UPPER SOUTH ISLAND RELIABILITY MCP STAGE 1

ATTACHMENT C INVESTMENT TEST ANALYSIS

Transpower New Zealand Limited

June 2012

Keeping the energy flowing

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1| Introduction

1.1 Purpose

The purpose of this document is to present and explain the results from our application of the investment test (**IT**), undertaken as a part of the Upper South Island (**USI**) Reliability MCP Stage 1 (the **Proposal**).

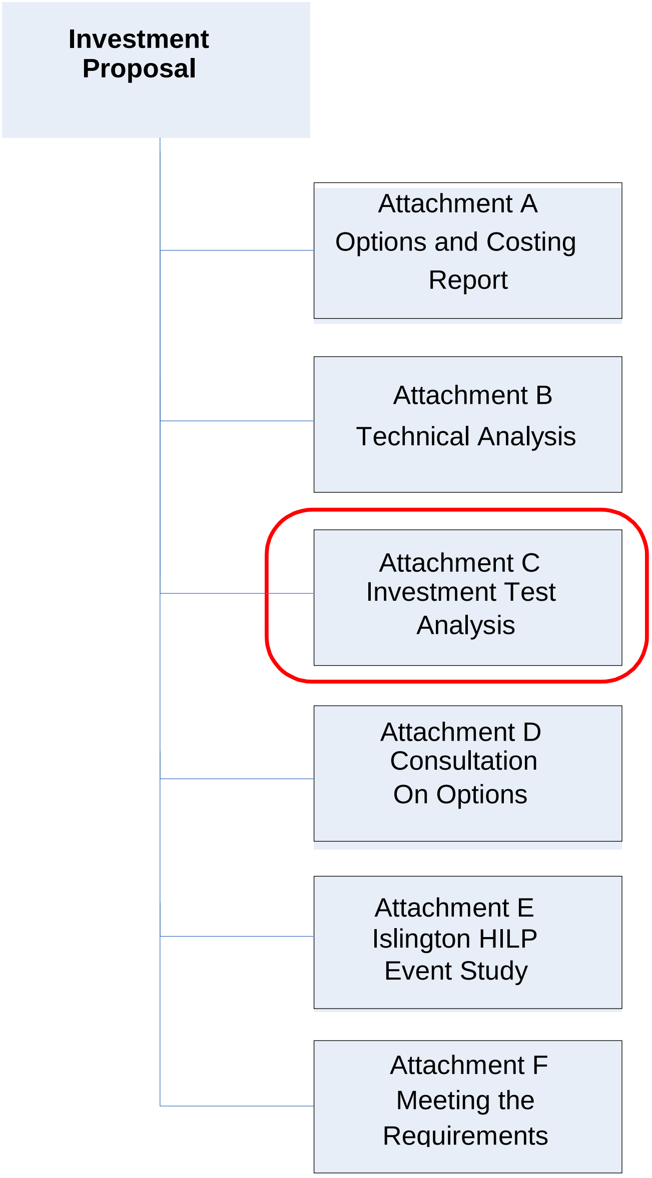
This document relates to the Waitaki to Islington transmission capacity. The Islington HILP mitigations are addressed in the Proposal and Attachment E, HILP Analysis.

This document follows the structure below:

- Section 2 – Models and Assumptions
- Section 3 – Application of the Investment Test
- Section 4 – Uncertainty in the Results
- Section 5 – Conclusion of Investment Test Analysis

1.2 Document context

This report forms part of the Upper South Island Reliability Investment Proposal, as set out in the diagram below:



1.3 Application of the Investment Test

Under Schedule D of the Capex IM[1], the Commerce Commission may approve proposed investments where Transpower has applied the IT reasonably.

We consider that the proposed investment, as set out in the Proposal, passes the IT in that it[2] (clauses relevant to this case in bold):

(a) is sufficiently robust under sensitivity analysis;

[1] Transpower Capital Expenditure Methodology Determination [2012], NZ Commerce Commission.
[2] *ibid*, Schedule D, Clause D1 (1)

(b) has 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; and

(c) has the highest expected net electricity market benefit, where only quantified electricity market benefit or cost elements are taken into account; or

(i) the highest expected net electricity market benefit including a qualitative assessment to take into account the contribution of associated unquantified electricity market benefit or cost elements, if the proposed investment has a similar expected net electricity market benefit to the investment option with the highest expected net electricity market benefit where only quantified electricity market benefit or cost elements are taken into account.

We consider that this document demonstrates that we have applied the IT reasonably and that the proposal satisfies the criteria.

2| Models and Assumptions

Under the Investment Test we are required to use the demand and generation scenarios published as the market development scenarios (**MDS**) in the Electricity Commission 2010 Statement of Opportunities[3] (the **SOO**), or reasonable variations of them.

2.1 Forecast new generation

Electricity generation in the upper South Island is another important input into the technical analysis. If sufficient new generation is built in the region, the peak electricity flows on the transmission circuits from the Waitaki Valley will not increase and further voltage support will not be required.

The new generation forecasts we initially used were based on the five market development scenarios (MDS) included in the Electricity Commissions 2010 Statement of Opportunities. We consulted on these forecasts in our June 2011 consultation and updated them accordingly. Those MDS are shown in Table 4-1. The data in red are the changes made to the Electricity Commissions original forecasts.

In our June 2011 long list consultation[4],we published our intended variations to the MDS which was based on an assessment of current generation plans.

These are the 2011 MDS.

Table 2-1 2011 MDS

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Aorere River (Hydro, run of river)	52 MW 2040				
Arahura (Hydro, run of river)	18 MW 2040				
Arawata River (Hydro, run of river)	62 MW 2039				
Arnold, (Hydro, run of river)	46 MW 2017	46 MW 2017	46 MW 2017		46 MW 2023
Belfast (Diesel)		11.5 MW 2018			
Biomass in Canterbury	21 MW 2036				
Biomass in Nelson/ Marlborough	21 MW 2040				
Bromley (Diesel)		11.5 MW 2020			

3 http://www.ea.govt.nz/industry/ec-archive/soo/2010-soo/
4 http://www.gridnewzealand.co.nz/f4827,54650251/usi-request-for-information-june-2011.pdf

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Butler River (Hydro, run of river)	23 MW 2037				
Clarence to Waiau Diversion, (Hydro, run of river)	70 MW 2021				
Generic Solar in Nelson/ Marlborough	50 MW 2026 50 MW 2036				
Generic Wave West Coast	38 MW 2027				
Hurunui (Wind)		76 MW 2020			
Interruptible load in Canterbury					30 MW 2033 +20 MW 2038
Lake Coleridge Development			70 MW 2020		
Matiri (Hydro)	5 MW 2020				
Mokihinui, (Hydro, run of river)	85 MW 2022		85 MW 2018		
Mt Cass (Wind)	34 MW 2039 +16 MW 2040	41 MW 2018	41 MW 2018		
Rakaia (Hydro, run of river)	16 MW 2018		16 MW 2018		
Stockton Mine (Hydro, run of river)				35 MW 2020	
Stockton Plateau (Hydro, run of river)	25 MW 2018				
Taipo (Hydro, run of river)	33 MW 2034				
Toaroha, (Hydro, run of river)	25 MW 2022	25 MW 2038			
Upper Grey (Hydro, run of river)	35 MW 2039				
Wairau, (Hydro, run of river)	73 MW 2020	73 MW 2020	-	26 MW 2035 +47 MW 2036	73 MW 2025

In its submission to the June 2011 consultation, Mighty River Power stated that it was assessing wind resources in Marlborough.

Trustpower stated that the Arnold expansion could be constructed in 3 years, but that it is on hold with the Transmission Pricing Methodology in its current form.

Orion emphasised their consents for diesel generation at Bromley and Belfast, and we have considered these in the development plans as a stage one development option.

The 2011 MDS reflect significant amounts of new generation being committed within the upper South Island over the next seven years. There is currently none committed, although there are several projects which are consented, or nearly consented. We recognise that generation investors are exposed to considerable uncertainty at the moment, particularly due to the short-term “surplus” of generation and the Transmission Pricing Methodology review.

Therefore, in our view, at the time of short-list consultation (May 2012) these scenarios were optimistic. We considered a modified set of scenarios to be more realistic. New generation which did appear before 2020 was deferred.

We modified the 2011 MDS to the short list consultation MDS as shown in Table 2-2, with the revised dates shown in green.

Table 2-2: Short-list Consultation MDS

Name (type)	1, Sustainable Path	2, SI Wind	3, Medium Renewable	4, Coal	5, High Gas
Aorere River (Hydro, run of river)	52 MW 2040				
Arahura (Hydro, run of river)	18 MW 2040				
Arawata River (Hydro, run of river)	62 MW 2039				
Arnold, (Hydro, run of river)	46 MW 2021	46 MW 2021	46 MW 2021		46 MW 2023
Belfast (Diesel)		11.5 MW 2022			
Biomass in Canterbury	21 MW 2036				
Biomass in Nelson/ Marlborough	21 MW 2040				
Bromley (Diesel)		11.5 MW 2022			
Butler River (Hydro, run of river)	23 MW 2037				
Clarence to Waiau Diversion, (Hydro, run of river)	70 MW 2021				

Name (type)	1, Sustainable Path	2, SI Wind	3, Medium Renewable	4, Coal	5, High Gas
Generic Solar in Nelson/ Marlborough	50 MW 2026 50 MW 2036				
Generic Wave West Coast	38 MW 2027				
Hurunui (Wind)		76 MW 2020			
Interruptible load in Canterbury					30 MW 2033 +20 MW 2038
Lake Coleridge Development			70 MW 2020		
Matiri (Hydro)	5 MW 2020				
Mokihinui, (Hydro, run of river)	85 MW 2022		85 MW 2022		
Mt Cass (Wind)	34 MW 2039 +16 MW 2040	41 MW 2022	41 MW 2022		
Rakaia (Hydro, run of river)	16 MW 2022		16 MW 2022		
Stockton Mine (Hydro, run of river)				35 MW 2020	
Stockton Plateau (Hydro, run of river)	25 MW 2022				
Taipo (Hydro, run of river)	33 MW 2034				
Toaroha, (Hydro, run of river)	25 MW 2022	25 MW 2038			
Upper Grey (Hydro, run of river)	35 MW 2039				
Wairau, (Hydro, run of river)	73 MW 2020	73 MW 2020	-	26 MW 2035 +47 MW 2036	73 MW 2025

Respondents to the short-list consultation[5] in May 2012 were all supportive of this change in general, or did not comment. Some thought that some projects should be included before or around 2020. In particular:

[5] See Attachment D, Summary of Submissions

- Mighty River Power anticipate making resource consent applications within the short to medium term for a 100-150 MW wind project located south-east of Blenheim.
- Trustpower noted that Arnold expansion and Wairau are not committed and will not be built before 2018.
- Trustpower noted that one or two 20 MW Canterbury Irrigation schemes are possible in the next 3-5 years.
- Network Tasman see solar possibilities around Nelson

As well as this feedback we have taken note of publicly available information on Stockton Plateau and various wind generation projects.

