UPPER SOUTH ISLAND RELIABILITY STAGE 1

APPLICATION FOR AMENDMENT TO THE APPROVED MAJOR CAPEX PROJECT OUTPUTS AND INCREASE IN THE MAJOR CAPEX ALLOWANCE

Transpower New Zealand Limited

August 2014

Keeping the energy flowing




TRANSPOWER

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1 Executive Summary

Transpower seeks approval from the Commerce Commission to change the approved major capex project outputs (**approved MCP outputs**) and major capex allowance (**MCA**) of the Upper South Island Reliability Stage 1 Major Capex Proposal[1] (the **USI Stage 1 Project**).

The Upper South Island region does not have enough electricity generation to meet demand and the shortfall is supplied via our transmission lines from the Waitaki Valley. Such long distance transmission increases the need to invest in voltage support in order to maintain a reliable supply of electricity. Possible solutions include bus couplers, switching stations and dynamic reactive support.

In 2007, we purchased land that had become available at Orari near Geraldine for a future switching station or point of connection (or both). Under the Electricity Governance Rules, we were not able to include this land in our Regulatory Asset Base (**RAB**) because it was not part of an approved project.

In February 2013 the Commerce Commission approved the USI Stage 1 Project, with an MCA of $4.99 million[2], largely for the installation of a bus coupler at our Islington substation. The USI Stage 1 Project also included funding to investigate future switching station options at Orari.

We have investigated these options and started our investigation for Stage 2 of the Upper South Island reliability upgrades (**USI Stage 2**). We have identified that building a dual-switching-station in the Orari-Rangitata area is likely to be our preferred long-term option.

Our prudent forecast indicates a need date for USI Stage 2 of 2022. Given the general trend of electricity demand in recent years has been flat, we do not consider it appropriate to submit a major capex proposal for USI Stage 2 at the moment. However, our experience from the North Island Grid Upgrade (**NIGU**) project is that securing designations and property rights as early as possible is critical for minimising the cost of project delivery. The NIGU project showed that acquiring property rights immediately prior to the need date is not cost effective: landowners have significant negotiation leverage in such situations as our alternative, compulsory acquisition, is both lengthy and costly. Given a need date for Stage 2 of 2022, and the results of the investment test preferring a dual-switching-station option for USI Stage 2, it is prudent and in the long term interests of consumers to begin the process of securing designations and property rights now in order to minimise the costs of what we currently assess to be the preferred USI Stage 2 works.

The switching station build works will be subject to approval by the Commerce Commission as part of a USI Stage 2 major capex project at a later time.

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[1] http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/upper-south-island-grid-upgrade-stage-1/
[2] http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/upper-south-island-grid-upgrade-stage-1/

We therefore propose that the acquisition of land, easements and designations for the Orari and Rangitata substation sites be undertaken as an amendment to the approved MCP outputs for the USI Stage 1 Project. This includes transferring the Orari land into the RAB as it is the appropriate site for the southern switching station. The northern site and all easements and designations are yet to be purchased.

The total cost of the additional MCP outputs associated with this proposed amendment is $5.93 million. However, because we have remaining funds of $1.78 million less than the current MCA for the USI Stage 1 Project, we propose to apply this $1.78 million to partially offset the cost of the additional MCP outputs. Accordingly, we request an increase in the MCA for the USI Stage 1 project of $4.15 million. These costs are based on the assumed completion date for USI Stage 1 being 2018.

	P50	MCA
Investigation	$ 360,000	$ 400,000
Substation Planning	$ 130,000	$ 150,000
Lines Planning	$ 490,000	$ 510,000
Designations	$ 940,000	$ 1,210,000
Existing Property	$ 1,480,000	$ 1,480,000
New Property	$ 600,000	$ 900,000
Project Management and Site Investigation	$ 390,000	$ 420,000
Inflation	$ 110,000	$ 190,000
IDC	$ 400,000	$ 680,000
Total	$ 4,900,000	$ 5,930,000
Excess Orari Funds	-$ 1,600,000	-$ 1,780,000
Total Requested	$ 3,300,000	$ 4,150,000

1.1 Layout of this Application

This application has been prepared in accordance with the requirements under Schedule H of the Capex IM[3] in relation to an amendment to the approved Major Capex Project Outputs and Increase in the Major Capex Allowance. It includes:

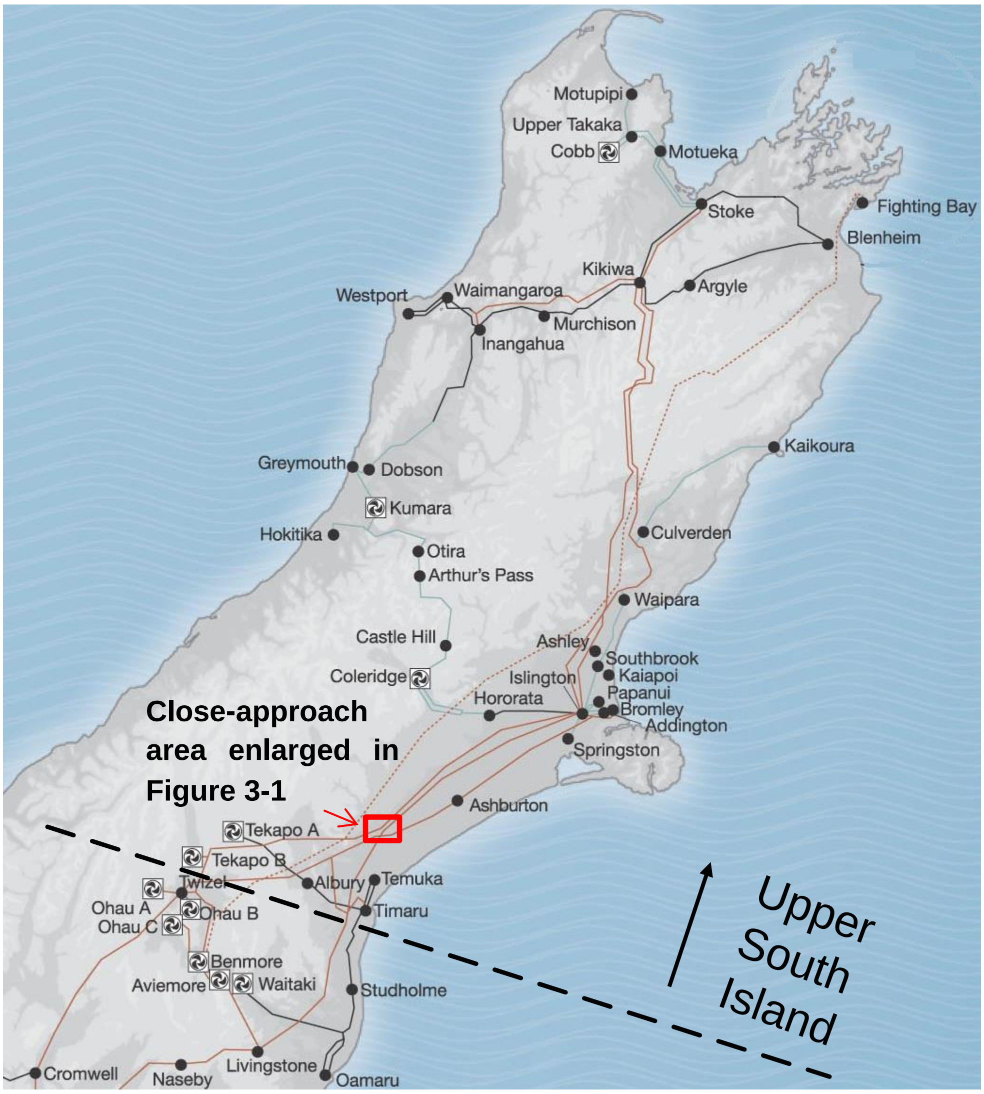
- background explanation of the investment need in the Upper South Island (section 2)
- USI Stage 1 Project Identification, Specifications and Progress (section 3)
- an explanation of the amendment sought (section 4)
- the reasons for this application (section 5)
- changes to cost assumptions (Appendix A)
- Investment Test analysis (Appendix B)
- a map of land use change in the Orari/Rangitata area (Appendix C)
- Capex IM Checklist (Appendix D)
- the Chief Executive's certification (Appendix E)

[3] Transpower Capital Expenditure Input Methodology Determination 2012

2 Need and background

The Upper South Island region comprises all of the South Island from Timaru and Tekapo north (see Figure 2-1). This region does not have enough electricity generation to meet demand and the shortfall is supplied via our transmission lines from the Waitaki Valley. Such long distance transmission increases the need for voltage support.

Figure 2-1 Upper South Island region



The long distance of supply to Christchurch is a long-standing issue. Synchronous condensers were installed at Islington for voltage support in 1955. In 1996 a further voltage support device, a static VAr compensator (SVC), called SVC3, was installed at Islington. A second, larger unit, SVC9, was installed in 2010.

Since the last of the three Waitaki Valley to Islington 220 kV lines[4] was built in 1975, their proximity to each other in the area highlighted in Figure 2-1 has led to consideration of a switching station being built there. The location of a switching station there means a line fault would remove only half the length of one of the four circuits so the voltage disturbance would be reduced.

We purchased a block of land at Orari (see Figure 3-1) in 2007, partly for an eventual switching station, and partly as a possible point of supply. Our studies in 2012 showed that investment in voltage support was required by 2014. However long-term demand growth was particularly uncertain – the long-term effects of the Christchurch earthquakes were unclear, the Pike River disaster was relatively recent, and irrigation load had been growing rapidly against an unprecedented background of zero overall demand growth.

As the immediate need was relatively urgent, but the outlook uncertain, we decided to split the investment into stages.

The USI Stage 1 Project gained funds to install a 6th 220 kV bus coupler at Islington and funds to investigate future switching station options further. We submitted our Stage 1 proposal in June 2012 and it was approved by the Commission in February 2013.

In March 2013, we consulted with our stakeholders on our approach, assumptions and long list of transmission and non-transmission solutions for USI Stage 2. Our demand forecast at the time indicated a 2018 investment need date which supported a major capex proposal submission by 2014. However, changes to our demand forecast, and low levels of demand growth, have led us to review the need date for Stage 2[5]. We currently do not consider USI Stage 2 will be required until 2022.

However we are concerned that delaying acquisition of property rights, easements and designations for our preferred USI Stage 2 option will expose the USI Stage 2 works to risks that are likely to result in increased project costs. Our experience from the NIGU project is that securing designations and property rights as early as possible is critical to minimising the cost of project delivery. In particular, early acquisition of property rights minimises the negotiation leverage of landowners, particularly where the alternative option of compulsory acquisition is both lengthy and costly. It is our opinion that given a need date for Stage 2 of 2022, it is prudent and in the long term interests of consumers for Transpower to begin the process of securing designations and property rights now to minimise the costs of the USI Stage 2 works.

[4] Christchurch to Twizel A, double circuit.
[5] This review reflects our general planning approach of regularly reviewing demand forecasts and need dates for major capital projects.

3 Project Identification, Specifications and Progress

The Capex IM (Schedule H, Division 1 and 3) requires us to identify the project, the approved MCP outputs and the progress of this project.

