margin	Contingency	Need date
Summer	1420	Ashburton–Timaru–Twizel–2	2028
Summer	1430	Livingstone–Norwood–1	2028
Summer	1450	Islington–Tekapo B–1	2028
Winter	1500	Livingstone–Norwood–1	2028
Winter	1510	Islington–Tekapo B–1	2028

Season	Dynamic stability MW (N-1): 1ph–gnd fault	Contingency	Need date
Summer	1500	Ashburton–Timaru–Twizel–2	2029
Summer	1500	Clandeboye–Timaru–Twizel–1	2029
Summer	1500	Islington–Tekapo B–1	2029
Winter	1550	Islington–Tekapo B–1	2030

Table 6 shows the following:

- For summer 2028, the USI load is restricted to the range from 1410 MW to 1450 MW for various contingencies including Clandeboye–Timaru–Twizel–1, Ashburton–Timaru–Twizel–2, Livingstone–Norwood–1, and Islington–Tekapo B–1.
- For winter 2028, the USI load is restricted to 1500 MW for the Livingstone–Norwood–1 contingency and 1510 MW for the Islington–Tekapo B–1 contingency.
- The N-1 thermal and PV limits determine the need date, closely followed by the dynamic limit.

6 The short-list

The short-list options comprise a combination of components that provide thermal and voltage stability throughout the future horizon to 2054. This section provides details of the short–listed component building blocks used in the short-list options.

6.1 Short-listed components

Dynamic reactive devices

Dynamic reactive support is modelled using STCs to represent the necessary dynamic response. STCs serve as building blocks that provide dynamic support to increase the dynamic voltage stability limit. All STC building blocks are modelled as connected at transmission voltage buses and are included in short-list options in ±150 MVAr blocks with no overload capability, in-line with the most recent ones at Hamilton and Otahuhu.

Shunt capacitors

Shunt capacitors are modelled for static reactive support to represent the necessary static voltage response. They prevent slow voltage collapse by maintaining voltage levels and can be switched post–fault to aid dynamic response and provide static support once voltage stabilises.

Line upgrade

Thermally upgrade the existing transmission lines to a higher thermal rating (90°C) to increase the thermal capacity of the constrained circuit.

New transmission line

A new transmission line reduces the thermal loading of existing transmission lines. An additional parallel 220 kV line in the USI decreases the electrical length of transmission circuits, thereby improving system stability. This becomes necessary when the existing transmission lines become overloaded, after their upgrade to withstand temperatures of 90°C.

Switching station

A switching station is a type of substation that does not contain power transformers and therefore does not change system voltage from one level to another. It ties together two or more circuits, allowing for flexibility in managing the flow of electricity and enhances the reliability of the system by providing alternative paths for the current in case of a circuit failure.

In the USI, there is not enough local generation to meet demand. The demand relies on electricity coming from the Waitaki Valley. The long distance 220 kV transmission lines into Islington requires extra voltage support to ensure a reliable power supply.

Building switching stations near Orari (ORI) and Rangitata (RTA) could help tackle the issues of thermal and voltage stability. This enable the four circuits between Christchurch and Waitaki Valley to be interconnected in the middle. The advantage of this approach is that it minimises the effect of an outage in a ‘long’ single circuit, as the switching stations would allow the remaining ‘half circuit’ to continue to provide power to the load after a circuit failure.

The site designations and property rights for Orari and Rangitata were secured back in 2015 via the Output Amendment to Stage 1 proposal[5]. This Output Amendment has allowed the switching station option components to remain possible.