We have updated the scenarios as follows (updated values in pink):

Table 2-3: Final MDS

Name (type)	1, Sustainable Path	2, SI Wind	3, Medium Renewable	4, Coal	5, High Gas
Aorere River (Hydro, run of river)	52 MW 2040				
Arahura (Hydro, run of river)	18 MW 2040				
Arawata River (Hydro, run of river)	62 MW 2039				
Arnold, (Hydro, run of river)	46 MW 2018	removed	removed	46 MW 2030	46 MW 2023
Belfast (Diesel)		11.5 MW 2022			
Biomass in Canterbury	21 MW 2036				
Biomass in Nelson/ Marlborough	21 MW 2040				
Bromley (Diesel)		11.5 MW 2022			
	23 MW 2037				
Marlborough Wind 1	300 MW 2018	300 MW 2022	150 MW 2020	150 MW 2026	
Marlborough Wind 2			150 MW 2024		
Clarence to Waiau Diversion, (Hydro, run of river)	70 MW 2030				

Name (type)	1, Sustainable Path	2, SI Wind	3, Medium Renewable	4, Coal	5, High Gas
Generic Solar in Nelson/ Marlborough	50 MW 2026 50 MW 2036				
Generic Wave West Coast	38 MW 2027				
Hurunui (Wind)	76 MW 2018	76 MW 2020	76 MW 2022		
Interruptible load in Canterbury					30 MW 2033 +20 MW 2038
Lake Coleridge Development 1	20 MW 2020	20 MW 2021	20 MW 2020		
Lake Coleridge Development 2	50 MW 2025		50 MW 2025		
Matiri (Hydro)	5 MW 2020				
Mokihinui, (Hydro, run of river)	removed		removed		
Mt Cass (Wind)	34 MW 2039 +16 MW 2040	removed	41 MW 2022		
Mt Cass (Wind)	+16 MW 2040				
Rakaia (Hydro, run of river)	16 MW 2022		16 MW 2022		
Stockton Mine (Hydro, run of river)				35 MW 2020	
Stockton Plateau 1 (Hydro, run of river)	8 MW 2016	8 MW 2016	8 MW 2016	8 MW 2016	8 MW 2016
Stockton Plateau 2 (Hydro, run of river)	25 MW 2020	25 MW 2022	25 MW 2024		

(Colour key: original MDS, long-list consultation, short-list consultation, final)

We weight the scenarios at 20% each, consistent with the SoO. In this report, we also include the IT results for each MDS to demonstrate the impact of new generation on each investment option.

2.2 Demand MDS

We published prudent and mean peak demand forecasts for the USI region in the long list consultation. Orion commented that our demand forecast was conservative (high), particularly given the recent Christchurch earthquakes and the Pike River disaster. We have an ongoing conversation with Orion on how to treat the Christchurch forecast in future. We have not adjusted our prudent base forecast, as lower values before 2014 are not relevant to the analysis and the load may rebound.

However, we include a low demand sensitivity of the results which assume 10% of the Christchurch load does not return (including 10% of motor load), and Pike River load not returning.

Figure 2-1: Upper South Island Demand Forecast

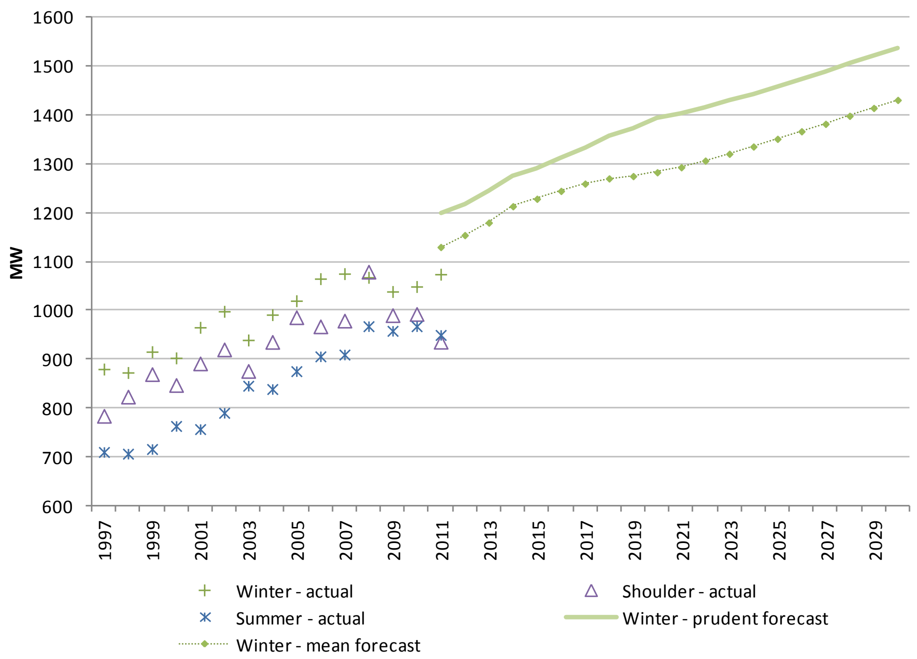


Table 2-4 Upper South Island Peak Demand - historical and forecasts

MW	Winter - actual	Winter - prudent forecast	Winter - mean forecast	Summer - actual	Summer - prudent forecast	Summer- mean forecast	Shoulder - actual	Shoulder - prudent forecast	Shoulder - mean forecast
1997	880			710			784		
1998	873			707			824		
1999	916			716			870		
2000	903			764			847		
2001	966			757			892		

MW	Winter - actual	Winter - prudent forecast	Winter - mean forecast	Summer - actual	Summer - prudent forecast	Summer- mean forecast	Shoulder - actual	Shoulder - prudent forecast	Shoulder - mean forecast
2002	998			790			920		
2003	940			846			876		
2004	992			839			936		
2005	1020			876			986		
2006	1065			906			968		
2007	1076			910			979		
2008	1068			968			1079		
2009	1039			958			990		
2010	1049			968			993		
2011	1074	1199	1130	950	1103	1081	936	1124	1094
2012		1217	1154		1138	1120		1159	1133
2013		1245	1180		1171	1147		1189	1157
2014		1276	1214		1191	1164		1210	1176
2015		1292	1229		1223	1192		1240	1203
2020		1393	1283		1326	1260		1327	1253
2025		1459	1352		1389	1320		1392	1312
2030		1537	1431		1464	1391		1467	1386

The detailed GXP peak demand forecasts can be found in Appendix A.

The analysis uses the prudent peak demand forecast for timing and the expected peak demand forecast in the investment test analysis.

2.3 Reference Case

Submitters agreed with our intention to use the lowest net cost option as the reference case. This is just the option against which we compare the results and in this case we present Option 6 as the reference case.

2.4 Cost of Unserved Energy

The value of expected unserved energy is the value placed on any unplanned electricity outage. We use this value to assess the benefit of reducing faults on the network that cause loss of supply.

The CapexIM specifies that unserved energy is valued as determined in the Grid Reliability Standards[6] (currently $20,000/MWh) or some other appropriate value. The $20,000/MWh was determined in December 2004. In the consultation we proposed to

[6] Electricity Industry Participation Code, http://www.ea.govt.nz/document/11336/download/act-code-regs/code-regs/the-code/part-12/ Schedule 12.2

inflate it accordingly to a June 2011 value of $24,200/MWh. We propose to continue using this value.

There are critical loads in the region which do have a higher cost of unserved energy, as noted in submissions on the first consultation. In principle we would take these values into account. However, none of these loads would be lost in scenarios that distinguish options discussed here, and so we use $24,200/MWh throughout.

2.5 Discount Rate

We intend to use a discount rate of 7%, with sensitivities of 4% and 10% as specified in the Capex IM.

2.6 Calculation Period

In response to the June 2011 consultation, Mighty River Power stated that at least 35 years was necessary. Orion agreed with the proposed 20 years but stated that more emphasis should be given to solutions that enable flexibility going forward.

Given that significant costs are likely to occur outside of the 20 year period due to the requirement to refurbish dynamic reactive devices every 20 years, we have extended the calculation period to 2050.

Note that in a few options, under some MDS, dynamic reactive devices are built in the early 2030s. For consistency, their 20 year refurbishment costs are included, even though they fall just beyond 2050.

2.7 Committed and Modelled Projects

Committed[7] projects are assets that are likely to be commissioned during the calculation period and which the proponent is financially and practically committed to doing.

Modelled projects are option- or scenario-dependent related projects.

We consider that there are no committed or modelled projects for this proposal, other than committed generation taken into account in Attachment B, Technical Analysis,

[7] The full definitions of committed and modelled projects are in the Capex IM, clause D9.

3| Application of Investment Test

3.1 Analysis of Options

In this section we apply the IT to the nine short list options. The options and the process by which the short list was derived are detailed in Attachment A, Options and Costing Report.

Six of the development plans start with the installation of a 6th bus coupler at Islington in 2014. Three plans use diesel generation as an alternative to installing the bus coupler. With an expected cost at commissioning of $1.9 million and increase in system limit of 95 MW (it replaces the capability of the synchronous condensers and meets demand growth until 2016), the bus coupler is always the logical first step ahead of the investment in other short-listed options with a higher capital cost.

Our assessment is that diesel generation would cost a minimum $2.4 million to defer the need for investment to 2016 and that demand-side response would cost a minimum $2.8 million. The assumptions behind these values are detailed in Attachment A, Options and Costing report.

We received feedback during the short list consultation that our estimates of diesel generation costs are very low. Hiring or capital costs and fuel costs are both higher than included in our calculations. In this instance, we have not increased our cost estimates because diesel generation is already uneconomic using our low costs and no change would result. However, we note that we will use a higher cost for diesel generation in the future.

The nine development plans which use the short-listed options are shown in Table 3-1.

Table 3-1 Short List Options

	Investments required in each development plan option			
Option	**2014**	**2016**	**2018 (if required)**	**post 2018**
1	Bus Coupler 6	Refurbish SVC3	Orari bussing	New line
2	Bus Coupler 6	Orari bussing		New line
3	Bus Coupler 6	Refurbish SVC3	New SVC	New SVC, new line
4	Bus Coupler 6	New SVC		New SVC, new line
5	Bus Coupler 6	Refurbish SVC3	New sync conds	New SVC, new line
6	Bus Coupler 6	Refurbish SVC3	New STATCOM	New STATCOM, new line
7	Diesel generation	Orari bussing		New SVC, new line

Investments required in each development plan option				
Option	2014	2016	2018 (if required)	post 2018
8	Diesel generation	Refurbish SVC3, new SVC		New SVC, new line
9	Diesel generation	Refurbish SVC3, new STATCOM		New STATCOM, new line

The development plans were derived for each MDS. Although the investments and order of them does not change between MDS, the timing of investment does.

