



T R A N S P O W E R

HVDC GRID UPGRADE PROJECT

PROPOSAL

APPLICATION FOR APPROVAL

MAY 2008

Executive Overview

Transpower's HVDC Grid Upgrade Proposal

The purpose of this high voltage direct current (HVDC) inter-island Grid Upgrade Proposal is to obtain Electricity Commission approval to recover the full costs (up to \$728 million) associated with procuring, constructing and commissioning a new thyristor-based 700 MW pole and associated equipment (including converters, condensers, new control systems, transformers) at Haywards and Benmore by 2012. This pole will replace the existing Pole 1 of the HVDC inter-island link, and together with Pole 2 will provide a 1000 MW link capacity from 2012.¹

Proposal at a Glance

What:	New 700 MW Pole and associated equipment and control systems at both Haywards (North Island) and Benmore (South Island) to replace existing Pole 1.
When:	Commissioning in two stages in 2012 and 2014
How much:	Transpower is seeking approval for up to \$728 million
Total link capacity	1000 MW in 2012 (Stage 1), 1200 MW in 2014 (Stage 2).

The proposal does not include replacement of the existing lines and cables of the HVDC link comprising 571 km of bipolar transmission line and 40 km of submarine cables.

HVDC Inter-Island Link

The HVDC inter-island link connects the North and South Islands of New Zealand.

The link is made up of two "poles", one of which was commissioned in 1965 utilising mercury arc valve technology (known as Pole 1), and the other commissioned in 1991 using newer thyristor technology (known as Pole 2).

Pole 1 is now over 42 years old, utilising equipment and technology that are no longer supported by manufacturers. Transpower has decommissioned half of the existing Pole 1 and is making the remainder available for limited operation during peak demand periods for 2008, with use of pole 1 for subsequent years to be determined on an annual basis. Without Pole 1, the capacity of the link with Pole 2 operating is presently 700 MW.

Process to Date

Transpower has been considering the future of Pole 1 of the HVDC inter-island link for some time - initially as part of its system vision planning work in 2003. Subsequent to this initial work, Transpower submitted a Grid Upgrade Plan to the Electricity Commission to replace Pole 1 in 2005.

Consideration of this proposal was suspended in June 2006 pending clarification of how the proposal should be assessed under the Grid Investment Test (the regulatory test that Transpower's major investments must meet).²

During late 2006 and early 2007, Transpower and the Electricity Commission held discussions to clarify those uncertainties. In March 2007, Transpower began an open and transparent process to consider whether it would be economic to replace Pole 1 pursuant to the requirements of the Electricity Governance Rules (Rules). This process included

¹ The investment is staged so that capacity can be released incrementally. Stage 2 of this proposal (scheduled for 2014) will increase the link capacity to 1200 MW. A further stage (Stage 3), has not been included as part of this proposal as it falls beyond 2017. However, if Stage 3 were undertaken the overall capacity of the link would increase to 1400 MW.

² The 2005 proposal was finally and formally withdrawn on 2 May 2008.

engagement with interested parties to develop a short list of options, and publish key assumptions, methodologies and models to be used in the analysis. From this process four short-listed options were developed:

- Base case option – no Pole 1 replacement;
- Option 1 – 500 MW pole at Benmore and Haywards;
- Option 2 – 700 MW pole at Benmore and Haywards; and
- Option 3 – 1000 MW pole at Benmore and Haywards.

Application of the Grid Investment Test

Once the overall approach to applying the Grid Investment Test had been clarified with the Electricity Commission, Transpower undertook an initial assessment of the four short-listed options. This assessment (taking into account points raised in consultation) showed that the preferred option from an economic perspective was the 700 MW Pole 1 option as it had a higher net market benefit (\$191 million) compared to the next closest option (500 MW pole, \$138 million).

Table 0-1: Grid Investment Test Results

Item	Base Case	Option 1	Option 2	Option 3
	No Pole 1 replacement	500 MW Pole 1	700 MW Pole 1	1000 MW Pole 1
Present Value 2007\$M				
Generation fixed costs (A)	7,000	6,847	6,769	6,800
Generation variable costs (B)	9,499	9,392	9,356	9,291
HVDC costs (C)	59	325	436	554
AC augmentation costs (D)	45	47	48	49
Terminal benefit (E)	5,858	5,712	5,660	5,661
Total cost (A+B+C+D+E)	22,461	22,323	22,269	22,355
Expected Net Market Benefit	-	138	191	106

Following its initial assessment, Transpower consulted with affected parties under Part F of the Rules between February and April 2008. The purpose of the consultation was to determine whether Transpower had applied the Grid Investment Test reasonably.

Transpower received four submissions to this consultation. In general terms, two submissions considered that the analysis was reasonable, and two raised concerns with some aspects of the analysis. Transpower has considered these submissions fully and without preconceptions in determining the final proposal.

Other benefits of the HVDC pole 1 replacement proposal

The Grid Investment Test assesses the economic merit of a proposal against a specific set of costs and benefits, which mostly assume normal operation of the system. Abnormal and high impact low probability (HILP) events are, in general, not considered.

Transpower considers that this Proposal also provides a number of benefits, not fully reflected in the Grid Investment Test results, including:

- enabling the development of renewable generation in the South Island by ensuring a reliable connection between the South and North Island;

- enabling development of ancillary markets (such as frequency keeping, reserves and balancing markets) to support increased generation from intermittent renewable sources;
- increasing resilience of the National Grid to high impact, low probability events by increasing the flexibility of system operation;
- improving security of supply in dry years, by enabling greater southwards transfer of electricity for North Island generators when there are low inflows into the South Island hydro schemes; and
- mitigating the consequences for security of supply of a Pole 2 failure, noting that the existing Pole 2 is aging and there is an inherent, increasing risk of it failing.

Capital Cost

Replacement of the existing Pole 1 with a new 700 MW thyristor-based pole will be undertaken in two stages, with the capacity of the link increasing to 1000 MW after Stage 1 (in 2012) and 1200 MW after Stage 2 (in 2014). Further work to increase the capacity to a maximum of 1400 MW has been modelled by Transpower, but not included within this investment proposal, as it would not be required until beyond 2017.

For approval purposes, the costs for each stage of investment are calculated for a 90% probability level (in other words, there is a 90% probability of the actual costs falling within the figures quoted). At this level, the capital costs total \$728 million in the expected commissioning years of 2012 and 2014, and this is the amount for which approval is sought from the Electricity Commission.

Category	Estimated P50 cost \$million	Estimated P90 cost \$million
Stage 1	573	676
Stage 2	47	52
Total	620	728

This Document

The remainder of this document is Transpower's formal submission to the Electricity Commission for the purposes of obtaining approval for the funding of the HVDC Grid Upgrade Proposal. It is split into two parts where:

- Part A provides the actual proposal in terms of the activities for which cost recovery up to \$728 million is sought; and
- Part B, together with the attachments, provides justification for the proposal set out in Part A. As well as the technical and economic analysis surrounding the development of the proposal, Part B also justifies the proposal against the requirements of the Rules.

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Structure of Volumes

Ref	Title
Volume 1	
Proposal	
A	Revised GIT results
B	Updated MAV Pole 1 - Economic Analysis
C	Covec Report on South Island demand
D	MMA Report on reserves risk
E	Transpower's consideration of submissions
F	Submissions received and Transpower's responses during the consultation period
Volume 2	
Consultation Paper	
A	Proposed GIT Results
B	Databook
C	Development plans for short-listed options
D	Options – Ranking
E	Options – Identification and Screening
F	MAV Pole 1 – Economic Analysis
G	Further information – PLEXOS results

PART A - The Proposal

This part presents Transpower's HVDC Grid Upgrade Proposal (the Proposal).

Transpower is seeking Electricity Commission approval to recover the full costs associated with implementing the Proposal.

Stage 1:

- Procuring, constructing and commissioning new HVDC converter station facilities including control systems at Haywards and Benmore that:
 - have nominal continuous ratings of around 700 MW at 350 kV; and
 - have AC filters suitable for bipole operation of around 1200 MW.
- Procuring and constructing seismic strengthening works for existing and new switchyards at Haywards and Benmore.
- Procuring, constructing and commissioning extended and new 220 kV switchyards to facilitate the connection of the new HVDC converter station facilities and (in preparation for Stage 2) new dynamic reactive power compensation facilities at Haywards.
- Procuring, constructing and commissioning extended 220 kV switchyards to facilitate the connection of the new HVDC converter station facilities at Benmore.
- Decommissioning and removal of existing HVDC control system facilities at Haywards and Benmore including:
 - Pole 2 control systems and valve base electronics; and
 - bipole control systems.
- Procuring, constructing and commissioning new HVDC control system facilities at Haywards and Benmore including:
 - Pole 2 control systems and valve base electronics;
 - bipole control systems; and
 - SCADA interfaces at the converter stations.
- Procuring, constructing and commissioning communication facilities to enable efficient operation of the bipole link.
- Procuring, constructing and commissioning new unit connection transformers for the existing C7, C8, C9 and C10 synchronous condensers at Haywards.
- HVDC transmission line works and activities required to facilitate the above.

Stage 2:

- Procuring, constructing and commissioning new dynamic reactive power compensation facilities at Haywards to enable bipole operation of at least 1200 MW.

Common to Stage 1 and Stage 2:

- Obtaining approvals under the Resource Management Act (including designations and consents) and easements and property purchases for the above.
- Any additional minor works and activities required to facilitate the above.

Timing

Transpower will work towards commissioning Stage 1 of the Proposal in 2012 and Stage 2 in 2014.

Costs

On commissioning of each stage of the Proposal, Transpower will recover the full costs associated with implementing that stage up to a total amount of \$728 million. This amount is the estimated "P90" level of costs to implement the Proposal, based on the timing above, expressed in New Zealand dollars exclusive of GST.

PART B - Justification

1 Introduction

1.1 Purpose

The purpose of the HVDC Grid Upgrade Proposal, submitted as part of Transpower's 2007 Grid Upgrade Plan (2007 GUP), is to obtain Electricity Commission approval to recover the full costs associated with implementing this investment.

The purpose of Part B of this document is to provide information for the Electricity Commission to assess compliance of this Proposal with the Electricity Governance Rules 2003 (Rules). This part also informs interested parties of Transpower's assessment of submissions received as part of the consultation process and its revised Grid Investment Test (GIT) analysis.

1.2 Background to the Proposal

Transpower has been considering the future of Pole 1 of the HVDC inter-island link (Pole 1) for some time, initially as part of Transpower's System Vision planning work. Subsequent to those initial investigations, Transpower submitted a Grid Upgrade Plan to the Electricity Commission in 2005 (2005 GUP), which included an investment proposal to replace Pole 1 (HVDC Investment Proposal). Consideration of the HVDC Investment Proposal was suspended in June 2006 pending clarification of how the GIT should be applied to such a situation. Transpower withdrew the HVDC Investment Proposal from consideration by the Electricity Commission today.

During late 2006 and early 2007, Transpower and the Electricity Commission held discussions to clarify those uncertainties and in March 2007 Transpower began an open and transparent process to consider whether it would be economic to replace Pole 1, pursuant to the requirements of the Rules. The approach, input assumptions and parameters and sensitivities to be used in applying the GIT were discussed with interested parties prior to any analysis being undertaken. That approach involved the development of a short list of options and publication of the key assumptions, methodologies and models to be used in the analysis, prior to application of the GIT.

Once the approach to applying the GIT had been established, Transpower initiated its formal HVDC Pole 1 Replacement Investigation Project pursuant to the requirements of the Rules. Independent of the HVDC Pole 1 Replacement Investigation Project, in September 2007 Transpower stood down Pole 1 pending further investigation and analysis into the risks that the aging technology posed, and possible remedial actions that could be undertaken in order to return the asset to service. Transpower engaged independent experts who advised that it would be possible to undertake sufficient remedial actions (at considerable cost and time) to bring Pole 1 up to an insurable state, but that due to environmental risks, Transpower should "only consider returning half of Pole 1 back into service, in a limited operation mode only, and for no more than 1-2 years, i.e. a return to full service should not be contemplated".

As a result of this advice and the fact that for the limited period Pole 1 could be recommissioned for, the expected benefits would not exceed the expected costs and hence it would not be economic, the decision was made to decommission half of Pole 1.

On the basis of a decommissioned Pole 1, Transpower applied the GIT to the HVDC Pole 1 Replacement Investigation Project. The results of that application of the GIT show that installing 700 MW converters at Benmore and Haywards (with related works) meets the requirements of the GIT.

Transpower has consulted on its proposed GIT application, and has reviewed its approach in light of submissions from interested parties. This document and its attachments incorporate changes made taking into account these submissions.

1.3 Document structure

1.3.1 Grid Upgrade Plan

This document forms Part V of the 2007 GUP.

Transpower has already submitted the following parts of the 2007 GUP to the Electricity Commission:

- Part I, the comprehensive plan for asset management, and Part II, investment contracts, on 21 September 2007;³
- Part III relating to the North Auckland and Northland Investment Proposal on 21 September 2007;
- Part IV relating to the West Coast Investment Proposal on 19 October 2007.

1.3.2 HVDC Grid Upgrade Project Investment Proposal

Part A of this document above contains the investment proposal.

Part B of this document describes the processes followed and information analysed by Transpower in reaching its decision to seek approval from the Electricity Commission to recover the full costs associated with implementing the Proposal set out in Part A. Accordingly, Part B of this document is not part of the Proposal itself, but contains justification for the Proposal.

Part B of this document contains:

- a description of the consultation process;
- discussion of which type of investment this Proposal is submitted against under the Rules, i.e. reliability or economic;
- a description of the process Transpower undertook and the information analysed to identify and consider all options with a view to producing a short list of options;
- a description of the process Transpower undertook and the information analysed to select the Proposal;
- illustration of how the Proposal meets the requirements of the Rules;
- consideration of timing of the Proposal;
- illustration of how the Proposal meets the wider policy objectives of the Government and Electricity Commission for transmission in New Zealand;
- a recommendation to the Electricity Commission to approve the Proposal; and
- discussion of how, post-approval, Transpower intends to manage the capital costs associated with implementing the Proposal.

1.4 Glossary/terminology

A glossary of terms and acronyms used in this document is included in Appendix A.

All references to Rules in this document refer to those in Section III of Part F of the Electricity Governance Rules 2003 unless otherwise specified.

³ As required under Rule 12.3, Section III of Part F of the Rules.

2 Consultation Process

2.1 Transpower's proposed application of the Grid Investment Test

On 1 February 2008, Transpower released and publicised a consultation paper entitled 'Inter-Island HVDC Pole 1 Replacement Investigation' (Consultation Paper), a copy of which is included in Volume 2 with its attachments. The Consultation Paper sets out Transpower's provisional view that the 700 MW replacement option was the most economic option available. The Consultation Paper attached documents as set out in Volume 2 to this Proposal.

The documents were clarified on the 7 February 2008 and 17 March 2008. This period of consultation followed the open and extensive engagement with customers, and other interested parties, detailed below at section 4.2.

The Consultation Paper sets out Transpower's thinking on the proposed application of the GIT, at the time, to the Inter-Island HVDC Pole 1 Replacement Investigation and on why its proposed application was reasonable. Its analysis at that stage showed that the 700 MW option, which is now the Proposal, maximised the expected net market benefit of the options considered, compared to the Base Case, the expected net market benefit was positive and that this result was robust to a number of sensitivities.

Transpower published a report from the results of PLEXOS modelling carried out by McLennan Magasanik Associates (MMA) on 29 February 2008. One of four appendices attached to this report – published slightly later on 20 March 2008 – covered PLEXOS modelling of competition and consumer benefits. These reports were published primarily for information. Transpower has relied on neither report in its application of the GIT. Nonetheless, consistent with views of MEUG that having two models with similar results was helpful, Transpower believes that the results of these reports reinforce its conclusions, as explained in more detail below.

2.2 Consultation on Transpower's proposed application of the Grid Investment Test

Transpower's consultation on the Consultation Paper ran from 1 February 2008 until 5pm on Friday 4 April 2008, as agreed with the Electricity Commission.⁴

A consultation briefing was held on 22 February 2008, at which 33 people attended from industry participants including Transpower customers, consumer representatives, engineering firms, consultants, the Electricity Commission and the office of the Parliamentary Commissioner for the Environment. The briefing summarised the Consultation Paper⁵ and gave an early opportunity for interested parties to make comments to Transpower.

Transpower received letters from Meridian Energy on the 21 and 22 February and 18 March 2008. Transpower responded to these letters on 12, 20 and 28 March 2008. Transpower also received a letter from Contact Energy on 11 March 2008 to which it responded on 27 March 2008.

Transpower received further submissions from Contact Energy, Genesis Energy, the Major Electricity Users' Group and Meridian Energy on 4 April 2008.

All submissions from interested parties, and Transpower's responses, have been posted on Transpower's website at <http://www.gridnewzealand.co.nz/n282,110.html>. For ease of

⁴ See Agreed process and timeline for consultation of 13 December 2007 at <http://www.gridnewzealand.co.nz/n282,110.html>.

⁵ A copy of Transpower's presentation is available at <http://www.gridnewzealand.co.nz/n282,110.html>.

reference, Transpower has also included these documents as Attachment F to this document.

Attachment E summarises the issues raised by these submissions and their impact, if any, on Transpower's analysis (as reflected in the Attachment A, Revised GIT Results, to this document). Broadly, two submissions considered that the analysis was reasonable and two raised concerns with some aspects of the analysis. Transpower has considered these submissions fully and without preconceptions in determining the final proposal.

3 Type of investment

Under the Rules, Transpower may propose an investment that meets a defined need to the Electricity Commission for approval. Those investments are split into two different types - "reliability investments" and "economic investments". As economic investments are investments which, amongst other things, are not reliability investments, one must first assess whether an investment is a reliability investment within the terms of the Rules in order to decide which type of investment a project involves.

3.1 Definition of reliability investment

Reliability investments are defined under the Rules as follows:

*"investments made by **Transpower** in the **grid**, or alternative arrangements by **Transpower**, the primary effect of which is, or would be, to reduce **expected unserved energy**".*

The Rules then provide for a catch all of economic investment which is defined as:

*"investments in the **grid** that can be justified on the basis of the **grid investment test** under section III of part F and are not **reliability investments**".*

Accordingly, the first step is to determine whether an investment's primary effect is to reduce expected unserved energy. Expected unserved energy is defined under the Rules as follows:

*"a forecast of the aggregate amount by which the **demand** for **electricity** exceeds the **supply** of **electricity** at each **grid exit point** as a result of likely planned and unplanned outages of **primary transmission equipment**".*

In turn, primary transmission equipment is defined in the Rules as follows:

*"any plant or equipment forming part of the **grid** which enables the bulk transfer of **electricity**, including without limitation transmission circuits, busbars and switchgear".*

Accordingly, for an investment to be a reliability investment it must pass the following four-limbed test:

- it must be an investment made by Transpower in the grid or an alternative arrangement by Transpower;
- it must have the primary effect of reducing expected unserved energy;
- the expected unserved energy must result from likely planned or unplanned outages; and
- the likely planned or unplanned outages must be to primary transmission equipment.