3.1 The USI Stage 1 Project

In February 2013 the Commerce Commission approved the USI Stage 1 Project. The approved major capex outputs are [with grouping added here to aid discussion below]:

[Bus Coupler:]

- a new 220 kV bus coupler and associated switchgear at Islington substation. The bus coupler and switchgear are incorporated into the Christchurch Reactive Power Controller scheme;
- an additional discriminating zone (zone F) for the Islington 220 kV bus bar protection;

[Load Monitoring:]

- 10 load monitoring units installed in substations in the Upper South Island;

[Orari Design:]

- solution study reports on two different configurations for Orari switching station, including cost estimates within +/- 30%;
- the initial stage of a detailed solution for the preferred Orari switching station configuration; and
- an area stage report of the transmission line route selection process, being the initial step in obtaining the required designation/consents.

This met the immediate need for investment and included funds (within the MCA) to further investigate future investment needs.

A major capex allowance (MCA) of $4.99m (in 2014/15 dollars) was approved.

3.2 Progress of the USI Stage 1 Project

For the purposes of the Capex IM we go into detail on the progress of these three groups in sections 3.3 to 3.7. In summary the bus coupler has been commissioned and work is advanced in incorporating it into the reactive power controller; the load monitoring units have been installed but the associated VoLL studies are yet to be completed; and the Orari SSRs have been completed but detailed design has been put on hold pending the outcome of this amendment application.

3.3 Planning processes

3.3.1 Bus coupler

We have completed detailed design, a constructability assessment and installation planning for the bus coupler and protection. Orion was consulted as their assets overlap the site.

3.3.2 Load monitoring

Planning for the load monitoring units was completed.

3.3.3 Orari Design

We considered two possible designs:

a) One switching station at Orari with an approximate 7 km deviation from the Benmore-Islington-A line

b) A dual-switching-station located at Orari and Rangitata, with no need for a line deviation

Two Solution Study Reports (SSRs) were completed to determine the preliminary scope and costs of these options.

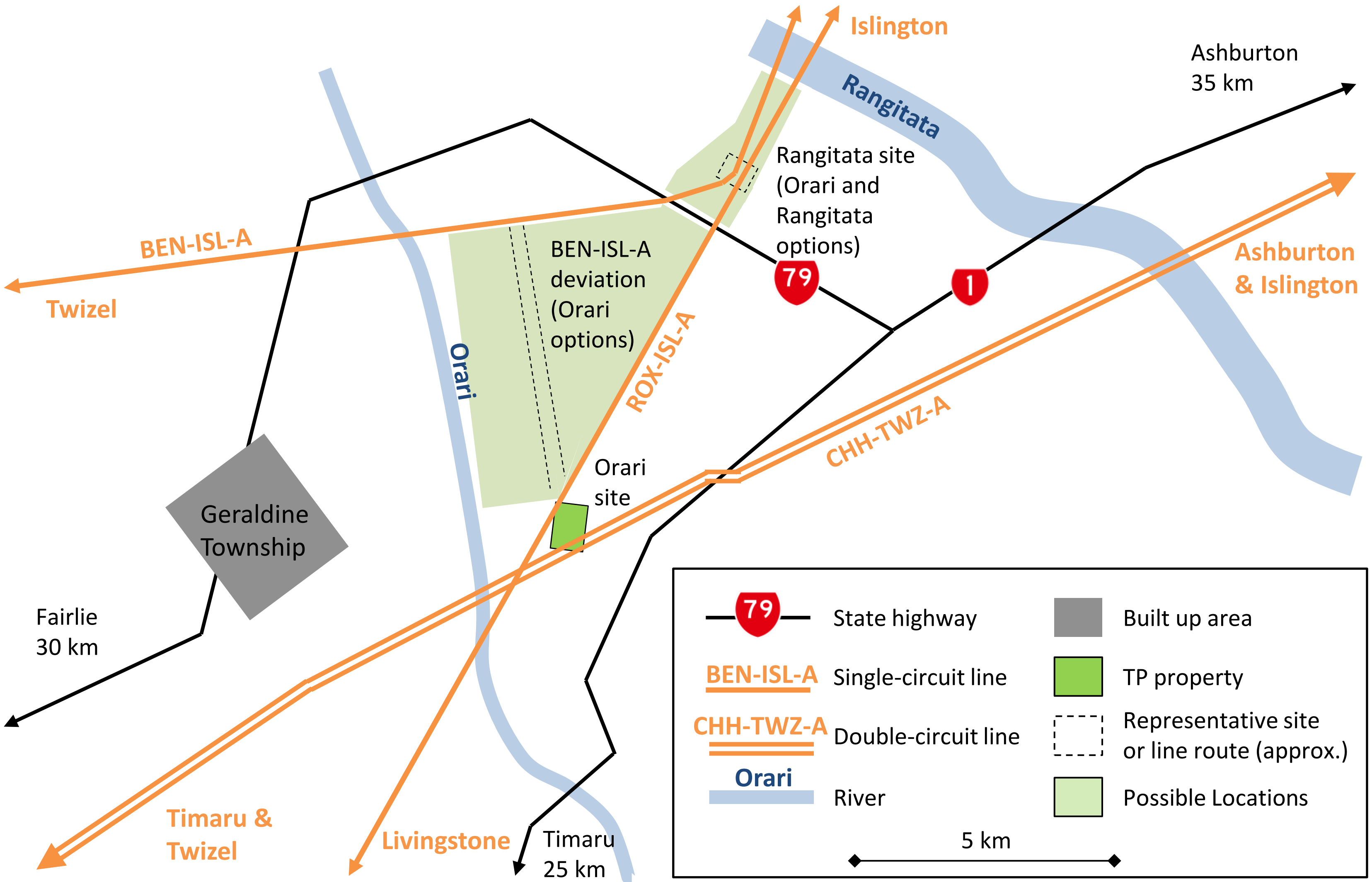
We completed an area study report, which supported three indicative routes for the 7km deviation of the transmission line.

The detailed solution for the preferred Orari switching station configuration is on hold pending the outcome of this amendment.

Below we summarise the major findings of these design studies. Figure 3-1 below shows the Geraldine – Orari – Rangitata area with the existing Transpower land at Orari, the line deviation needed for the first option, and the land needed for the second option[6].

[6] See Figure 2.1 to show the location of the relevant area in the South Island

Figure 3-1: Detail of the Geraldine-Orari-Rangitata area showing possible locations of new switching stations



The changes to our cost assumptions for the switching stations are as follows:

Table 3-1 Switching station cost change summary

	Component	Cost $M	Cost estimate source
Stage 1 listing	Orari bussing (plus line deviation)	$58.3	System Study Reports (SSRs)
Amendment	Switching Station at Orari plus line deviation	$69	New SSR under Stage 1 output
	Switching Stations at Orari and Rangitata	$56	New SSR under Stage 1 output

The high cost of the Orari-only solution is largely driven by the cost of the line deviation (see Figure 3-1: Detail of the Geraldine-Orari-Rangitata area showing possible locations of new switching stations). Table 3-2 provides a breakdown of our amended costs.

Table 3-2 Switching station costs breakdown

Component	Switching Station at Orari plus line deviation	Switching Stations at Orari and Rangitata
	Cost $M	Cost $M
North site	0	$20
South site	$31	$23
New line	$28	-
Termination costs	$10	$13
TOTAL	$69	$56

For further discussion of the design works undertaken in respect of switching station options, see section 5.1.1 and Appendix B.

3.3.3.1 Land use changes

We commissioned Boffa Miskell to undertake a report on the proposed switching station sites. The land use in the area of the proposed Orari and Rangitata switching station has changed and is continuing to change from mainly extensive unirrigated pastoral and cropping farming, to intensive dairy farming supported by irrigation. Much of this irrigation is supplied by the large Rangitata South Irrigation scheme covering 16,000 ha - the first stages of which were commissioned in October 2013. Centre-pivot irrigators and on-farm irrigation storage ponds are becoming a significant feature of the area. Neither activity is conducive to the construction of high voltage switching stations or power lines.

The map in Appendix C illustrates this change, which is still ongoing. The map dated January 2013 shows the extent of irrigation infrastructure observed by site visits in late 2012, along with approved on-farm storage ponds.[7]

A comparison of the map in Appendix C with our plans in Figure 3-1 shows that our preferred site for the Rangitata switchyard is already occupied by a pond and that the switchyard will have to be slightly to the north. Securing designations will ensure that the designated land will be available for the switching station, should they be required in the future, and at a lower cost.

3.4 Resource management and regulatory consents; property and access rights

3.4.1 Bus Coupler

Islington Substation is designated as a substation. An outline plan of the site works was submitted and accepted by the Christchurch City Council in July 2013. No other property rights are required.

There are no property or access rights associated with the other elements.

3.5 Construction contracts

3.5.1 Bus Coupler

All design and construction contracts have been awarded.

3.5.2 Load Monitoring

No separate contract was required as installation was included in the terms and conditions of our metering maintenance contract.

[7] Source: Study Area Report, Transmission Lines for Proposed Orari Facility, Map 17. A study undertaken by Boffa Miskell for Transpower

3.5.3 Orari Design

Not applicable.

3.6 Construction completed

3.6.1 Bus Coupler

The bus coupler and zone F have been commissioned. Incorporation into the reactive power controller is forecast for October 2014.

3.6.2 Load Monitoring

The system has been commissioned but we are still planning to undertake the associated VoLL studies.

3.6.3 Orari Design

Not applicable.

3.7 Testing undertaken

3.7.1 Bus Coupler

Successful testing was carried out in May 2014.

3.7.2 Load Monitoring

Software unit testing was carried out in Q1 2014. Production and user-acceptance testing was carried out in June-July 2014.

3.7.3 Orari Design

Not applicable.

3.8 Current and forecast expenditure

Table 3.3 shows the approved P50 and MCA for the USI Stage 1 project, together with actual costs incurred to date, and forecast at completion (as at August 2014).

Table 3-3 Current and forecast expenditure

Item	Approval		August 2014			
All values in 2014 $M	**P50**	**MCA**	**Major Capex incurred to date**	**Forecast Major Capex**	**Forecast variation to P50**	**Forecast variation to MCA**
Bus coupler and load monitoring	$2.55	$2.85	$1.87	$2.14	-$0.41	-$0.71
Orari design & preliminaries	$1.96	$2.14	$0.36	$0.36	-$1.60	-$1.78
Total	$4.51	$4.99	$2.24	$2.50	-$2.01	-$2.49

3.8.1 Bus Coupler and Load Monitoring

The bus coupler and load monitoring programme is forecast to come in under the P50 budget.

3.8.2 Orari design & preliminaries

The two SSRs for Orari have been completed and were delivered on budget.

Further work has been suspended pending the outcome of this application and the balance of the unspent budget (being $1,600,000 P50 and $1,780,000 MCA, as indicated in table 3.3) has been subtracted from the budget for the additional MCP outputs.