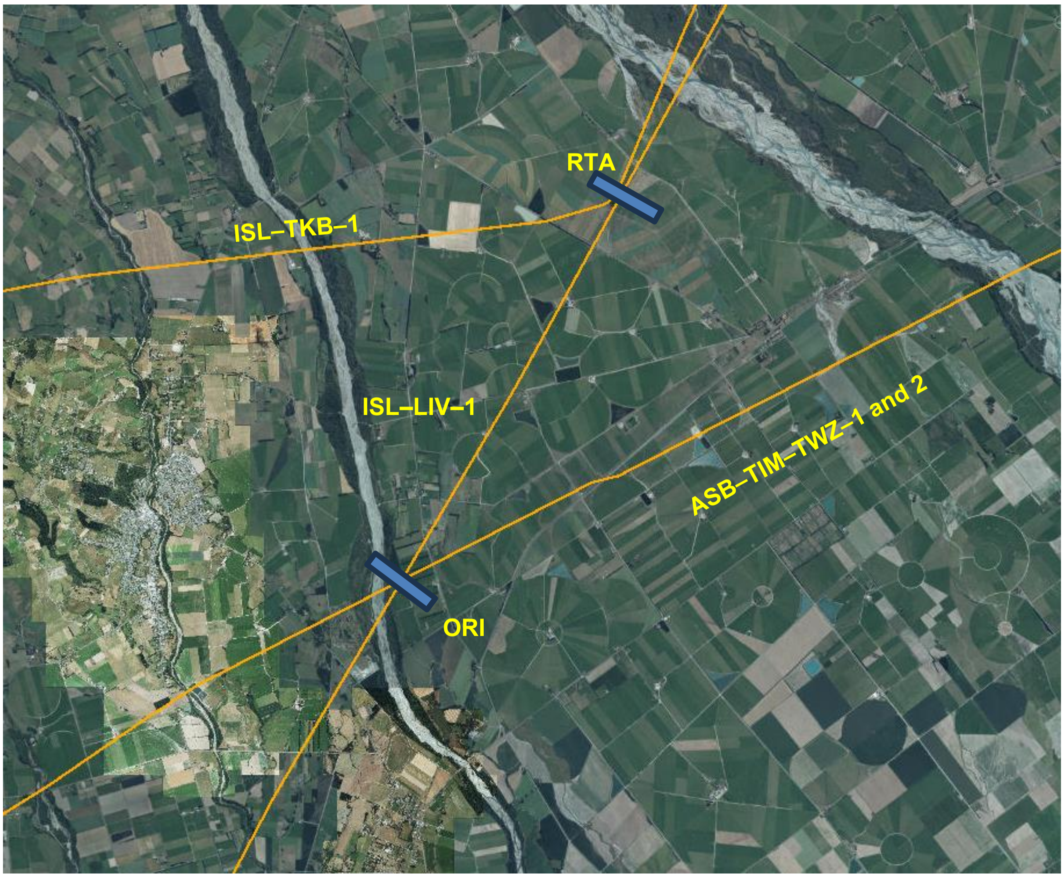

Figure 6: locations of the Orari and Rangitata switching stations

If Orari is built, the Clandeboye connection is assumed to consist of two 220/110 kV transformers, two 110 kV lines, and two 110/33 kV supply transformers. (see Fig 7)

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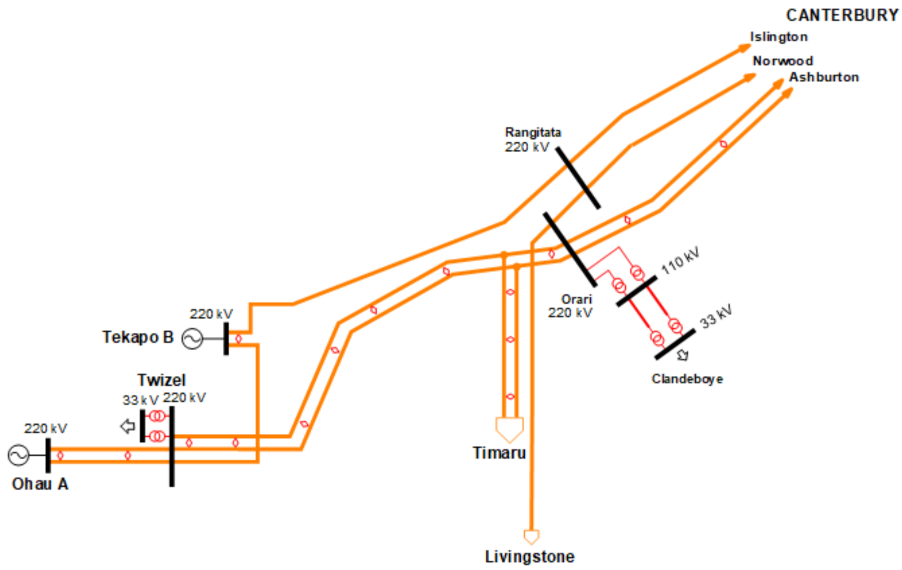

Figure 7: Clandeboye connection via Orari

Automatic Over-Voltage Capacitor and Reactor Switching Scheme

An automatic over-voltage capacitor and reactor switching scheme is a protection-based automation system to control over–voltage, working alongside dynamic devices like STATCOMs (**STCs**). It aims to reduce reactive power needs at a lower cost by using existing and future shunt capacitors and reactor in the USI region to address over–voltage conditions. The scheme would activate within a few hundred milliseconds and monitor the real–time status of capacitors and shunt reactors to ensure the correct number are switched if voltages exceed their setpoints. This scheme does not replace the need for dynamic reactive devices but can reduce their necessity.

6.2 Option 1 – Orari switching station path

This option proposes the construction of a switching station at Orari as shown in Figure 8. This station would connect the 220 kV Ashburton–Timaru–Twizel–1 and 2, and Livingstone–Norwood–1 at their intersection point, effectively dividing the circuits into:

- Norwood–Orari–1
- Livingstone–Orari–1
- Ashburton–Orari–1
- Ashburton–Orari–2
- Orari–Timaru–Twizel–1
- Orari–Timaru–Twizel–2