Table 3-1 shows a succession of need dates. After the new 220 kV bus coupler or diesel generation in 2014, further investment is needed in 2016 and then again, in some development plans, by 2018. The right hand column shows the investments required after 2018. The timing for the new line varies between 2028 and 2050. The timing for the new line varies between 2028 and 2045.

Our economic analysis determines the total cost of each development plan out to 2050, using the capital costs for each element in the plan, the resultant operating and maintenance costs and other cost differences.

Note that while we apply the Investment Test to the entire development plan to arrive at a preferred development plan, this draft proposal is concerned only with the investment required in 2014 and preparatory work for 2016

3.2 Costs

Capital Costs

In Attachment A, Options and Costing Report Table 4-11, we present the estimates of the capital costs of each option. These are repeated in the third column of Table 3-2 below. The estimated cost of the new line is added to each option in the next two columns. In the rest of the table we calculate the net present value (**NPV**) of capital costs of each option in each MDS and average over the five MDS.

Table 3-2 Capital Costs and NPV to 2012

Opt.	Description	Capital costs excl. new line	New line	Total	MDS1 NPV	MDS2 NPV	MDS3 NPV	MDS4 NPV	MDS5 NPV	Average capital costs NPV
		$M	$M	$M	$M	$M	$M	$M	$M	$M
1	BC6, refurb SVC3, Oraril bussing	$93.8	$500	$593.8	$85.8	$185.2	$176.8	$203.9	$203.9	$171.1
2	BC6, decomm SVC3, Orari bussing	$69.4	$500	$569.4	$105.1	$180.7	$172.3	$199.4	$199.4	$171.4
3	BC6, refurb SVC3, new SVCs	$125.8	$500	$625.8	$80.5	$183.2	$167.4	$204.6	$203.6	$167.9
4	BC6, decomm SVC3, new SVCs	$110.5	$500	$610.5	$91.3	$177.2	$166.3	$199.0	$201.4	$167.0

Opt.	Description	Capital costs excl. new line $M	New line $M	Total $M	MDS1 NPV $M	MDS2 NPV $M	MDS3 NPV $M	MDS4 NPV $M	MDS5 NPV $M	Average capital costs NPV $M
5	BC6, refurb SVC3, new sync cons, new SVCs	$139.7	$500	$639.7	$96.2	$191.7	$182.6	$218.8	$211.2	$180.1
6	BC6, refurb SVC3, new Statcoms	$100.8	$500	$600.8	$84.8	$172.4	$162.7	$195.7	$192.1	$161.6
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	$113.1	$500	$613.1	$106.0	$195.2	$184.3	$217.0	$219.4	$184.4
8	Diesel gen, refurb SVC3, new SVCs	$147.7	$500	$647.7	$104.1	$190.5	$179.4	$218.6	$218.8	$182.3
9	Diesel gen, refurbish SVC3, new Statcoms	$165.2	$500	$665.2	$111.6	$200.8	$184.4	$223.3	$224.9	$189.0

The total cost in each case is dominated by $500 million for the new line in 2028 or later. In the NPV this reduces to $170 million for 2028, or less for later. Importantly, no dynamic reactive investments affect the thermal need date and so, while the timing of the new line varies with MDS, it does not vary with option, and has no effect on option relativities. Therefore we have not considered any alternatives to a new line.

Option 2, BC6 and Orari, has the lowest capital cost by some $20 million dollars but, because all costs (excluding the new line) occur early, it does not have the lowest NPV cost. Option 6 has the lowest average NPV cost, followed by options 4 and 3.

Generation delays the need for investment and reduces the NPV. The most and earliest generation occurs in MDS1 followed sequentially by MDS3, MDS2, and lastly MDS4 and MDS5 close together. The NPV values reflect that ranking for every option.

If some hundreds of MW of generation are built in the region, as in MDS1–3, then less reactive support is needed before a new line is required. In some options this means that the last reactive support devices in the plan are not required. Other options, particularly those with Orari bussing, do not have this flexibility. This point is a major determinant of the different “winners” under different scenarios as discussed in the proposal. As an example, the timings for no generation and MDS1 are compared for options 2 and 6 in Table 3-3.

Table 3-3 Timing example showing impact of new generation on development plans

	No Generation		MDS1	
	Option 2 Orari	Option 6 Statcoms	Option 2 Orari	Option 6 Statcoms
2014	bus coupler	bus coupler	bus coupler	bus coupler
2016	Orari bussing	SVC3	Orari bussing	SVC3
2018		STC		Small STC
2024		STC 2		
2028	new line	new line		
2045			new line	new line

For Option 2, MDS1 generation delays Option 2's new line build until 2045 but has no other effect; for Option 6, it delays the line, removes the need for the second STC, and allows the replacement of the first STC with a smaller one.

Operations and Maintenance Costs

Operations and Maintenance (**O&M**) costs for each option are shown in Table 3-4.

Table 3-4 Operations and Maintenance Costs

Option	Description	Total $M	MDS1 NPV $M	MDS2 NPV $M	MDS3 NPV $M	MDS4 NPV $M	MDS5 NPV $M	Average NPV $M
1	BC6, refurb SVC3, Orari bussing	$5.7	$0.9	$1.6	$1.6	$1.6	$1.6	$1.5
2	BC6, decomm SVC3, Orari bussing	$4.6	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
3	BC6, refurb SVC3, new SVCs	$4.4	$0.7	$1.2	$1.1	$1.2	$1.2	$1.1
4	BC6, decomm SVC3, new SVCs	$3.1	$0.7	$0.8	$0.7	$0.8	$0.9	$0.8
5	BC6, refurb SVC3, new sync cons, new SVCs	$4.3	$0.7	$1.1	$1.1	$1.2	$1.2	$1.1
6	BC6, refurb SVC3, new Statcoms	$4.5	$1.0	$1.2	$1.1	$1.2	$1.2	$1.2
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	$5.4	$1.3	$1.5	$1.4	$1.5	$1.6	$1.5
8	Diesel gen, refurb SVC3, new SVCs	$5.2	$1.1	$1.2	$1.2	$1.5	$1.6	$1.3
9	Diesel gen, refurbish SVC3, new Statcoms	$6.9	$1.5	$1.8	$1.6	$1.9	$1.9	$1.8

The O&M costs are similar across options.

Reactive Loss Costs

Reactive devices such as SVCs and STATCOMs are electrical devices and consume energy while they are operating. Bus couplers are static devices and do not consume energy. We have therefore calculated the total amount of energy consumed by the reactive devices in each development plan over the analysis period. This is called the reactive loss cost. Development plans with a smaller number, or later installation of, reactive devices will consume less energy and return a lower cost. The lost energy is valued at the long run marginal cost (LRMC) of generation of $120/MWh. This value is estimated[8] from the LRMC in the 2010 SOO.

The reactive loss costs are shown in Table 3-5.

Table 3-5 Reactive Losses Costs

Option	Description	Total $M	MDS1 NPV $M	MDS2 NPV $M	MDS3 NPV $M	MDS4 NPV $M	MDS5 NPV $M	Average NPV $M
1	BC6, refurb SVC3, Orari bussing	$12.7	$4.4	$4.4	$4.4	$4.4	$4.4	$4.4
2	BC6, decomm SVC3, Orari bussing	$1.3	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1

[8] Specifically the plateau of wind or hydro generation in the LRMC stack in figures 22 to 26 of section 6.2.4.

Option	Description	Total $M	MDS1 NPV $M	MDS2 NPV $M	MDS3 NPV $M	MDS4 NPV $M	MDS5 NPV $M	Average NPV $M
3	BC6, refurb SVC3, new SVCs	$28.1	$5.3	$8.3	$8.1	$8.7	$8.6	$7.8
4	BC6, decomm SVC3, new SVCs	$20.0	$4.9	$5.8	$5.4	$6.1	$6.4	$5.7
5	BC6, refurb SVC3, new sync cons, new SVCs	$60.7	$13.4	$16.8	$16.6	$17.1	$17.0	$16.2
6	BC6, refurb SVC3, new Statcoms	$32.7	$8.1	$9.1	$8.8	$9.3	$9.4	$9.0
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	$7.8	$1.1	$2.5	$2.2	$2.9	$3.2	$2.4
8	Diesel gen, refurb SVC3, new SVCs	$33.6	$7.2	$8.0	$7.7	$10.0	$10.2	$8.6
9	Diesel gen, refurbish SVC3, new Statcoms	$49.2	$10.9	$13.0	$12.1	$13.7	$14.0	$12.7

Reactive losses are the second largest cost component after capital costs.

Synchronous condensers have the greatest reactive losses, followed by STATCOMs and SVCs. Orari and the bus coupler options have none. This creates the ordering of options shown in Table 3-6. This ordering explains the values in Table 3-5.

Table 3-6 Reactive Loss Ordering of Options 1 To 9

	Option	Reason
Lowest Losses	**2**	BC6 & Orari: no new dynamic plant. Reactive losses from existing plant only
	7	Diesel and Orari: SVC much later if needed
	1	SVC3 in 2016, constant across MDS
	4	bigger, more efficient SVC than SVC3, but multiple SVCs
	3	SVC3 in 2016 then more SVCs
	6	Similar to option 3 but with STATCOMs
	8	Similar to option 3 but diesel generation instead of bus coupler 6 is temporary so SVCs earlier
	9	Similar to option 8 but with STATCOMs
Highest Losses	**5**	Similar to option 3 but with synchronous condensers

Transmission Loss Costs

Transmission loss costs arise because the different development plans result in different flows over the transmission lines between the Waitaki Valley and grid exit points as far away as the West Coast. We have used the Digsilent Powerfactory modelling tool to calculate the transmission losses at peak. These are then scaled to average losses and valued at a long run marginal cost of generation.

In this proposal, differences in the transmission loss costs are limited to changes when the circuits are bussed at Orari.[9]

The results are expressed as a penalty when Orari is not built, or not yet built, and are shown in Table 3-7.

Table 3-7 Transmission Losses

Option	Description	Total	MDS1 NPV	MDS2 NPV	MDS3 NPV	MDS4 NPV	MDS5 NPV	Average NPV
		$M	$M	$M	$M	$M	$M	$M
1	BC6, refurb SVC3, Orari bussing	$0.3	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0
2	BC6, decomm SVC3, Orari bussing	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	BC6, refurb SVC3, new SVCs	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
4	BC6, decomm SVC3, new SVCs	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
5	BC6, refurb SVC3, new sync cons, new SVCs	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
6	BC6, refurb SVC3, new Statcoms	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
8	Diesel gen, refurb SVC3, new SVCs	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
9	Diesel gen, refurbish SVC3, new Statcoms	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

The net effect is small.

Avoided Unserved Energy n-2 events

Even with a reliable and resilient network there is still some chance of loss of supply. We cost this at the value of unserved energy, $24,200/MWh[10]. The result is a cost on less reliable options. The main reliability difference between options is that dynamic reactive devices are about 99% reliable and circuits 99.9%+ reliable. Options with fewer reactive devices will have a lower cost.

As each option is a development plan to meet n-1 under the prudent forecast, the unserved energy when zero or one system components are out of service is negligible. This leaves n-2 failures, i.e., double faults or failures during maintenance, and worse (HILP) events.