3.1.1 Investment in the grid

The "grid" is defined in the Rules as:

*"the system of transmission lines, substations and other works, including the **HVDC link** used to connect the **grid injection points** and **grid exit points** to convey **electricity** throughout the North Island and South Island of New Zealand".*

The Proposal is an investment by Transpower in the grid as it involves investment in the HVDC link.

3.1.2 Reducing expected unserved energy

If demand for electricity exceeds supply of electricity there will be unserved energy (i.e. energy that is unable to be transported to where it is required).

The HVDC link provides access to the South Island's large hydro generation capacity for North Islanders, which may be important for the North Island in peak winter periods. For South Islanders, the link provides access to the North Island's gas and coal generation, which may be important for the South Island during dry winter and summer periods. However, providing all currently commissioned generation in both the North and South Island's is available, both islands are self-sufficient at peak times, or in dry years, and hence the primary effect of the HVDC cannot currently be classified as reducing expected unserved energy.

3.1.3 Conclusion on type of investment

The Proposal is an investment in the grid but does not meet the second limb of the reliability investment test. Therefore, provided it meets the requirements of the GIT, the Proposal is an economic investment as defined in the Rules.⁶

4 Identification and consideration of Options

4.1 Alternative Projects

To obtain cost recovery of economic investments under the Rules, Transpower must apply the GIT reasonably. The investments being contemplated by the HVDC Pole 1 Replacement Investigation Project are economic investments (i.e. it is an investment in the grid, the main purpose of which is not to reduce expected unserved energy). For economic investments, the GIT requires a proposed investment to maximise the expected net market benefits compared with a number of alternative projects and result in expected net market benefits greater than zero.

Accordingly, to enable Transpower to compare a proposed investment with "alternative projects" under the GIT Transpower must first identify those options that fall within the definition of "alternative projects" under the Rules. "Alternative Projects" are defined in the Schedule F4 of the Rules as follows:

19. ... any alternative transmission augmentation projects and **transmission alternatives** to the **proposed investment**, including any variant of the **proposed investment** that involves a non-negligible change in the timing of that **proposed investment**, that are:

19.1. technically feasible;

19.2. reasonably practicable having regard to the matters set out in clauses 8.1 to 8.4;

⁶ It is possible at some time in the future, that investment in the HVDC link may meet the criteria to be classified as a reliability investment. In some circumstances, the generation expansion plans developed as a part of the GIT analysis presented in this document, show either or both North and South Islands becoming capacity (MW) constrained and hence no longer being self-sufficient. At the point where the HVDC link is required to meet peak capacity in one or other islands, it might be argued that the primary purpose would become reducing expected unserved energy. The implications of this change are not explored further in this document.

- 19.3. *reasonably likely to proceed if neither the **proposed investment** nor any other **alternative project** proceeds and unlikely to proceed if the **proposed investment** does proceed;*
- 19.4. *reasonably expected to provide similar benefits, in type but not necessarily in magnitude, to relevant nodes, as the **proposed investment**; and*
- 19.5. *reasonably expected to enable the deferment of investment of the type contemplated by the **proposed investment** for a period of 12 months or more.*

4.2 Option identification

4.2.1 Long list of options

A full description of the Options Identification process used to produce the long list of options is provided in Attachment E to the Consultation Paper (see Volume 2).

To qualify for the long list, options only needed to be technically feasible (i.e. meet the clause 19.1 criteria only (set out in section 4.1 above)) for consideration as an alternative project. For the long list of options, no attempt was made to determine whether an option was reasonably practicable or likely to proceed based on technical practicality or cost.

Transpower identified 83 options (including transmission and non-transmission options) that are technically possible for inclusion in the long list of options. Those options fell within four broad categories:

- an option with no new investment;
- HVDC options - the 66 HVDC options reflect different combinations of HVDC terminal locations in the North Island and South Island and differing HVDC pole capacities;
- HVAC options - the 8 HVAC options reflect replacing the HVDC with HVAC, over a limited number of locations; and
- other options - the 9 other options represent alternatives to replacing Pole 1 of the HVDC with either HVDC or HVAC equipment.

4.2.2 Options screening

A set of high level screening criteria was developed to eliminate those options that are not appropriate and, therefore, do not warrant further analysis. These criteria reflect the requirements of the definition of alternative projects set out in section 4.1 above in order for options to be included as alternative projects, along with requirements from the Government Policy Statement on Electricity Governance (GPS).

A full description of the screening criteria is provided in Attachment E to the Consultation Paper (see Volume 2), but in summary they are:

- A. Fit for purpose
 - a. Purpose - Interconnection of the two island markets
- B. Technical feasibility (Rules)
 - a. Complexity of solution
 - b. Reliability, availability and maintainability of the solution
 - c. Future flexibility - Grid Development Strategy
- C. Practicality of implementation
 - a. Solution implementable by required date (probability of proceeding) (Rules and GPS)

- b. Property and environmental risks
- c. Implementation risks
- D. Good electricity industry practice (GEIP)
 - a. Consistent with good international practice
 - b. Ensure safety and environmental protection
 - c. Accounts for relative size, duty, age and technological status
 - d. Prior industry experience with this technology
 - e. Low technology risks
- E. System security (additional benefit resulting from an economic investment)
 - a. Improved system security
 - b. System operator benefits (controllability)
 - c. Dynamic benefits (modulation features and improved system stability)
- F. Facilitating Renewables (GPS)
 - a. Transport energy
 - b. Balancing MW transfer

The options screening analysis identified 11 options from the long-list which met these criteria and these constitute the long-short list of options.

Transpower held a workshop (“Options Workshop”) with interested parties on 8 June 2007 to discuss:

- the long-list of options;
- assessment criteria for reducing the long-list;
- the long-short list;
- the options ranking approach;
- the GIT approach; and
- the assumptions to be used in the analysis.

Approximately 35 people attended the Options Workshop representing generators, consumer representatives, government officials, the Electricity Commission and other interested members of the general public. The workshop was chaired by Mr Tony Baldwin, an independent facilitator within the industry.

At the Options Workshop there was general agreement that the long list, assessment criteria and long-short list were appropriate. It was requested that a life extension option be included on the long-short list, but otherwise it was considered complete.

Accordingly, life extension options aside, Transpower confirmed the long-short list of options for consideration in the options ranking analysis was appropriate and complete.

Following the Options Workshop, Transpower commissioned further investigation into life extension options. As a part of those investigations, advice was received with respect to the insurability and environmental risks associated with continuing to operate the Pole 1 assets. That advice led Transpower to conclude that it would be imprudent to continue to operate the Pole 1 assets in other than a limited mode, for a limited time. For that reason, life extension options are no longer included as potential options in the Pole 1 replacement investigation. Separate investigations continue into recommissioning one half-pole for limited operation, for system security reasons, but any outcome from those investigations will not affect the Pole 1 replacement investigation.

A more detailed summary of the assessment of the long list of options against the specified criteria is provided in Attachment E to the Consultation Paper (see Volume 2).

4.2.3 Options ranking

The options ranking analysis was a high level economic analysis, the purpose of which was to consider whether the long-short list of options could be reduced to a short list, prior to application of the GIT. This was undertaken because the detailed analysis required in the GIT would be extremely time consuming for all 11 options on the long-short list. It seemed

likely that some options would be highly unlikely to pass the GIT based on a high level economic analysis.

The approach and application of ranking options are fully described in Attachment D to the Consultation Paper (see Volume 2), but a summary follows.

The options ranking approach was to:

- identify a suitable Base Case;
- apply a simplified GIT analysis to each long-short list option;
- determine the expected net market benefit of the 10 long-short list options versus the Base Case using the simplified GIT analysis;
- rank the 10 long short list options based on expected net market benefit of the simplified GIT analysis; and
- if possible, identify a sensible cut-point and determine a short list of options to be taken forward for detailed GIT analysis.

The Base Case for the options ranking analysis was determined on the basis that any HVDC Pole 1 replacement would be justified as an economic investment. In line with the essence of economic investments, the most appropriate and practicable Base Case is to “do-nothing” and for options to be considered against the counterfactual of doing nothing.

Therefore, Transpower considered that the option not to replace Pole 1 of the HVDC should be the Base Case for the options ranking analysis. It was also assumed that Pole 2, which reaches the end of its economic life in 2025, would be replaced with like-for-like equipment. Transpower used this assumption as it is conservative, in that if anything, it would not favour a Pole 1 replacement, plus it avoids the uncertainties associated with that replacement decision itself.

The options ranking analysis applied a simplified GIT approach to the long-short list options. The simplified GIT approach considered a targeted subset of the major variables in the GIT analysis:

- considered medium demand growth only;
- considered a simplified set of costs and benefits;
- used GEM for generation expansion modelling, with SDDP-derived dispatch costs; and
- included limited sensitivity analysis.

In summary the simplified GIT approach used for the options ranking analysis was applied as follows:

Table 4-1: Simplified GIT approach used for the options ranking analysis

Base Case:

Existing Pole 2 only

compared to:

HVDC alternatives:

Existing Pole 2 plus new 300 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 500 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 700 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 1000 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 500 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 700 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 1000 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 500 MW link at ROX-HAY in 2012
 Existing Pole 2 plus new 700 MW link at ROX-HAY in 2012
 Existing Pole 2 plus new 1000 MW link at ROX-HAY in 2012

over the following range of assumptions:

Demand (Commission draft 2007 SoO demands):

Medium

Market development scenarios (MDS)⁷ (Commission draft 2007 SoO scenarios):

MDS 1 - High Gas

MDS 2 - Mixed Technologies

MDS 3 - Primary Renewables

MDS 4 – South Island Surplus Renewables

Market cost and benefits:

Generation expansion costs from GEM

Dispatch costs from SDDP

HVDC alternative capital costs

HVDC alternative O&M costs

AC augmentation capital costs

AC augmentation O&M costs

Market development scenarios using the following weightings:

MDS 1 High Gas 15%

MDS 2 Mixed Technologies 15%

MDS 3 Primary Renewables 50%

MDS 4 South Island Surplus 20%

Other GIT parameters:

Analysis period: 30 years

Discount rate: 7%

HVDC charge: \$40/MW

Reference date for costs: 30 April, 2007

Exchange rate approach: +/- 20 business days around 30 April, 2007

Inflation: 3%

Terminal benefits: annuities used for all investments and no costs/benefits after analysis period included

Sensitivities:

No South Island Surplus scenario

Low demand growth

High demand growth

Discount rate 4%

Discount rate 10%

The options ranking analysis was undertaken prior to advice that Meridian Energy and Rio Tinto Aluminium had reached agreement on a long term supply contract and Transpower's introduction of a fifth market development scenario, 90% renewables by 2025, in the analysis. Transpower does not consider that either of these changes, later reflected in the GIT assumptions, affects the resultant short list of options.

Transpower held a workshop ("HVDC Update Briefing") with interested parties on 25 October 2007 to discuss the options ranking results, along with other issues. Approximately 20 people attended the HVDC Update Briefing representing generators, consumer representatives, government officials, the Electricity Commission and other interested members of the general public. The HVDC Update Briefing was chaired by Mr Tony Baldwin, an independent facilitator within the industry.

Transpower presented the results of the options ranking analysis and there was discussion with respect to the results. There was general agreement that the options ranking approach was reasonable and that the short of list of options identified for consideration in the GIT was

⁷ Transpower used the term "market development scenarios" as used in the GIT for this document and its attachments. The term is related to, and is used at many other times interchangeably with, the term "generation scenarios".

appropriate. There was further discussion about whether a life extension option should be included on the short list of options.

Accordingly, life extension options aside, Transpower confirmed the following short list of options:

Table 4-2: Short list of options

Option No.	Description
Base Case	No Pole 1 replacement
1	HVDC 500 MW pole at BEN-HAY
2	HVDC 700 MW pole at BEN-HAY
3	HVDC 1000 MW pole at BEN-HAY

At that time, Transpower had commissioned further investigation into life extension options, as mentioned in Section 4.2.2. The outcome of those investigations and subsequent investigations led Transpower to conclude that it would be imprudent to continue to operate the Pole 1 assets in other than a limited mode, for a limited time. For that reason, life extension options were no longer included as potential options in the Pole 1 replacement investigation.

4.3 Description of Short List Options

The detailed development plans for and a full description of each short list option consulted on, including a description of the approach used in deriving the development plans are set out in Attachment C to the Consultation Paper (see Volume 2). The development plan for each short list option, including that for the base case option, consists of a staged development plan for the HVDC equipment, plus a list of AC augmentations that would be required to fully enable the HVDC capacity installed.

Transpower has refined and updated these short-listed development plans in light of further available information from the version consulted upon. Tables 4-3 to 4-6 below describe each of the short list options in detail:

4.3.1 Base Case – No Pole 1 replacement

Table 4-3 Base Case Option Development Timetable

Stage	HVDC Investment
Stage 1	Electrode and HVDC transmission line works for continuous mono-polar operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of three Haywards Synchronous condensers
	Low order harmonic filter at Haywards
	Seismic strengthening at Haywards and Benmore sites
Stage 2	Pole 2 valve base electronics and control system replacement

4.3.2 Option 1 – 500 MW pole at BEN-HAY

Table 4-4 Option 1 Development Timetable

Stage	HVDC Investment
Stage 1	New 500 MW, 350 kV, converter pole terminating at Benmore and Haywards including new Pole 1 and bipole control system
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 500 MW option at Benmore and Haywards
	Electrode and HVDC Transmission line works for 500/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 60 MVAR

4.3.3 Option 2 – 700 MW pole at BEN-HAY

Table 4-5 Option 2 Development Timetable

Stage	HVDC Investment
Stage 1	New 700 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 700 MW option at Benmore and Haywards
	Electrode and HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
Stage 3	Additional filters suitable for 1400 MW operation
	Add one new HVDC submarine cable rated, 350 kV, 500 MW

4.3.4 Option 3 – 1000 MW pole at BEN-HAY

Table 4-6 Option 3 Development Timetable

Stage	HVDC Investment
Stage 1	New 1000 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 1000 MW option at Benmore and Haywards
	Electrode refurbishment for 1000/700 MW operation.
	HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
Stage 3	Additional filters suitable for 1400/1700 MW operation
	Add one new HVDC submarine cable rated, 350 kV, 500 MW
Stage 4	New synchronous condenser C12 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
	HVDC Transmission Line works for BEN-HAY 1000/700 MW bipole operation

In relation to the Project (i.e., the 700 MW options above) Transpower intends to carry out the following related works as ongoing “business as usual” projects (non-Part F) and are not included within this Proposal (i.e. would proceed with or without this Proposal):

- Decommissioning of the existing Pole 1 converter stations and associated equipment at Haywards and Benmore;
- Reconfiguration of 110kV switchyard at Haywards;
- DC electrode refurbishment at Te Hikowhenua (North Island) and Bog Roy (South Island); and
- Cable terminal roof bushings at Oteranga Bay and Fighting Bay.

4.3.5 Description of AC augmentations

Transpower has considered which AC augmentations would be required for each short-listed option, for each level of demand considered (high, medium and low) and for each market development scenario. A detailed description of the approach is set out in Attachment C to the Consultation Paper (see Volume 2). These are only treated as modelled projects for the purposes of this analysis and none are included in the Proposal.

Table 4-7 below sets out the full list of North Island AC augmentations identified as being required in at least one of the market development scenarios considered.

Table 4-7 North Island AC augmentation list

North Island AC Augmentation	
Name	Description of augmentation
BPE-TKU	Duplexing of BPE-TKU 1&2 circuits raises rating to 492/404 MVA each
TKU-WKM	Duplexing of TKU-WKM 1&2 circuits raises rating to 492/404 MVA each
ATI-OHK	Reconductoring of the ATI-OHK circuit: raises rating from 358/333 to 716/666 MVA
OHK-WRK	Reconductoring of the OHK-WRK circuit: raises rating from 358/333 to 716/666 MVA
PPT-WKM	Reconductoring of the PPT-WKM circuit: raises rating from 448/421 to approximately 764/694 MVA
PPT-WRK	Reconductoring of the PPT-WRK circuit: raises rating from 448/421 to approximately 764/694 MVA
BPE-HAY	Duplexing of BPE-HAY 1&2 circuits: raises the rating from 335/307 to 650-750 MVA
HAY-TF	New Haywards interconnector T4
BPE-TNG	Thermal upgrade raises the rating to 382/347 MVA
RPO-TNG	Thermal upgrade raises the rating to 382/347 MVA
BRK-SFD	Thermal upgrade raises the rating to at least 332/289 MVA
BRK-SFD-DUPLEX	Reconductoring of BRK-SFD 1, 2, & 3 circuits raises rating to at least 500/470 MVA each
CAP100-LNI	Install 100 MVAR of Capacitor banks at one of: BPE or HAY 220kV substations
SVC100-LNI	Install 100 MVAR of Dynamic Reactive (capacitive) support at one of: BPE or HAY 220kV substations

Table 4-8 below sets out the full list of South Island AC augmentations identified as being required in at least one of the market development scenarios considered.

Table 4-8 South Island AC augmentation list

South Island AC Augmentation	
Name	Description of augmentation
AVI-WTK	Duplex just the AVI-WTK section of AVI-WTK-LIV 220kV circuit (9km)
AVI-WTK-LIV	Duplex the AVI-WTK and WTK-LIV 220kV circuits (42 km total) : increases rating from 323/293 to 646/586 MVA and reduces resistance
BEN-AVI	Thermal upgrade of BEN-AVI 1&2 220kV circuits (18km each) : raise simplex op. temp - increases rating from 246/202 to 310/278 MVA each
CAP100-MSI	Install 100 MVAR of Capacitor banks at one of : ASB or LIV 220kV substations
CAP100-USI	Install 100 MVAR of Capacitor banks at one of : TWZ, ISL or KIK 220kV substations
GDE-BUS	Install GDE busbar schemes
ROX-NSY-LIV	Duplex the ROX-NSY (94 km) and NSY-LIV 220kV (48 km) circuit : increases rating from 246/202 to 492/404 MVA and reduces resistance
SVC100-USI	Install 100 MVAR of Dynamic Reactive (capacitive) support at one of : TWZ, ISL or KIK 220kV substations
WTK -LIV	Duplex just the WTK-LIV section of AVI-WTK-LIV 220kV circuit (33km)

A full description of which of these augmentations is required in each of the demand and market development scenario combinations is given in Attachment C to the Consultation Paper (see Volume 2).