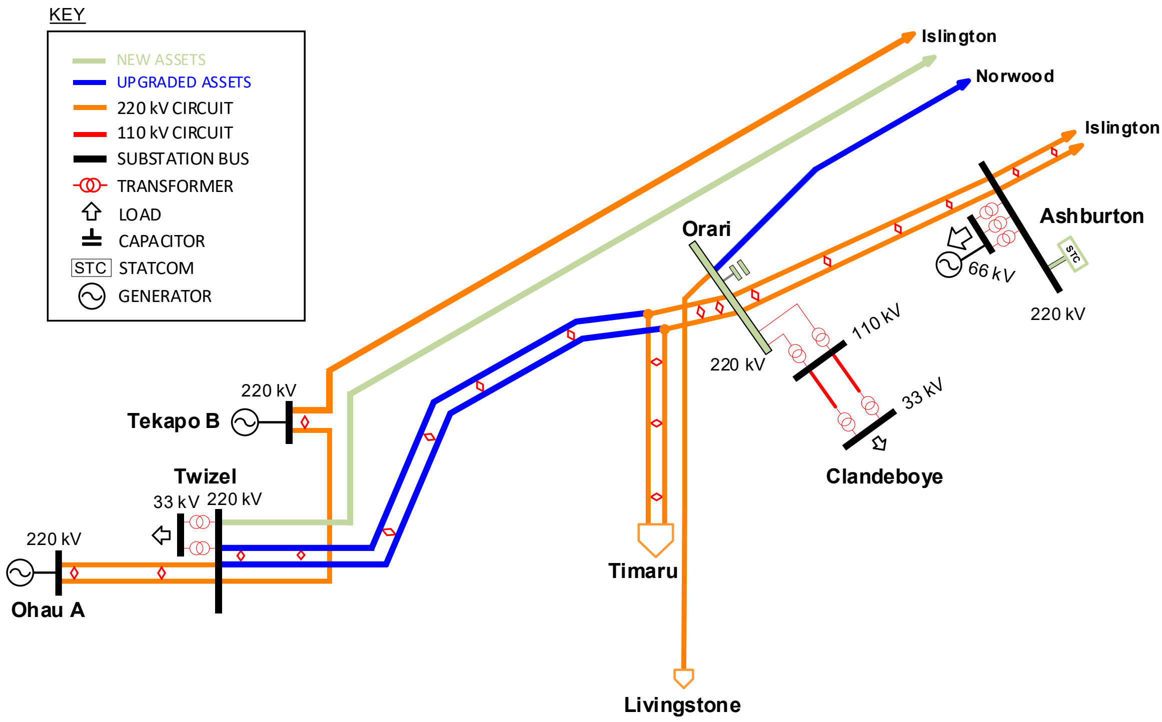

Figure 8: Orari development path – future USI 220 kV transmission configuration

This reconfiguration alters the binding contingency, making Islington–Tekapo B–1 the most critical contingency. In the event of this outage, the Norwood–Orari circuit section is projected to overload by 2028, requiring a thermal upgrade of this circuit section to 90°C.

A total of 100 MVAr of shunt capacitors are needed at Orari 220 kV to maintain static voltage stability by 2029 for a contingency of the Islington–Tekapo B–1 circuit. By 2030, a STATCOM will be required for dynamic voltage recovery following a fault on the Islington–Tekapo B–1 circuit. In 2031, a thermal upgrade of the Opihi–Twizel circuit sections to 90°C will be needed to handle Orari–Timaru–Twizel–1 or 2 contingencies.

Following the Opihi–Twizel upgrade in 2031, a new 220 kV line will be required by 2034 to address voltage, and thermal capacity issues in the USI. No further investment is necessary within the forecast period after the new line is completed.

Table 7: Option 1 – Orari switching station path

Investment	Binding	Need date
Orari switching station	Thermal / PV	2028
Thermal upgrade Norwood–Orari–1 to 90°C	Thermal	2028
A total of 100 MVAr shunt capacitor banks at Orari 220 kV	PV	2029
Automatic over–voltage capacitor and reactor switching	Dynamic	2029
150 MVAr STATCOM at Ashburton 220 kV	Dynamic / PV	2030
Thermal upgrade Opihi–Twizel–1 and 2 (duplex ZebraGZ 90°C)	Thermal	2031

Investment	Binding	Need date
New Islington–Twizel line (duplex Sulfur AAAC 75°C)	Dynamic / PV / Thermal	2034

6.3 Option 2 – Orari and Rangitata switching station path

In this scenario, both the Orari and Rangitata switching stations are constructed as shown in Figure 9. The Rangitata switching station would connect the 220 kV circuits of Islington–Tekapo B and Norwood–Orari, effectively dividing the circuits into:

- Rangitata–Tekapo B–1
- Islington–Rangitata–1
- Norwood–Rangitata–1
- Orari–Rangitata–1
- Livingstone–Orari–1
- Ashburton–Orari–1
- Ashburton–Orari–2
- Orari–Timaru–Twizel–1
- Orari–Timaru–Twizel–2