The n-2 unserved energy calculation is relatively technical and detailed in Appendix B. The results are shown in Table 3-8.

[9] Reactive power flow differences are only observed during a fault as the options include the same *static* reactive devices, and differ only in *dynamic* reactive devices. Dynamic reactive devices only come into play during and following a fault. This is an insignificant fraction of the total time.

[10] $20,000/MWh in 2004 inflated to 2011 as per our June 2011 consultation.

Table 3-8 Unserved Energy Costs

Option	Description	Total	MDS1 NPV	MDS2 NPV	MDS3 NPV	MDS4 NPV	MDS5 NPV	Average NPV
		$M	$M	$M	$M	$M	$M	$M
1	BC6, refurb SVC3, Orari bussing	$2.5	$3.4	$1.2	$1.2	$1.2	$1.2	$1.7
2	BC6, decomm SVC3, Orari bussing	$1.6	$0.8	$1.0	$0.8	$1.3	$1.2	$1.0
3	BC6, refurb SVC3, new SVCs	$3.0	$3.4	$1.3	$1.4	$1.5	$1.6	$1.8
4	BC6, decomm SVC3, new SVCs	$3.4	$1.3	$1.9	$2.1	$2.1	$1.8	$1.8
5	BC6, refurb SVC3, new sync cons, new SVCs	$3.3	$2.4	$1.9	$1.7	$1.8	$2.3	$2.0
6	BC6, refurb SVC3, new Statcoms	$2.2	$1.3	$1.4	$1.4	$1.5	$1.7	$1.5
7	Diesel gen, decomm SVC3, Orari bussing,	$7.1	$4.0	$4.5	$4.9	$4.5	$4.0	$4.4
8	Diesel gen, refurb SVC3, new SVCs	$5.1	$3.0	$3.6	$3.6	$3.8	$3.9	$3.6
9	Diesel gen, refurbish SVC3, new Statcoms	$4.4	$2.6	$3.1	$3.3	$3.3	$3.1	$3.1

The net effect is small.

3.3 Investment Test Results

Under the Transpower Capital Expenditure Input Methodology Determination (Capex IM), the proposed option must pass the Investment Test and be the option that returns the lowest expected net electricity market cost including a qualitative assessment to take into account the contribution of unquantified electricity market benefit or cost elements.

For the quantitative assessment, we calculate the net cost for each option using the costs detailed above.

The net cost results are driven primarily by the magnitude and timing of capital costs, with a secondary effect being the reactive loss costs. Differences in O&M, transmission loss, and reliability costs are relatively minor.

We applied the Investment Test using the modified MDS and the results are shown in Table 3-9. The expected net market cost is the sum of the costs detailed above. The last column compares the results to our reference case, Option 6.

Table 3-9 Expected Net Market Cost (Present Value 2012 $m) relative to Option 6

Option	Description	Present Value Expected costs (2012 $m)	Present Value Relative Expected costs (2012 $m)
1	BC6, refurb SVC3, Orari bussing	178.7	5.1
2	BC6, decomm SVC3, Orari bussing	174.9	1.3
3	BC6, refurb SVC3, new SVCs	179.1	5.4
4	BC6, decomm SVC3, new SVCs	175.9	2.2
5	BC6, refurb SVC3, new sync cons, new SVCs	199.9	26.2
6	BC6, refurb SVC3, new STATCOMs	173.6	0.0
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	192.6	19.0
8	Diesel gen, refurb SVC3, new SVCs	196.4	22.7
9	Diesel gen, refurbish SVC3, new STATCOMs	207.0	33.4

A positive value in the final column indicates an expected net market cost greater than that for Option 6.

The results show that Option 6 passes the Investment Test, although Option 2 and 4 could be considered similar[11].

We have also considered the results by MDS and these are shown in Table 3-10.

Table 3-10 Expected Net Market Cost (Present Value 2012 $m) relative to Option 6 by MDS using 2012 MDS

Option	Description	Expected Net Market Cost relative to Option 6, (Present Value 2012 $m)						
		No gen	MDS1	MDS2	MDS3	MDS4	MDS5	Average
1	BC6, refurb SVC3, Orari bussing	1.0	-1.2	7.8	9.5	3.0	6.3	5.1
2	BC6, decomm SVC3, Orari bussing	-7.1	12.6	-0.5	1.0	-5.0	-1.9	1.3
3	BC6, refurb SVC3, new SVCs	8.6	-5.4	9.9	4.0	8.2	10.5	5.4
4	BC6, decomm SVC3, new SVCs	1.0	2.8	1.4	0.5	0.3	6.1	2.2
5	BC6, refurb SVC3, new sync cons, new SVCs	31.3	17.4	27.4	28.0	31.2	27.2	26.2
6	BC6, refurb SVC3, new STATCOMs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Diesel gen, decomm SVC3, Orari bussing, new	17.7	16.6	19.1	18.3	17.6	23.3	19.0
8	Diesel gen, refurb SVC3, new SVCs	27.8	20.2	19.3	17.9	26.2	30.1	22.7

[11] According to the Investment Test, investments can be considered similar if the difference between the expected net market benefit is less than 10% of the cost of the expected proposal. In such cases, unquantified benefits may be used to differentiate a preferred investment.

9	Diesel gen, refurbish SVC3, new STATCOMs	35.6	31.3	34.5	27.3	34.4	39.4	33.4

In this table, the 1st, 2nd and 3rd ranked options for each MDS are highlighted in gold, silver and bronze respectively.

This table illustrates how sensitive the outcome is to the generation assumptions. Under MDS1, when large amounts of generation are built continuously, bus coupler 6 followed by SVC3 refurbishment is sufficient until 2032. This makes option 3 the best. If a moderate amount of generation is built, and virtually none before 2020, as in MDS2 and 3 then options 2 4 and 6 are similar. If there is little or no generation built, as in MDS4 or MDS5 then Option 2 is the most economic.

On average, option 6 minimises transmission investment due to the impact of increased generation build.

If no, or little, new generation appears during the 2020s, the results indicate we should invest in Orari bussing.

The expected cost of development plan for Options 2, 4 and 6 are within $2.2 million of each other on a present value basis. We have determined that the difference in quantum between the quantified expected net electricity market benefit of our reference case,[12] Option 6 (being the option with the highest expected electricity market benefit where only quantified electricity market benefit or cost elements are taken into account), and the expected net electricity market benefit of Options 2 and 4 is 10% or less of the aggregate project costs of Option 6.

Accordingly, we have undertaken a qualitative assessment taking into account the contribution to the expected net market electricity benefits of associated unquantified electricity market benefit or cost elements.

3.4 Unquantified benefits

Our qualitative assessment shows the relativity between the options as in Table 3-11 below.

The benefit for each option has been qualitatively assessed between ✓ and ✓✓✓, where ✓✓✓ means more benefit than ✓.

Considering both the Investment Test result and the qualitative assessment, our overall ranking of the options is then shown at the bottom of Table 3-11.

[12] There is no requirement to define a reference case under the Capex IM. We have only done so for ease of presentation of the Investment Test results. The reference case is the lowest cost overall development plan, but this does not imply it is the most economic, or preferred option in any way.

Table 3-11 Qualitative assessment of non-quantified benefits (NQB) and overall preferred option

Item	Option 2	Option 4	Option 6
Expected Net Market Benefit	-1.3	-2.2	0
Other differences:			
Option differences	✓✓✓	✓✓✓	✓✓✓
Robust to no new generation	✓✓✓	✓✓	✓✓
Consumer benefits through enhanced competition	✓	✓	✓
Minimises disruption	✓	✓✓✓	✓✓✓
Diversity benefits	✓	✓✓	✓✓
Operational benefits	✓✓✓	✓	✓
Aligns long term grid development	✓✓✓	✓✓	✓✓
Overall ranking ENMB + NQB	1	3	2

The following benefits have been considered:

Option benefits – does the option include flexibility to be amended in the future if there are significant changes?

We do not consider there are any significant option differences between Options 2, 4 and 6 because new investment in voltage support can be added in all options, if required, with the same lead time.

Robust to no new generation – is the option still economic if new generation does not appear in line with the MDS?

Option 2 is the most economic if new generation does not appear in line with the MDS, so does have an advantage in being robust to no new generation which at this stage appears the most likely outcome.

Consumer benefits through enhanced competition – to what extent will the option enhance competition in the New Zealand electricity market? The more competitive a market is, the more efficient it will be at delivering the advantages that markets can provide to consumers.

The options are equivalent in terms of enhancing competition in the upper South Island.

Minimises disruption – to what extent will the local community be disrupted by the implementation of an alternative?

Option 2 involves more disruption to the community and landowners because it involves building a new transmission facility with a short section of transmission line, whereas Options 4 and 6 involve development within our existing substation at Islington.

Diversity benefits – to what extent will the option provide diversity of supply?

Option 2 potentially reduces diversity by creating a common point of connection. All practical steps would be taken to reduce this risk, including having two separate switchyards with physical separation, civil works designed to cope with one in 450-year floods, and appropriate breaker/ bus configurations.

Operational benefits – to what extent does the option provide operational benefits not reflected in the economic analysis?

Option 2 has operational benefits compared to Options 4 and 6. These arise because Orari bussing will make outage planning of the circuits into Islington easier and because it may allow Alpine Energy and other lines companies to avoid distribution costs:

- Orari is within the Alpine Energy network. We are currently investigating[1] supply to the Alpine network as the Timaru interconnecting transformers are nearing their capacity. Options involving a new point of supply from the 220 kV circuits north-west of Temuka may be lower-cost if the Orari bus is built. The extent of the benefit depends on the alternative connection configuration and location, and whether this becomes the preferred option following the Timaru investigation.

- Option 2 has the advantage of increasing security during maintenance, voltage quality and connection option flexibility and could have value if more supply points are needed by Network Waitaki, Alpine Energy, Electricity Ashburton or Orion.

- Lessens our dependence on increasing numbers of reactive support devices and associated control equipment. These are not as easy or quick to repair compared to transmission lines and core primary plant and add complexity to grid operation.

None of these benefits are easy to quantify at present.

Aligns with long term grid development – to what extent is the option consistent with our longer term vision for the grid.

Our longer term vision for how the grid should develop considers a longer time period than considered in the investment test analysis. This factor considers whether an option is consistent with the long term vision, or whether considering a shorter term analysis period may have led to a different decision.

Option 2 is better aligned with our long term development of the grid as it maximises the capability of existing transmission assets without the need for voltage support. Introducing more reactive devices increases the complexity of the grid. Option 2 also provides another future site for the installation of reactive support, if they were to be required in the future.

[1] http://www.gridnewzealand.co.nz/n5475.html

In conclusion, having considered both the quantified electricity market benefit or cost elements and unquantified benefits we believe that Option 2 subject to robustness, discussed below, satisfies the Investment Test.