5 Transpower's application of the Grid Investment Test

5.1 The Grid Investment Test

Under Rule 14.4, the Electricity Commission may approve proposed investments where Transpower has applied the GIT reasonably. Clause 4 of Schedule F4 of the Rules (the schedule of the Rules which contains the GIT) states that:

*"A **proposed investment** satisfies the **grid investment test** if the **Board** is reasonably satisfied that:*

- 4.1. *for a **proposed investment** that is necessary to meet the reliability standard set out in clause 4.2 of the **grid reliability standards**:*
 - 4.1.1. *the **proposed investment** maximises the **expected net market benefit** or minimises the **expected net market cost** compared with a number of **alternative projects**; and*
 - 4.1.2. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis; or*
- 4.2. *for any other **proposed investment**:*
 - 4.2.1. *the **proposed investment** maximises the **expected net market benefit** compared with a number of **alternative projects**;*
 - 4.2.2. *the **expected net market benefit** of the **proposed investment** is greater than zero; and*
 - 4.2.3. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clauses 4.2.1 and 4.2.2 is sufficiently robust having regard to the results of that sensitivity analysis".*

As set out at section 3.1 above, the investment set out in the Proposal is not necessary to meet the grid reliability standards. As such, the Proposal falls to be considered as an economic investment within the scope of clause 4.2 of the GIT. To satisfy the GIT therefore, the Proposal must:

- maximise the expected net market benefit compared with a number of alternatives, in a robust manner with respect to sensitivity analysis; and
- result in an expected net market benefit greater than zero, in a sufficiently robust manner with respect to sensitivity analysis.

5.2 Methodology and assumptions

Attachment B to the Consultation Paper (see Volume 2) sets out in detail Transpower's methodology and assumptions for applying the GIT. Transpower addresses in this section a number of areas in which industry participants have made submissions at either (or in some cases both) the early customer engagement phase of consultation or the recent GIT consultation process, namely:

- generation expansion modelling approach;
- demand growth assumptions; and
- market development scenarios.

5.2.1 Generation expansion modelling approach

Generation expansion modelling arises in this GIT analysis because different HVDC link sizes (i.e. the different short list options) may lead to different investments in generation, in both the North and South Islands and, therefore, generation expansion plans are required for each short-listed option considered.

Modelling how generation will develop, under a market-led generation environment, such as in New Zealand can be a contentious and difficult area. Depending on the form of market-based expansion used it may rely on assumptions of market behaviour, which over a long period of time may be very different to how the market evolves. The use of these same assumptions may also mean that the generation expansion plan diverges significantly from a supply side least cost expansion.

Transpower's analysis in this proposal uses a form of market-led generation expansion modelling where new generation investment decisions are made based on price signals as may be observed by market participants. Such signals include the capital cost of different generation technologies (after accounting for tax effects, depreciation), nodal price differences and industry tariffs including the HVDC charge, allocated to South Island generators under the transmission pricing methodology (TPM).

As this is the first time Transpower has used generation expansion modelling for GIT analysis, Transpower consulted widely on its approach. The GIT analysis uses the Commission's published GEM model, but separately, the same analysis was undertaken by MMA using PLEXOS, a proprietary generation expansion model. Results from the PLEXOS analysis are reported for information at Attachment G to the Consultation Paper (see Volume 2).

There was much discussion at the Options Workshop, HVDC Update Briefing and other forums held, with respect to generation expansion modelling. In particular, early versions of the GEM model were formulated with an N-2⁸ capacity constraint in a manner which appeared to build more new generation than the market would likely deliver. Discussion focussed on which of two general approaches were most appropriate:

⁸ Note that the terms N-1 and N-2 do not reflect the traditional use of those terms in terms of grid planning but these are a parameter that is used in GEM with respect to a capacity constraint. N-2 is effectively a reference to N-2 generation plants, not transmission assets.

- security constrained modelling, where generation expansion occurs as required to meet peak MW; and
- revenue adequacy modelling, where generation expansion only occurs once a new generator is assured of adequate revenue from sales into the national market to be commercially viable.

The Electricity Commission considered this issue and in a letter to Transpower on 31 August 2007, stated that:

Transpower has had various discussions with participants over the last three months about the inputs for the application of the grid investment test (GIT) to the HVDC Pole 1 replacement investigation project (HVDC project).

These have included whether the models used to produce the generation scenarios should include settings that provide revenue adequacy for generators or those that provide adequate generation to meet security requirements.

The Commission discussed this at its 24/25 July 2007 and 28/29 August 2007 meetings. The Commission's view, as confirmed at its 28/29 August 2007 meeting is that, *"for the purposes of developing credible generation scenarios for the application of the GIT to transmission investments, it is reasonable and credible to assume that adequate generation will be introduced to meet peak and energy security margins...it is not necessary to specify the mechanism(s) through which adequate generation will emerge"* (for example, whether market mechanisms will deliver the new generation, or whether market intervention occurs to facilitate the new generation).

Transpower, having carefully considered all submissions received, considers that applying a security-constrained model is a reasonable application of the GIT.

Further analysis by Electricity Commission staff on the use of capacity constraints in generation expansion modelling led them to further indicate, in a letter to Transpower of 2 November 2007:⁹

While the Commission still considers this matter as under review, in the interests of assisting Transpower to progress its preparation of an HVDC investment proposal, the Commission has taken the step of advising Transpower that the current view of the Commission is that using an N-1 capacity constraint in GEM is preferable to (ie, more reasonable than) using an N-2 capacity constraint when applying the GIT.

Transpower, having regard to the submissions received, considered that applying an N-1 constraint in GEM was an appropriate constraint to be applied in the proposed GIT analysis.

Meridian Energy's submission of 4 April 2008 on Transpower's application of the proposed GIT requested that:

"The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario."

Transpower undertook this analysis. Three cases were considered:

- no constraint applied – as suggested by Meridian Energy;
- N-1 constraint applied as used in the GIT;

⁹ The letter from the Electricity Commission also cautioned that Transpower is required to reach its own view, but offered some guidance on the issue of security constrained modelling. Transpower has fully considered the matter and sets out its reasoning and views in this document.

- N-2 constraint applied as used in early analysis.

The outcomes of this analysis are fully reported in section 4.6 of Attachment A – Revised GIT Results to this document.

The analysis shows that the N-1 capacity constraint results in generation expansion plans under the prudent peak demand forecast, whereby demand is met whilst meeting the reserves requirement, with the largest unit out of service.

Under the no capacity constraint case, prudent demand will not be met from 2013 on. From around 2017, there will not be sufficient capacity to run the system with reserves intact, which increases the risk of load shedding. From around 2023 there is just enough capacity to meet peak demand but with no allowance for reserves at all – not even for frequency keeping. Such a level of generation is clearly not sustainable.

The Electricity Commission has also, more generally, analysed the impact on security of supply of running GEM with and without the capacity constraint. The Commission used a probabilistic model that took GEM market development scenarios as inputs and assessed the periods where the system would operate at N-security, i.e. running with too few reserves to deal with the loss of largest unit.

The Commission's analysis showed that the number of half-hourly trading periods, where there is insufficient capacity to cover the loss of the largest unit rises to 2,000 by the end of the horizon, using an N capacity constraint - approximately 20% of the year. The historical level is at around 5-6 half-hourly trading periods per year. The Commission found that this level was maintained when using the model with an N-1 capacity constraint. The Commission also found that this reduces even further to below 1 half-hourly trading period using an N-2 capacity constraint.

Based on all of the analysis undertaken, including the work in response to Meridian Energy's submission, Transpower considers that the N-1 capacity constraint is the most realistic assumption for the purposes of this analysis, most importantly because it maintains the current level of reliability and security.

Ignoring an N-1 constraint by running the model with no constraint applied results in a significant, unrealistic lack of new generation built in the system. Running the model with an N-2 constraint builds more generation than using the N-1 constraint. Given that the results using N-1 were consistent with current levels of reliability, the results suggest that, unless the preference for reliability changes significantly, the market would not be likely to deliver N-2 security.

Transpower's overall assessment of the GEM model is that it is suitable for this HVDC GIT economic analysis and this was supported by a recent review by Dr Grant Read, which can be found at:

<http://www.electricitycommission.govt.nz/opdev/modelling/gem/documentation>

Transpower also applied the PLEXOS model to this analysis (which Dr Read's review also considered a reasonable model for the purposes of this HVDC GIT analysis) and the results of that analysis, which are for information only, are set out in Attachment G to the Consultation Paper (see Volume 2). While Transpower has not relied on the PLEXOS model to produce its GIT results, it is reassuring, consistent with the submissions by Genesis and MEUG, that it has produced similar results to Transpower's own GIT analysis.

5.2.2 Demand growth assumptions

Transpower has used the Electricity Commission's draft 2007 Statement of Opportunities demand forecasts for this GIT analysis. These are included in Appendices B and C of Attachment B – Databook to the Consultation Paper (see Volume 2). Transpower considered whether to use these forecasts or its own demand forecasts published in its 2007 Annual Planning Report (APR) for the purposes of this GIT analysis. Having sought feedback from industry participants, Transpower considered that, while application of its own

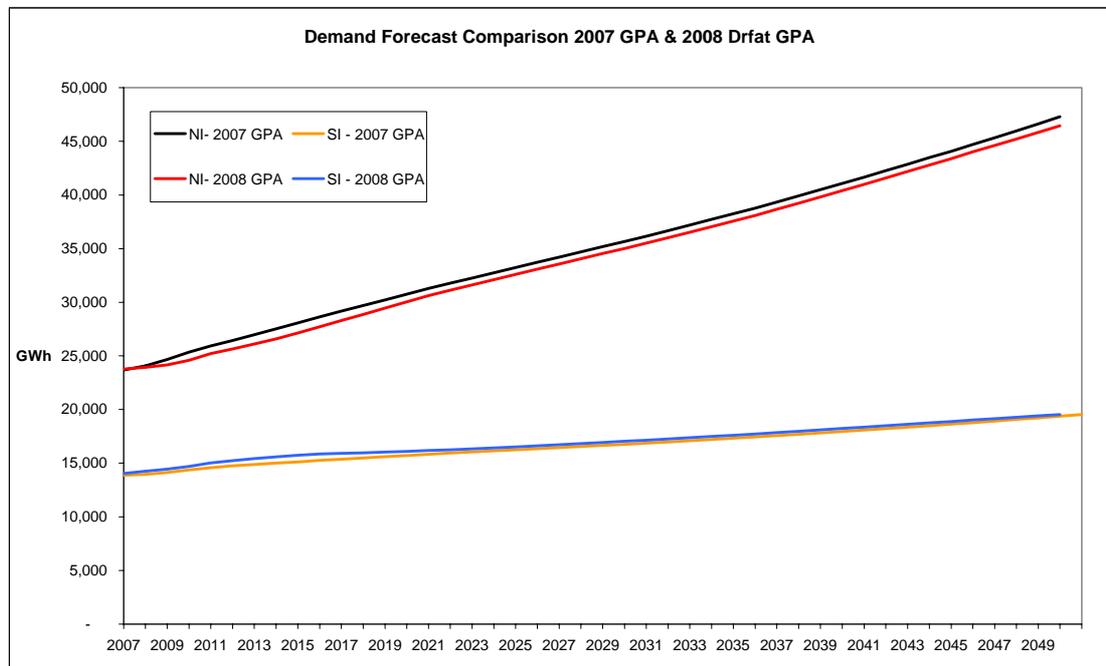
demand forecasts may have also been reasonable, the forecasts suggested by the Commission were reasonable for the purposes of the proposed analysis.

During consultation on Transpower's proposed application of the GIT, submissions suggested that since the Commission had published draft 2008 Statement of Opportunity demand forecasts, that these should be considered.

The chart below shows the Electricity Commission's draft 2008 demand forecasts (GWh) by island against the draft 2007 demand forecasts which were used in the GIT analysis. Overall, the national demand forecast has fallen by around 1% in the current proposed draft 2008 forecasts.

The allocation between islands has changed a little more significantly with the draft 2008 demand forecasts showing slightly more demand in the South Island than in the North Island, in other words, there is a higher allocation to the South Island.

Figure 5-1: Comparison of Demand Forecasts – 2007 GPA and draft 2008 GPAs



Transpower has not undertaken any specific analysis using the draft 2008 demand forecasts, as it believes the results would be captured by the further sensitivity outlined below in response to a Meridian Energy submission. The results of that analysis indicate that the Proposal would still meet the requirements of the GIT. Transpower therefore concludes that use of the draft 2008 Statement of Opportunities demand forecast would still result in this Proposal passing the GIT.

Meridian Energy raised issues with regard to the demand forecasts in the recent consultation. Meridian's main contention is that the Transpower demand forecasts understate demand growth in the South Island, resulting in more generation being available for transfer on the HVDC than would actually be available. Meridian Energy considers that Transpower's forecasts therefore overstate the value of replacing Pole 1.

Transpower's response to Meridian Energy's various submissions are contained in Attachment E to this document. The main point Meridian Energy make is that demand growth in South Island in recent years has been much higher than Transpower reflects in its

forecasts and that a forecast based on actual demand growth over the last 10 years would be more appropriate.

Transpower commissioned Covec to consider Meridian's proposition. Covec's report, South Island Electricity Load Growth¹⁰, is included as Attachment C to this document. Covec concluded that the recent high South Island demand growth has mainly been attributable to growth from dairy farming and that there are emerging constraints which are likely to mean that the recent high demand growth will not be sustained. The constraints include the competition for water resources and an increasing trend towards the use of bio-energy systems on dairy farms.

Nevertheless, Transpower has undertaken two new sensitivity studies to consider the effect on the GIT results if the recent high South Island demand growth did continue:

- High South Island growth - South Island demand growth is extrapolated, based on recent historical data (1997-2007), out over the full period of analysis; and
- 10 year high South Island growth - South Island demand growth extrapolated as above based on the historical data out over approximately the first 8 years at which time it over 4 years reverts to mean demand growth rates.

Although the expected net market benefit of replacing Pole 1 was reduced, in both sensitivities, the Proposal was still the preferred option and still had a positive expected net market benefit.

Having considered submissions received on the demand growth assumptions, sought expert advice on South Island demand growth and having undertaken further sensitivity studies, Transpower is satisfied that the demand forecasts used in the HVDC analysis are reasonable and fit for purpose.

5.2.3 Market development scenarios

Transpower discussed with Electricity Commission staff the market development scenarios and weightings to be used in the HVDC analysis. The Commission staff suggested a set of market development scenarios.

Having sought feedback from industry participants, Transpower considered that the suggested market development scenarios were reasonable for use in the analysis.

Establishing weightings to be applied to the market development scenarios is somewhat subjective, but some observations can be made which assist establishing reasonable weightings:

- Scenarios with higher proportions of renewables are likely, as only these scenarios enable the electricity sector to contribute its share toward reducing emissions of greenhouse gases in line with New Zealand's Kyoto commitments.
- The South Island surplus scenario should be considered unlikely, given recent announcements that Meridian Energy and Rio Tinto now have a supply agreement through to 2030.
- A more detailed and complete description of the reasoning Transpower applied in deriving the weightings can be found in section 5.6.4 of Attachment A – Revised GIT Results and with that in mind, Transpower derived and used the following market development scenarios and weightings to calculate the expected net market benefit of each short list option:

• High gas discovery (MDS 1)	20%
• Mixed technologies (MDS 2)	10%
• Primary renewables (approx 75%) (MDS 3)	15%
• South Island surplus renewables (MDS 4)	5%
• 90% renewables by 2025 (MDS 5)	50%

¹⁰ See Attachment C to the Proposal.

More description of the market development scenarios used in Transpower's GIT analysis and the weightings is provided in the table below:

Table 5-1: Summary of market development scenarios, weightings and descriptions

Scenario	Description	Weighting
High Gas Discovery (MDS 1)	Timely and extensive exploration for gas leads to a relatively unrestricted supply of natural gas at prices similar to today's. Several new gas-fired power stations are constructed. Low carbon prices lead to less renewable generation. It is assigned a moderate probability, reflecting uncertainty around gas discoveries.	20%
Mixed Technologies (MDS 2)	Low carbon price lead to less renewable generation. A mixture of generation technologies is the result, including new coal-fired generation in the North Island after 2020, as well as geothermal, wind, and hydro. Thermal peakers support intermittent generation. Demand-side measures also contribute to peak management. The coal-fired units at Huntly remain in operation until 2030 but are replaced with new fossil generation. Carbon emissions will increase significantly in this scenario.	10%
Primary Renewables (MDS 3)	High carbon prices discourage the development of fossil-fuel-based generation. Combined with a constrained gas supply, this leads to the development of renewable options. Geothermal, hydro and wind generation all feature strongly. In the later part of the scenario, both renewable and thermal projects are added to provide peaking capacity in the North Island (including pumped and peaking hydro schemes, and gas- or oil-fired thermal units). Demand-side measures also contribute to peak management. The coal-fired units at Huntly Power Station remain in operation until 2030.	15%
South Island Surplus Renewables (MDS 4)	This is a variant of the 75% Renewables scenario, and is similar in many respects (with a strong emphasis on geothermal, wind, and hydro generation). The key difference is that in the SI Surplus variant, the Tiwai Point aluminium smelter ceases operations with a gradual phase-out from 2014 to 2019. The results include increased northward power flows, and delays in generation build relative to the 75% Renewables scenario.	5%
90% renewables (MDS 5)	Government policies strongly discourage the development of fossil-fuel-based generation, and raise the proportion of renewable electricity generation to 90% by 2025. The coal-fired units at Huntly are decommissioned between 2013 and 2017 and replaced by renewable generation. Geothermal, hydro and wind generation all feature strongly, with biomass-fired cogeneration, marine, and coal with carbon sequestration added later in the scenario. In the later part of the scenario, both renewable and thermal projects are added to provide peaking capacity in the North Island. Demand-side measures also contribute to peak management.	50%

In its submission on Transpower's proposed application of the GIT, MEUG did question whether Transpower's reasoning for the scenario weightings was sufficient and this is also addressed in section 5.6.4 of Attachment A – Revised GIT Results, along with some sensitivities showing the effect of applying different weightings. As those sensitivities show, the GIT outcome is robust to variations in scenario weightings, favouring the same option in each case.

5.3 Cost refinements

Since publishing its proposed GIT analysis for consultation, Transpower has refined and updated the estimated scope and costs for the options in light of further available

information. As a result, Transpower's GIT analysis has used slightly different costs to those used in its proposed analysis.

In summary, the overall development plans for each of the options considered in the GIT have changed by, in \$2007 million:

Table 5-2: Change in costs of development plans

	\$2007 million (not discounted)	PV, \$million	Expected net market benefit change (compared to Base Case), PV \$million
Base Case	+\$36	+\$24	-
Option 1	+\$32	+\$21	+\$3
Option 2	+\$30	+\$20	+\$4
Option 3	+\$15	+\$14	+\$10

The change in relativities of these costs does mean that the expected net market benefit calculations change, as shown in the right hand column. These changes are reflected in the revised GIT results, but as can be seen, they are not material to the GIT outcomes or conclusions.