4 Amendment Sought

4.1 Proposed Amendments to the approved MCP outputs

In summary, we seek to acquire the necessary property rights (freehold title and/or easements) and designations to best enable us to prudently meet a 2022 need date for USI Stage 2 and to maintain the dual-switching-station option at Rangitata and Orari for USI Stage 2 at the lowest possible cost. We seek to acquire the Rangitata site together with easements and designations. We already own the site for the Orari switching station but seek approval to add this to our regulated asset base, and obtain associated easements and designations.

More specifically, we seek approval to amend the approved MCP outputs for the USI Stage 1 project by adding the following additional outputs:

- undertaking preliminary processes to obtain designations and easements necessary for Orari and Rangitata switching stations
- obtaining designations for substations at the two sites, and any transmission line realignments at each site
- purchasing easements for any transmission line realignments at each site
- transferring the Orari site to the regulated asset base
- purchasing land at Rangitata for the second switching station

For the avoidance of doubt it should be noted that the planning protocols for a thermal upgrade to the section of line between the dual switching stations are not included as they are not required at this time.[8]

4.1.1 Changes to assets to be commissioned

The proposed amendments to the approved MCP outputs relate solely to land at Orari and Rangitata for future development as part of USI Stage 2. The proposed amendments do not reflect a change to any other assets to be commissioned as part of the USI Stage 1 Project.

4.1.2 Changes to functional capability of the grid

The proposed amendments to the approved MCP outputs will not immediately result in a change to the functional capability of the grid. However, the proposed amendments provide an opportunity to minimise the costs of increasing transfer

[8] In general the thermal upgrade will be a permitted activity in accordance with the provisions of the National Environmental Statement for Transmission Activities (NESTA) in association with the Timaru District Plan, although some supporting activities may require consents when the detailed design is undertaken. This is considered to be more routine than the property and designation activities associated with the dual–switching-station sites.

capacity from Waitaki Valley to Islington from 1269 MW to 1512 MW[9] as part of a USI Stage 2 project.

4.1.3 Achieved quantum of electricity market benefit

The updated Investment Test analysis concludes that the net market benefit of the preferred option for USI Stage 2 is likely to be $5.7 million dollars greater than for any non-switching station option. (See Appendix B.)

4.2 Quantum of proposed amendment to the major capex allowance

We request an increase in the MCA for the USI Stage 1 Project of $4.15 million.

We consider the acquisition of the property rights and designations for the future dual-switching-station is best funded through an amendment to the approved MCP outputs of the USI Stage 1 Project, with a concurrent increase in the MCA. This is because the proposed change in the outputs are part of a programme that forms part of an existing major capex project.

We will apply for approval for the USI Stage 2 works (as noted above, based on current analysis, likely to be a dual-switching-station) at a later date. Non-transmission solutions (NTS) may be economic to defer the eventual build date of the switching station, and we expect to seek tenders for NTS closer to the need date.

[9] These are winter capacities and are approximate as they depend on the generation and load distribution.

4.3 Assumptions and calculations showing how the quantum of proposed amendment was calculated

The cost breakdown for the proposed increase in MCA is as follows:

Table 4.1 Amendment cost breakdown

	P50	MCA
Investigation	$ 360,000	$ 400,000
Substation Planning	$ 130,000	$ 150,000
Lines Planning	$ 490,000	$ 510,000
Designations	$ 940,000	$ 1,210,000
Existing Property	$ 1,480,000	$ 1,480,000
New Property and Easements	$ 600,000	$ 900,000
Project Management and Site Investigation	$ 390,000	$ 420,000
Inflation	$ 110,000	$ 190,000
IDC	$ 400,000	$ 680,000
Total	$ 4,900,000	$ 5,930,000
Excess Orari Funds	-$ 1,600,000	-$ 1,780,000
Total Requested	$ 3,300,000	$ 4,150,000

In summary, the MCA is higher than the P50 cost because it includes increased price contingency at a P90 level plus allowance for inflation and financing costs.

4.3.1 Investigation

This includes system studies that we have undertaken following the Orari SSRs, economic analysis, review of the outputs and preparation of this application.

4.3.2 Substation and Lines Planning

Substation and lines preliminary design is required to support obtaining designations and easements. The tasks include:

- producing photomontages and flood mitigation plans,
- locating access roads,
- substation outline design and layouts, and
- design of the minor line deviations into the switching stations.

The costs have been estimated based on similar works we have carried out in the past.

4.3.3 Designations

These are the cost estimates of the environmental planning required to obtain the designations. The P90 assumes the costs of an Environment Court hearing which is not included in P50.

4.3.4 Property

Easement costs have been estimated from compensation estimates received from registered valuers who undertook roadside and some site inspections. These estimates include processing and resourcing costs.

Transpower purchased the land now proposed for the Orari switching station in 2007, with the intention at the time that it may be required for a future switching station or point of connection (or both). The Orari land costs are the current carrying value of the land in Transpower's books, and the commissioned value of the land will be the carrying value in Transpower's books at the date the land is transferred into Transpower's regulatory asset base.

The Rangitata cost is estimated by a market value estimate from a registered valuer.

4.3.5 Project Management

We have estimated the project management and other overhead costs for the entire switching station build based on similar works we have carried out in the past. We have then estimated the fraction the preparatory works in this amendment would consume.

4.3.6 Inflation

We use the CPI as defined in the Capex IM, i.e. Reserve Bank estimates up to their horizon of Q1 2017.[10]

4.3.7 Interest During Construction (IDC)

IDC assumes we add these costs to the Regulated Asset Base (RAB) in 2018 therefore we assume three years of IDC. We do not expect significant delays so the MCA margin is commensurate with the P50 margin. A possible 6 months delay is included in the P90.

4.3.8 Excess Orari Funds

We describe in section 3.8 how we have suspended work on Orari planning and preliminaries awaiting approval of this proposed amendment. The unspent funds

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[10] There are costs in Q2 2017-Q2 2018 and we project the average of the last four quarters forwards into those periods as required under the Capex IM. Recent proposed changes to the Capex IM method of projecting past the horizon will not make a material difference.

from that output have been taken into account (by deducting the unspent funds from the budget for the proposed additional MCP outputs) in calculating the proposed increase in MCA.

5 Reasons for this Application

5.1 Factors leading to this application

Transpower is applying for an amendment to the approved MCP outputs and MCA for the USI Stage 1 Project we consider it to be of long-term benefit to consumers for Transpower to begin securing the necessary property rights for USI Stage 2 works now. Our experience from NIGU is that securing designations and property rights can take a number of years and we must prudently begin this process now[11]. The amendment will preserve our ability to meet a 2022 need date for USI Stage 2 without requiring us to commit to any USI Stage 2 works at this time. The further detailed design and actual build would occur at a later date, and be subject to approval by the Commission as a major capex project for USI Stage 2.

5.1.1 Further analysis on USI Stage 2 options

Further analysis has confirmed that building a new dual–switching-station in the Orari-Rangitata area is likely, given present demand forecasts, to be our preferred long-term USI Stage 2 development option for maintaining a reliable supply of electricity to the Upper South Island. (See the Investment Test analysis in Appendix B.)

In summary, we have added the new cost information from the solution study reports into our analysis, along with a new demand forecast, updates on equipment condition and more detailed estimates of the later development plans.

Although uncertainties still exist some points are now clearer:

- Switching stations are likely to be the best option in the longer term, when demand grows to the point where a new line is needed to supply the Upper South Island from the Waitaki Valley, as they allow for that new line to be built in stages.
- A dual-switching-station will almost certainly be more cost-effective than one switching station and a line deviation, due to the significant costs associated with building a 7 km double circuit 220 kV line.

Using today's assumptions, a dual-switching-station, possibly delayed by a new static VAr compensator (SVC) installed in Christchurch would be the most cost-effective long-term development option for USI Stage 2.

Our current forecast suggests that USI Stage 2 will not be required before 2022.

[11] See Transpower's application for an increase in the major capex allowance for the NIGU Project, dated 30 September 2013. See also the Calverton Report: *Evaluating Transpower's property and easement acquisition strategy and implementation for the NIGU project*. Report prepared for the Commerce Commission, dated 30 June 2014

5.1.2 Avoiding higher future cost of obtaining property rights

Experience from our NIGU project is the acquisition of the necessary land, easements and designations can take a number of years. As such we must prudently commence this process now to meet the need date of 2022 rather than waiting until closer to the need date of the USI Stage 2 works where time and alternatives become limited. Allowing enough time to obtain these rights avoids real and substantial risks that could increase the cost of acquiring the necessary property rights in the future, that could adversely impact on our ability to meet a 2022 need date for commissioning of the USI Stage 2 works.

5.1.2.1 Changing land use

As noted earlier in section 3.3.3, our investigation of investment in switching stations in the Orari-Rangitata area has highlighted the potential for land use changes in the area. In particular, the proliferation of centre-pivot irrigators, often over 1.5 km in diameter, from the Rangitata South irrigation scheme (currently under construction) threatens our future ability to construct these switching stations. Therefore there is a real and substantial risk that imminent land use changes in the Orari-Rangitata area will adversely impact our ability to acquire land and associated easements and designations for constructing the dual-switching-station in the future.

The change in land use raises the risk that valuations of the relevant land will be higher, due to land use change and general property market inflation.

5.1.2.2 Property rights acquisition

Furthermore, land use change may increase landowner opposition to substation construction works. This in turn raises the risk that:

- landowner hold-out exposes Transpower to negotiating the acquisition of property rights under time pressure. Our experience in the NIGU project showed that it is not cost effective to acquire property rights at a time immediately prior to a reliability investment need date, as this exposes Transpower to a costly compulsory acquisition process and negotiation leverage of landowners, resulting in Transpower having to pay elevated prices for property rights for necessary grid upgrade works[12];
- Transpower cannot obtain the property rights in a timely manner that enables optimisation of build timetable to meet the need date. The compulsory acquisition process would be available to Transpower, however this process is itself costly and subject to delays that may adversely impact on the build timetable.

[12] The Calverton Report for the Commerce Commission details Transpower's NIGU experience of this in detail.

This combination of factors means that deferring acquisition of the necessary land and associated easements and designations will very likely result in significantly higher costs and time risks being incurred in the future for the acquisition of the property rights.

5.1.3 Greater flexibility for timing of USI Stage 2 works

Our current prudent demand forecast suggests that the investment will not be required before 2022, which provides a longer lead time than we need to build the switching stations. However as there are always uncertainties with demand forecasts, and the Upper South Island now has significant summer demand, we need to be able to mobilise quickly if forecasts change. Acquiring property rights, easements and designations now will reduce the timeframes required for the USI Stage 2 works. (See section 3 - Planning Processes and Appendix A - Changes to Assumptions.)

5.1.4 Greater certainty for the local community

Approval will provide greater certainty of our intentions to the local lines companies as they consider future augmentation of their networks. Additionally, we can provide certainty to the wider local community, ensuring investment decisions are made with the benefit of advance signalling of Transpower's future developments in the region.

5.2 Application of the Investment Test

In relation to the proposed change to the approved MCP outputs, we outline the changes that have occurred in our assumptions underlying the Investment Test in Appendix A and present the results from our updated analysis in Appendix B.