3.5 Investment Test Sensitivities

3.5.1 Range of Sensitivities

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

The sensitivities considered for the application of the IT to the short list of options are set out in the table below.

Table 3-12 Range of Sensitivities

Sensitivity	Included/Not Included, Value(s)
Forecast demand	Low value included – Christchurch decreased by 10% and no Pike River High demand forecast included
Capital cost	Included, Low 80%, high 120%
Operations and Maintenance costs	Not included – insignificant
Fuel Costs	Included, diesel costs 80% and 120%
Discount rate	4% and 10%
Exchange rates	Included +/- 20%
Losses	Included in LRMC generation: half value $60/MWh
Value of unserved energy	Included – $12,100 /MWh and $36,300/MWh
Generation scenarios	Included: Analysed using 2011 MDS
Demand and generation scenario weightings	Included: 100% each in turn
Timing of decommissioning	Not included. SVC3 decommissioning accounted for in options
Variation in hydrological inflow sequences	Not included: effects covered in variations of timing of generation build
Generator and demand side bidding strategies	Not included – would not vary between options
Competition benefits	Not included – options would not impact significantly on competition
Carbon charges	Not included – equivalent to LRMC of generation sensitivity
Property Costs	Not included: effect is captured within capital costs +/- 20% sensitivity

The results of the sensitivity analysis are shown in Table 3-13 and Table 3-14. The values are in millions of 2012 dollars and relative to the reference case, Option 6.

Table 3-13 Net Cost Non-MDS sensitivities - NPV in 2012 $ million relative to Option 6, winning option in green

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9
Analysis Results	5.1	1.3	5.4	2.2	26.2	0.0	19.0	22.7	33.4
Sensitivities									
Demand									
High	4.7	-3.5	7.8	2.5	31.0	0.0	19.7	25.6	38.2
Low	4.5	-0.7	4.8	0.1	22.9	0.0	15.5	20.3	30.2
Capital Cost									
120%	7.7	4.5	6.5	3.4	29.9	0.0	24.5	26.3	38.1
80%	2.5	-2.0	4.4	1.0	22.6	0.0	13.4	19.2	28.7
Maintenance									
120%	5.2	1.3	5.4	2.2	26.2	0.0	19.0	22.8	33.5
80%	5.0	1.2	5.4	2.3	26.3	0.0	18.9	22.7	33.3
Diesel Gen Cost									
120%	5.1	1.3	5.4	2.2	26.2	0.0	19.5	23.2	33.9
80%	5.1	1.3	5.4	2.2	26.2	0.0	18.5	22.2	32.9
Discount Rate									
4%	-0.8	-13.5	9.1	0.9	37.2	0.0	13.8	30.2	46.6
10%	7.0	8.1	3.5	2.8	19.6	0.0	20.4	18.3	25.7
Exchange Rate									
120%	8.3	5.9	4.3	1.0	23.9	0.0	21.9	19.7	29.9
80%	0.2	-5.8	7.1	4.1	29.7	0.0	14.5	27.2	38.7
Cost of losses									
$60/ MWh	7.6	5.4	6.0	3.8	22.6	0.0	22.5	22.9	31.5
Value of Lost Load									
150%	5.2	1.0	5.6	2.4	26.5	0.0	20.4	23.8	34.2
50%	5.0	1.5	5.2	2.1	26.0	0.0	17.5	21.7	32.6

All of the options with the 6th bus coupler are robustly more economic than those which include diesel generation.

The results also show that Option 2 can be considered similar in 10 out of 15 of the sensitivities.

The results also show that Option 2 can be considered similar in all but six of the sensitivities. These include the sensitivities in which the discount rate is changed, the exchange rate changes considerably and the cost of losses is only $60/ MWh.

It would be expected that relatively high capital cost options, such as Option 2, would appear cheaper using a low discount rate and more expensive using a high discount rate. Similarly, Option 2, which has a smaller component of foreign exchange than other options, is cheaper when the exchange rate weakens, but becomes more expensive when the exchange rate strengthens. Option 2 is not similar in the "cost of losses" sensitivity because transmission losses are a reasonably significant cost.

We believe this sensitivity analysis does not change our conclusion that Option 2 is preferred and demonstrates it is sufficiently robust to meet the requirements of the Investment Test.

As a further sensitivity, we have applied the Investment Test using the June 2011 MDS, rather than our modified MDS. These results are shown in Table 3-14.

Table 3-14 Expected Net Market Cost (Present Value 2012 $ million) relative to Option 6 by MDS using 2011 MDS

Option	Description	Expected Net Market Benefit relative to Option 6 (Present Value 2012 $m)						
		No gen	MDS1	MDS2	MDS3	MDS4	MDS5	Average
1	BC6, refurb SVC3, Orari bussing	1.0	6.0	7.8	6.5	2.9	5.3	5.7
2	BC6, decomm SVC3, Orari bussing	-7.1	21.6	19.6	21.0	-5.4	-3.1	10.8
3	BC6, refurb SVC3, new SVCs	8.6	1.8	2.4	1.8	8.2	7.7	4.4
4	BC6, decomm SVC3, new SVCs	1.0	14.7	16.5	16.4	1.3	5.4	10.9
5	BC6, refurb SVC3, new sync cons, new SVCs	31.3	10.3	13.3	11.1	31.1	30.7	19.3
6	BC6, refurb SVC3, new Statcoms	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	17.7	30.5	32.2	31.5	14.7	19.9	25.8
8	Diesel gen, refurb SVC3, new SVCs	27.8	27.1	37.4	36.4	23.9	24.7	29.9
9	Diesel gen, refurbish SVC3, new Statcoms	35.6	30.0	33.9	31.8	35.6	38.5	34.0

This sensitivity shows that Option 3 is similar, but Option 2 is not. This is because new generation is built earlier in MDS 1-3, making Option 2 more expensive than in the modified MDS. It is worth noting that Option 2 is still favoured in MDS 4 and 5 where less new generation is built in the 2020s. Given our preliminary view on new generation, this does not change our conclusion.

3.6 Conclusion

Based on the Investment Test results using our modified MDS and the sensitivity analysis, we consider that Option 2 is the most economic option and satisfies the requirements to be considered as a proposal under the Capex IM.

3.7 Timing of the Proposal

The bus coupler is required in 2014 and the second investment (Orari bussing in option 2 or SVC3 refurbishment) in 2016. The bus coupler has a two year lead time, Orari bussing a four year lead time and SVC3 refurbishment a three year lead time.

3.8 Cost-Benefit in Expected Net Market Benefit Format (ENMB)

The results above are expressed as costs, both here and in the proposal, to aid understanding. However, the formal requirements of the Investment Test require them in the form of expected net market benefit (ENMB). This means moving all items to the benefits side of the cost-benefit ledger. Table 3-15 shows the results from Table 3-9 in this format. There is no change to relativities or interpretation.

Table 3-15 Investment Test Results as Expected Net Market Benefit (Present Value 2012 $ million) averaged over 5 MDS

Option	Description	Present Value Expected costs (2012 $m)	Present Value Relative Expected costs (2012 $m)	Expected Net Market Benefit (2012 $m)
1	BC6, refurb SVC3, Orari bussing	178.7	5.1	-$178.7
2	BC6, decomm SVC3, Orari bussing	174.9	1.3	-$174.9
3	BC6, refurb SVC3, new SVCs	179.1	5.4	-$179.1
4	BC6, decomm SVC3, new SVCs	175.9	2.2	-$175.9
5	BC6, refurb SVC3, new sync cons, new SVCs	199.9	26.2	-$199.9
6	BC6, refurb SVC3, new STATCOMs	173.6	0.0	-$173.6
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	192.6	19.0	-$192.6
8	Diesel gen, refurb SVC3, new SVCs	196.4	22.7	-$196.4
9	Diesel gen, refurbish SVC3, new STATCOMs	207.0	33.4	-$207.0

4| Uncertainty in the results

The results set out in this document have uncertainty associated with them. The uncertainty arises from two main sources.

1) Uncertainty inherent in the input assumptions. The modelling assumes certain costs which may or may not be accurate.

2) Uncertainty in the problem formulation. The fact that the analysis is assessing the differences in generation investment and operation costs over 35+ years can lead to a high degree of uncertainty in the results. To some extent this is mitigated by considering the results over five scenarios. However, aspects such as unexpected or structural changes (such as a big gas discovery or mass electric vehicle charging) could contribute to the scenarios modelled not being representative of the actual future.

However, as noted in the Proposal and these attachments, we have taken steps to mitigate these impacts as much as possible by testing the options over a range of sensitivities.

Therefore, Transpower considers that, given the level of information currently available, the application of the IT to the transmission options is reasonable and that any changes to the assumptions and modelling parameters is likely to lead to changes in the option costs that are common across all the options, except where this is discussed in the proposal.

5| Conclusion of the Investment Test Analysis

Technical analysis has determined that unless new generation is commissioned before then, investment in transmission or non-transmission is required by 2014.

In reviewing our assumptions for this analysis we found that the 2011 MDS seem overly optimistic regarding the amount of new generation which may appear in the upper South Island in the medium (before 2020) term.

We therefore modified the MDS to be more realistic and have undertaken our analysis using the modified 2012 MDS.

Using a short list derived from the June 2011 consultation on a long list of options, we have found that investment in a bus coupler in our Islington substation is the most economic option for meeting the 2014 need.

NTS are not viable for this Stage 1 proposal, because the expected cost of the bus coupler is low, at $1.9 million, and cheaper than either diesel generation or demand-side response.

The bus coupler will provide 95 MW of voltage support, which replaces the capability of the synchronous condensers and meets demand growth until 2016, at which point, further voltage support. Our economic analysis shows that the following options are essentially the same from an economic point of view, either:

- installing a new SVC at Islington
- refurbishing the existing SVC3 at Islington
- installing a new transmission facility at Orari to bus four of the circuits into Islington.

In those MDS where significant new generation is built in the early 2020s, the SVC options are preferred. If no new generation is built until the 2020s, the Orari option is preferred.

Using unquantified benefits in our analysis, we have concluded that overall, building a new facility at Orari is the leading option of the three similar options. At an expected cost of $58 million, this option has several advantages.

- It insulates reliability of supply in the upper South Island from new generation uncertainty.
- It is a conventional transmission solution that actually reduces the need for voltage support, in contrast to options that install more voltage support devices to address an increasing need.
- It avoids some of the complexities in managing high levels of voltage support, as outlined in our Transmission Code.

Sensitivity analysis shows that the Orari option remains similar in all sensitivities except where the cost of that option increases significantly. However, there are several uncertainties in our assumptions which could affect our choice of leading option, namely:

- whether demand will recover to pre-earthquake levels
- whether new generation is likely to be commissioned in the upper South Island by 2020
- the cost to build a new transmission facility at Orari
- whether NTSs may be economic to defer or manage delivery risk for the 2016 investment.

For that reason we are deferring a decision on a proposal to meet the 2016 need until we have completed further work. We will submit a proposal for the 2016 need in 2013 – our Stage 2 proposal.