5.4 Results

The weight-averaged expected net market benefit for each short list option is set out in Table 5-3 below.

Table 5-3: Overall results of application of the Grid Investment Test

Item	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Generation fixed costs (A)	7,000	6,847	6,769	6,800
Generation variable costs (B)	9,499	9,392	9,356	9,291
HVDC costs (C)	59	325	436	554
AC augmentation costs (D)	45	47	48	49
Terminal benefit (E)	5,858	5,712	5,660	5,661
Total cost (A+B+C+D+E)	22,461	22,323	22,269	22,355
Expected Net Market Benefit	-	138	191	106

These results show that Option 2, building a 700 MW Pole 1 at Benmore and Haywards, has the highest expected net market benefit of the short list options, being some \$53 million in 2007 present value terms higher than the next highest short list option, building a 500 MW

Pole 1 at Benmore and Haywards. Transpower notes that there is analysis suggesting that omitting reserve costs significantly underestimates the expected net market benefit of investment, in particular Option 2, compared to the Base Case (see 5.8.1 below).

Without including these benefits, the expected net market benefit of Option 2 is \$191 million and, being greater than zero, Transpower concludes that Option 2, therefore, meets the requirements of clauses 4.2.1 and 4.2.2 of the GIT (as quoted in section 5.1 above).

Transpower has gone on to consider the sensitivity of this result to changes in key variables and parameters to assess the robustness of this result (see clause 4.2.3 of the GIT).

5.5 Sensitivity analysis

Table 5-4 below sets out a summary of weight-averaged sensitivity studies. These show that the ranking of the short list options is stable to a range of sensitivities. All sensitivities show Option 2, the 700 MW replacement option, having the highest positive expected net market benefit.

Table 5-4: Sensitivity of expected net market benefit of the short list options

\$2007 million	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Base results	-	138	191	106
Sensitivity:				
Discount rate, 4%				
Discount rate, 10%	-	446	600	514
HVDC capital 80%	-	-7	4	-76
HVDC capital 120%	-	191	267	205
10 yr avg x-rate	-	84	115	6
HVDC O&M 0.2%	-	135	174	83
HVDC O&M 1.0%	-	143	199	116
Base – med demand, 90% renewables only				
Base – med demand, 90% renewables only	-	300	395	292
N-2 cap constraint	-	531	672	509
Generation capital	-	312	375	260
No HVDC charge	-	305	352	271
Base – med demand, Option 2 only				
Base – med demand, Option 2 only	-	-	221	-
ROX termination	-	-	211	-
BPE termination	-	-	204	-

5.6 Conclusions of Transpower's application of the Grid Investment Test

Option 2, a 700 MW Pole 1 replacement terminated at Benmore and Haywards, satisfies the GIT because:

- it maximises the expected net market benefit when compared with the alternative projects;
- it has a positive net market benefit; and

- it is robust having regard to the results of a sensitivity analysis.

It is noted that whilst the expected net market benefit of Option 2 is \$187 million, this is averaged over five market development scenarios and uses a 7% discount rate.

The net market benefit of Option 2 for the 90% renewables by 2025 scenario, which is most consistent with the government's New Zealand Energy Strategy, is \$348 million, using a 7% discount rate. If a 5% discount rate is used, consistent with the New Zealand Energy Strategy, the net market benefit of Option 2, for the 90% renewables by 2025 scenario, would be approximately \$700 million.

These results are robust to the wide range of sensitivity analysis carried out by Transpower. It therefore fulfils the criteria of clause 4.2 of the GIT.

5.7 Timing of the Proposal

The quantitative analysis in section 7 of Attachment A - Revised GIT Results, to this document shows that the net benefits for the various stages of Option 2 are:

- Stage 1 – similar between 2012 – 2014, and then net benefits decrease after 2014;
- Stage 2 – similar between 2012 – 2018, and then net benefits decrease after 2018; and
- Stage 3 – not required before 2018 and in thermal scenarios, potentially after 2030.

This Proposal seeks approval to recover the costs for implementing Stage 1 and Stage 2. Stage 3 is not included in this Proposal and will form the basis of a separate proposal, when the need for Stage 3 is nearer.

Transpower proposes to commission Stage 1 in 2012 and Stage 2 in 2014.

5.7.1 Stage 1 timing

Given that the quantitative analysis for investment in Stage 1 shows that it is close to breakeven between 2012 and 2014, it is necessary to consider other factors in deciding when to aim for commissioning within this band.

Generation option value

Meridian Energy and Contact Energy consider that there is a significant option value in delaying the commissioning of Stage 1. For example, Meridian Energy considers such a value exists due to considerable uncertainty in generation costs, and generation build plans, of market participants, and the greater relative costs of generation than transmission.¹¹

Transpower accepts such an option value exists, but does not believe that it exists to the extent suggested. Transpower considers that there is a more significant countervailing option value. This results from early commissioning of Stage 1 creating options for generators which would not be there otherwise. Transpower believes that it is widely accepted that, as the lead times of transmission investment exceed that of generation investment, an efficient generation investment market requires transmission investment to lead generation investment.

Uncertainty over continued Pole 1 limited operation

Transpower notes that the HVDC plays an important role in improving security of supply in dry years, by enabling southwards transfer of electricity for North Island generators when there are low inflows into the South Island hydro schemes. The potential difficulties the New

¹¹ Meridian Energy's other arguments regarding deferral benefits and demand forecasts are addressed in Transpower's quantitative analysis in section 7 of Attachment A to this document.

Zealand electricity supply system faces this coming 2008 winter have highlighted the importance of having more than the existing Pole 2 transfer capacity available at such times. Transpower's insurers have agreed to insure the existing Pole 1 for limited operation with annual reviews. There is no certainty that it will be available even for limited operation beyond 2009.

Further, the equipment is old and susceptible to terminal failure at any time.

From this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Susceptibility to Pole 2 failure

The existing Pole 2 is aging and there is an inherent, increasing risk of it failing. A replacement Pole 1 would mitigate the consequences for security of supply of a Pole 2 failure. Although the critical failure of Pole 2 is a low probability event, it would have a high impact. This suggests that it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Increased resilience to high impact, low probability events

A larger HVDC, in bipole configuration, will increase the flexibility of system operations to deal with other high impact, low probability events that could occur elsewhere in the electricity supply system. This will improve the overall reliability of supply. Therefore from this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Enhanced ability to develop ancillary markets

Replacing Pole 1 will offer opportunities to develop the market for ancillary services (such as frequency keeping, reserves and balancing markets) and lower the cost of these services overall. Some such developments are already being contemplated by the Electricity Commission. From this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible, as otherwise potential benefits to be derived from these enhanced markets will be foregone.

Earlier development of support required for intermittent renewable sources

The development of renewable generation in the medium term is likely to include a substantial proportion from intermittent sources. As the proportion of intermittent generation in the system increases, so to does the need for the supporting generation required to ensure a reliable electricity supply. The HVDC will play an important role in ensuring that support does not have to be physically located in the same island as the intermittent generation. It is possible that a smaller link could restrict the development of intermittent renewable generation from this point of view. This also suggests that it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Constructability risk

There is a risk that construction could take longer than forecast. Given the way costs increase if the replacement Pole 1 is commissioned after 2014, it would be imprudent to aim for 2014, as there would be a higher risk that these costs would be incurred.

Conclusion on Stage 1 timing

Overall, these considerations lead Transpower to the conclusion that the potential costs of commissioning the Proposal in 2012, as opposed to 2014, are far outweighed by the potential benefits of commissioning in 2012.

Transpower's Proposal therefore targets commissioning Stage 1 in 2012.

5.7.2 Stage 2 timing

Transpower's quantitative analysis also shows that the optimal timing for commissioning Stage 2 timing is close to breakeven between 2012 and 2018.

Stage 2 consists of a new synchronous condenser which is to be placed on the same site as the existing Pole 1. It is estimated that Stage 2 will take approximately 18 months to construct, as it consists of decommissioning/demolishing the existing Pole 1,¹² clearing the site and constructing the new equipment. Transpower recommends that this work does not commence until Stage 1 of this project is successfully commissioned, in order to maximise the possibility that more than 700 MW of HVDC transfer capacity between the islands will be available until then.

Most of the arguments discussed above for the earliest possible commissioning of Stage 1 of the Proposal, also apply to Stage 2. Transpower recommends aiming for the earliest possible commissioning of Stage 2 for those same reasons.

Given the estimated 18 month construction time for Stage 2, and the imperative to keep the existing Pole 1 operating in its limited operation mode, if possible, Transpower therefore proposes targeting commissioning of Stage 2 in 2014.

If it is not possible to maintain the existing Pole 1 operating in its limited operation mode until Stage 1 of the Proposal is commissioned, Transpower recommends building Stage 2 as early as possible. This Proposal is submitted on the basis of commissioning Stage 2 in 2014, but if it turns out to be plausible to commission it earlier, Transpower will discuss that possibility with the Commission at the time.

5.8 Other benefits favouring the Proposal

While outside Transpower's application of the GIT in whole or in part, a number of factors reinforce Transpower's view that Pole 1 of the HVDC link should be replaced and that the Proposal is the best option available. These factors include:

- Reserves modelling;
- Strategic benefits;
- Enabling wind diversification;
- Cost effectiveness of carbon abatement;
- Wholesale competition benefits;
- Retail competition benefits;
- Consumer benefits;
- System stability improvement;
- Transient stability;
- Frequency control / stabiliser; and
- Other benefits of HVDC dynamic performance.

Transpower considers each of these factors in turn below.

5.8.1 Reserves modelling

Genesis Energy expressed concern in its submission on Transpower's proposed GIT application that the GEM and SDDP models do not include the modelling of instantaneous

¹² Outside the scope of this Proposal, see section 4.3 above.

reserves. In particular, Genesis Energy queried whether the modelling scheduled enough capacity (particularly in the Base Case) to meet reserve energy requirements.

Transpower considered this issue early in the HVDC Pole 1 Replacement Investigation Project and while agreeing with Genesis Energy that not modelling reserves is likely to “under-schedule” capacity in the Base Case, that this was reasonable for the purposes of analysing this economic investment.

As Genesis Energy noted, the PLEXOS analysis did include the modelling of reserves. It is also noted that the expected net market benefit of replacing Pole 1, in the PLEXOS analysis, is higher than in Transpower’s analysis.

In response to Genesis Energy submission, Transpower asked MMA to undertake further analysis to ascertain how much of the PLEXOS net benefit could be explained by reserves modeling. To do this, MMA compared results with and without reserves modelling. Their report is attached to this Proposal as Attachment D. In summary, they found that the expected net market benefit, under medium demand growth, for the 700 MW replacement option, varied as follows if reserves were not modelled:

Table 5-5: Additional benefits as a result of modelling reserves for each market development scenario

Market development scenario	Additional benefits as a result of modelling reserves (\$M)
High Gas	\$26
Mixed Technologies	\$43
Primary renewables	\$64
SI Surplus	\$51
90% renewables by 2025	\$46
Weighted average	\$44

MMA also undertook the same analysis using the expansion plan obtained using GEM for the 90% renewables by 2025 scenario only. Their results show that without modelling reserves there was a reduction in the net market benefits of the 700 MW replacement of \$34 million, which is consistent with their own results.

This supplementary MMA analysis supports Transpower’s supposition that the GEM/SDDP modelling, without reserves, is conservative. The analysis suggests that the GEM/SDDP modelling underestimates the expected net market benefit of the Proposal by approximately \$30 - \$50 million.

5.8.2 Strategic benefits

Transpower considers that this Proposal also provides a number of benefits, not fully reflected in the Grid Investment Test results, including:

- enabling the development of renewable generation in the South Island by ensuring a reliable connection between the South and North Island;
- enabling development of ancillary markets (such as frequency keeping, reserves and balancing markets) to support increased generation from intermittent renewable sources;
- increasing resilience of the National Grid to high impact, low probability events by increasing the flexibility of system operation;
- improving security of supply in dry years, by enabling greater southwards transfer of electricity from North Island generators when there are low inflows into the South Island hydro schemes; and
- mitigating the consequences for security of supply of a Pole 2 failure, noting that the existing Pole 2 is aging and there is an inherent, increasing risk of it failing.

5.8.3 Enabling wind diversification

As more wind farms are built in the North Island, the non-firm nature of this resource is likely to put a strain on the rest of the system from a reliability perspective. When the wind is not blowing, there still needs to be sufficient capacity to cover demand. Over time, an additional reserve market may emerge to back up the intermittency of wind. With a larger link capacity than a 700 MW monopole, there is potential for more South Island hydro capacity to be built, resulting in less reliance on wind capacity in the North Island. Furthermore, if more South Island wind capacity is built as a result of the larger link, the geographical diversity may help smooth out the intermittency of supply and improve overall reliability of supply.

In a recent joint study between Meridian Energy and Imperial College, London into the system integration impacts of wind generation in New Zealand¹³, it is reported that the additional capacity costs that wind generation impose on overall energy costs will be reduced once HVDC capacity is increased from 1000 MW to 1500 MW capacity.

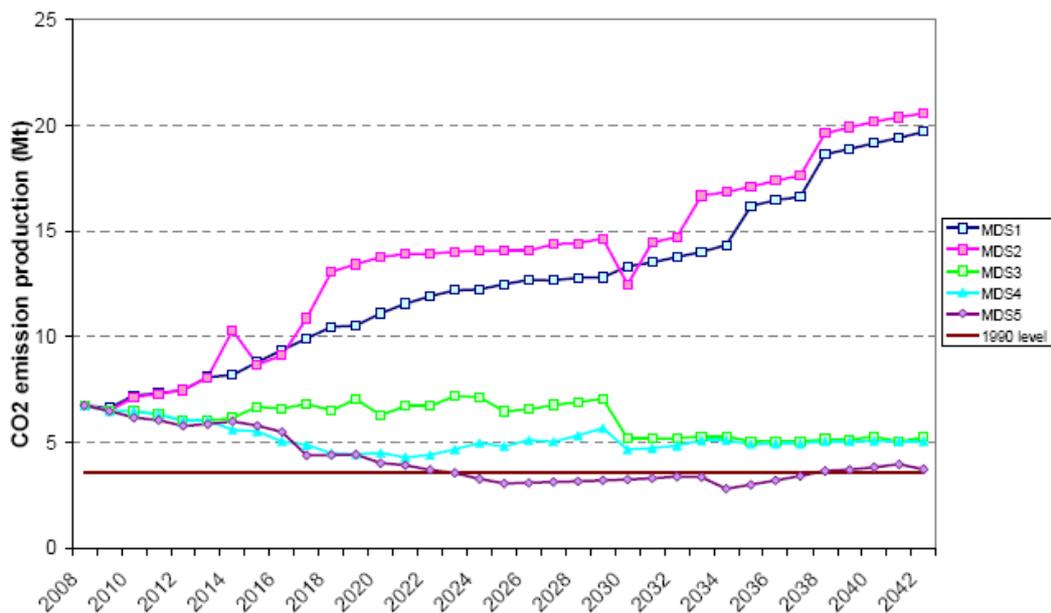
The study finds that the additional capacity cost of wind generation decreases by approximately \$0.5 per MWh once Pole 1 is replaced. Using the wind generation estimates included in the report, this equates to a saving of approximately \$14 million, as a present value, between 2010 and 2020 alone.

The \$0.5 per MWh decrease in capacity related cost is achieved over a decade (2010-2020) where the generation from wind power triples. Capacity related costs also increase the following decade (2020-2030) with the explanation being even higher wind penetration. Thus, the impact from the extra HVDC capacity is likely to be even higher than \$14 million estimated benefits quoted in this study.

5.8.4 Cost effectiveness of emission abatement

MMA's PLEXOS analysis shows that the Government's emission abatement target to return to 1990 CO₂ production levels by 2025 would probably only be achievable for the stationary energy sector under market development scenario 3, 4 or 5, as shown in Figure 5-2 below.

Figure 5-2: Market Development Scenario by CO₂ emission production



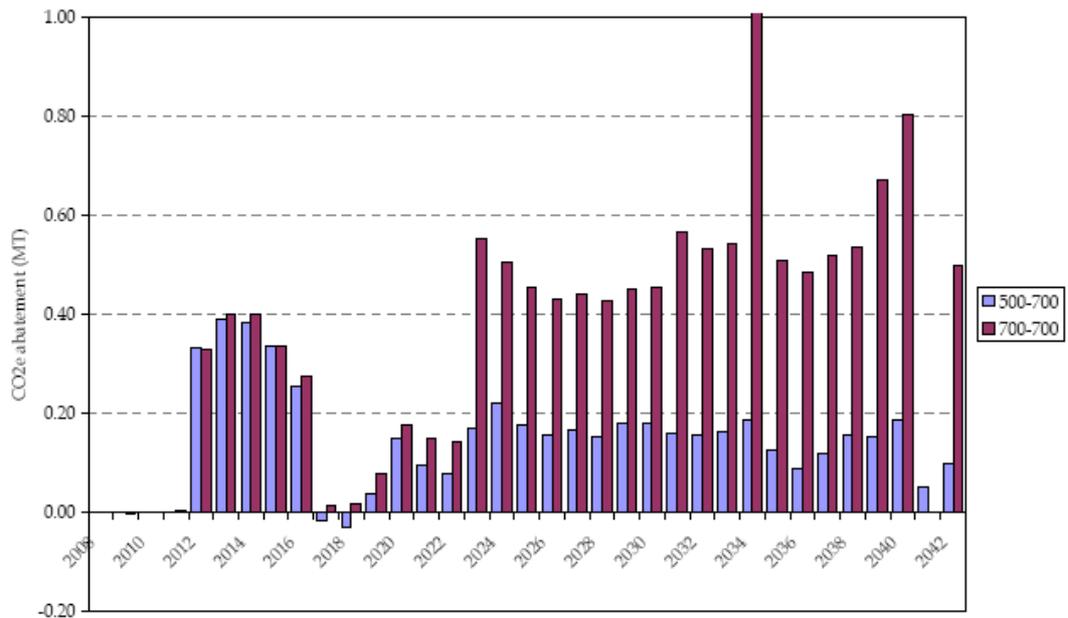
¹³ <http://www.meridianenergy.co.nz/AboutUs/News/Economic+virtues+of+future+wind+generation.htm>

The 1990 target could be met in 2025 in all cases (the Base Case and all options), although it cannot be sustained for more than five years under the Base Case and 500 MW option. The 700 MW option is the most cost-effective CO₂ emission abatement alternative, as it produces fewer emissions than the other options.