In summary, the dual-switching-station solution is cheaper overall because it does not require any major transmission line deviations compared with the single-switching-station solution. The single-switching-station solution requires an expensive 7 km new transmission line deviation which results in a higher overall cost compared with the dual-switching-station solution.

It also has a higher net benefit to other options as it has lower losses associated with it than installing dynamic voltage support equipment, such as SVCs. Costs are further reduced when a new line is required to supply the Upper South Island from the Waitaki Valley, by allowing the build to be done in two halves.

The timing of any USI Stage 2 application would be dependent on our assessment of future demand forecasts. Non-transmission solutions (NTS) may be economic to defer the eventual build date of the switching stations, and we expect to seek tenders for NTS closer to the need date.

Assuming a best case scenario of no issues in acquiring property and designations we can reduce the lead time to build the switching stations from seven years to just over three years by securing property rights, including designations in advance. This would safeguard us against rapid demand growth.

5.3 Net Electricity Market Benefits

At the time of approval of the USI Stage 1 Project, our preferred option of a new switching station at Orari (then known as Option 2) had a net market benefit of $1.3 million less than the reference case. It was considered similar to the reference case and was the preferred option when unquantified benefits were considered.

Additional analysis, coupled with refined cost estimates, indicates that a dual-switching-station option (with the inclusion of the proposed additional MCP outputs), now has a net electricity market benefit $5.7 million greater than any non-switching station option. This difference largely comes from the ability to stage a later line build.

We therefore conclude that the net electricity market benefit of the USI Project is materially higher as at time of this application than it was at time of approval of the USI Stage 1 Project in February 2013.

5.4 Application is consistent with the Capex IM

This application is consistent with the Capex IM. In particular:

- this application has been submitted to the Commerce Commission in accordance with clause 3.3.4(1) of the Capex IM.
- we have complied with clause 7.4.2 of the Capex IM. Specifically, the application contains the information specified in Schedule H Division 1 and Division 3 of the Capex IM. Please refer to the table in Appendix D of this application that indicates where in the document the information specified can be found.

Because this application is consistent with the requirements of the Capex IM, we consider that the proposed amendment will promote the purpose of Part 4 of the Commerce Act 1986.[13] We elaborate on how this amendment promotes Part 4 below.

5.5 This application promotes the long-term benefit of consumers

Approval of this application to change the approved MCP outputs and MCA for the USI Stage 1 Project will promote the long-term benefit of consumers in the following ways:

13 Commerce Commission, Decision on the Otahuhu Substation Diversity Project Major Capex Allowance Amendment [2013] NZCC 8, para A4, where the Commerce Commission observed that when an approved project is amended in accordance with the requirements of the Capex IM, the amendment will promote the purpose of Part 4 of the Commerce Act 1986.

- Approval of this application will incentivise us to quickly acquire the necessary property rights for the current preferred option for USI Stage 2 by 2018. We will then be able to prudently plan for the commissioning of Stage 2 as required and minimise costs. If we do not hold the property rights, there is a real and substantial risk of exposure to further costs as discussed in section 5.1.2 above.
- Acquisition of the necessary property rights now will provide greater certainty to the local community of our likely grid upgrade plans for the region, allowing other investment decisions to be made by the local community on a more informed basis.

5.6 Data, analysis, and assumptions are fit for purpose

We also consider that the data, analysis, and assumptions underpinning this application are fit for the purpose of the Commerce Commission exercising its powers under Part 4 of the Commerce Act, including consideration as to the accuracy and reliability of data and the reasonableness of the assumptions and other matters of judgement. We have provided information in (and with) this application which demonstrates how the application is consistent with the Capex IM, including the basis for the proposed amendment to the approved MCP outputs and MCA for the USI Stage 1 Project.

Appendix A: **Changes to Assumptions**

This appendix outlines the key assumptions that have changed since the Commission's approval of our USI Stage 1 Project. The USI Stage Project included the further investigation of some key options. As such, revisions to the investment analysis associated with the USI Stage 1 Project were envisaged. Since the USI Stage 1 Project was approved, we have reassessed the following factors:

1. The demand forecast that has reduced
2. Our expectations of the existing voltage support equipment lifespans that have reduced
3. Various options' cost estimates

Changes to our demand forecasts

In 2013 we reviewed and made changes to our demand forecasting methodology[14]. The changes we made incorporated effects of the unprecedented zero growth that have occurred since about 2006. This resulted in lower expected and prudent demand forecasts for the region.

Figure A1-1 shows the recent winter peaks and revision of the winter peak demand forecasts, both prudent and expected. Note that the mean to prudent gap is wider in the near term than it was for the USI Stage 1 Project. The expected forecast is close to a continuation of the long-term trend of the historic values, while the step up to the prudent combines an allowance for inter-year variation (seen in the historic values) and new developments, largely irrigation. The graph also shows the dynamic reactive and thermal limits for the region, including the status of existing assets[15] and the proposed development plan.[16] The overall limit at any time is the lower of the two limits.[17]

The need date of 2022 can be seen as the point where the prudent forecast exceeds the dynamic reactive limit unless the switching stations are built; the need date when we consulted on the assumptions we should use in a USI Stage 2 proposal in 2013 was 2018.

Note there is a significant difference between the prudent demand forecast, which determines the need date of 2022, and the expected demand forecast, which does not exceed the voltage stability load limit until 2029. This horizontal separation between the prudent and expected forecasts is a key indicator to us of the need to be

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14 https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Summary%20of%20Transpower%20demand%20forecastFINAL.pdf

15 See Existing Equipment Condition, later in this section

16 See Table B-4

17 Strictly the *static* reactive limit also comes into play, but it can fixed relatively cheaply with shunt capacitors and is left off to simplify the picture.

flexible. The separation has been steadily increasing as our forecasts have been flattening.