Orari bussing is currently the leading option for our Stage 2 development, but it has a minimum four year lead time, so if we want to ensure it is a viable option for 2016, we need to start the process now.

For that reason, we are including some preliminary costs for the Orari option in our Stage 1 Proposal. The expected cost for these preliminary costs is $2.14 million and would cover the detailed design and most of the consenting costs.

While our June 2011 consultation served as a RFI for non-transmission solutions (NTS) and we believe there are no economic alternatives to the 2014 need date, we are not satisfied that we have fully explored the viability of alternatives for 2016.

Given the 2016 investment is likely to be at least $11 million (the estimated cost to refurbish SVC3 and cheapest of the similar options), it may be economic to defer this investment or manage delivery risk of other investments using NTS. We will actively explore the viability of NTS ahead of the Stage 2 submission.

Appendix A. Demand Forecast

This demand forecast is identical to that consulted on in 2011.

The prudent forecast is interpreted as having a 10% probability of exceedance, such that the probability of the peak being higher than the forecast is 10%. Forecast values are in MW.

Prudent Peak Demand Forecast (MW)											
Supply point	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Nelson/Marlborough											
Blenheim	Winter	75.9	78.3	79.7	81.1	82.5	84.0	85.5	87.0	88.6	90.2
	Shoulder	72.4	73.7	75.1	76.5	77.9	79.4	80.9	82.4	83.9	85.5
	Summer	63.9	65.1	66.3	67.5	68.8	70.1	71.4	72.7	74.1	75.5
Kikiwa	Winter	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	2.9
	Shoulder	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.3	3.3
	Summer	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.3	3.3
Motueka	Winter	19.6	20.0	20.4	20.8	21.2	21.6	22.0	22.4	22.7	22.9
	Shoulder	18.4	18.8	19.2	19.6	20.0	20.4	20.8	21.2	21.6	22.0
	Summer	16.1	16.4	16.8	17.1	17.5	17.8	18.2	18.5	18.9	19.2
Motupipi	Winter	6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.0	7.1
	Shoulder	6.2	6.3	6.5	6.8	6.9	7.1	7.3	7.5	7.7	8.0
	Summer	7.2	7.4	7.6	7.9	8.1	8.3	8.5	8.8	9.0	9.3
Stoke	Winter	126	128	131	134	136	139	142	145	148	151
	Shoulder	115	117	120	122	124	127	130	132	135	137
	Summer	102	104	106	108	110	112	114	117	119	121
West Coast											
Arthur's Pass	Winter	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Shoulder	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Summer	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Atarau	Winter	11.1	11.1	11.1	11.4	11.8	12.1	12.5	12.9	13.3	13.7
	Shoulder	11.1	11.1	11.1	11.4	11.8	12.1	12.5	12.9	13.3	13.7
	Summer	11.1	11.1	11.1	11.4	11.8	12.1	12.5	12.9	13.3	13.7
Castle Hill	Winter	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
	Shoulder	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
	Summer	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Dobson	Winter	16.6	17.3	18.0	18.7	19.5	20.2	21.7	22.3	22.9	23.5
	Shoulder	16.6	17.3	18.0	18.7	19.5	20.2	21.7	22.3	22.9	23.5
	Summer	15.5	16.1	16.8	17.4	18.2	18.9	20.2	20.7	21.3	21.9
Greymouth	Winter	13.7	13.8	13.9	13.9	13.9	13.9	14.3	14.8	15.2	15.6
	Shoulder	11.7	11.8	11.8	11.8	11.9	11.9	12.2	12.6	13.0	13.5
	Summer	10.1	10.2	10.2	10.2	10.2	10.2	10.6	10.9	11.2	11.7
Hokitika	Winter	16.0	16.4	16.8	14.1	14.4	14.7	14.9	15.1	15.3	15.5
	Shoulder	18.5	19.0	19.4	16.8	17.2	17.6	17.9	18.1	18.5	18.9

Prudent Peak Demand Forecast (MW)											
Supply point	Season	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Summer	15.4	15.8	16.2	14.0	14.3	14.6	14.9	15.1	15.3	15.7
Murchison	Winter	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.1
	Shoulder	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1
	Summer	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1
Orowaiti 110kV-1	Winter	5.7	5.8	6.3	6.9	6.9	7.0	7.1	7.2	7.2	7.3
	Shoulder	5.6	5.7	6.2	6.8	6.8	6.9	7.0	7.1	7.1	7.2
	Summer	4.5	4.5	5.0	5.4	5.5	5.5	5.6	5.6	5.7	5.8
Orowaiti 110kV-2	Winter	5.7	5.8	6.3	6.9	6.9	7.0	7.1	7.2	7.2	7.3
	Shoulder	5.6	5.7	6.2	6.8	6.8	6.9	7.0	7.1	7.1	7.2
	Summer	4.5	4.5	5.0	5.4	5.5	5.5	5.6	5.6	5.7	5.8
Otira	Winter	0.7	0.7	0.8	0.8	0.8	0.8	1.6	2.0	2.1	2.2
	Shoulder	0.7	0.7	0.8	0.8	0.8	0.8	1.6	2.0	2.1	2.2
	Summer	0.7	0.7	0.8	0.8	0.8	0.8	1.6	2.0	2.1	2.2
Reefton 110kV-1	Winter	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
	Shoulder	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
	Summer	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
Reefton 110kV-2	Winter	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
	Shoulder	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
	Summer	4.1	4.1	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.2
Westport	Winter	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	Shoulder	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	Summer	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Canterbury											
Addington 11kV-1	Winter	38.4	31.3	31.8	32.2	32.5	32.7	32.9	33.1	33.4	33.6
	Shoulder	32.7	26.7	27.0	27.4	27.7	27.8	28.0	28.2	28.4	28.6
	Summer	26.8	21.9	22.2	22.5	22.7	22.9	23.0	23.2	23.3	23.5
Addington 11kV-2	Winter	20.0	28.8	29.4	29.8	30.2	30.6	31.1	31.6	32.1	18.2
	Shoulder	24.0	34.5	35.2	35.7	36.2	36.6	37.3	37.9	38.5	21.8
	Summer	20.2	29.0	29.6	30.0	30.4	30.8	31.3	31.8	32.4	18.3
Addington 66kV	Winter	71.9	71.7	72.5	73.3	73.5	74.2	75.0	75.8	74.5	66.7
	Shoulder	63.7	63.4	64.2	64.9	65.0	65.7	66.4	67.1	65.9	59.0
	Summer	51.4	51.2	51.8	52.3	52.5	53.0	53.6	54.1	53.2	47.6
Addington 66kV	Winter	71.9	71.7	72.5	73.3	73.5	74.2	75.0	75.8	74.5	66.7
	Shoulder	63.7	63.4	64.2	64.9	65.0	65.7	66.4	67.1	65.9	59.0
	Summer	51.4	51.2	51.8	52.3	52.5	53.0	53.6	54.1	53.2	47.6
Ashburton 33	Winter	54.1	54.9	55.6	56.3	57.1	57.8	58.5	59.3	60.0	60.7
	Shoulder	52.2	52.8	53.3	53.9	54.5	55.1	55.7	56.3	56.8	57.4
	Summer	54.0	54.6	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.5
Ashburton 66	Winter	76.4	80.4	82.9	85.3	87.6	89.9	91.5	93.1	94.6	96.0
	Shoulder	103	110	112	114	116	119	120	122	123	124
	Summer	105	112	114	116	118	121	122	124	125	127
Ashley	Winter	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5

Prudent Peak Demand Forecast (MW)											
Supply point	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	Shoulder	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
	Summer	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Bromley 11kV	Winter	56.4	57.2	58.0	58.8	59.3	59.8	60.4	58.4	59.1	59.8
	Shoulder	48.6	49.3	50.0	50.6	51.1	51.6	52.1	50.3	50.9	51.5
	Summer	42.1	42.7	43.3	43.9	44.3	44.7	45.1	43.6	44.1	44.6
Bromley 66kV	Winter	154	157	165	167	170	171	173	176	181	269
	Shoulder	120	123	129	131	133	134	135	138	142	213
	Summer	103	105	111	112	114	115	115	118	121	182
Coleridge	Winter	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Shoulder	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Summer	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Culverden	Winter	10.6	10.9	11.1	11.3	11.5	11.7	11.8	12.0	12.1	12.3
	Shoulder	20.3	21.9	23.1	24.2	27.7	28.4	29.1	29.6	30.1	30.5
	Summer	21.2	22.9	24.1	25.3	28.9	29.7	30.3	30.9	31.4	31.8
Hororata	Winter	20.9	21.2	21.5	21.8	22.1	22.4	22.7	23.1	23.4	23.7
	Shoulder	23.7	29.3	29.6	24.4	24.6	9.6	9.7	9.8	9.9	10.1
	Summer	22.5	27.8	28.0	22.7	22.9	7.7	7.8	7.9	8.0	8.1
Hororata 66kV	Winter	14.5	14.6	14.7	14.8	14.9	15.0	15.1	15.2	15.3	15.4
	Shoulder	24.7	25.8	30.6	39.4	40.5	64.5	65.7	66.8	67.9	69.0
	Summer	23.9	25.1	29.7	38.5	39.5	63.5	64.6	65.7	66.8	67.8
Islington 33kV	Winter	76.3	78.7	81.1	83.3	86.5	88.9	91.0	93.2	87.7	90.1
	Shoulder	70.5	72.7	74.9	77.0	80.0	82.2	84.1	86.2	81.0	83.3
	Summer	68.7	70.8	73.0	75.0	77.9	80.0	81.9	83.9	78.9	81.1
Islington 66kV	Winter	132	133	135	137	138	140	143	145	148	151
	Shoulder	89.0	90.3	91.6	96.8	98.1	99.5	102	111	114	116
	Summer	74.9	75.9	77.1	82.0	83.2	84.4	86.4	95.7	97.7	99.7
Kaiapoi	Winter	24.4	25.8	27.6	29.5	31.0	31.9	32.9	33.7	34.6	35.4
	Shoulder	22.4	23.8	25.6	27.5	29.0	29.9	30.9	31.7	32.6	33.4
	Summer	18.1	19.2	20.7	22.2	23.4	24.2	25.0	25.7	26.3	27.0
Kaikoura	Winter	7.9	8.2	8.4	8.7	9.0	9.3	9.5	9.8	10.1	10.3
	Shoulder	8.2	8.5	8.7	9.0	9.2	9.5	9.7	10.0	10.3	10.5
	Summer	8.8	9.1	9.4	9.6	9.9	10.2	10.4	10.7	11.0	11.3
Middleton 66kV-1	Winter	22.1	22.4	22.7	23.0	23.3	23.6	23.8	24.1	24.4	24.7
	Shoulder	14.0	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
	Summer	14.0	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
Middleton 66kV-2	Winter	25.0	25.3	25.7	26.0	26.3	26.7	26.9	27.2	27.6	27.9
	Shoulder	14.0	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
	Summer	14.0	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
Papanui 11kV-1	Winter	34.2	34.9	21.5	29.2	29.8	30.4	31.3	32.1	33.0	25.1
	Shoulder	32.7	33.4	20.6	28.0	28.5	29.1	29.9	30.8	31.7	24.1
	Summer	25.2	25.8	15.9	21.6	22.0	22.4	23.1	23.7	24.4	18.6
Papanui 11kV-2	Winter	33.4	33.9	34.3	34.6	34.7	34.9	35.1	35.4	35.7	35.9
	Shoulder	32.0	32.5	32.9	33.1	33.3	33.4	33.7	33.9	34.2	34.4