Figure 5-3 shows the emission abatement from the 500 MW and 700 MW options relative to the Base Case, for the 90% renewables by 2025 scenario and for medium demand growth. From 2024 onwards, emission abatement under the 700 MW option is nearly double the abatement from the 500 MW option. This is largely driven by the additional North Island wind that is built in the 700 MW option, compared with other thermal and DSR technologies chosen under the 500 MW option. In all but the High Gas scenario, the emission costs are lower and hence the emission abatement is higher under the 700 MW option than the 500 MW option.

It should be noted that the emission abatement benefits have already been included in the GIT analysis, with the value of abatement assumed to be equal to the carbon price assumed. However, if carbon prices were higher than assumed in this analysis, the Proposal would offer even more benefit than attributed in the GIT analysis.

Figure 5-3: Emission abatement – MDS 5, medium growth



5.8.5 Competition benefits

Whilst it is intuitive that providing a link between the North Island and South Island should enable greater competition between generators in both islands, it is difficult to calculate the benefits that result from that enhanced competition.

Transpower employed MMA to consider the effect of the various Pole 1 replacement options on competition benefits and consumer benefits. A summary of their findings can be found in Appendix B to this report and their full report is included as Attachment G to the Consultation Paper (see Volume 2). Although the GIT does allow competition benefits to be included provided they are quantified, given the exploratory nature of this work Transpower has chosen not to include them in the GIT result for this proposal.

Competition benefits only arise in situations where one or more competitors in a market are in a position to exercise market power and they exercise that power in a manner that results

in inefficient outcomes, compared to a situation where they could not exercise that power. Hence, to model competition benefits in a market requires assumptions to be made about the extent of potential market power and the market behaviour of those competitors when they exercise that power.

For the purpose of this project, that requires assumptions to be made about the ownership of new generation built and how competitors would exert market power, e.g. by withdrawing some generation to enable more of their less efficient and more expensive generation to run

In the analysis undertaken, some surprising results emerged - both positive and negative competition benefits were found, depending on the market development scenario.

That may be explained by the observation that, when the North Island becomes capacity constrained, a lot of new generation is built in the North Island, particularly in the Base Case. Hence the North Island has a very competitive market in the Base Case and by expanding the HVDC and reducing the amount of new generation in the North Island, the level of competition is potentially reduced.

Whilst this may help explain the outcomes observed, it does highlight how important the assumptions are and it raises a question about whether enough work has been undertaken to robustly conclude the extent of competition benefits for the HVDC options considered. Different assumptions about new generation ownership and market behaviour, would likely produce different outcomes.

For information, a summary of the competition benefits for individual scenarios and for high, medium and low demand, for the 700 MW replacement option, were as follows:

Table 5-6: Competition benefits by generation and demand scenario.

Competition benefits (\$2007 m)	Demand scenario		
	High	Med	Low
High Gas	-\$55	-\$40	-\$119
Mixed technologies	-\$13	-\$22	-\$33
Primary renewables	\$171	-\$57	-\$194
SI surplus	\$213	-\$526	-\$481
90% renewables by 2025	\$101	\$188	\$111

Applying the weightings used in the GIT, this gives a competition benefit to the Proposal of approximately \$42 million compared to the Base Case. As discussed above, these results are explainable.

Transpower is encouraged by the MMA analysis, as it produces explainable results for the assumptions made, but considers that other ownership/market behaviour combinations would need to be modelled to draw robust conclusions about competition benefits.

Whilst this analysis may not support the existence of positive competition benefits for the Proposal, Transpower would still expect a positive competition benefit emerge with further modelling. It seems intuitive that linking the North Island and South Island enhances competition nationally.

5.8.6 Consumer benefits

Consumer benefits are benefits to consumers of electricity and in general are related to the competitiveness of a market and the resulting efficiency of the market. In an efficient market, consumers could expect that electricity prices would be close to long run marginal costs to produce electricity, whereas in an inefficient market, electricity prices could be well above long run marginal costs. The cost differences related to these market inefficiencies are largely wealth transfers between generators and consumers. These wealth transfers are not

considered in the GIT.¹⁴ Nevertheless Transpower would expect the Electricity Commission to have a preference for competitive markets which deliver consumer benefits.¹⁵

MMA also considered a range of consumer benefits at the same time as considering competition benefits. Their conclusions are summarised in Appendix B and are described fully in Attachment G to the Consultation Document – Volume 2. In brief:

HVDC constraints

Congestion on the HVDC can place generators in the constrained region in a position of market power, so in general, the fewer constraints on the HVDC, the better from this point of view.

Generally, the results indicate that there are fewer constraints if Pole 1 is replaced than if it is not. Additionally constraints decrease as replacement Pole 1 capacity increases.

Market concentration/competitiveness

Market concentration was assessed using an adjusted Herfindahl-Hirschman Index (HHI). The HHI is calculated using the following formula:

$$HHI^{adj} \equiv \sum_{i=1}^m s_i (s_i + s_c / m)$$

where s_i is the market share of the i -th unconstrained firm ($i = 1, \dots, m$) and s_c is the total market share of the constrained firms.

Markets with many competitors and small market shares are less concentrated and have a smaller HHI than markets with few competitors with large market shares.

A smaller HHI is preferred. MMA found that the HHI drops over time whether Pole 1 is replaced or not. In all cases though, the commissioning of a replacement Pole 1 in 2012 reduces the HHI and generally results in a lower HHI over time than if Pole 1 had not been replaced, i.e. the replacement of Pole 1 ensures the electricity market is less concentrated.

Price Mark-ups

The Lerner index was used to calculate how price mark-ups (amount a generator bids over and above their marginal cost) change with HVDC link size. The Lerner Index is calculated as:

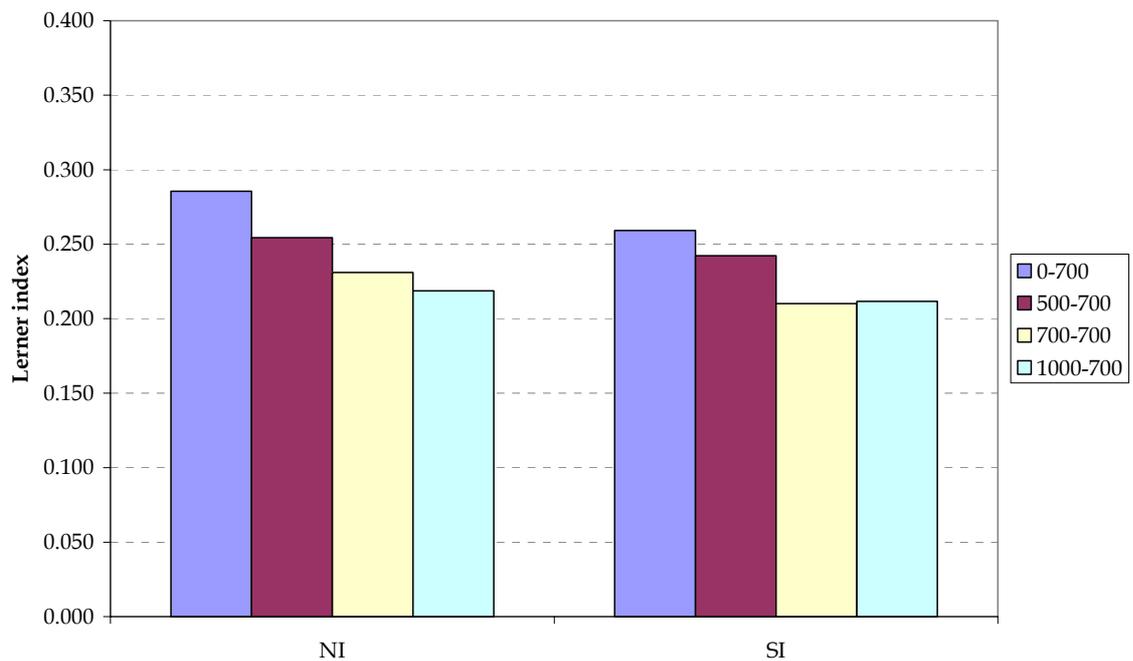
Lerner Index: $LI = (\text{bid price} - \text{short run marginal cost}) / \text{bid price}$

The Lerner index for each year is calculated based on the average bid prices from the Nash-Cournot simulations and the average short run marginal cost from the non-competition simulations.

The figure below shows that the weighted average Lerner index ranged from 0.2 to 0.3 across all augmentation scenarios in both North Island (NI) and South Island (SI). A Lerner index of zero would imply that there is no market power in the system, so a lower index is preferred.

¹⁴ However, any associated deadweight loss due to levels of generation being lower than optimal could be.

¹⁵ See the Government Policy Statement on Electricity Governance, e.g., clause 80.

Figure 5-4: Average Lerner index for North Island and South Island

As seen, the Lerner index indicates that the price mark-ups decrease as link size increases.

Nodal price changes

Nodal prices were calculated at Penrose and Islington, over time, for each option.

The table below shows the annual average price differential between the specific nodes in the North Island and South Island for the same scenario and level of demand. Increasing the capacity of the HVDC link reduces the price differential between the North Island and the South Island, with the price in the South Island typically increasing more than the decrease in price in the North Island.

Table 5-7: Price differential between North and South Islands, 90% renewables by 2025, medium demand

HVDC option	Average annual price differential post augmentation (\$/MWh)
0-700	25.9
500-700	8.0
700-700	6.6
1000-700	6.3

5.8.7 Retail competition

While the presence of an HVDC link affects competition on the wholesale market, it also affects retail competition in as much as it effectively increases the geographic market in which retailers can operate.

Electricity generation and retail are vertically integrated in New Zealand and the retail arm of these vertically integrated companies offers the generator a natural hedge for its generation

output. Retail competition is not considered to be “as vigorous as it could be¹⁶” with only three retail companies offering contracts in the majority of the South Island¹⁷.

Currently, it is common practice for a retailer to offer contracts in the island in which its parent company has generation located. For example, Genesis Energy only offers retail contracts in the North Island¹⁸ where all of its generation is located. One of the reasons for this is likely to be the risk of price separation between islands in the absence of the link or at times of constraint.

Compared with the Base Case, all options 1-3 will lead to a lower risk of price separation between the islands. This may make it more attractive for retailers to offer contracts to consumers on the “other” island. Furthermore, it may enable retailers that already offer retail agreements on the “other” island, to offer more competitive prices as their hedging costs are reduced.

Finally, a bipole link (i.e. options 1-3) will lead to a reduction in the amount of time the South Island price is separated from the North Island price. It will therefore be relatively more attractive to invest in generation in the South Island. Such investments, if made by generators currently not present in the South Island, may result in increased retail competition.

Conclusion

The consumer benefit analysis demonstrates that, in general, competitiveness is increased with a replacement Pole 1 and that competitiveness increases as the replacement link size increases.

Overall, there is expected to be a transfer of wealth from consumers to generators in the South Island, and from generators to consumers in the North Island, upon the building of the replacement link. The analysis suggests replacement of Pole 1 is likely to result in benefits to consumers.

This analysis does not include sensitivity analysis, which would improve the robustness of the results. The trends, however, do indicate that replacing Pole 1 of the HVDC link will enhance the competitiveness of the New Zealand electricity market and the benefits to consumers.

5.8.8 System stability improvement

The HVDC controls will incorporate several power and current modulation functions which exploit the high degree of controllability inherent in the HVDC link. The net market benefit derived from the special control functionality provided by the Proposal is difficult to quantify but forms an essential part for maintaining the stability and economic operation of the grid. Investment in a replacement Pole 1 (options 1-3) will provide additional modulation capacity to respond to AC system events over and above possible with the Base Case.

5.8.9 Frequency control/stabiliser

The HVDC frequency stabiliser provides a temporary fast reaction to frequency changes in either or both islands following system disturbances. This assists in arresting the frequency drop as a result of system disturbances. Without this function, more reserves or load shedding would need to be available to ensure the frequency is kept within defined frequency limits. This has a consequential flow-on effect in terms of increased costs for generators and consumers.

¹⁶ Draft Government Policy Statement on Electricity Governance, para 132, 29 Feb 2008.

¹⁷ Christchurch and Central Canterbury are the exception with four retailers offering contracts.

¹⁸ <http://www.consumer.org.nz/powerswitch/>

In the event that Haywards is separated from the upper North Island during high DC transfer north, over frequency is limited by the emergency over frequency control on the HVDC until the HAY islanded constant frequency control can be manually switched on.

The HVDC link can control the frequency in the Wellington area if it is separated from the upper North Island while being supplied from DC transfer.

Having an increased capacity over the Base Case provides increased head room required for frequency stabilisation functions to operate and to improve power system stability.

5.8.10 Other benefits of HVDC dynamic performance

In addition to the above known benefits of HVDC other new benefits, such as from improved frequency keeping and extending automatic generation control between the two islands, may result from the Proposal.

Transpower has not finalised the methodology for the cost/benefit analysis of such features. It has, therefore, not quantified the benefits of implementing such solutions in this Proposal. However, if it considers such potential benefits are likely, even if their value is difficult to estimate at this stage.

These benefits flow from (a) the increase in inter-island capacity and (b) the bipole link that will result from the Proposal:

- The increase in inter-island capacity will provide many benefits including an increased head room required for dynamic modulation for improving power system stability, enhancing the ability to block dispatch renewable generation via HVDC across the two islands. This will also provide a better means of catering for fluctuating generation sources and/or demand across the two islands.
- Having two poles in the Proposal instead of a monopole will provide self cover in the event of a pole outage reducing the need for additional spinning reserves and/or shedding large blocks of customer load.

5.8.11 Summary of other benefits

Transpower considers that the Proposal leads to a wide variety of benefits not accounted for in its GIT application. Transpower has not relied on these benefits in deciding to make this Proposal, but considers that these benefits reinforce the view that the outcome of its GIT analysis is consistent with wider policy objectives.

6 The Proposal meets the Rule requirements

Rule 14.4 sets out two criteria that a proposed economic investment must meet in order for Transpower to obtain approval from the Electricity Commission to recover the costs associated with implementing it, namely:

- Transpower's application of the GIT must be reasonable; and
- Transpower has followed any agreed consultation process.

Transpower also considers that the Proposal is consistent with GEIP, as were all the short-listed options.¹⁹

6.1 Transpower's application of the Grid Investment Test

Transpower considers that its application of the GIT, described above and in the attached documents, is reasonable.

6.2 Compliance with agreed consultation process

Rule 14.2 requires the Electricity Commission and Transpower to agree a timetable for consultation and approval of economic investments. In the absence of agreement, the Electricity Commission may stipulate such a timetable.

Additionally, the Electricity Commission must consult with Transpower on the process for consultation and persons who the Electricity Commission thinks are:

“representative of the interests of persons likely to be substantially affected by economic investments and content of draft grid upgrade plans”.

The Electricity Commission and Transpower agreed a timetable and process for consultation on, and approval of, the Proposal to Transpower on 6 November 2007. This was replaced by a revised process and timeline on 13 December 2007.²⁰ Transpower has complied with the process and timeline to date, and will work with the Electricity Commission to achieve the remaining agreed process and timeline.

6.3 Compliance with criteria for approval

As set out above, Transpower has applied the GIT reasonably and complied with the agreed process for consultation as required by the Rules for the Proposal. Transpower therefore considers that the Proposal satisfies the requirements of the Rules for approval by the Electricity Commission of a proposed economic investment to recover the costs associated with implementing it.

¹⁹ Transpower considered GEIP at the identification and screening of options stage (see section 4 above).

²⁰ Both are available at <http://www.gridnewzealand.co.nz/n282,110.html>.

7 The Proposal is consistent with wider policy objectives

In addition to the Rules requirements set out above, the Proposal is being submitted within the context of a wider regulatory framework.

Set out in this section is a brief assessment of the Proposal against the:

- purpose of section III of Part F of the Rules;
- Government Policy Statement on Electricity Governance (GPS); and
- principal objectives and specific outcomes under the Electricity Act 1992 (the Act).

7.1 The purpose of section III of Part F

Transpower submits that the objectives of Part F of the Rules are relevant to the Electricity Commission's consideration of the proposal.

Table 7-1: Alignment of the Proposals with the objectives of section III of Part F of the Rules

Rule (purpose of Part F)	Would approval of the Proposal contribute to this purpose?
2.1 Facilitate Transpower's ability to develop and implement long term plans (including timely securing of land access and resource consents) for investment in the grid	The investigation into the need for the Proposal, or other investment, has been a part of Transpower's long-term plan for the grid and has been included in: <ul style="list-style-type: none"> ◦ Transpower's 'Future of the National Grid' document of 2003; ◦ Transpower's 2005 GUP; and ◦ all of Transpower's Annual Planning Reports (the first being in 2006).
2.2 Assist participants to identify and evaluate investments in transmission alternatives	The development of the Proposal, particularly the extensive consultation process, has allowed and assisted participants to identify and propose transmission alternatives.
2.3 Facilitate efficient investment in generation	The Proposal will facilitate efficient investment in generation nationally and in the South Island in particular.
2.4 Facilitate any processes pursuant to Part 4A of the Commerce Act 1986	Any proposed investment that follows the Part F processes will achieve this.
2.5 Enable the cost of approved investments to be recovered through the transmission pricing methodology applied in transmission agreements	Any proposed investment that follows the Part F processes will achieve this.

7.2 The Government Policy Statement

Under section 172O(1) of the Electricity Act 1992, one of the functions of the Commission is to give effect to GPS objectives and outcomes. The current GPS is that issued in October 2006.

Table 5-2 below considers how the Proposal would contribute to giving effect to the relevant policies as laid out in the GPS.