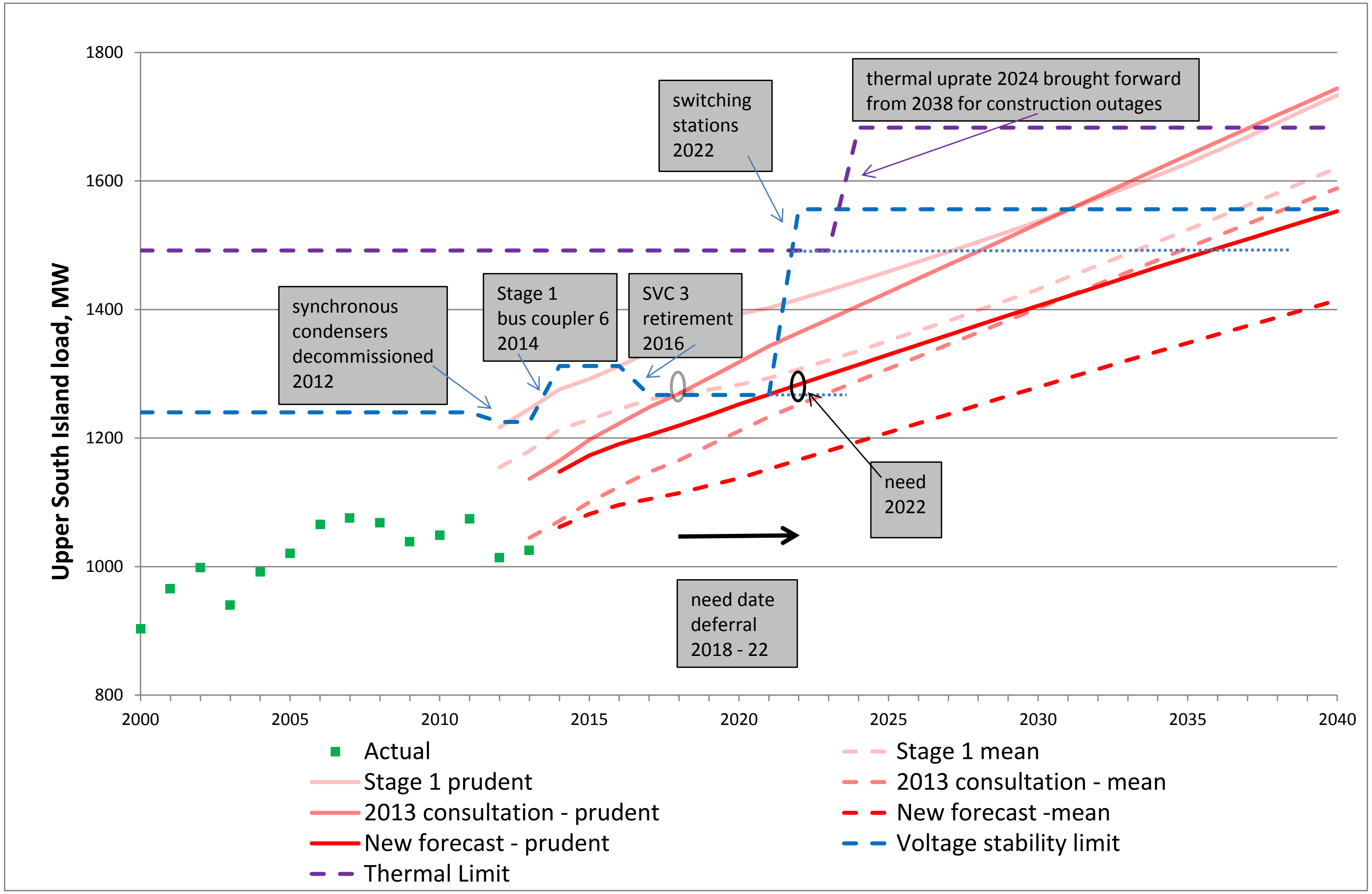

Figure A1-1, Winter Peak Forecasts and Build Plan

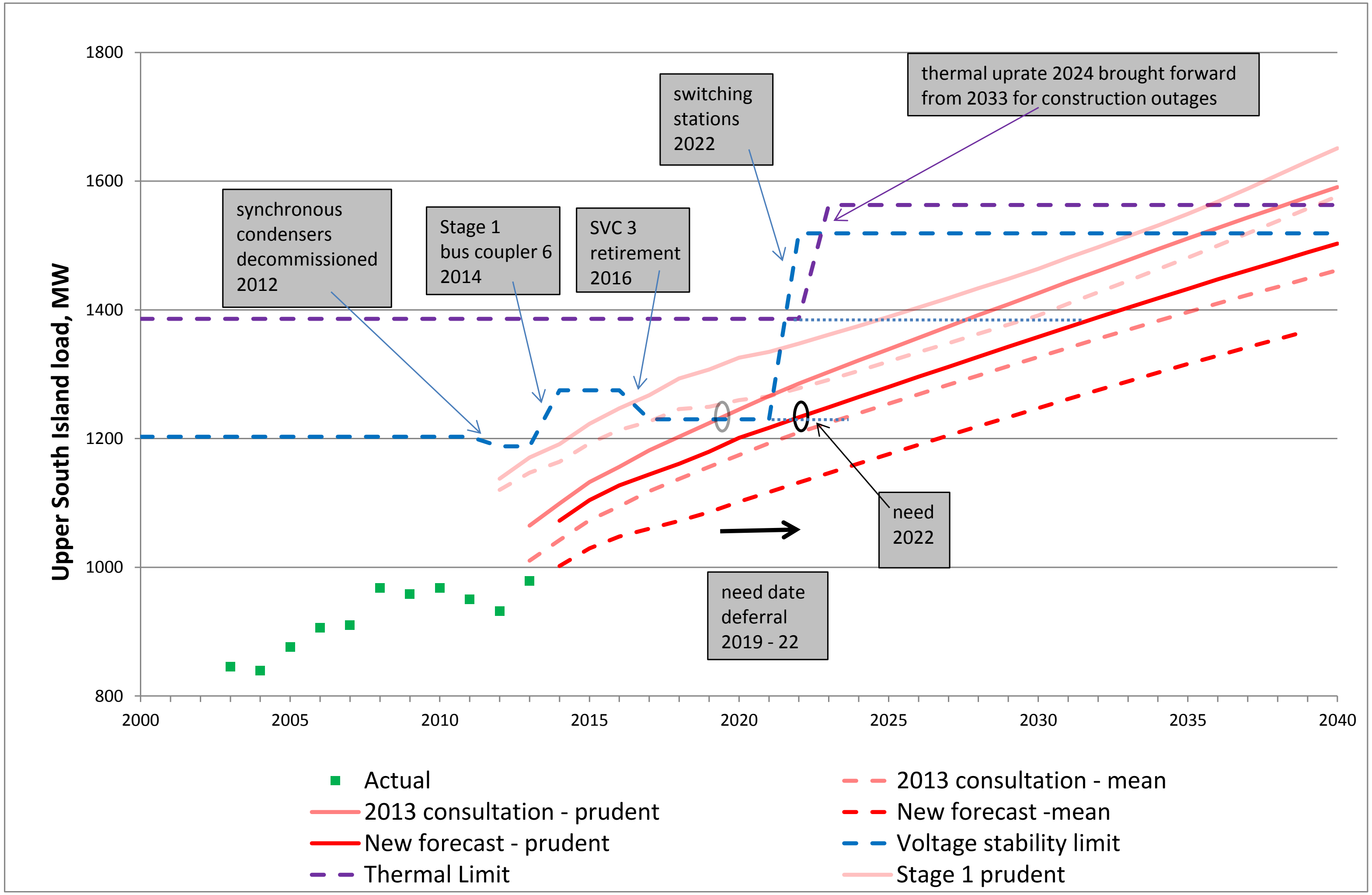

Figure A1.2, Summer Peak Forecasts and limits

The summer peak forecast, Figure A1-2, also predicts a need date of 2022. Note that the summer forecast has reduced less than the winter – a result of the dairy and irrigation boom. There is a small but definite chance of a coincidence of a late cold snap coinciding with the start of milking season, leading to a high peak in spring. We will monitor the situation and update our forecasts if the limits are approached and/or the annual profile changes to make this event more likely.

As is the nature with forecasts, they can change and we need to be ready for high growth if it happens, while at the same time not investing too early against an expectation of growth that may not happen.

Given the flat forecast growth, and the indicative costs from our recent Demand Response programme,[18] we are confident that non-transmission solutions could potentially be used to defer investment. However, the feedback from our long list consultation suggested it is premature to seek a firm non-transmission solution contract this far ahead of the USI Stage 2 need date.

Were these changes foreseeable

Changes to demand forecasts are not unexpected as they respond to new information. However, the size and direction of those changes are not within our control. We respond to changes in actual demand and the forecast drivers as best we can. The mitigation we applied for this project was to split the project into two stages at the time of our Stage 1 application.

Changes to our assumptions about existing equipment condition

Synchronous condensers

The two synchronous condensers, C4 and C5, were installed in 1955 and provided a total of 60 Mvar of voltage support. In our 2007 studies it was assumed they would be refurbished and retained. By the time of the Stage 1 application we had concluded that the investment (circa $20 million) required to refurbish or replace the condensers was not economic.

Following this conclusion, both C4 and C5 have been mothballed. Replacements were one of the short-listed options for Stage 1, but are not cost-effective compared to SVCs and did not make the short list for this amendment analysis.

18 https://www.transpower.co.nz/projects/demand-response-project/demand-response-programme

Static Var Compensators (SVCs)

The two Static Var Compensators, SVC3 and SVC9, are modern voltage support devices. SVC3 was installed 15 years ago and SVC9 3 years ago.

The newer SVC9 is in good condition. SVC3 is due for major refurbishment in 2016. Our estimate of the cost of losses from SVC3 was $330,000 per annum in Stage 1, but has since been revised to $712,000 per annum with recent use patterns. This is against $364,000 for SVC9 or a new SVC,[19] and makes SVC3 uneconomic to refurbish. We have therefore assumed that SVC3 will be decommissioned.

This unfortunate experience with SVC3 will not be the same with SVC9 or others – the high losses are due to an older technology.

Refurbishment at 20 years is estimated at 67% of the cost of a new SVC based on experience with SVC3 and this has been incorporated into the costing since our Stage 1 proposal.

Were these changes foreseeable

We were expecting that SVC 3 might not be worth overhauling at the time of our Stage 1 application. We are now definite that this is the case. The possibility of having to retire some of the voltage support equipment, or of leaving open the ability to, if it was strongly preferred, was one of the reasons for going ahead with the bus-coupler as soon as possible in Stage 1

Cost Changes

Tables A1-1 to Table A1-2 illustrate the changes in costs used in the analysis since our Stage 1 application.

Table A1-1 SVC cost change summary

	Component	**Cost $M**	**Cost estimate source**
Stage 1 listing	Large SVC	$31.9	SSR
Amendment	+150 / -75 Mvar	$27.5	None further

Exchange rate movements have accounted for most of the difference.

[19] Further details are available in Appendix B

Table A1-2 New line cost change summary

	Component	Cost $M	Cost estimate source
Stage 1 listing	New single circuit line from Waitaki hydro scheme to Islington. Exact southern terminal and line configuration unspecified	~$500	Very approximate
Amendment	New double circuit line on the existing ISL-TKB-TWZ line route (remove existing)	$830	Very high level response (HLR), no line route studied.
	New (half) double circuit from ISL to ORI on existing ISL-LIV route (remove existing)	$410	
	New (half) double circuit from ORI to TKB and onto TWZ (remove existing)	$350	
	Thermally up-rate ISL-LIV between ORI(S) and ORI(N) to 120 degrees (7km in length).	$9	HLR, route but no tower study
	Thermally up-rate ISL-LIV from ISL to ORI(N) to 75 degrees.	$11	
	Double 220kV Circuit line – TWZ-ASB	$500	Very HLR, no line route study
	Double 220kV Circuit line – ASB-ISL	$330	

This expansion of one very high-level option for a new line into various combinations of seven new line options arose from examining in more detail the longer term implications of our initial investment on longer term needs for new lines.

Cost changes associated with building new switching stations is outlined in table 3.1 and table 3.2.

Were these changes foreseeable

Some cost changes have resulted from exchange rate movements, which are foreseeable in general (although it could be argued that the recent very high NZ dollar was not). Again the split into two phases was the mitigation here.

Appendix B: Investment Test

This appendix outlines our provisional investment test results for future development options accounting for changes in key assumptions outlined in Appendix A. It includes:

- a description of our approach to developing a short list of future development options for analysis
- a comparison of options to those assessed in our Stage 1 application
- our application of the Investment Test to those development options
- our assessment of the robustness of the results to changes in assumptions
- our view on the use of non-transmission solutions

Long list and short listing

This section details how we reduced the long list to a short list of options and presents the short-listed development plans.

We consulted on the long list of options in March 2013 as part of formulating what we intended then as a Stage 2 proposal, which is now this amendment. No new solutions were identified in the long-list consultation from those assessed in our Stage 1 application.

The short-list options were derived by applying our short-list criteria to the long list

The short-listing criteria are:

A. <u>Fit for purpose</u>
   - The design will assist meeting future energy demand growth
   - The extent to which the option resolves the relevant issue.

B. <u>Technical feasibility</u>
   - Complexity of option
   - Reliability, availability and maintainability of the option
     - Is this proven technology (ie used commercially, internationally and/or with available data on performance, and expected life cycle)?
     - Does Transpower have experience with the technology?
     - Is there a low level of risk associated with implementing this technology (such as ongoing maintenance requirements and availability of after sales support and spare parts)?
   - Future flexibility - Grid Development Strategy
     - To what extent does the option open up or foreclose future development options?
     - Could the investment be stranded under certain conditions?

C. <u>Practicability of implementing the option</u>
   - It must be possible to implement the solution by the required dates (probability of proceeding)
     - How long will it take to implement this option? Consideration includes:
       - Property acquisition time

    - Likelihood of gaining required environmental approvals
    - Equipment lead time
    - Time taken to build
  - Implementation risks, including potential delays due to property and environmental issues
  - Are there technical issues with access or available space for the works?
    - Implementation risks eg are outage constraints on the existing system going to impact on this option?
- The availability of proponent for or potential counterparty to a transmission alternative

D. <u>Good electricity industry practice (GEIP)</u>

- Ensure safety
- Consistent with good international practice
- Minimise or mitigate environmental impacts
- Accounts for relative size, duty, age and technological status
- Manage technology risks

E. <u>System security (additional benefit resulting from an economic investment)</u>

- Improved system security
- System Operator benefits (controllability)
  - Does the option provide operational flexibility?

F. <u>Indicative cost</u>

- Whether an option will clearly be more expensive than another option with similar or greater benefits
  - The cost estimates, if used, are high level.

Any option that does not meet one or more of the criteria is removed from further investigation.

The overall assessment is indicated by a ✘ or ✓

Table A2.1 summarises the short-listing process.

Table A2-1 Short Listing

Option	Short-Listed	Reason
Non-Transmission Solutions		
New generation	×	No significant generation committed
Existing generation grid support contract	×	No additional generation of sufficient capacity has been offered
Diesel generation	×	Belfast and Bromley consented but not directly short-listed as we consider it too soon to enter into firm contracts for demand response non-transmission solutions
Upper SI load controller	×	Already accounted for in the demand forecast assumptions
Special protection scheme (SPS)	×	Complex, short-term solution that would need to target multiple sites to be of benefit
Fuel switching	×	Not viable on scale required
Energy efficiency	×	Not viable on scale required. On-going efficiency gains are accounted for in the forecast
Local network augmentation	×	Not feasible on scale required
System Operation improvements	×	Already achieved via Reactive Power Controller
Ancillary services	×	Requested but none offered, no significant generation committed
Demand response	×	Not directly short-listed as we consider it too soon to enter into firm contracts for demand response non-transmission solutions
Transmission – Existing Assets		
Tee 220kV circuit near Bromley	×	Only minor improvement
Reconductor existing transmission circuits	×	Too expensive for marginal improvement in voltage stability
Transmission – New Assets		
Islington 220 kV bus tie circuit	×	Only helps during bus maintenance
SVCs or STATCOMs north of Christchurch or West Coast	×	Not as effective as at Islington or Bromley due to distance from load?
SVC at Islington (or Bromley)	✓	Increases voltage stability limit, high-level economics suggest option is viable
STATCOM at Islington (or Bromley)	×	STATCOMs are not as cost-effective as SVCs
SVC at Ashburton	×	Reconfiguration of 220 kV bus required. 66 kV solution less useful.