Prudent Peak Demand Forecast (MW)											
Supply point	Season	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Summer	24.7	25.0	25.3	25.6	25.7	25.8	26.0	26.2	26.3	26.5
Papanui 66kV	Winter	43.9	44.3	56.5	47.9	48.1	48.3	48.6	48.9	49.2	0.0
	Shoulder	42.5	42.9	54.8	46.4	46.6	46.9	47.1	47.4	47.7	0.0
	Summer	31.0	31.2	39.9	33.8	34.0	34.1	34.3	34.5	34.8	0.0
Southbrook	Winter	40.2	42.5	46.5	48.4	49.6	51.1	52.5	53.9	55.2	56.5
	Shoulder	42.2	43.5	47.6	49.5	50.7	52.3	53.8	55.1	56.5	57.8
	Summer	42.2	43.5	47.6	49.5	50.7	52.3	53.8	55.1	56.5	57.8
Springston 33kV	Winter	55.7	50.9	52.7	49.6	44.6	45.8	46.4	47.9	47.4	48.9
	Shoulder	47.2	48.5	45.0	42.5	43.3	44.2	45.2	38.9	39.9	40.8
	Summer	47.2	48.5	45.0	42.5	43.3	44.2	45.2	38.9	39.9	40.8
Springston 66kV	Winter	11.3	11.3	11.3	39.4	40.3	41.3	42.2	43.1	51.8	52.7
	Shoulder	10.5	10.7	15.6	15.9	16.3	16.6	16.9	17.2	17.6	17.9
	Summer	11.8	12.1	17.0	17.4	17.7	18.1	18.4	18.8	19.1	19.4
Waipara	Winter	10.6	10.8	10.8	10.9	11.0	11.0	11.0	11.1	11.1	11.1
	Shoulder	10.6	10.8	10.8	10.9	21.1	21.1	21.2	21.3	21.3	21.3
	Summer	10.6	10.8	10.8	10.9	21.1	21.1	21.2	21.3	21.3	21.3
Waipara	Winter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Shoulder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Canterbury											
Albury	Winter	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9
	Shoulder	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.0
	Summer	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.0
Timaru	Winter	70.9	71.8	72.7	80.3	81.2	82.2	83.2	84.2	85.2	86.3
	Shoulder	65.4	66.8	69.6	69.9	70.2	70.5	69.9	70.2	70.5	70.8
	Summer	58.1	59.4	61.9	62.1	62.4	62.7	62.1	62.4	62.7	62.9
Tekapo A	Winter	3.9	4.0	4.1	4.2	4.2	4.3	4.4	4.5	4.6	4.7
	Shoulder	3.5	4.5	4.8	5.0	5.3	5.5	5.7	6.1	6.5	6.8
	Summer	3.0	3.9	4.1	4.3	4.6	4.7	4.9	5.2	5.5	5.8
Temuka	Winter	61.7	64.8	68.0	71.4	75.0	78.7	82.6	86.7	91.1	95.6
	Shoulder	53.6	59.1	62.6	64.1	65.8	67.3	69.0	76.8	78.6	80.4
	Summer	51.0	56.2	59.6	61.0	62.6	64.1	65.7	73.1	74.8	76.5

The expected forecast is interpreted as having a 50% probability of exceedance, such that the probability of the peak being higher than the forecast is 50%.

Expected Peak Demand Forecast (MW)

Supply point	Season	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nelson/Marlborough											
Blenheim	Winter	75.9	78.3	79.7	81.1	82.5	83.5	84.2	84.6	84.9	85.4
	Shoulder	72.4	73.7	75.1	76.5	77.9	78.8	79.4	79.9	80.2	80.6
	Summer	63.9	65.1	66.3	67.5	68.8	69.6	70.2	70.5	70.8	71.2
Kikiwa	Winter	2.5	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.8
	Shoulder	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.2
	Summer	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.2	3.2
Motueka	Winter	19.6	20.0	20.4	20.8	21.1	21.3	21.5	21.6	21.8	21.9
	Shoulder	18.4	18.8	19.2	19.6	20.0	20.2	20.3	20.5	20.6	20.7
	Summer	16.1	16.4	16.8	17.1	17.4	17.6	17.8	17.9	18.0	18.1
Motupipi	Winter	6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.0	7.1
	Shoulder	6.2	6.3	6.5	6.7	6.8	6.9	7.0	7.0	7.1	7.1
	Summer	7.2	7.4	7.6	7.8	7.9	8.0	8.1	8.2	8.2	8.3
Stoke	Winter	126	128	131	133	135	136	137	137	137	137
	Shoulder	115	117	120	122	123	124	125	125	125	125
	Summer	102	104	106	108	109	110	110	110	111	111
West Coast											
Arthur's Pass	Winter	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Shoulder	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
	Summer	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Atarau	Winter	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
	Shoulder	10.9	11.1	10.9	10.7	10.5	10.4	10.3	10.2	10.1	10.0
	Summer	11.1	11.1	10.9	10.7	10.5	10.4	10.3	10.2	10.1	10.0
Castle Hill	Winter	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
	Shoulder	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
	Summer	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
Dobson	Winter	16.5	17.3	17.0	16.7	16.4	16.2	16.0	15.8	15.7	15.6
	Shoulder	16.5	17.3	17.7	18.0	18.4	18.6	18.9	19.1	19.3	19.5
	Summer	15.4	16.1	16.5	16.8	17.1	17.4	17.6	17.8	18.0	18.2
Greymouth	Winter	13.7	13.8	13.9	13.9	13.9	13.9	14.0	14.1	14.2	14.3
	Shoulder	11.7	11.8	11.8	11.8	11.9	11.9	12.0	12.1	12.1	12.2
	Summer	10.1	10.2	10.2	10.2	10.2	10.2	10.3	10.4	10.5	10.5
Hokitika	Winter	16.0	16.4	16.8	14.1	14.4	14.7	14.9	15.1	15.3	15.5
	Shoulder	18.5	19.0	19.4	16.8	17.2	17.6	17.9	18.1	18.5	18.8
	Summer	15.4	15.8	16.2	14.0	14.3	14.6	14.9	15.1	15.3	15.6
Murchison	Winter	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0
	Shoulder	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9

Expected Peak Demand Forecast (MW)											
Supply point	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	Summer	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9
Orowaiti 110kV-1	Winter	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.1	6.2
	Shoulder	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1
	Summer	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.8	4.8
Orowaiti 110kV-2	Winter	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.1	6.2
	Shoulder	5.6	5.7	5.7	5.9	5.9	6.0	6.1	6.1	6.1	6.2
	Summer	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.8	4.8
Otira	Winter	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Shoulder	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Summer	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Reefton 110kV-1	Winter	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.4	4.4
	Shoulder	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.4	4.4
	Summer	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.4	4.4
Reefton 110kV-2	Winter	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.4	4.4
	Shoulder	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4
	Summer	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4
Westport	Winter	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	Shoulder	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	Summer	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Canterbury											
Addington 11kV-1	Winter	35.8	31.3	31.8	32.2	32.5	32.7	32.9	33.1	33.4	33.6
	Shoulder	30.5	26.7	27.0	27.4	27.7	27.8	28.0	28.2	28.4	28.6
	Summer	25.1	21.9	22.2	22.5	22.7	22.9	23.0	23.2	23.3	23.5
Addington 11kV-2	Winter	20.0	20.5	21.1	21.6	22.0	22.4	22.7	23.1	23.4	18.2
	Shoulder	24.0	34.5	35.2	35.7	36.2	36.6	37.2	37.8	38.3	21.8
	Summer	20.2	29.0	29.6	30.0	30.4	30.8	31.3	31.7	32.2	18.2
Addington 66kV	Winter	65.8	67.5	69.2	70.9	72.3	73.6	74.8	75.8	74.5	66.7
	Shoulder	58.3	59.8	61.3	62.7	64.0	65.1	66.2	67.1	65.9	59.0
	Summer	47.0	48.2	49.4	50.6	51.6	52.5	53.4	54.1	53.2	47.6
Addington 66kV	Winter	65.8	67.5	69.2	70.9	72.3	73.6	74.8	75.8	74.5	66.7
	Shoulder	58.3	59.8	61.3	62.7	64.0	65.1	66.2	67.1	65.9	59.0
	Summer	47.0	48.2	49.4	50.6	51.6	52.5	53.4	54.1	53.2	47.6
Ashburton 33	Winter	51.8	53.0	54.3	55.5	56.7	57.6	58.4	59.2	59.9	60.6
	Shoulder	52.2	52.8	53.3	53.9	54.5	55.1	55.7	56.3	56.8	57.4
	Summer	54.0	54.6	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.5
Ashburton 66	Winter	60.3	62.1	64.2	66.1	67.9	69.3	70.5	71.7	72.7	73.8
	Shoulder	103	110	112	114	116	119	120	122	123	124
	Summer	105	112	114	116	118	121	122	124	125	127
Ashley	Winter	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
	Shoulder	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
	Summer	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Bromley 11kV	Winter	54.6	56.1	57.6	58.8	59.3	59.8	60.4	58.4	59.1	59.8