Table 7-2: Alignment of the Proposals with the GPS (directly relevant policies only)

Government Policy Statement (directly relevant policies only)	Would approval of the Proposal contribute to this policy?
Renewable Energy	
<p>Encouraging the development of renewable energy resources is a key part of the Government's strategy for managing climate change and long term energy security. To further this aim the Government's objectives in relation to renewable energy, are that:</p> <ul style="list-style-type: none"> • undue barriers to investment in renewables should be reduced or removed • the efficient uptake of renewable generation should be promoted and • the national transmission grid should be planned and made available so as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies. 	<p>The Proposal will enable efficient levels of renewable generation, in the South Island by increasing transfer capacity, and in the North Island by increasing options for balancing with South Island plant.</p>
Security of Supply	
<p>Key components of security of supply are that:</p> <ul style="list-style-type: none"> • Hydro and thermal generating capacity and fuels are appropriately managed, to deal with the risks of extended dry hydro periods better than we have in the past • The national grid and distribution lines meet specified reliability objectives. (Transmission and distribution issues are covered in separate sections) 	<p>The Proposal allows for greater quantities of electricity to be transferred between the North and South Islands (inter-island transfer capacity). This improves security of supply in relation to dry year risks by enabling increased southward flows.</p> <p>The Proposal is consistent with the Grid Reliability Standards.</p>
Transmission - objectives for the provision of transmission services	
<p>80 The Government's objectives for the provision of transmission services are that:</p> <ul style="list-style-type: none"> • the services are provided in a manner consistent with the Government's policy objectives for electricity and in particular that grid reliability should be maintained at a level required by residential, commercial and industrial users and the Government's economic development objectives • the transmission grid should be adequately resilient against the effects of low probability but high impact events having regard to the load which could be disrupted and the duration of any disruption • where practical, the transmission grid should provide adequate supply diversity to larger load centres having regard to the load which could otherwise be disrupted and the duration of any disruption • competition in generation and retail is facilitated and transmission constraints are minimised 	<p>The Proposal is consistent with and assists the Government's policy objective of delivering electricity to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner.</p> <p>The Proposal is consistent with the Grid Reliability Standards.</p> <p>The Proposal improves the resilience of the grid in that it allows greater inter-island transfer capacity. This increases the number of management options available to Transpower in the event of low probability, high impact events. The probability of an outage preventing any inter-island transfer will be significantly reduced.</p> <p>While the Proposal does not directly serve a major load centre, it does improve reliability for North Island centres including Auckland and Wellington, and in dry years South Island centres including Christchurch, by increasing inter-island transfer capacity.</p> <p>The Proposal facilitates competition in generation by enabling new generation in the South Island in particular.</p> <p>The Proposal will reduce constraints to power flow between the islands. This will in turn facilitate competition in generation and retail by creating a more national market.</p>



	<ul style="list-style-type: none"> the national transmission grid should be planned and made available so as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies 	<p>The Proposal will enable efficient levels of renewable generation, in the South Island by increasing transfer capacity, and in the North Island by increasing options for balancing with South Island plant.</p> <p>The Proposal's consistency with the Government's climate change and renewables policies is well illustrated by fact that its net benefit almost doubles under the 90% renewables by 2025 scenario relative to that weighted across all scenarios, and doubles again under a lower discount rate.</p>
	<ul style="list-style-type: none"> the efficiency of transmission services should be continuously improved so as to produce the services grid users and consumers want at least cost, and 	<p>The Proposal provides a net market benefit and a higher benefit than alternatives, demonstrating that it meets grid users' and consumers' needs at least overall economic cost.</p>
	<ul style="list-style-type: none"> stakeholders and the public are kept well-informed about how security of supply is to be maintained throughout the development and consideration of any grid upgrade plans. 	<p>This document and its attachments, the preceding meetings and consultation and Transpower's Annual Planning Reports have ensured the public are well-informed on security and investment issues.</p>
<p>Transmission - Investment in and maintenance of the transmission network</p>		
87B	<p>The grid upgrade plan should also be consistent with statement of opportunity forecasts and wider government energy policy including applicable policies on renewable generation and climate change.</p>	<p>In developing the Proposal, Transpower has had regard to the Electricity Commission's draft 2007 forecasts.</p> <p>The Proposal is consistent with wider government energy policy including applicable policies on renewable generation and climate change, as outlined in this section.</p>
87C	<p>Grid upgrade plans should demonstrate the rationale for all expenditure (operation, maintenance and capital), taking into account the prescribed reliability standards and good industry practice for power system operation. The plans should demonstrate that the proposed expenditure is required to meet reliability standards and/or deliver the greatest net benefit after taking into account transmission alternatives and government energy policy requirements.</p>	<p>This Proposal demonstrates the rationale for the costs of the Proposal, taking into account good electricity industry practice.</p> <p>The Proposal is consistent with the Grid Reliability Standards.</p> <p>The Proposal delivers the greatest net benefit after taking into account transmission and non-transmission alternatives.</p> <p>This section outlines how the Proposal contributes to government energy policy requirements.</p>
87D	<p>In the development of grid upgrade plans; the Government's objective is that:</p> <ul style="list-style-type: none"> Transpower should undertake the detailed planning role (including the assessment of both transmission and non transmission alternatives); and the Electricity Commission should review and approve grid upgrade plans that meet the criteria set out in the Electricity Governance Rules and reject applications that fail them. 	<p>The process of developing this Proposal is consistent with these roles.</p>
87F	<p>The Electricity Commission should ensure that affected parties are fully consulted on grid upgrade plans.</p>	<p>Transpower has followed the consultation process agreed with the Electricity Commission in developing this Proposal.</p>
87G	<p>In developing and considering grid upgrade plans, Transpower and the Electricity Commission should seek to maintain business confidence by making it clear that adequate grid reliability will be maintained.</p>	<p>Transpower has undertaken a detailed assessment of the Proposal and it will not detrimentally affect the reliability of the grid. This will assist in maintaining business confidence.</p> <p>The benefits of the Proposal in terms of security of supply can be expected to improve business confidence.</p> <p>For possible investors in renewable generation, the Proposal will improve business confidence as their investment options will be increased.</p>



Transmission - planning ahead

88BB The risks to maintaining grid reliability resulting from uncertainties in demand forecasting and easements should be conservatively managed.

Transpower believes that this statement of government policy focuses on reliability rather than economic investments.

Nevertheless, Transpower will continue to monitor demand growth and, if necessary, refine the physical scope of works, design or timing of the Proposal, with Electricity Commission agreement as necessary.

88C This should help the essential process of maintaining stakeholder confidence in ongoing security of electricity supply even if, at times, there is some loss of flexibility around investment choices and some additional cost for electricity consumers.

Transpower is always concerned with stakeholder confidence and has developed this document and attachments to ensure that this confidence is maintained.

The Proposal achieves this without loss of flexibility around investment choices or additional cost for electricity consumers. Indeed, the Proposal will significantly increase flexibility around generation investment choices and is expected to reduce costs for electricity consumers.

Transmission - transmission alternatives

As part of the consideration of transmission investments, the Electricity Commission should ensure that transmission alternatives are considered to the extent practicable subject to the following conditions:

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- only alternatives which have a high probability of proceeding and where grid reliability can be maintained by contingency measures if the alternative is delayed or does not proceed should be considered;
 - alternatives which are only likely to proceed if they are assisted financially by the Government or relevant body should not be considered unless the Government or relevant body has agreed to provide such assistance.

Transpower believes that this statement of government policy focuses on reliability rather than economic investments.

Nevertheless, in reaching the Proposal Transpower has considered a wide range of transmission and non-transmission options. Transpower has assessed the proposal against two transmission alternatives, and did not consider that any non-transmission options were practicable. Transpower took the GPS into account in its option screening process.

The alternatives considered satisfied the two conditions specified here.

7.3 The Electricity Act 1992

Transpower submits that the following objectives, outcomes and functions of the Electricity Commission and corresponding assessments are relevant to its consideration of the proposal.

Table 7-3: Assessment of the Proposal against the principal objectives and specific outcomes of the Electricity Commission

172N	Principal Objectives of the Electricity Commission	Would approval of the Proposal contribute to this purpose?
172N(1)	<p>The principal objective of the Commission in relation to electricity are:</p> <ul style="list-style-type: none"> • to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable and environmentally sustainable manner; and • to promote and facilitate the efficient use of electricity. 	<p>By increasing transfer capacity, the Proposal will allow electricity to be dispatched at lower overall cost.</p> <p>In addition to this, the Proposal will improve the reliability and security of supply to the South Island in dry years.</p> <p>The Proposal will also facilitate least cost renewable generation investment, which will help ensure that electricity is produced in a sustainable and efficient manner.</p>
172N(2)	<p>Consistent with those principal objectives, the Commission must seek to achieve, in relation to electricity, the following specific outcomes:</p> <ul style="list-style-type: none"> • energy and other resources are used efficiently; • risks (including price risks) relating to security of supply are properly and 	<p>The Proposal allows for the efficient use of energy and resources, as demonstrated by the result of Transpower's GIT analysis.</p> <p>The Proposal improves security of supply and is</p>

efficiently managed;	consistent with the grid reliability standards. The Proposal will reduce price risks by reducing the frequency of inter-island constraints and enabling efficiencies in ancillary service procurement.
<ul style="list-style-type: none"> incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment. 	<p>The proposal will enhance incentives for investment in generation by providing more (and hence some cheaper) investment options to generators, and by providing greater access to markets and balancing services and fewer constraints.</p> <p>The Proposal will not introduce discrimination between public and private investment.</p>
<ul style="list-style-type: none"> delivered electricity costs and prices are subject to sustained downward pressure 	The Proposal will facilitate investment in least cost generation, especially in the South Island, and can be expected to reduce ancillary service costs and the price impacts of constraints. This will, in the long term, ensure downwards pressure on electricity prices.
<ul style="list-style-type: none"> the electricity sector contributes to achieving the Government's climate change objectives by...removing barriers to investment in new generation technologies, renewables, and distributed generation. 	The Proposal facilitates investment in renewable generation in the South Island by increasing inter-island transfer capacity, which in turn avoids constraints that may otherwise discourage this investment.

Table 7-4: Assessment of the Proposal against the functions of the Electricity Commission

1720	Functions of the Electricity Commission	Would approval of the Proposals contribute to this purpose?
1720 (1)	give effect to GPS objectives and outcomes	The Proposal will not give effect to all GPS objectives and outcomes, but will contribute significantly to some key GPS objectives and outcomes, as outlined in Table 7-2 above.

7.4 Summary of Consistency with Wider Objectives

The Proposal is consistent with, and will assist in achieving, the Electricity Commission's wider policy objectives as set out in the Electricity Act, section III of Part F of the Rules and the GPS.

8 Costs of Proposal

Transpower seeks approval of the Proposal and approval to recover the lesser of actual costs or the estimated 90th percentile of project costs (P90 cost). The P50 cost (mid-range) is estimated to be \$620 million and the P90 cost (upper range) of the Proposal is estimated to be \$728 million. This section sets out how Transpower has estimated the P50 and P90 costs and describes the difference between the expected costs used in the GIT analysis and the P50 and P90 costs.

Method of calculating P50 and P90 costs

Transpower applies a Monte Carlo simulation technique to estimate the P50 and P90 costs, whereby the cost of the Proposal is simulated a large number of times, each time changing a number of variables related to the cost within an expected range. A distribution of the resultant project costs is plotted and the P50 cost is the 50th percentile of those project costs (and therefore represents a mid-range cost estimate for the Proposal) and the P90 cost is the 90th percentile of those project costs (and therefore represents an upper range cost estimate for the Proposal with 10% probability of exceedance).

The following inputs and variables are considered in deriving the P50 and P90 costs:

- **Estimated capital costs.** The estimated capital costs are the estimated costs of procuring, constructing and commissioning the components which make up the Proposal. These costs can include decommissioning costs and the costs of obtaining designations, easements, resource consents and property purchases for these works if applicable. The estimated capital costs do not include contingencies. The estimated capital costs are in Reference date dollars.
- **Reference date.** Transpower prepared estimated capital costs as at 30 April 2007. A reference date is used to ensure consistency between the estimated capital costs of components within each option considered in the GIT and between options. For calculating costs at commissioning time, Transpower has assumed a commissioning date of 30 April 2012 for Stage 1 and 30 April 2014 for Stage 2. These commissioning dates are assumed to be the dates at which accumulated costs for the project would be included in Transpower's regulated asset base and from which costs would start to be recovered through the Transmission Pricing Methodology. Note that the evolving nature of the regulatory regime under the Commerce Act may introduce some uncertainty into this assumption. The consequences of that uncertainty are further discussed in section 10 below.
- **Scope contingency.** Transpower also estimates scope contingencies, which are added to the estimated capital costs, to cover two distinct categories of costs: (a) costs for works which are planned, but which have not been included in the estimated capital costs except through this general allowance, and (b) costs for works not anticipated at the time costs were estimated. The estimated capital cost plus scope contingency equals the **expected cost** of the project or various components of it and this is the cost used in GIT analyses. For the purpose of simulation modelling scope contingencies are not varied, but rather are treated as a fixed percentage of estimated capital costs, added to the estimated capital cost. They may vary in dollar terms because of changes in other input variables. This is consistent with the use of Expected costs used in the GIT analysis. In this proposal the percentage allowance for scope contingencies varies from item to item between 8% and 40%, with an overall average of 14%.
- **Price accuracy.** As regulatory approval occurs prior to the issuing of tenders, there is uncertainty over the price of equipment to be installed. In particular, this includes the risks that:

- market pressures may affect the cost of capital items, e.g. if worldwide demand for transformers is high at the time Transpower seeks tenders, the prices offered may reflect a tighter supply situation and therefore be higher than at other times; and
- commodity price movements. Tender prices for some capital items include escalators linked to market price variations in significant elements of that item eg metals such as steel and copper. As with exchange rate variations, Transpower would not, typically, consider hedging anticipated commitments until a contract is awarded/signed. This is because of the somewhat speculative nature of entering commodity futures contracts in advance of commitment and the costs involved, which may or may not be required, depending upon the terms of the eventual contract. Hence, Transpower is exposed to commodity price movements up until contracts are signed and so an estimate is made of the potential cost variation this might cause.

Transpower has modelled commodity price risk by expressing the accuracy of estimates as a triangular distribution for the purposes of the simulation modelling with the minimum and maximum variations varying by item, but between -10% and +10% to -22% and +22% respectively. The point estimate of costs is given as the most likely outcome, and lower and upper bounds are expressed as percentages of the midpoint.

The market pressure risks referred to above are considered separately and treated in the same manner as scope contingency for the purposes of the simulation modelling, i.e. they are added to the estimated capital costs but are not varied in the simulation runs.

- **Exchange rates.** Transpower's current practice is to enter foreign exchange contracts to hedge foreign exchange movements, once contractual commitments are made. This provides NZ dollar cost certainty from the point that tenders are awarded/contracts signed.
Transpower does not, typically, hedge anticipated commitments. This is because of the somewhat speculative nature of entering foreign exchange contracts in advance of commitment and the added costs of having to pay option premiums for hedging a range of possible currencies and execution dates, most of which would not be exercised. Hence the requirement to estimate the effect on costs of exchange rates moving in the interim period before signing contracts.
Point estimates of capital cost were based on the average exchange rate 20 business days either side of 30 April 2007. For the simulation runs exchange rates have been sampled from daily exchange rates over the period 1 July 1996 to 12 September 2007. This approach assumes that the simulated exchange rates and cross-rates have a similar mean and variance to historical rates.²¹
- **Inflation.** Transpower modelled inflation by drawing from a uniform distribution in a range from 2% to 4%, with a mean of 3%.
- **Real interest rates.** Transpower modelled real interest rates, used in the calculation of interest during construction, by drawing from a uniform distribution in a range from 4.2% to 6.2%, with a mean of 5.2%. The nominal interest rate is the real interest rate plus the inflation rate, equating to a mean nominal interest rate of 8.2% in this instance. This is approximately Transpower's current cost of debt.

²¹ Over a large number of simulations the exchange rate will be close to the 10-year average rate which is reflected in the mean cost figures.

Results of P50 and P90 cost calculations

The expected cost of the Proposal, as estimated in 2007, is \$470 million. This cost includes an average scope contingency of 14% and represents Transpower's estimate of the cost of purchasing, constructing and commissioning the Proposal. Transpower will not start recovering the costs of a stage of this Proposal until it is commissioned, i.e. 2012 for Stage 1 and 2014 for Stage 2. The cost Transpower will look to recover at that time is higher, due to financing costs incurred throughout the construction period and inflation. Transpower's P50 estimate of the cost it will look to recover from commissioning is \$620 million. A P90 cost has also been estimated, being an upper range cost that Transpower would look to recover from commissioning. The P90 cost allows for uncertainties between now and commissioning, in capital costs, exchange rates, interest rates and inflation. The estimated P90 cost for the Proposal is \$728 million and Transpower is seeking approval to recover the lesser of actual costs or the P90 cost. By definition, there is a 10% probability of exceedance of this cost based on the modelling assumptions set out above. If there are changes to modelling assumptions that are materially different to those used then the P90 cost may also be exceeded. In either case, Transpower would apply for approval for the revised costs of the project in accordance with Rule 17.2.

Table 8-1: Costs for Stages 1 and 2, \$million

Category	Estimated capital cost	Expected cost	Estimated P50 cost	Estimated P90 cost
Stage 1	381	436	573	676
Stage 2	31	34	47	52
Total	412	470	620	728

(*) As defined above and as used in GIT economic analysis.

To determine a P90 cost for this approval request, Transpower has developed a distribution of likely project costs using Monte Carlo simulation techniques, as previously described.

The following table shows how the expected cost is related to the estimated P50 cost of the Proposal. The P50 cost is estimated to be \$620 million and this is the mid-range estimate of the cost Transpower will seek to recover, following commissioning of the Proposal in 2012 (and 2014). Note that the P50 is the median from the cost distribution and is not the mean.

Table 8-2: P50 cost for the Proposal, \$million

Category	Expected Cost	Price Contingency	Exchange Rate Variation	Interest During Construction	Inflation	Estimated P50 Cost
Stage 1	436	0	19	39	79	573
Stage 2	34	0	1	3	9	47
Total	470	0	20	42	88	620

Applying the Monte Carlo simulation technique, as discussed above, the P90 cost is estimated to be \$728 million. Please note that the 90th percentile outcomes for each individual variable are shown in the table below, but that these do not simply add to become the overall P90 cost as reported in the right-hand column. This table shows, when compared to Table 8-2 above, the general source of the variation between the P50 and P90 costs.

Table 8-3: P90 cost for the Proposal, \$million

Category	Expected Cost	Price Contingency	Exchange Rate Variation	Interest During Construction	Inflation	Estimated P90 Cost
Stage 1	436	66	48	51	109	676
Stage 2	34	2	3	4	11	52
Total	470	68	51	55	120	728

Summary of estimated P50 and P90 cost

Transpower therefore estimates the P50 cost of the Proposal to be \$620 million and the P90 cost of the Proposal to be \$728 million.

9 Recommendation

On the basis of this investment proposal contained within the 2007 Grid Upgrade Plan, Transpower **recommends** that the Electricity Commission **approve the HVDC Grid Upgrade Proposal as defined in Part A of this document** on the grounds that:

- Transpower's application of the GIT is reasonable; and
- Transpower has followed the agreed consultation process.

10 Post Approval

This section describes what Transpower's approach to project managing and reporting and to change management will be following approval by the Electricity Commission of the Proposal as defined in Part A of this document.

10.1 Project management and reporting

Transpower will continue to have appropriate project management techniques in place to manage project costs and risks, including:

- Undertaking independent periodic audits of its project management, procurement and commercial processes for the Transpower Board. These audits are aimed at demonstrating that project controls are in place and there is a process to identify areas where Transpower can improve its processes and performance.
- Tracking and reporting project progress on Transpower's website, and sending the Electricity Commission copies of those reports.
- Reporting periodically to the Transpower Board on progress against both expected costs and cost with contingencies, and reasons for any divergence (e.g. exchange rate fluctuations), allowing for indexed escalation or deflation of linked costs.
- Ensuring quality assurance is applied in planning, designing, and manufacturing, commissioning, testing and maintaining Transpower's assets in accordance with good electricity industry practice.