Option	Short-Listed	Reason
		Not as cost-effective as SVC at Islington
Refurbish Islington SVC3	×	The combination of high losses and refurbishment cost means refurbishment is uneconomic
New synchronous condensers	×	Not as cost-effective as SVCs
Shunt capacitors	×	Do not meet dynamic stability need
Shunt reactors	×	May be required but not as a solution to the voltage stability limit
New switching station(s) near Orari	✓	Meets need and high-level economics suggest option is viable
Series capacitors	×	Not cost-effective
New AC transmission line from the Waitaki Valley to Christchurch	first option × later ✓	Too expensive as a means for increasing the voltage stability limit. A good option once the existing thermal capacity is reached.
North Canterbury HVDC tap-off	×	Not cost-effective

Neither STATCOMs nor synchronous condensers are as cost-effective as SVCs so we have removed both from the short list.[20]

Comparison with Stage 1

We combined the short-listed options into a list of development plans, bearing in mind the development plans from Stage 1.

The Stage 1 plans and investment test results were as follows:

[20] O9's greater cost-benefit in Stage 1 was an accident to do with the discrete jumps in capability versus the granularity of the forecast from one year to the next and is not true in general

Table A2-2, Stage 1 short list options and investment test results

Option	Description	Present Value Expected costs (2012 $M)	Present Value Relative Expected costs (2012 $M)
O1	Bus Coupler, refurbish SVC3, Orari bussing	178.7	5.1
O2	Bus Coupler, decommission SVC3, Orari bussing	174.9	1.3
O3	Bus Coupler, refurbish SVC3, new SVCs	179.1	5.4
O4	Bus Coupler, decommission SVC3, new SVCs	175.9	2.2
O5	Bus Coupler, refurbish SVC3, new sync. conds., SVCs	199.9	26.2
O6	Bus Coupler, refurbish SVC3, new STATCOMs	173.6	0
O7	Diesel gen, decommission SVC3, Orari Bussing	192.6	19.0
O8	Diesel gen, refurbish SVC3, new SVCs	196.4	22.7
O9	Diesel gen, refurbish SVC3, new STATCOMs	207.0	33.4

We have since installed the sixth bus-coupler and decided that SVC 3 at Islington is not worth refurbishing. This leaves only[21] options O2 (Orari) and O4 (SVCs) from Stage 1.

For this amendment we have included a high-level assessment of the cost of line upgrades and/or new lines which are eventually required for each option. While not required for some time the high cost associated with new lines is still significant. The lowest cost continuation of O4 is a new circuit from Twizel to Ashburton and later a continuation on to Islington. Below this forms the new option 1a.

[21] Variations of O2 and O4 with STATCOMs or new synchronous condensers instead of SVCs are also possible, but these have been ruled out in the long list.

As discussed above, further design of the Orari facility under Stage 1 has shown that two basic designs are possible, either a single switching station at Orari and a line deviation, or dual-switching-station at Orari and Rangitata. Either of these can be followed by a new line, or a thermal upgrade first, delaying a new line. Therefore we have four more options: 2a, 2b, 3a and 3b. The northern half of the line works is required first.

All switching station solutions are at risk of the land required not being available for this purpose, so they have some combination of new land purchases, easements and consents required as soon as possible, i.e., by 2017.

Finally it is possible to delay the switching stations by installing one SVC first. This is option 1b.

Table A2-3 Development plans with prudent and expected demand timing

	Switching station preliminaries	**First need date**		
Prudent timing:	**2015-18**	**2022**	**2025-2029**	**2030+**
Expected timing:	**2015-18**	**2029**	**2032-2039**	**2040+**
Option				
1a	none	SVC	2nd SVC	3rd and 4th SVCs New single circuit from Twizel to Ashburton, (later) new single circuit from Ashburton to Islington
1b	Rangitata land, Orari & Rangitata designations and consents	SVC	Orari and Rangitata switching stations	Thermally up-rate ISL-LIV from Islington to Rangitata to Orari (later) replace single circuit ISL-LIV from Islington to Rangitata to Orari with double circuit, (later) replace single circuit ORI-TKB-TWZ with double circuit
2a	Designations and consents for Orari switching station and BEN-ISL line deviation	Orari switching station, BEN-ISL line deviation	Thermally up-rate ISL-LIV from Islington to Orari	SVC, replace single circuit ISL-LIV from Islington to Orari with double circuit, (later) replace single circuit ORI-TKB-TWZ with double circuit
2b	Designations and consents for Orari switching station and BEN-ISL line deviation	Orari switching station, BEN-ISL line deviation	Replace single circuit ISL-LIV from Islington to Orari with double circuit	SVC, (later) replace single circuit ORI-TKB-TWZ with double circuit
3a	Rangitata land, Orari and Rangitata designations and consents	Orari and Rangitata switching stations	Thermally up-rate ISL-LIV from Islington to Rangitata to Orari	SVC, replace single circuit ISL-LIV from Islington to Rangitata to Orari with double circuit, (later) replace single circuit ORI-TKB-TWZ with double circuit
3b	Rangitata land, Orari and Rangitata designations and consents	Orari and Rangitata switching stations	Replace single circuit ISL-LIV from Islington to Orari with double circuit	SVC, (later) replace single circuit ORI-TKB-TWZ with double circuit

Table A2-3 shows a succession of need dates. Other than switching station preliminaries, the first need date is 2022 based on the prudent demand forecast. It is likely that this may be deferred by a non-transmission solution. Some combination of SVCs, switching stations and thermal line uprates follows. All options eventually require a new circuit between Twizel and Islington. Note that switching station preliminaries are in 2015-18 under both forecasts. This work is required as soon as possible to keep the option open, regardless of the forecast.[22]

As we did in the USI Stage 1 Project and in other applications, we calculate the need date using the prudent forecast. In the Investment Test we have assumed investment is needed to meet the expected forecast, except for the purchase of property rights and designations that are assumed to be required now.

Application of the Investment Test

Under the Transpower Capital Expenditure Input Methodology Determination (Capex IM), a proposed investment must satisfy the Investment Test and have "*a positive expected net electricity market benefit unless it is designed to meet an investment need the satisfaction of which is necessary to meet the deterministic limb of the grid reliability standards.* "

In this case, the investment is to meet the deterministic limb of the grid reliability standards.

Costs

We calculate the costs of each entire development plan, including: capital, contracting, operating, maintenance, reactive device losses and transmission losses costs.

The costs have been calculated under each market development scenario (MDS)[23]. The MDSs have been weighted equally to arrive at the figures shown in Table A2.4. All quantities are expressed as a Present Value (PV) $2014 to account for phasing of the required works.

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[22] This penalises the switching station options, relative to option 1a, in the investment test.
[23] The MDSs as outlined in the 2010 Statement of Opportunities (2010 SoO) were updated in the USI Stage 1 Project to incorporate new and committed generation and lower build expectations. We have not updated them further. We have used equal weightings of the 5 scenarios (the same as the weighting for the scenarios set out in the SoO).

Table A2-4, NPV to 2014 of Costs by Option

Option	Description	Capital	O&M	Reactive Losses	Transmission Losses	Total Costs
		$M	$M	$M	$M	$M
1a	SVCs, new line	$26.4	$0.5	$1.8	$0.0	$28.6
1b	SVCs, 2 switching stations, north half line uprate, new north half line	$22.4	$0.3	$1.0	-$0.8	$22.9
2a	1 switching station, north half line uprate, new north half line	$27.9	$0.3	$0.3	-$0.3	$28.1
2b	1 switching station, new north half line	$32.0	$0.3	$0.2	-$0.3	$32.1
3a	2 switching stations, north half line uprate, new north half line	$24.0	$0.3	$0.3	-$1.7	$22.9
3b	2 switching stations, new north half line	$35.8	$0.3	$0.2	-$1.7	$34.6

Assuming Upper South Island total demand grows to the point where an additional line is needed, the switching station(s) would allow the new line to be built in two stages, with the southern half deferred by 10-15 years. Because of the high cost of new lines, this is a major advantage of switching stations over other solutions.

Switching station(s) would also allow the northern parts of the circuits to be thermally upgraded first, providing additional delay benefits for a new line.

A dual-switching-station solution is likely to cost less than a single switching station with a line deviation (see Section 3.3), have lower transmission losses and a lower environmental impact.

SVCs are more cost-effective than other dynamic reactive solutions, but are still expensive compared to switching stations, and have significant reactive device losses.

One SVC before the switching station(s) is close to cost neutral (compare total costs of 1b and 3a), but multiple SVCs give diminishing returns, so several instead of switching station(s) are not economic (compare total costs of 1a and 3a).

Benefits

The only benefit considered in our quantitative analysis is the avoided unserved energy benefit. This is essentially the cost of involuntary demand curtailment under the “do nothing” option so the benefit (avoided cost) is common to all options.

The table below shows the expected unserved energy under the prudent and the expected peak demand forecast in each of the MDS for the “do nothing” option.

Table A2-5, Expected Unserved Energy (MWh)

Demand Forecast	MDS	2021	2022	2023	2024	2025	2026	2030	2035	2040	2045
Prudent	no build	0	8	24	40	55	71	133	208	280	352
	mds1	0	0	0	0	0	0	0	22	0	20
	mds2	0	0	0	0	0	15	76	115	175	247
	mds3	0	0	0	0	0	0	45	120	193	265
	mds4	0	0	2	18	34	50	88	163	236	308
	mds5	0	4	0	13	28	44	106	116	169	241
Expected	no build	0	0	0	0	0	0	3	73	140	205
	mds1	0	0	0	0	0	0	0	0	0	0
	mds2	0	0	0	0	0	0	0	0	34	100
	mds3	0	0	0	0	0	0	0	0	52	118
	mds4	0	0	0	0	0	0	0	28	95	161
	mds5	0	0	0	0	0	0	0	0	29	94

Table A2-5 shows that there is considerable variation in the expected amount of unserved energy depending on how demand grows in the future.

Table A2-6 below shows the 40 year NPV of the avoided expected unserved energy[24] under each of the MDS compared to the “do nothing” option.

Table A2-6, Avoided Expected Unserved Energy Benefit (NPV)

[24] The value of expected unserved energy is calculated using the expected peak demand forecast.

MDS	Unserved Energy Benefit $2014 million
Base - no generation	$ 3,877
MDS1	$ 0.3
MDS2	$ 774.9
MDS3	$ 975.5
MDS4	$ 2,048.3
MDS5	$ 786.6
Average MDS1-5	$ 917.1

Expected net market benefits

Under the Investment Test, the option that returns the highest positive expected net electricity market benefit satisfies the Investment Test.

The relative expected net market benefit is the difference between benefits and costs for each option on the short list compared to the reference case of Option 3a, the dual-switching-station followed by thermal uprating. These results are summarised in Table A2-7..