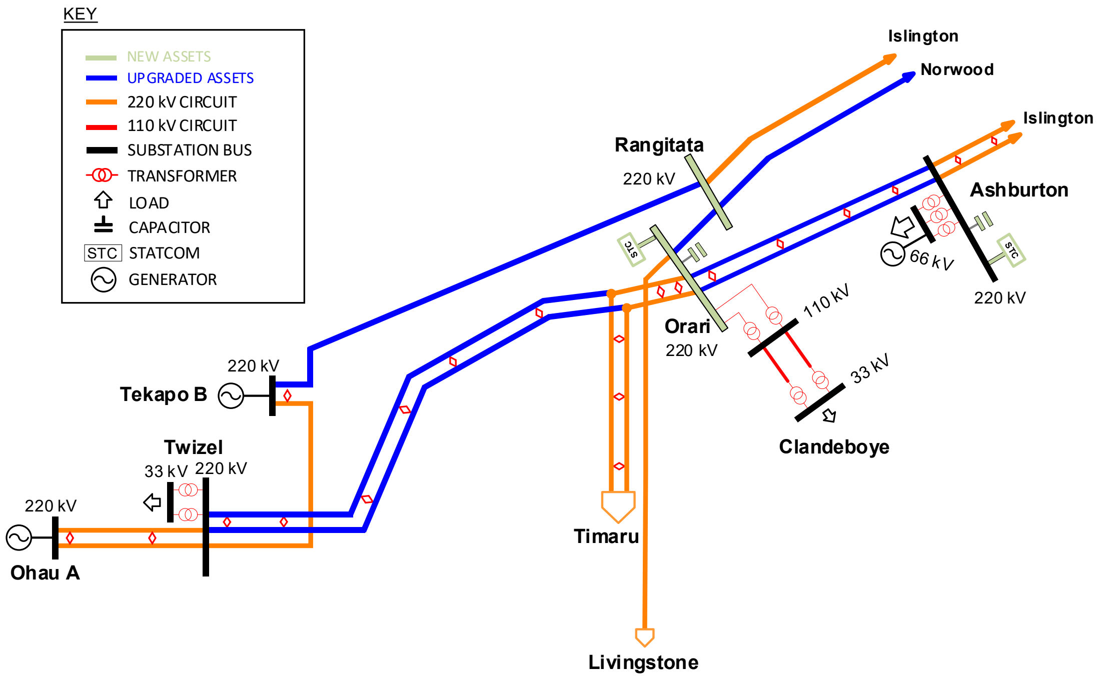

Figure 9: Orari and Rangitata development path future USI 220 kV transmission configuration

By 2028, a thermal upgrade of the Norwood–Rangitata circuit to 90°C is needed for a contingency of Islington–Rangitata–1. The circuit section between the Orari and Rangitata switching stations will require a thermal upgrade to 100°C in 2030 to handle a contingency of Rangitata–Tekapo B–1. The introduction of the Rangitata switching station will defer the need for a new STATCOM by three years and defer the thermal upgrade of Opihi–Twizel by two years compared to Option 1.

To maintain static voltage stability by 2030, a total of 150 MVAr of shunt capacitor is needed at Orari 220 kV for contingencies of Orari–Timaru–Twizel–1 or 2 circuit. By 2033, the Opihi–Twizel circuit sections will require a thermal upgrade to 90°C to manage these contingencies. In the same year, a STATCOM will be needed at Ashburton for dynamic voltage recovery following a fault on the Orari–Timaru–Twizel–1 or 2 circuit.

By 2035, a thermal upgrade of Rangitata–Tekapo B–1 is required to address the thermal capacity issue, along with thermal upgrades of Ashburton–Orari–1 and 2 circuit. In the same year, a total of 100 MVAr of shunt capacitors at Ashburton 220 kV will be needed for voltage stability. By 2046, additional STATCOM will be needed to resolve voltage stability issues following a fault on the Orari–Timaru–Twizel–1 or 2 circuit.

The introduction of Rangitata also makes it possible to avoid investment in long transmission lines, such as the new Islington–Twizel line in Option 1 and Option 3. Both Orari and Rangitata switching stations create flexibility for less expensive investments through thermal upgrades, shunt capacitors and STATCOM(s).

Table 8: Option 2 – Orari and Rangitata switching station path

Investment	Binding	Need date
Orari and Rangitata switching station[6]	Thermal / PV	2028
Thermal upgrade Norwood–Rangitata–1 to (duplex GoatAC 90°C)[7]	Thermal	2028
Thermal upgrade Orari–Rangitata–1 (duplex GoatAC 100°C)	Thermal	2030
A total of 150 MVAr shunt capacitor banks at Orari 220 kV	PV	2030
Automatic over–voltage capacitor and reactor switching	Dynamic	2031
Thermal upgrade Opihi–Twizel–1 and 2 (duplex ZebraGZ 90°C)	Thermal	2033
150 MVAr STATCOM at Ashburton 220 kV	Dynamic	2033
Thermal upgrade Rangitata–Tekapo B–1 (duplex GoatGZ 90°C)	Thermal	2035
A total of 100 MVAr shunt capacitor banks at Ashburton 220 kV	PV	2035
Thermal upgrade Ashburton–Orari–1 and 2 (duplex ZebraGZ 90°C)	Thermal	2035
150 MVAr STATCOM at Orari 220 kV	PV / Dynamic	2046

6 We expect commissioning of the two switching stations to be delayed to 2029 due to longer lead times.

7 We expect the TTU of Norwood–Rangitata circuit may finish as late as 2030 due to discussions with landowners to ensure under clearance requirements are met (including existing under clearance violations as discussed in Attachment 5).

6.4 Option 3 – STATCOM path

This option does not involve the use of a switching station. Instead, it relies on a primary plant (STATCOM) to address both PV and dynamic voltage instabilities, shown in Figure 10. However, thermal upgrades for Opihi–Twizel in 2028 and Livingstone–Norwood in 2029 are necessary, as the STATCOM cannot resolve thermal capacity constraints. Without switching stations, a new line will be required by 2031 to tackle both voltage and thermal capacity constraints. This new line will defer the next investment until 2048, when a STATCOM will be needed to resolve PV and dynamic issue