Expected Peak Demand Forecast (MW)											
Supply point	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	Shoulder	47.1	48.4	49.7	50.6	51.1	51.6	52.1	50.3	50.9	51.5
	Summer	40.8	41.9	43.0	43.9	44.3	44.7	45.1	43.6	44.1	44.6
Bromley 66kV	Winter	142	146	149	153	156	159	161	163	166	244
	Shoulder	111	114	117	120	122	124	126	128	130	195
	Summer	103	105	108	110	113	114	115	117	119	178
Coleridge	Winter	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Shoulder	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Summer	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Culverden	Winter	10.5	10.8	11.1	11.3	11.5	11.7	11.8	12.0	12.1	12.3
	Shoulder	20.3	20.9	21.5	22.1	22.6	23.1	23.5	23.9	24.3	24.7
	Summer	21.2	21.8	22.5	23.1	23.6	24.1	24.5	25.0	25.4	25.8
Hororata	Winter	19.5	20.0	20.5	21.0	21.4	21.7	22.1	22.4	22.7	23.0
	Shoulder	23.7	24.3	24.9	24.4	24.6	9.6	9.7	9.8	9.9	10.1
	Summer	22.5	23.0	23.6	22.7	22.9	7.7	7.8	7.9	8.0	8.1
Hororata 66kV	Winter	13.7	14.1	14.4	14.8	14.9	15.0	15.1	15.2	15.3	15.4
	Shoulder	23.8	24.4	29.2	38.0	38.8	62.8	63.9	64.8	65.6	66.5
	Summer	23.0	23.6	28.3	37.0	37.8	61.9	62.9	63.8	64.6	65.5
Islington 33kV	Winter	69.0	70.8	72.6	74.3	75.9	77.1	78.4	79.5	73.9	74.9
	Shoulder	69.9	71.7	73.5	75.3	76.8	78.1	79.4	80.5	75.4	76.4
	Summer	68.1	69.9	71.6	73.3	74.8	76.1	77.3	78.4	73.4	74.4
Islington 66kV	Winter	114	117	120	123	126	128	130	132	133	135
	Shoulder	89.0	90.3	91.6	93.7	95.7	97.3	98.9	109	110	111
	Summer	74.9	75.9	77.1	78.9	80.5	81.9	83.2	92.5	93.7	95.0
Kaiapoi	Winter	21.7	22.3	22.9	23.4	23.9	24.3	24.7	25.1	25.5	25.8
	Shoulder	20.2	20.8	21.3	21.8	22.3	22.7	23.0	23.4	23.7	24.0
	Summer	16.4	16.8	17.2	17.6	18.0	18.3	18.6	18.9	19.2	19.4
Kaikoura	Winter	7.0	7.2	7.4	7.6	7.8	8.0	8.1	8.3	8.4	8.5
	Shoulder	7.5	7.7	7.9	8.1	8.3	8.5	8.6	8.8	8.9	9.1
	Summer	8.0	8.2	8.4	8.7	8.9	9.1	9.2	9.4	9.5	9.7
Middleton 66kV-1	Winter	20.7	21.2	21.8	22.3	22.7	23.1	23.5	23.8	24.1	24.4
	Shoulder	13.8	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
	Summer	13.8	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
Middleton 66kV-2	Winter	23.4	24.0	24.6	25.2	25.7	26.1	26.5	26.9	27.3	27.6
	Shoulder	13.8	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
	Summer	13.8	14.1	14.3	14.5	14.7	14.9	15.0	15.2	15.4	15.6
Papanui 11kV-1	Winter	31.2	32.0	21.5	29.2	29.8	30.3	30.8	31.2	31.6	23.7
	Shoulder	29.9	30.7	20.6	21.1	21.5	21.9	22.2	22.5	22.8	23.1
	Summer	23.1	23.7	15.9	16.2	16.6	16.9	17.1	17.4	17.6	17.8
Papanui 11kV-2	Winter	31.2	32.0	32.8	33.6	34.3	34.9	35.1	35.4	35.7	35.9
	Shoulder	29.9	30.7	31.5	32.2	32.9	33.4	33.7	33.9	34.2	34.4
	Summer	23.1	23.7	24.2	24.8	25.3	25.7	26.0	26.2	26.3	26.5
Papanui 66kV	Winter	41.9	42.9	55.2	47.9	48.1	48.3	48.6	48.9	49.2	0.0
	Shoulder	40.6	41.0	52.8	44.5	45.4	46.1	46.9	47.4	47.7	0.0

Expected Peak Demand Forecast (MW)											
Supply point	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	Summer	29.6	30.3	39.0	32.9	33.5	34.1	34.3	34.5	34.8	0.0
Southbrook	Winter	40.0	41.1	42.3	43.4	44.4	45.3	46.2	46.9	47.7	48.5
	Shoulder	40.0	41.1	45.2	46.3	47.5	48.4	49.3	50.2	51.0	51.8
	Summer	40.0	41.1	45.2	46.3	47.5	48.4	49.3	50.2	51.0	51.8
Springston 33kV	Winter	47.3	48.5	49.7	49.6	44.6	45.4	46.1	46.8	47.4	48.0
	Shoulder	47.2	48.4	45.0	42.5	43.3	44.1	44.8	38.9	39.4	40.0
	Summer	47.2	48.4	45.0	42.5	43.3	44.1	44.8	38.9	39.4	40.0
Springston 66kV	Winter	10.9	11.2	11.3	39.4	40.2	40.8	41.5	42.1	50.7	51.4
	Shoulder	10.3	10.6	10.8	11.1	11.3	11.5	11.7	11.9	12.0	12.2
	Summer	11.7	12.0	12.3	12.6	12.8	13.0	13.3	13.4	13.6	13.8
Waipara	Winter	10.6	10.8	10.8	10.9	11.0	11.0	11.0	11.1	11.1	11.1
	Shoulder	10.6	10.8	10.8	10.9	21.1	21.1	21.2	21.3	21.3	21.3
	Summer	10.6	10.8	10.8	10.9	21.1	21.1	21.2	21.3	21.3	21.3
Waipara 66kV	Winter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Shoulder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Summer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Canterbury											
Albury	Winter	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.8
	Shoulder	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0
	Summer	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0
Timaru	Winter	67.5	69.9	72.0	79.6	81.1	82.2	83.0	83.5	84.0	84.5
	Shoulder	64.1	66.4	68.4	69.9	70.2	70.5	69.9	70.2	70.5	70.8
	Summer	57.0	59.0	60.8	62.1	62.4	62.7	62.1	62.4	62.7	62.9
Tekapo A	Winter	3.9	4.0	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.4
	Shoulder	3.4	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.0	5.0
	Summer	2.9	3.8	3.9	4.0	4.1	4.2	4.2	4.2	4.3	4.3
Temuka	Winter	57.7	60.9	64.1	65.6	66.9	67.8	68.6	69.0	69.5	70.0
	Shoulder	53.6	55.5	57.2	58.6	59.7	60.5	61.2	69.0	69.5	69.9
	Summer	51.0	52.8	54.4	55.8	56.8	57.6	58.2	65.7	66.1	66.6

Power factors indicate the proportion of real power (MW) to total power (MVA) at each point of supply.

Diversity values account for the fact that GXP's will not all peak at the same time. The diversity value indicates the percentage of the GXP peak value that contributes to the Upper South Island regional peak.

POINT OF SUPPLY	Power factor	Diversity winter peak	Diversity summer peak	Diversity shoulder peak
NELSON/MARLBOROUGH				
Blenheim	0.970	90.27%	84.93%	80.25%
Kikiwa	0.782	83.71%	61.64%	77.28%
Motueka	0.971	88.67%	76.39%	83.63%
Motupipi	0.970	70.72%	64.15%	84.80%
Stoke	0.999	92.32%	88.56%	90.65%
WEST COAST				
Arthur's Pass	0.998	52.04%	53.79%	58.18%
Atarau	0.970	89.90%	91.89%	32.08%
Castle Hill	-0.976	49.73%	54.51%	54.71%
Dobson	0.983	66.49%	67.46%	62.43%
Greymouth	-0.977	81.00%	90.46%	83.08%
Hokitika	-0.986	44.72%	69.02%	71.80%
Murchison	0.984	62.07%	78.45%	82.21%
Orowaiti 110kV - 1	0.989	86.79%	86.27%	78.89%
Orowaiti 110kV - 2	0.989	86.79%	86.27%	78.89%
Otira	0.861	43.91%	17.46%	47.83%
Reefton 110kV - 1	0.975	89.90%	66.38%	58.18%
Reefton 110kV - 2	0.975	89.90%	66.38%	58.18%
Westport	0.956	73.57%	71.52%	64.93%
CANTERBURY				
Addington 11kV -1	0.989	84.01%	92.02%	88.45%
Addington 11kV -2	0.989	84.01%	92.02%	88.45%
Addington 66kV	0.993	87.31%	90.49%	83.15%
Addington 66kV	0.993	87.31%	90.49%	83.15%
Ashburton 33	0.949	83.94%	91.97%	89.90%
Ashburton 66	0.949	0.00%	61.83%	51.07%

POINT OF SUPPLY	Power factor	Diversity winter peak	Diversity summer peak	Diversity shoulder peak
Ashley	0.848	77.83%	88.79%	73.31%
Bromley 11kV	0.988	73.44%	76.09%	79.20%
Bromley 66kV	1.000	89.84%	97.77%	70.64%
Coleridge	-0.992	69.79%	65.77%	57.77%
Culverden	-0.993	55.82%	59.88%	64.67%
Hororata	0.991	43.12%	68.23%	69.39%
Hororata 66kv	0.991	10.17%	66.46%	62.41%
Islington 33kV	0.968	81.63%	91.95%	90.59%
Islington 66kV	0.995	68.69%	92.66%	66.21%
Kaiapoi	0.985	96.00%	96.29%	83.80%
Kaikoura	0.992	77.35%	68.88%	58.78%
Middleton 66kV-1	0.961	39.23%	75.81%	84.99%
Middleton 66kV-2	0.939	39.23%	75.81%	84.99%
Papanui 11kV-1	0.994	94.55%	75.67%	79.63%
Papanui 11kV-2	0.994	94.55%	75.67%	79.63%
Papanui 66kV	0.997	90.53%	91.79%	63.29%
Southbrook	0.980	95.50%	93.55%	92.23%
Springston 33kV	0.981	90.77%	85.77%	87.12%
Springston 66kV	0.959	27.05%	44.05%	49.40%
Waipara 33kV	0.987	87.63%	87.82%	74.52%
SOUTH CANTERBURY				
Albury	0.958	68.50%	0.00%	9.25%
Timaru	0.970	92.41%	94.25%	91.48%
Tekapo A	-0.998	72.72%	73.72%	68.37%
Temuka	0.956	37.47%	89.34%	80.78%
Timaru	0.970	92.41%	94.25%	91.48%

Appendix B. Unserved Energy Calculation

The main differences between development plans in n-2 event contribution to unserved energy is that dynamic reactive devices are only approximately 99% reliable compared with circuits 99.9%+ reliable.

There are 4 cases:

a) 2 Circuit or bus section failures, which are relatively rare and can be ignored except for a double circuit outage of the Twizel-Timaru-Ashburton-Islington/Bromley line. If the double circuit fails, the thermal limit of the two remaining circuits will be the binding constraint on transfer into the USI. This limit will be unaffected by reactive devices and almost unaffected by Orari bussing. Double circuit outages can be ignored.

b) A circuit or bus-section failure followed by dynamic reactive device failure, in which the dynamic reactive device failure causes no further problems as the system will have stabilised after the first fault.

c) 2 dynamic reactive device failures, where there is similarly no immeadiate problem; and finally

d) A dynamic reactive device failure followed by circuit or bus section failure, which must be considered in detail. Suppose load is near the prudent n-1 peak. If a dynamic reactive device fails and then a circuit or bus-section fails, the system could collapse. This risk cannot be tolerated and so, during a dynamic reactive device fault, the demand will be limited to a lower value, the n-(dynamic reactive device)-1 limit. Any load above this value will be shed. This possible load shedding imposes a cost that varies between zero and $300,000 per annum per dynamic reactive device, depending on the reduction of the peak, i.e., the effectiveness of the missing reactive device, and on how close the demand peak is to the n-1 limit. The result is the costs shown in Table 3-8.