Table A2-7 Calculation of Relative Expected Net Market Benefit (NPV to 2014)

Option	Description	Total Costs	Unserved Energy Benefit	Net Benefit	Relative Expected Net Market Benefit
		$M	$M	$M	$M
1a	SVCs, new line	$28.6	$917.1	$888.5	-$5.7
1b	SVCs, 2 switching stations, north half line uprate, new north half line	$22.9	$917.1	$894.2	-$0.0
2a	1 switching station, north half line uprate, new north half line	$28.1	$917.1	$889.0	-$5.3
2b	1 switching station, new north half line without uprate first	$32.1	$917.1	$885.0	-$9.3
3a	2 switching stations, north half line uprate, new north half line	$22.9	$917.1	$894.2	$0.0
3b	2 switching stations, new north half line, without uprate first	$34.6	$917.1	$882.5	-$11.7

With one constant benefit associated with all the options, the relativity between options is determined by the costs.

The results show that Option 3a satisfies the quantitative elements of the Investment Test.

However, Option 1b's net benefit is very similar and 1a and 3b are within the uncertainty bounds[25] and could be considered similar.

[25] Defined in the investment test as 10% of the cost of the preferred option.

Unquantified benefits

We have compared the options under several headings:

Option Benefits

This is the timing flexibility of each option. With land purchased and designations gained the lead time for a switching station solution is around one year greater than for an SVC solution. In addition the switching station comes in a larger expenditure block than SVCs. For this reason, Option 1a, has the greatest option benefit.

Options 3a and 3b are relatively similar as both include a dual-switching-station and they only differ in the longer term, with Option 3a including thermal uprating of existing circuits and Option 3b going straight to a new line. The deferral of the eventual new line build in Option 3a means that it has greater option value through a more incremental build plan. Option 1b that builds a SVC and then the dual-switching-station, defers the switching station so is better than 3a.

Robust to no new generation

The plans are very similar as far as generation availability is concerned.

Consumer benefits through enhanced competition

All plans will remove any constraints between the Waitaki Valley and Christchurch, except near peak when asset(s) are out of service. The plans that build a switching station will have greater capacity when the station is built and so lead to fewer constraints.

Minimises disruption

In general, new lines are more disruptive than new substations or switching stations which are more disruptive than new work at existing switching stations. Therefore option 1b is less disruptive than 3a or 3b. 3a, with the thermal upgrade delaying the new line will be less disruptive than 3b. 1a is least disruptive early, but more disruptive later when a new line is required.

Diversity benefits - HILP risks and new connections

Orion has expressed concern[26] that a new switching station adds another single site risk to the Christchurch supply. This is true, but will be mitigated for all except total site incapacitation events (plane crashes etc.) in the design. The current designs include bus configuration to maximise through-connectivity reliability, lightning conductors rather than earth wires, civil works to lift the entire site above the flood plain A dual-switching-station solution does not bring all four circuits together in one

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26 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Orion%20response%20to%20USI%20RFI.pdf

place and will be more resilient to high-impact low probability (HILP) events. This last point was also noted by Orion in our long-list consultation.

Either switching station solution may also provide convenient site(s) for future grid connections, as envisaged at the time of land-purchase in 1997 and discussed by Alpine Energy in its submission on Stage 1[27].

Overall we consider a dual–switching-station solution equivalent to SVCs alone, and better than single switching station solution that requires a line deviation.

Operational benefits – Technology Risks

A switching station, being a passive solution, is more reliable than an SVC.

Aligns with long-term grid development

Our aims for long-term grid development include making full use of existing assets. A dual-switching-station solution increases the n-1 capacity of the existing lines and so fulfils this requirement. Conversely, Options 1b and 1a start with new assets – an SVC and a line deviation respectively.

Overall assessment

These results are summarized in Table A2-8.

Overall Option 3a, the leading option in the quantified cost-benefit test, also has the greatest unquantified benefits. Importantly, Option 1a is markedly worse than Option 3a and 3b which start with obtaining Rangitata land and designations and consents for the dual-switching-station.

27 https://www.transpower.co.nz/sites/default/files/plain-page/attachments/alpine-usi-feedback.pdf

Table A2-8: Qualitative assessment of unquantified benefits and overall preferred option.

Item	Option 1a	Option 1b	Option 3a	Option 3b
	SVCs, new line	SVCs, 2 switching stations, north half line uprate, new north half line	2 switching stations, north half line uprate, new north half line	2 switching stations, new north half line
Relative expected net market benefit ($M)	**-$10.9**	**-$0.3**	**0**	**-$6.7**
Other differences:				
• Option benefits	✓✓✓	✓✓	✓	
• Robust to no new generation	✓✓✓	✓✓✓	✓✓✓	✓✓✓
• Consumer benefits through enhanced competition	✓✓	✓✓	✓✓✓	✓✓✓
• Minimises disruption	✓✓✓	✓✓	✓✓	✓
• Diversity benefits	✓✓	✓✓	✓✓	✓
• Operational benefits		✓✓	✓✓✓	✓✓✓
• Aligns with long term grid development	✓✓	✓✓	✓✓✓	✓✓✓
Total	15	14	17	14
Overall ranking	**2**	**4**	**1**	**3**

Robustness of the economic results

The future is uncertain and it is important that we “stress test” the results against a range of sensitivities. By adjusting key variables we can assess how robust the economic results are to changes in assumptions.

We take the list of key variables from the Capex IM Schedule D8.

Demand

As variations to the expected demand, we include the prudent demand as high growth and zero growth as a low growth scenario

Fuel and Operations and Maintenance Costs

Fuel is not relevant here. O&M costs are relatively small and a sensitivity is not considered necessary

Capital Costs

Capital costs may vary and we apply sensitivities of ±20%. In addition exchange rate movements will affect the different projects differently. For simplicity we assume the New Zealand dollar moves against other currencies held constant with respect to each other. The New Zealand dollar is relatively high at present, so we choose sensitivities of +10% and -40%.

Timing of Decommissioning

The only decommissioning involved is that of SVC3, which applies equally to all projects, unless the life is to be extended past 2022 which is not likely so a sensitivity is not required.

Value of Lost Load (VOLL)

We include sensitivities of ±50%, i.e., $13,000 / MWh and $39,000 / MWh.

Discount Rate

As required in the Capex IM we sensitise the base value 7% with 4% and 10%.

Range of Hydrological Inflow Sequences

As the Upper South Island contains relatively little local hydro generation, a sensitivity is not required

Market Development Scenario (MDS) Weightings

We compare the average across 5 MDS with the results for each of the scenarios.

Competition Effects

The competitiveness of the market would be maintained by any of the options, in the sense of removing potential constraints, but will not differ significantly between them, so no sensitivity is necessary.

Sensitivity Results

The summary of the sensitivities calculated and the results are shown in Table A2.9 and Table A2.10. For ease of comparison, Table A2.9 shows the net market benefit relative to Option 3a for all sensitivities except VOLL. The VOLL sensitivities are shown as absolute net market benefits in Table A2.10.

Table A2.9, Sensitivities' net market benefit in $million relative to Option 3a with winning option in bold

	1a	1b	2a	2b	3a	3b
	SVCs	1 SVC then 2 switching stations	1 switching station, thermal upgrade	1 switching station, new line	2 switching stations, thermal upgrade	2 switching stations, new line
Base Results	-$5.7	-$0.0	-$5.3	-$9.3	**$0.0**	-$11.7
Sensitivities						
Demand						
Low	**$3.3**	$0.0	-$4.5	-$4.5	$0.0	$0.0
High	-$42.3	**$9.6**	-$4.5	-$38.5	$0.0	-$37.8
MDS						
1 high gen.	**$2.4**	**$0.6**	-$5.1	-$5.6	$0.0	-$0.5
2 mid gen.	-$5.8	**$0.6**	-$4.8	-$9.2	$0.0	-$7.6
3 mid gen.	-$2.6	**$0.5**	-$5.3	-$7.6	$0.0	-$5.9
4 low gen.	-$14.5	-$1.6	-$5.3	-$13.2	**$0.0**	-$35.3
5 low gen.	-$8.2	-$0.4	-$5.9	-$10.9	**$0.0**	-$9.4
Capital Cost						
80%	-$5.3	-$0.3	-$4.5	-$7.7	**$0.0**	-$9.4
120%	-$6.2	**$0.3**	-$6.1	-$10.9	$0.0	-$14.1
Discount Rate						
4%	-$37.2	-$2.0	-$5.3	-$21.1	**$0.0**	-$31.8
10%	**$0.8**	$0.2	-$4.9	-$5.6	$0.0	-$4.0
Exchange Rate						
-40%	-$10.5	-$2.1	-$5.3	-$9.4	**$0.0**	-$12.0
+10%	-$5.1	**$0.3**	-$5.3	-$9.3	$0.0	-$11.7
Cost of Losses						
$60	-$3.8	**$0.9**	-$4.6	-$8.6	$0.0	-$11.8
$180	-$8.5	-$1.3	-$6.0	-$9.9	**$0.0**	-$11.6

Table A2.10, VoLL sensitivities, net market benefit $million, with best option in bold

	1a	1b	2a	2b	3a	3b
Base Results	$888.5	$894.2	$889.0	$885.0	**$894.2**	$882.5
Sensitivities						
VOLL						
50%	$429.9	$435.7	$430.4	$426.4	**$435.7**	$423.9
150%	$1,347.0	$1,352.8	$1,347.5	$1,343.5	**$1,352.8**	$1,341.0

The sensitivity analysis shows that if demand grows to the expected level or above then Option 3a or 1b, a dual-switching-station, is preferred. If there is no growth then Option 1a, SVCs with no spend upfront, is preferred.

With expected demand (Base results) Option 3a is better than Option 1b by a narrow margin. If demand grows rapidly the cost of bringing forward the switching station favours Option 1b.

A similar pattern is observable in the variation by MDS or generation build: high generation is equivalent to low demand and favours SVCs, mid generation favours an SVC delaying the switching stations, low generation is equivalent to low demand and favours switching stations

Note that Option 3a or Option 1b is best against a range of capital costs. If capital costs increase then the advantage of avoiding the losses from the 1b SVC is cancelled out and Option 1b is best.

Option 3a's margin over 1b increases if the discount rate is lowered as Option 3a has more upfront costs. The converse is also true.

Option 3a is also best if the New Zealand dollar falls as switching stations have less foreign built component than SVCs. If the dollar rises, SVCs are better.

Option 3a is best if the cost of losses increases, as this counts against SVCs. Again the converse applies.