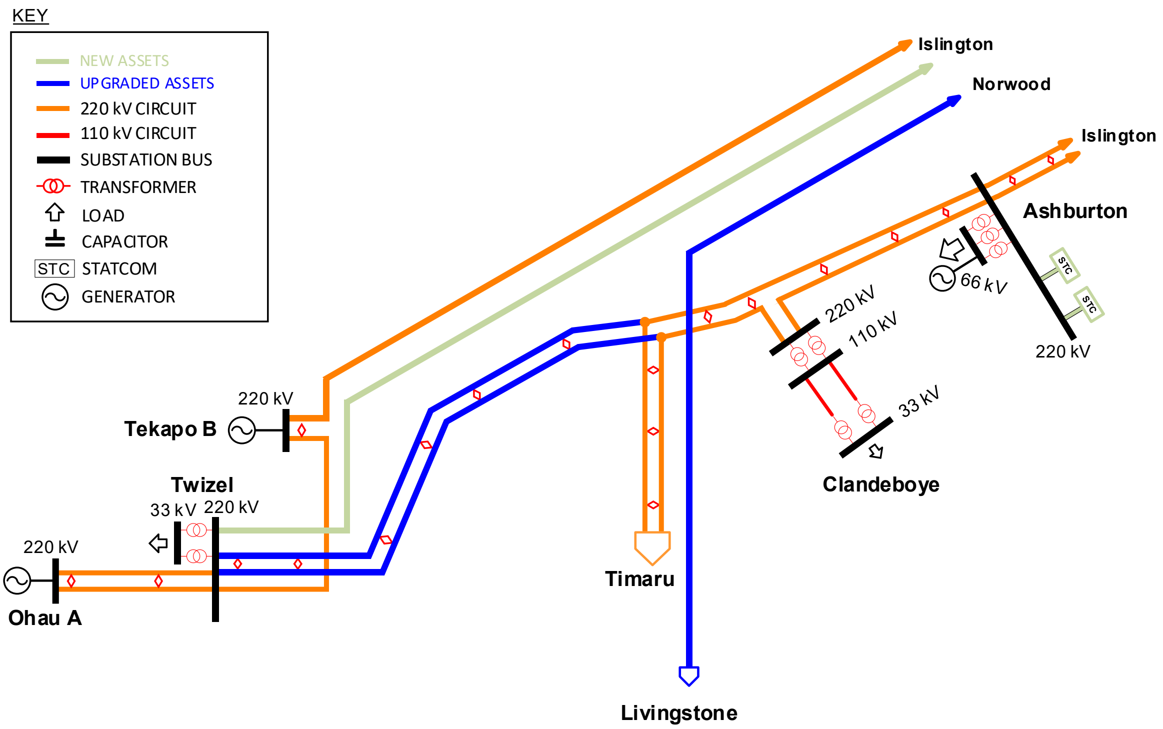

Figure 10: STATCOM development path future USI 220 kV transmission configuration

Table 9: STATCOM path

Investment	Binding	Need date
150 MVAr STATCOM at Ashburton 220 kV	PV / Dynamic	2028
Thermal upgrade Opihi–Twizel–1 and 2 (duplex ZebraGZ 90°C)	Thermal	2028
Thermal upgrade Livingstone–Norwood–1 (duplex GoatAC 90°C)	Thermal	2029
New Islington–Twizel line (duplex Sulfur AAAC 75°C)	Thermal / PV	2031
150 MVAr STATCOM at Ashburton 220 kV	PV / Dynamic	2048

7 Sensitivity analysis

The Canterbury region benefits from strong solar irradiance, making it suited for solar generation. An analysis was conducted to assess the impact of future solar uptake in the Upper South Island on the project need date.

The scenario assumed a total installed solar capacity of 339 MW, with a 15% contribution during summer and no contribution in winter. Table 10 illustrates how additional solar generation affects the need date, using Option 2 as an example.

Despite the introduction of new solar plants, the overall need date remains unchanged at 2028. However, some project components can be deferred by one year. Under the revised plan, only the Orari and Rangitata switching stations, along with the thermal upgrade of the Norwood–Rangitata circuit, are required before 2030.

Table 10: Impact of additional solar generation on system need date and Option 2 development plan.

Year	Option 2 (ORI + RTA switching stations)		Option 2 (ORI + RTA switching stations) (Additional Solar Plants)	
	Need date	Investment	Need date	Investment
2028	Static voltage stability (summer & winter) Thermal capacity (summer)	Build two new switching stations near Orari and Rangitata. Thermal upgrade of the Norwood-Rangitata circuit to 90°C.	Static voltage stability (winter)	Build two new switching stations near Orari and Rangitata. Thermal upgrade of the Norwood-Rangitata circuit to 90°C.
2029	Dynamic (summer)		Static voltage stability (summer) Thermal capacity (summer)	
2030		Thermal upgrade of the Orari-Rangitata circuit to 100°C. A total of 150 Mvar shunt capacitor banks at Orari 220 kV.	Dynamic (winter)	
2031		Automatic over–voltage capacitor and reactor switching.		Thermal upgrade of the Orari-Rangitata circuit to 100°C. A total of 150 Mvar shunt capacitor banks at Orari 220 kV.

Appendix A Modelling Assumptions

A.1 Load assumptions

Table A–1 shows the load and power factor at each grid exit point at the time of the summer USI peak forecast.