10.2 Change management

Transpower will continually look for opportunities to minimise project costs and maximise market benefits where practicable, considering reliability standards, good electricity industry practice, timing delays, requirements under the Resource Management Act 1991 and any other relevant matters.

Design

Following approval of the Proposal, Transpower may refine the design of this Proposal to reduce costs, increase benefits or resolve practical or safety issues as they arise. Should any such design refinement fall outside the physical scope of works defined in Part A, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of project scope under Rule 17.2.

Two particular design issues that may arise are:

- Transpower will include short-term overload capacity as a desirable characteristic of the new converter and will value overload capacity when assessing tenders.
- Transpower has not included in the Proposal overhauls and replacement of control, excitation, protection and starting systems for the synchronous condensers at Haywards. It is continuing to investigate the need and costs of this work, and expects these investigations to taken 6-12 months to complete.

Once each of these is progressed, Transpower will, if necessary, discuss with the Electricity Commission whether this work remains within scope, requires amendment to this Proposal, or requires a separate proposal.

Commissioning dates

Transpower will proceed to commission the Proposal to the target dates set out in Part A, allowing for sound legal, environmental, commercial and safety processes.

Should the Electricity Commission's approval of the Proposal be challenged through judicial review, Transpower may suspend the project pending the outcome of such review.

Transpower will keep the industry and Electricity Commission informed of expected commission dates as described under reporting above.

Costs

Transpower is seeking Electricity Commission approval to recover the full costs associated with implementing the physical works defined in Part A up to an amount reflecting the current estimate of the P90 cost to implement the Proposal.

Where it is likely that costs will exceed, in a material respect, this estimated P90 cost, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of the approved amount under Rule 17.2.

While Transpower has endeavoured to provide a reasonable estimate of the P90 cost to implement the Proposal, Transpower notes that there is significant uncertainty in estimating the range of variation in factors affecting costs and their likelihoods. The consequence of this is that the "P90" cost for which approval is sought may have a probability of being exceeded of more or less than 10%.

One particular cost issue that may arise is that, depending on how the regulatory regime under the Commerce Act evolves, Transpower may only be able to add assets to its regulated asset base at the end of a 1 April to 31 March year. If this occurs and Stage 1 is commissioned in April 2012, then Transpower may not be able to start recovering the costs until 2013. Further interest during construction costs would accrue, which have not been included in these cost estimates and which are not reflected in the amount Transpower is seeking approval for. If such an event does occur and Transpower could in consequence exceed the approved amount, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of the approved amount under Rule 17.2.

Unforeseen events

In addition to the above, Transpower will continually review factors material to the justification of this project, including generation developments and demand growth. If it becomes apparent that in consequence changes to the physical scope of works, design or timing of the Proposal would be of national benefit, and any such changes fall outside the scope of the Proposal as defined in Part A, Transpower will discuss with the Electricity Commission and consider seeking an amendment of project scope under Rule 17.2.

Appendix A Glossary

Term	Description
Alternative Project	Projects that are reasonable to consider as alternatives to the proposed investment in applying the Grid Investment Test, in accordance with rule 19, Schedule F4, Part F Section III, Electricity Governance Rules.
APR	Annual Planning Report
Base Case	The “do nothing” option, a counterfactual for other options to be considered against.
Climate Bill	Climate Change (Emissions and Renewable Preference) Bill, 187-1, introduced on 4 December 2007.
Consultation Paper	Document published by Transpower on 1 February 2008 setting out Transpower’s provisional view that the 700 MW replacement option was the most economic option available.
economic investment	Investments in the grid that can be justified on the basis of the Grid Investment Test under section III of part F, Electricity Governance Rules, and are not reliability investments.
expected project costs	Expected project costs (or expected costs) represent the estimated (P50) cost plus a contingency for scope accuracy. Scope accuracy allows for unexpected variations in the design scope and a standard allowance, based on experience, for items not considered in the design.
expected unserved energy	A forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment.
GEIP	Good Electricity Industry Practice.
GEM	Generation Expansion Model , a model for generation expansion modelling developed by the Electricity Commission.

GIT **Grid Investment Test.** A cost-benefit analysis for both reliability and economic investments. The specific rules defining the Grid Investment Test, as developed according to the process in rule 6 of section III, are set out in Schedule F4 of section III of Part F.

GPS **Government Policy Statement on Electricity Governance.**

Grid Development Strategy A 40-year development strategy used by Transpower to provide a framework within which to consider and propose upgrades to the National Grid.

GUP **Grid Upgrade Plan.** A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules.

HHI **Herfindahl Hirschman Index,** a measure of market concentration.

HVAC **High Voltage Alternating Current**

HVDC **High Voltage Direct Current**

Inter-Island HVDC Pole 1 Replacement Investigation Project Investigation by Transpower to consider the feasibility of different replacement options that has resulted in this Proposal.

Lerner Index The Lerner index is a measure of price mark-ups (amount a generator bids over and above their marginal cost). The Lerner Index is calculated as:
Lerner Index: $LI = (\text{bid price} - \text{short-run marginal cost}) / \text{bid price}$

Matlab A modelling program used by Transpower to undertake Monte Carlo analysis

MAV **Mercury Arc Valve**

modelled projects Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur in a market scenario, are reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects, and the likelihood, nature and timing of which will be affected by whether

	the proposed investment or any alternative project proceeds.
Monte Carlo	Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of numbers randomly generated within certain ranges as inputs. It creates a distribution of possible outcomes on which descriptive statistics can then be run.
NZES	New Zealand Energy Strategy 2050, published by Ministry of Economic Development, October 2007.
P90 cost	Estimated 90 th percentile of project costs.
PLEXOS	A proprietary power market model suitable for short, medium and longer term studies including generation expansion planning. It can furthermore model market behaviour to assess competition benefits.
Rules	The Electricity Governance Rules 2003. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments.
SCADA	Supervisory Control and Data Acquisition.
SDDP	Stochastic Dual Dynamic Programming , a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies.
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the National Grid).
Transpower's System Vision	Intended to drive Transpower strategies and policies for the long-term growth and management of the transmission system. It includes the two related initiatives of Grid Vision and System Operation Vision.

Appendix B Summary of competition and consumer benefits analysis

The GIT allows competition benefits to be included as a market benefit, provided they can be separately identified and calculated. Whilst it seems intuitive that providing a link between the North Island and South Island enables greater competition between generators in both islands, it is not straightforward to calculate the benefits that result from that enhanced competition.

Transpower employed McLennan Magasanik Associates (MMA) to consider the effect of the various Pole 1 replacement options on competition and consumer benefits. Their full report is set out at Appendix 4 to Attachment G to the Consultation Paper (see Volume 2). Transpower has not included any competition benefits in its application of the Grid Investment Test.

However, the results are plausible and do provide at least directional information on the effect on consumers if Pole 1 of the HVDC link is replaced compared to not being replaced.

B.1 Competition benefits

Competition benefits for each replacement option were determined as follows:

- calculate non-competition benefits by comparing outcomes between the base case and replacement options assuming generators bid in at their true marginal cost;
- calculate total benefits by comparing outcomes between the base case and replacement options assuming some market power is exerted; and
- calculate competition benefits by subtracting the non-competition benefits from total benefits.

The modelling of competition benefits was undertaken using PLEXOS. PLEXOS' Nash-Cournot game-theoretic model was used to assess the impact of future bidding behaviour of market participants with market power.

Market power is exerted by participants lowering the capacity offered into the market to increase prices and thereby maximise profit.

The magnitude of competition benefits depends on a number of factors including:

- the choice of company ownership for new generation projects;
- the capacity expansion plan, in particular the mix of renewable and thermal technologies in the North Island;
- the choice of price elasticity of demand; and
- the rules assumed to govern the degree to which renewable generation can participate in the game.

In the analysis undertaken, some initially surprising results emerged. Competition benefits were found to be both positive and negative, depending on the market development scenario.

Market power was assumed to be exerted by withdrawing some existing thermal capacity and/or new renewable capacity in the North Island. This withdrawn capacity was replaced with more costly thermal generation. The resulting fuel and emission cost increases represent reductions in productive efficiency. The more renewable generation withdrawn, the greater the reduction in productive efficiency, as the difference between renewable and thermal fuel costs is greater than between different thermal technologies.

If more renewable generation is withdrawn under a replacement option than under the Base Case, then the cost of the replacement option also increases more than under the Base Case and negative competition benefits are observed. Typically, in the Base Case in

each scenario, more new thermal generation is built in order to satisfy the North Island capacity constraint, and market power is exerted by existing thermal generators rather than new renewable generators. Also, the additional capacity built to satisfy the capacity constraint is always greater than or equal to the additional capacity on the HVDC link, due to the peak contribution factors assigned to various new entrants. Hence, once capacity constraints become binding, there is more competition in the North Island in the Base Case, than in the alternatives where Pole 1 is replaced.

The 90% renewables by 2025 market development scenario is an exception, due to the greater emphasis on renewable generation. Without Pole 1 being replaced, more North Island renewable generation is built. In this analysis, this new renewable generation is assumed to be owned by a single new competitor. Their market share in the North Island increases to 25% by 2030 and 30% by 2040, and its ability to exert market power increases. In this scenario, there is significantly more North Island renewable capacity withdrawn if Pole 1 is not replaced, and therefore the cost increases are greater in the Base Case and this results in positive competition benefits for the replacement options.

A summary of the competition benefits for individual scenarios and for high, medium and low demand, for the 700 MW replacement option, were as follows:

Competition benefits (\$2007 m)	Demand scenario		
	High	Med	Low
High Gas	-\$55	-\$40	-\$119
Mixed technologies	-\$13	-\$22	-\$33
Primary renewables	\$171	-\$57	-\$194
SI surplus	\$213	-\$526	-\$481
90% renewables by 2025	\$101	\$188	\$111

Applying the weightings used in the GIT, this gives a competition benefit of approximately \$42 million. These results are explainable, as discussed above, but they make it difficult to conclude whether replacing Pole 1 would have any positive competition benefit.

Transpower is encouraged by the MMA analysis, as it produces explainable results for the assumptions made, but considers that other ownership/market behaviour combinations would need to be modelled to draw robust conclusions about competition benefits.

Whilst this analysis may not support the existence of positive competition benefits for the Proposal, Transpower would still expect a positive competition benefit emerge with further modelling. It seems intuitive that linking the North Island and South Island enhances competition nationally.

B.2 Consumer benefits

With respect to consumer benefits though, Transpower considers some conclusions can be drawn.

This consumer benefits analysis considered the following:

- HVDC constraints;
- market concentration/competitiveness;
- price mark-ups; and
- nodal price changes.

B.2.1 HVDC constraints

More congestion on the HVDC will result in more periods where generators will be in a position to exert market power.

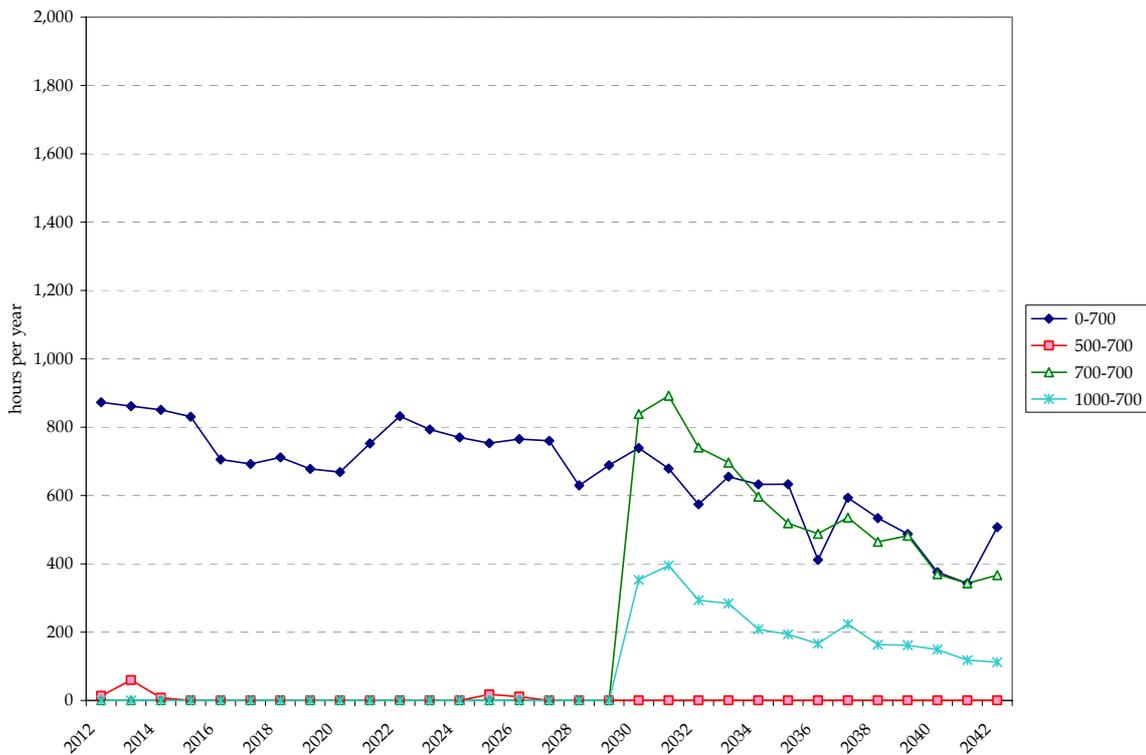
The following diagrams show how congestion on the HVDC changes over time for two market development scenarios. Congestion on both the existing Pole 2 and the replacement Pole 1 is shown.

In the High Gas scenario two new South Island lignite plants are built in 2030, to take advantage of the additional HVDC capacity in the 700 MW and 1000 MW replacement options, but not in the 500 MW replacement option. This additional South Island generation capacity results in more congestion after 2030 in the 700 MW and 1000 MW options, than in the 500 MW option, despite the larger link capacity.

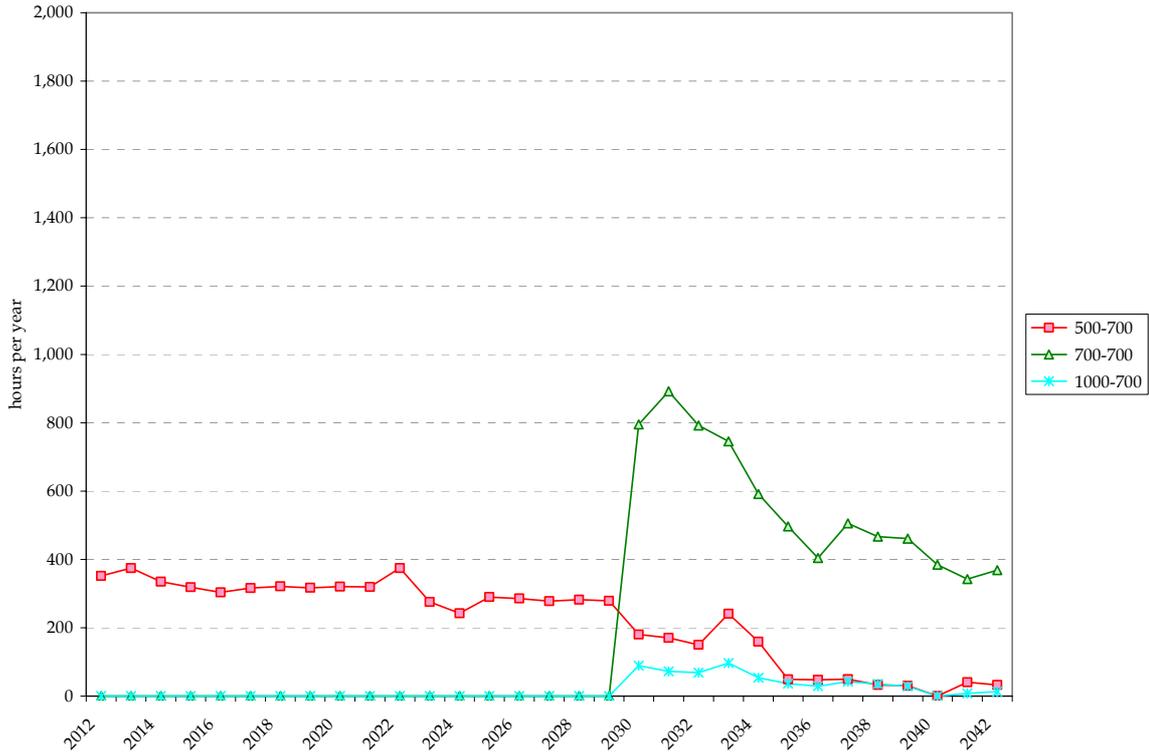
Generally though, it can be seen that:

- There is less congestion if Pole 1 is replaced, than if it is not
- Congestion decreases as replacement Pole 1 capacity increases

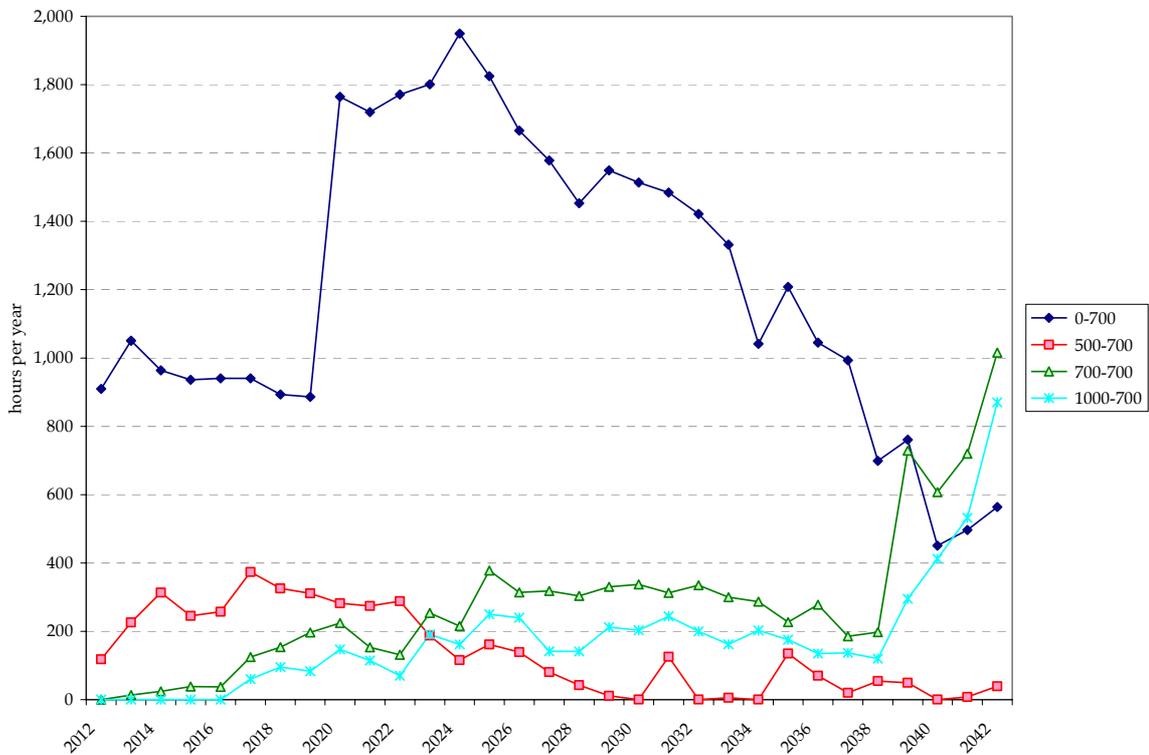
Pole 2 congestion – hours per annum, High Gas, medium demand