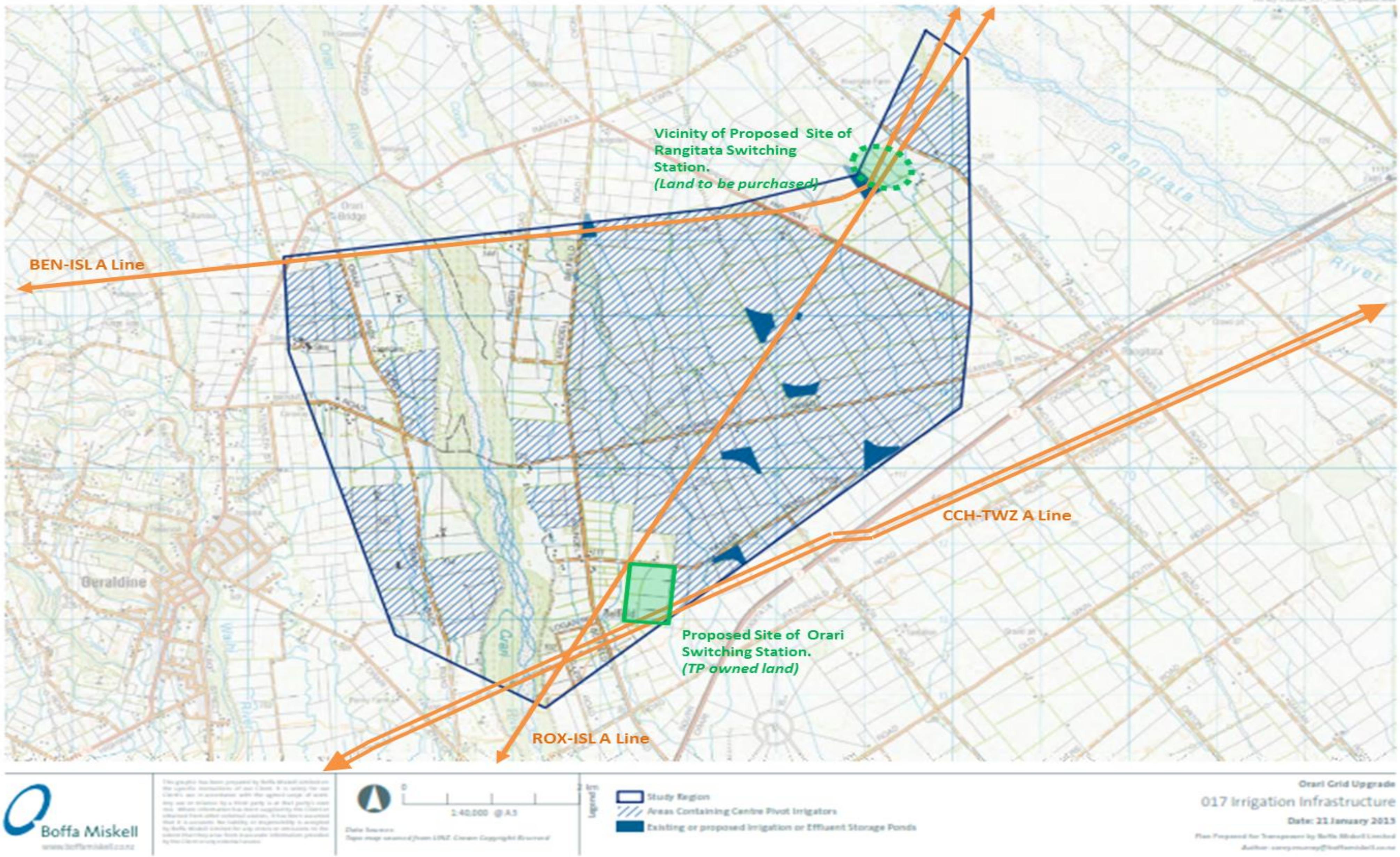
Overall a clear winner is not available at this time, but Options 1b and 3a, that include the dual-switching-station, are most often preferred. Option 1a, SVCs, remains in the mix as do SVCs. The single switching station, Options 2a and 2b, can be discounted.

Non-transmission solutions

Over the last few years, we have been developing demand response (DR) as a non-transmission solution. Our current DR programme seeks to find the natural price points for demand response under a range of network conditions and market scenarios. The programme is structured to understand what is required to deliver demand response as a non-transmission solution at an economic level. The initial focus of the project was on the Upper North Island but subsequently this has been expanded to consider demand response across the country.

Based on the results of the programme, we believe demand response can be an economic non-transmission solution if there is sufficient capability developed within the specific area of the transmission network in question.

Appendix C: **Land Use Changes**



Appendix D: Appendix – Capex IM Checklist

APPLICATION FOR AMENDMENT TO MAJOR CAPEX ALLOWANCE		
Capex IM clause reference	**Information requirement**	**Cross reference to location in document**
Schedule H Division 1, H2	Identification of the relevant **major capex project** and its **major capex allowance**	Section 3.1
Schedule H Division 1, H3 (1)	quantum of proposed amendment to **major capex allowance**;	Section 4.2
Schedule H Division 1, H3 (2)	calculations showing how the quantum of the proposed amendment was calculated;	Section 4.3
Schedule H Division 1, H3 (3)	assumptions made in making those calculations; and	Section 4.3
Schedule H Division 1, H3 (4)	evidence in support of the calculations, including, where relevant- (a) correspondence from manufacturers, suppliers, contractors and other relevant parties; and (b) equipment test results;	Section 4.3
Schedule H Division 1, H3 (5)	proposed **P50**; and	Section 4.3
Schedule H Division 1, H3 (6)	calculations, **key assumptions** and supporting evidence used to determine proposed **P50**, by reference to specified **P50**;	Section 4.3
Schedule H Division 1, H4	description of progress made on the **major capex project**, including details of- (a) planning processes undertaken; (b) resource management consents, other regulatory consents, and property rights and access rights obtained; (c) construction and labour contracts and arrangements made; (d) construction completed; and (e) testing undertaken;	Section 3
Schedule H Division 1, H5 (1)	**major capex** incurred to the date of the application;	Section 3.8

Schedule H Division 1, H5 (2)	forecast **major capex**; and	Section 3.8
Schedule H Division 1, H5 (3)	difference between forecast **major capex** and the **major capex allowance**;	Section 3.8
Schedule H Division 1, H6 (1)	reason for applying, including- (a) description of key factors leading to the application; (b) commentary on the extent to which each key factor is within **Transpower's** control; and (c) commentary on the extent to which each key factor was reasonably foreseeable by **Transpower** before the relevant **major capex proposal** was approved;	Section 5 and Appendix A
Schedule H Division 1, H6 (2)	description of the implications of the proposed amendment on the relevant **approved major capex project outputs**;	Section 4.1
Schedule H Division 1, H6 (3)	where an application for amendment to the **approved major capex project outputs** is being made concurrently, explanation as to how the proposed amendments relate to each other;	Sections 4.2 and 4.3
Schedule H Division 1, H6 (4)	where no application for amendment to the **approved major capex project outputs** is being made concurrently, explanation as to why those **approved major capex project outputs** will remain appropriate were the proposed adjustment made;	N/A
Schedule H Division 1, H6 (5)	statement as to whether the **net electricity market benefit** of the **major capex project** is materially lower at the time of the application than when the relevant **major capex proposal** was approved and if so, current quantum of its **net electricity market benefit**; and	Section 5.3
Schedule H Division 1, H6 (6)	explanation as to why making the proposed amendment would promote the long term benefit of **consumers**;	Section 5.5

APPLICATION FOR AMENDMENT TO APPROVED MAJOR CAPEX PROJECT OUTPUTS		
Capex IM clause reference	**Information requirement**	**Cross reference to location in document**
Schedule H Division 3, H14	identification of relevant **major capex project** and its **approved major capex project outputs**;	Section 3.1
Schedule H Division 3, H15 (1)	proposed amendments to the **approved major capex project outputs**;	Section 4.1
Schedule H Division 3, H15 (2)	explanation as to how each proposed amendment was arrived at;	Section 4.1
Schedule H Division 3, H15 (3)	description of the extent to which each proposed amendment reflects a change to the- (a) assets to be **commissioned**; (b) functional capability of the **grid**; (c) quantum of **electricity market benefit or cost elements** directly related to the **supply** of **electricity transmission services** that are likely to be achieved as a result of undertaking the **project**; and (d) in the case of a **non-transmission solution**, description of the extent to which each proposed amendment reflects a change to any relevant service provided by a third party;	Section 4.1
Schedule H Division 3, H16	description of progress made on the **major capex project**, including details of- (a) planning processes undertaken; (b) resource management consents, other regulatory consents, and property rights and access rights obtained; (c) construction and labour contracts and arrangements made; (d) construction completed; and (e) testing undertaken;	Section 3
Schedule H Division 3, H17 (1)	in the case of a **transmission investment**: (a) **major capex** incurred; and (b) forecast remaining **major capex**;	Section 3.8
Schedule H Division 3, H17 (2)	in the case of a **non-transmission solution**: (a) total costs incurred proposed to be classified as **recoverable costs**; (b) total costs incurred in relation to assets to be **commissioned** in relation to the **non-transmission solution**;	N/A

	(c) forecast remaining costs proposed to be classified as **recoverable costs**; and (d) forecast remaining costs incurred in relation to assets to be **commissioned** in relation to the **non-transmission solution**;	
Schedule H Division 3, H18 (1)	reason for applying, including- (a) description of key factors leading to the application; (b) commentary on the extent to which each key factor is within **Transpower's** control and actions taken to mitigate it; and (c) commentary on the extent to which each key factor was reasonably foreseeable by **Transpower** before approval of the **major capex proposal**;	Section 5 and Appendix A
Schedule H Division 3, H18 (2)	description and, where relevant, quantum of any current **key assumptions** different to those relied upon in applying the **investment test** in the **major capex proposal**	Appendixes A + B
Schedule H Division 3, H18 (3)	description of the outcome of applying the **investment test** as it was applied in the **major capex proposal** modified by the proposed amendments and **key assumptions** described in subclause (2), including all relevant calculations and justifications for any exercises of judgment;	Appendix B
Schedule H Division 3, H18 (4)	explanation as to why making the proposed amendment would promote the long-term benefit of **consumers** taking account of- (a) the outcome referred to in subclause (3); (b) any costs that are sunk; (c) the context in which the **major capex proposal** was made; and (d) the context in which any subsequent amendments to the approval were made by the **Commission**;	Section 5.5
Schedule H Division 3, H18 (5)	where no application for amendment to the **major capex allowance** or **maximum recoverable costs**, as the case may be, is being made concurrently, explanation as to why that allowance or those costs will remain appropriate were the proposed amendment to **approved major capex project outputs** made	N/A

Appendix E: Appendix – Chief Executive Certification

Chief Executive Certification

CHIEF EXECUTIVE OFFICER'S CERTIFICATION AS TO MAJOR CAPEX PROJECT AMENDMENT (UPPER SOUTH ISLAND GRID UPGRADE STAGE ONE PROJECT APPLICATION FOR AMENDMENT)

(Transpower Capital Expenditure Input Methodology Determination 2012 Part 9 Clause 9.3.1) (the ***Capex IM****)*

I, Alison Moira Andrew, Chief Executive Officer of Transpower New Zealand Limited (**Transpower**) hereby Certify, in relation to all information provided in accordance with Schedule H to the Capex IM with respect to the Upper South Island Reliability Stage 1 Project Application for Amendment to the Approved Major Capex Outputs and Increase in the Major Capex Allowance, that having made all reasonable enquires, it is my belief that:

(a) the information was derived from and accurately represents, in all material respects, the operations of Transpower; and

(b) all parts of the major capex project to which the information relates have been approved in accordance with the applicable requirements of Transpower's director and management approval policies; and

(c) the application for amendment of project outputs and major capex allowance complies, in all material respects, with the requirements of clause 7.4.2 of the Capex IM.

DATED:

ALISON MOIRA ANDREW