Table A–1: 10–year forecast demand and power factor at each grid exit point at time of summer USI peak

Grid exit point	Power factor	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nelson-Marlborough											
Blenheim	0.992	77	78	80	82	86	87	88	89	90	94
Stoke 33 kV	0.983	92	94	95	98	100	102	103	105	106	103
Stoke 66 kV	0.953	21	21	22	22	30	31	31	31	32	33
West Coast											
Arthur's Pass [1]	0.941	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Castle Hill[1]	0.819	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0
Dobson	0.993	9	9	9	9	10	10	10	10	10	10
Greymouth[1]	0.987	9	9	9	10	10	11	11	11	11	11
Hokitika	0.981	19	19	19	20	21	22	22	22	23	23
Kikiwa[1]	0.982	3	3	3	3	3	3	3	3	3	3
Kumara	0.962	3	3	3	3	3	3	3	3	3	3
Murchinson[1]	0.956	2	2	2	2	2	2	2	2	2	2
Otira	0.921	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0
Reefton	1.000	4	4	4	4	4	4	4	4	4	4
Robertson Street[1]	0.997	9	9	9	9	10	10	10	10	10	10
Canterbury											
Ashburton 66 kV	0.978	210	212	215	218	222	223	226	228	230	238
Ashley (Main Power)	0.949	6	6	7	7	11	11	12	12	12	12
Ashley (Daiken)	0.949	7	7	7	7	7	7	7	7	7	7
Bromley 66 kV[1]	0.963	67	68	70	101	108	149	153	154	156	164
Coleridge[1]	0.937	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Culverden 33 kV	0.982	22	23	24	24	25	26	26	27	27	28
Culverden 66 kV[1]	0.995	4	4	4	5	5	5	5	5	6	6
Fonterra Darfield Dairy	1.000	0	0	0	0	0	0	0	0	0	73
Hororata 33 kV	0.975	22	23	23	24	24	25	25	25	25	26
Hororata 66 kV	0.974	16	16	16	17	17	17	10	10	10	10
Islington 33 kV	0.997	71	72	74	75	78	80	82	82	59	58

Grid exit point	Power factor	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Islington 66 kV[1]	0.995	336	343	347	336	324	265	268	272	310	298
Kaiapoi	0.998	25	26	28	29	26	27	28	29	30	30
Kimberley	0.996	16	16	16	16	16	16	16	16	16	17
Norwood[1]	0.995	43	44	51	53	72	104	113	115	118	124
Southbrook 66 kV	0.987	58	61	64	67	70	72	75	78	80	81
Waipara 33 kV	0.980	10	10	11	11	12	12	13	13	14	14
Waipara 66 kV	0.850	3	4	4	4	4	4	4	4	5	5
South Canterbury											
Albury	0.956	4	4	4	4	5	5	5	5	5	5
Studholme	0.985	14	14	14	14	14	14	14	15	15	14
Tekapo A[1]	0.929	6	6	7	7	7	7	7	8	8	8
Temuka 33 kV	0.970	39	41	43	46	49	51	53	55	56	59
Clandeboye	0.970	28	28	38	46	48	48	62	62	62	65
Timaru 11 kV	0.979	51	51	53	54	60	60	61	61	62	63
Timaru 33 kV	0.979	25	25	26	27	29	30	30	30	30	31
Total		1333	1357	1403	1454	1513	1545	1585	1608	1638	1734
Note 1: This is a leading power factor											

Table A–2 shows the load and power factor at each grid exit point at the time of the winter USI peak forecast.

Table A–2: 10–year forecast demand and power factor at each grid exit point at time of winter USI peak

Grid exit point	Power factor	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Nelson-Marlborough											
Blenheim	0.999	84	86	87	88	90	93	94	95	97	98
Stoke 33 kV	0.989	133	135	137	140	142	146	148	151	154	155
Stoke 66 kV	0.977	25	25	26	26	27	27	28	28	29	29
West Coast											
Arthur's Pass[1]	0.978	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Castle Hill[1]	0.882	1	1	1	1	1	1	1	1	1	1
Dobson	0.891	8	8	8	9	9	10	10	10	10	10
Greymouth[1]	1.000	13	13	14	14	15	16	16	17	17	17
Hokitika	0.970	19	20	21	21	22	23	24	24	24	25
Kikiwa[1]	0.979	2	2	2	2	2	2	3	3	3	3
Kumara	0.928	2	2	2	2	2	2	2	2	2	2

Grid exit point	Power factor	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Murchinson[1]	0.886	2	2	2	2	2	2	2	2	2	2
Otira	0.928	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0
Reefton[1]	0.966	4	4	4	4	4	4	4	4	4	4
Robertson Street[1]	0.992	11	11	11	11	11	11	11	12	12	12
Canterbury											
Ashburton 66 kV[1]	0.957	83	83	84	85	86	88	90	91	92	92
Ashley (Main Power)	0.961	8	9	9	9	18	18	19	19	19	20
Ashley (Daiken)	0.961	7	7	7	7	7	7	7	7	7	7
Bromley 66 kV[1]	0.996	107	108	109	151	153	207	210	213	214	216
Coleridge[1]	0.953	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0
Culverden 33 kV[1]	0.938	6	6	7	7	7	8	8	8	9	9
Culverden 66 kV[1]	0.987	6	6	6	7	7	7	7	7	8	8
Fonterra Darfield Dairy	1.000	0	0	0	0	0	0	0	0	0	0
Hororata 33 kV[1]	0.989	12	12	12	12	13	13	13	14	14	14
Hororata 66 kV[1]	0.868	5	5	6	6	6	6	4	4	4	4
Islington 33 kV	0.999	82	82	84	85	87	89	91	93	68	68
Islington 66 kV[1]	0.999	494	499	504	486	474	392	396	401	448	454
Kaiapoi	0.999	41	42	43	44	35	35	37	38	39	40
Kimberley[1]	0.884	4	4	4	4	4	4	4	5	5	5
Norwood[1]	0.999	40	40	47	48	63	94	102	105	107	108
Southbrook 66 kV[1]	0.999	56	59	61	63	66	68	71	73	75	77
Waipara 33 kV	0.998	7	8	8	8	9	9	9	9	10	10
Waipara 66 kV	0.962	2	2	2	2	2	2	3	3	3	3
South Canterbury											
Albury	0.966	5	5	5	6	6	6	6	6	6	6
Tekapo A[1]	0.951	9	10	10	10	10	10	10	10	11	11
Temuka 33 kV	0.984	22	24	25	26	28	29	31	32	33	34
Clandeboye	0.984	19	19	26	31	31	31	40	40	40	40
Timaru 11 kV	0.993	61	61	63	64	64	68	69	69	70	70
Timaru 33 kV	0.993	30	30	31	31	32	34	34	34	35	35
Total		1411	1431	1469	1513	1534	1563	1603	1629	1669	1689
Note 1: This is a leading power factor.											

Appendix B List of faults

The following faults are considered in the analysis.

B.1 Contingencies

Table B–1 lists the contingencies considered in the investigation for both summer and winter period.

Table B–1: Contingencies

Ashburton–Bromley–1
Ashburton–Islington–1
Ashburton–Timaru–Twizel–2
Bromley–Islington–1
Inangahua–Kikiwa–2
Islington–Kikiwa–1
Islington–Norwood
Islington–Tekapo B–1
Islington–Waipara–Culverden-Kikiwa–2
Islington–Norwood–1
Islington–Kimberley–Hororata–1
Kikiwa–Murchison-1
Kikiwa–Stoke–1
Kikiwa–Stoke–2
Kikiwa–Stoke–3
Livingston-Norwood–1
Ashburton–Orari –1
Orari–Timaru–Twizel –1
Islington–T3
Islington–T6
Islington–T9
Kikiwa–T2
Stoke–T3
Stoke–T7
Timaru–T5
Ashburton 220 A

Ashburton 220 B
Ashburton 220 C
Bromley 220 A
Bromley 220 B
Islington 220 A
Islington 220 B
Islington 220 C
Islington 220 D
Islington 220 E
Islington 220 F
Kikiwa 220 A
Kikiwa 220 B
Kikiwa 220 C
Norwood 220 A
Norwood 220 B
Stoke 220 A
Stoke 220 B
Twizel 220 B

B.2 Fault type

Faults are implemented as follow:

- Circuits: Permanent one–phase (1f) to ground faults are applied at one end of a circuit.
- Transmission bus: Bus tripping without a fault.
- Transformers: Permanent 1f to ground faults are applied to transformers on their HV terminals.

The faults are mostly cleared in the main protection time of 100 ms except for the four terminal circuits (Islington–Waipara–Culverden–Kikiwa) where the fault is cleared in 130ms. The auto–reclose time for transmission circuits varied from 1.5 sec to 4.5 sec.

A summary of the fault locations and auto–reclose times are given in Table B–2.

Table B–2: Location of faults

Cleared circuits	Location	Fault Duration (ms)	Auto–reclose time (sec)
Islington–Tekapo B–1	Islington	100	4
Islington–Tekapo B–1	Tekapo B	100	4.5
Islington–Kikiwa–1	Islington	100	1.5
Islington–Kikiwa–1	Kikiwa	100	1.5

Cleared circuits	Location	Fault Duration (ms)	Auto–reclose time (sec)
Islington–Norwood–1	Islington	100	1.5
Islington–Norwood–1	Norwood	100	1.5
Livingstone-Norwood–1	Livingston	100	1.5
Livingstone-Norwood–1	Norwood	100	1.5
Ashburton–Islington–1	Ashburton	100	1.5
Ashburton–Islington–1	Islington	100	1.5
Ashburton–Orari–1	Ashburton	100	1.5
Orari–Timaru–Twizel–1	Orari	100	1.5
Orari–Timaru–Twizel–1	Timaru	100	2.5
Orari–Timaru–Twizel–1	Twizel	100	1.5
Ashburton–Timaru–Twizel–1	Ashburton	100	1.5
Ashburton–Timaru–Twizel–2	Timaru	100	2.5
Ashburton–Timaru–Twizel–2	Twizel	100	1.5
Bromley–Islington–1	Bromley	100	1.5
Bromley–Islington–1	Islington	100	1.5
Islington–Waipara–Culverden-Kikiwa–2	Islington	130	1.5
Islington–Waipara–Culverden–Kikiwa–2	Kikiwa	130	1.5
Islington–T3	Islington	100	–
Islington–T6	Islington	100	–
Islington–T9	Islington	100	–
Kikiwa–T2	Kikiwa	100	–
Stoke–T3	Stoke	100	–
Stoke–T7	Stoke	100	–
Timaru–T5	Timaru	100	–

Appendix C Voltage recovery criteria

Transpower's transient voltage recovery criteria are derived from the requirements set out in the Electricity Industry Participation Code (Code) reliability standard for the New Zealand power transmission system. For generator buses the recovery criteria follow the generator voltage fault ride through criteria in the EIPC[8].

Note that for under–voltage criteria the fault occurs at time 1 second, and the graph is discontinuous between 9 and 60 sec, so for example, the 61 second line represents 60 seconds after the fault.

Note that over–voltage criteria apply from the point at which the voltage is above 1.1 p.u. This is illustrated at 1 second in the graph but could be at a different time.

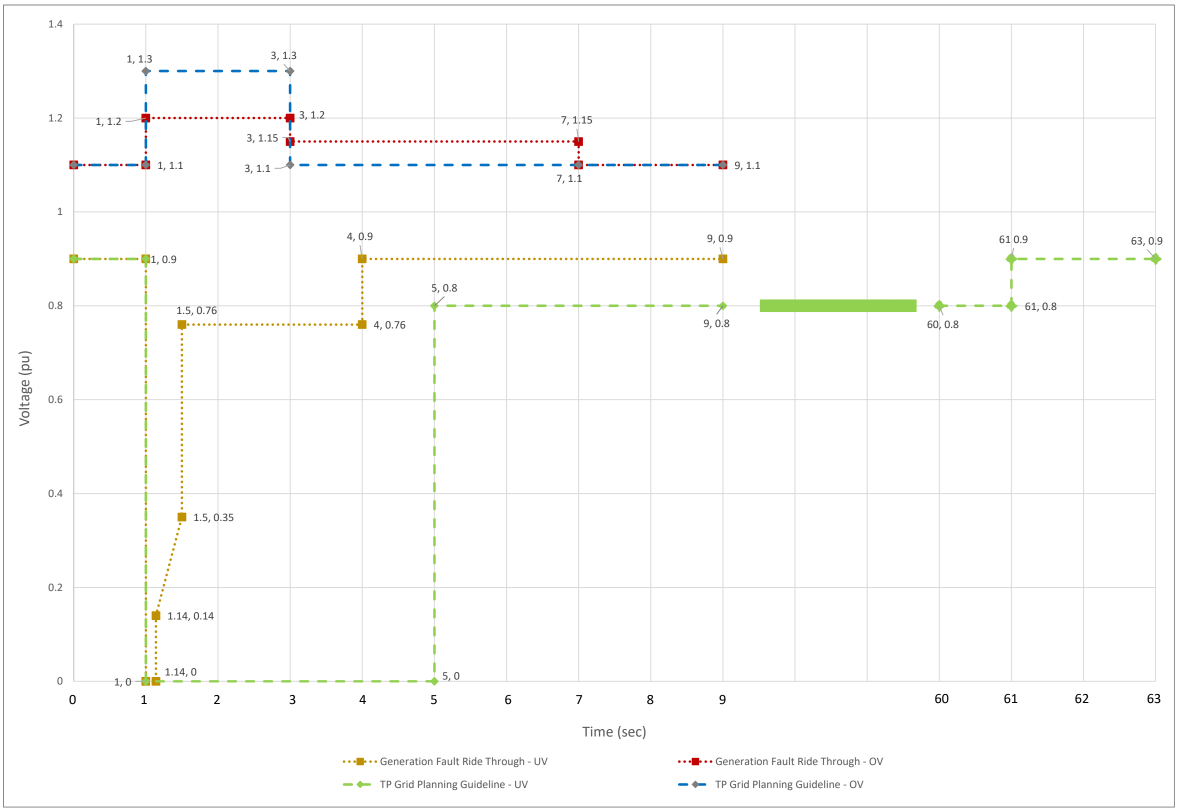

Figure C–1: South Island no–trip zone during 110 kV or 220 kV faults

8 Section 8.25A of the EIPC.

Appendix D Circuit ratings

Table D 1: USI 220 kV circuit data between Islington and Waitaki Valley

Circuit	Lowest rated Conductor	Configuration	Temp. (ºC)	Circuit Length (km)	Conductor Rating, MVA		
					Summer	Shoulder	Winter
Islington–Tekapo B	GoatGZ	Duplex	70	213	557	589	620[1]
Tekapo B–Twizel	GoatGZ	Duplex	70	26	557	589	620[2]
Livingstone–Norwood	GoatGZ	Duplex	50	207	404	451	493
Islington–Norwood	GoatGZ	Duplex	50	26	404	451	493
Ashburton–Islington	ZebraGZ	Duplex	75	79	694	730	764
Ashburton–Opihi–1[5]	ZebraGZ	Duplex	75	69	694[3]	730[3]	764[3]
Ashburton–Opihi–2[5]	ZebraGZ	Duplex	75	69	694[3]	730[3]	764[3,4]
Opihi–Timaru– 1 and 2[5]	ZebraAC	Simplex	50	32	244	272	298
Opihi–Twizel–1 and 2[5]	ZebraGZ	Duplex	75	75	694	730	764
Bromley–Islington	ZebraGZ	Duplex	75	28	694	730	764
Ashburton–Bromley	ZebraGZ	Duplex	75	92	694	730	764

1 Winter rating is limited by an Islington disconnector rating to 610 MVA.

2 Winter rating is limited by a Twizel disconnector rating to 610 MVA.

3 Ashburton to Opihi forward flow is limited by a protection relay to 517 MVA across all seasons. Reverse flow ratings match the conductor thermal limits.

4 Ashburton–Opihi–2 winter reverse rating is limited by an Ashburton disconnector to 762 MVA.

5 Ashburton–Opihi–1, Opihi–Timaru–1, Opihi–Twizel–1 is one circuit. (Ashburton–Timaru–Twizel–1). The circuit is divided into sub circuits in Table D 1 to show the rating and length of each sub circuit. This is also true for the second circuit (Ashburton–Timaru–Twizel–2).