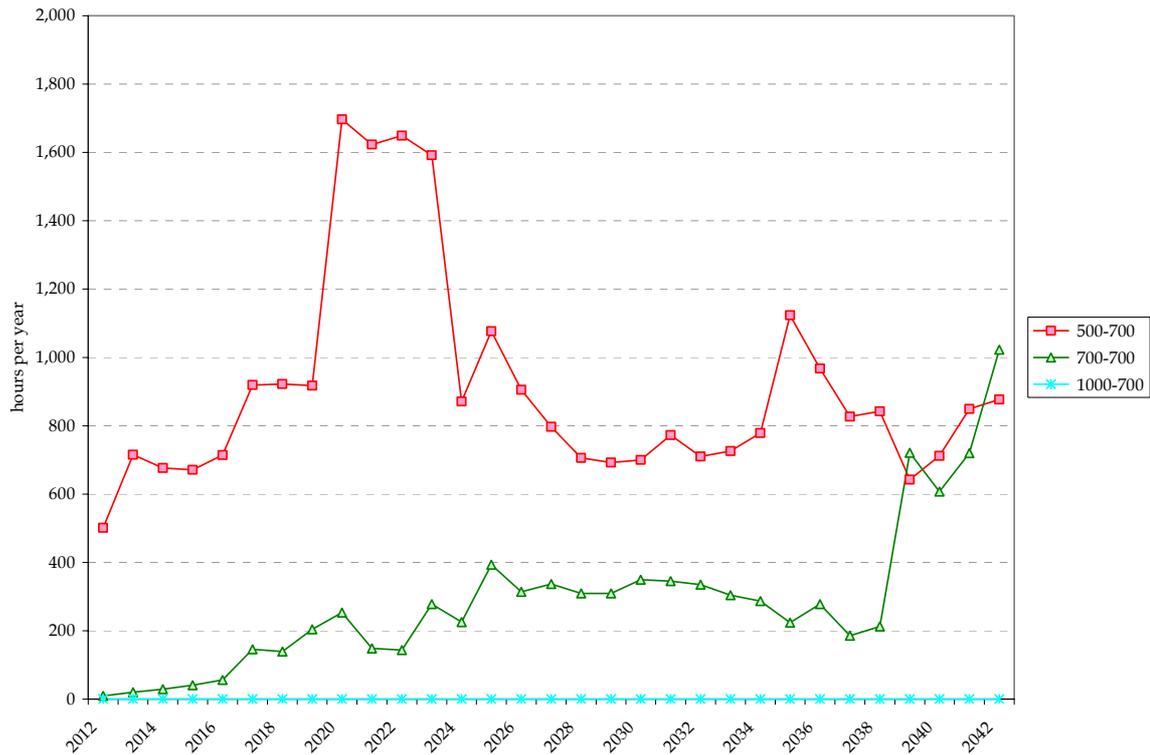
Pole 1 congestion – hours per annum, High Gas, medium demand



Pole 2 congestion – hours per annum, 90% renewables by 2025, medium demand



Pole 1 congestion – hours per annum, 90% renewables by 2025, medium demand



B.2.2 Market concentration/competiveness

Market concentration was assessed using the adjusted Herfindahl-Hirschman Index (HHI), defined as:

$$HHI^{adj} \equiv \sum_{i=1}^m s_i (s_i + s_c / m)$$

where s_i is the market share of the i -th unconstrained firm ($i = 1, \dots, m$) and s_c is the total market share of the constrained firms.

Constrained firms are defined as those with plant whose output depends on the primary energy available at the moment (wind, geothermal, run-of-river hydro units, cogeneration units) and not on an operating decision regarding how much of the stored primary energy to use (hydro plants with reservoirs and thermal plants).

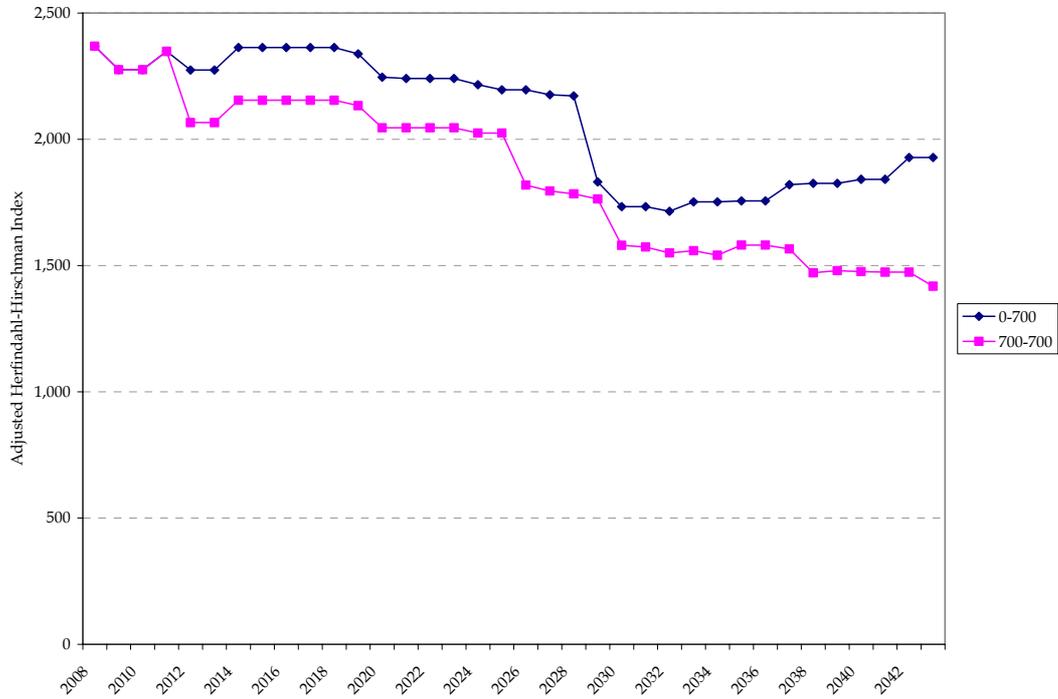
Since some of the firms have both constrained and unconstrained generation, their total capacity is divided in two parts, one constrained and one unconstrained.

The HHI is used by the US Department of Justice. According to their merger guidelines, the US Department of Justice will regard a market in which the post-merger HHI is below 1000 as "unconcentrated," between 1000 and 1800 as "moderately concentrated," and above 1800 as "highly concentrated." A merger potentially raises "significant competitive concerns" if it produces an increase in the HHI of more than 100 points in a moderately concentrated market or more than 50 points in a highly concentrated market. A merger is presumed "likely to create or enhance market power or facilitate its exercise" if it produces an increase in the HHI of more than 100 points in a highly concentrated market.

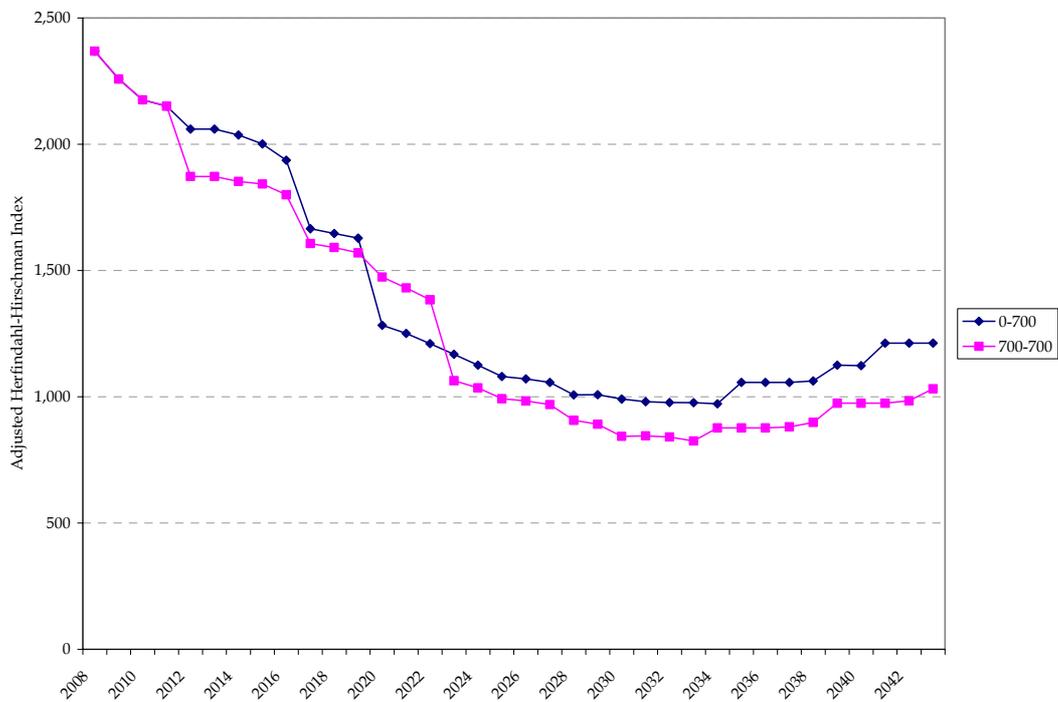
The figures below show how the HHI changes in both the North and South Islands for the High Gas and 90% renewables by 2025 scenarios.

As can be seen, the HHI drops over time whether Pole 1 of the HVDC is replaced or not. In all cases though, the commissioning of a replacement Pole 1 in 2012 reduces the HHI and generally results in a lower HHI over time than if Pole 1 had not been replaced.

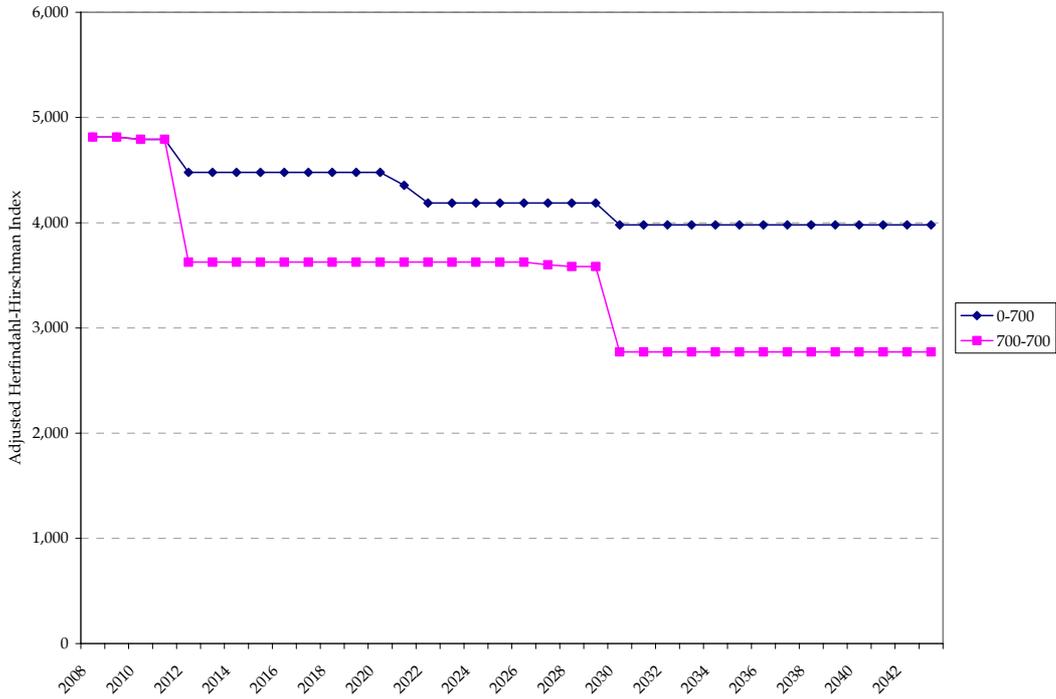
Adjusted HHI in North Island for High Gas scenario



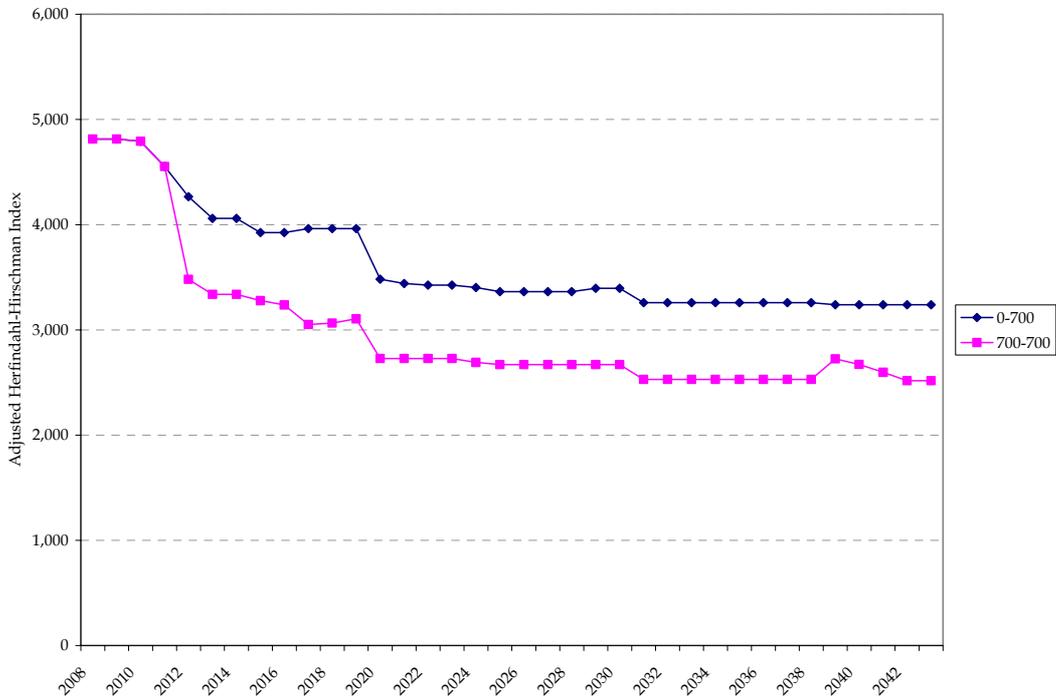
Adjusted HHI in North Island for 90% renewables by 2025 scenario



Adjusted HHI in South Island for High Gas scenario



Adjusted HHI in South Island for 90% renewables by 2025 scenario



B.2.3 Price mark-ups

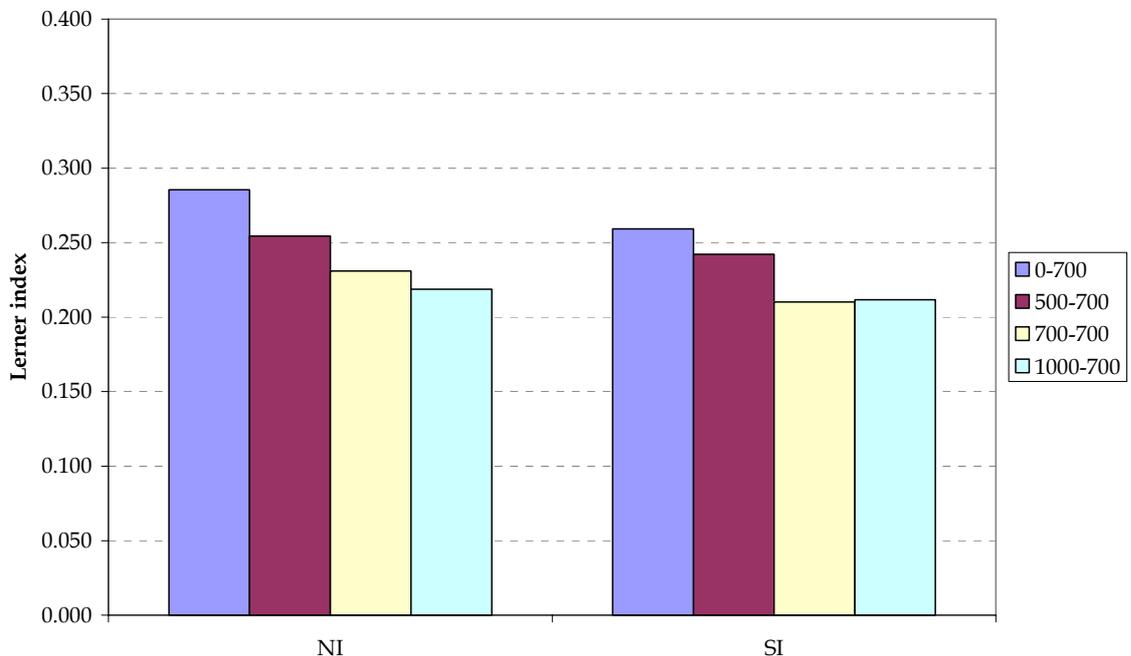
The Lerner index is used to calculate how price mark-ups (amount a generator bids over and above their marginal cost) change with HVDC link size. The Lerner Index is calculated as:

$$\text{Lerner Index: LI} = (\text{bid price} - \text{short run marginal cost}) / \text{bid price}$$

The Lerner index for each year is calculated based on the average bid prices from the Nash-Cournot simulations and the average short run marginal cost from the non-competition simulations. Then, the average Lerner index is calculated as the simple average of the Lerner indices for each year.

The figure below shows that the weighted average Lerner index ranged from 0.2 to 0.3 across all augmentation scenarios. A Lerner index of zero would imply that there is no market power in the system. The moderately low Lerner index values are a reflection of the price elasticity of demand assumed in the Nash-Cournot game, which was estimated based on the back cast study undertaken for 2005.

Average Lerner index



As seen though, the Lerner index indicates that the price-mark-ups decrease as link size increases.

B.2.4 Nodal price changes

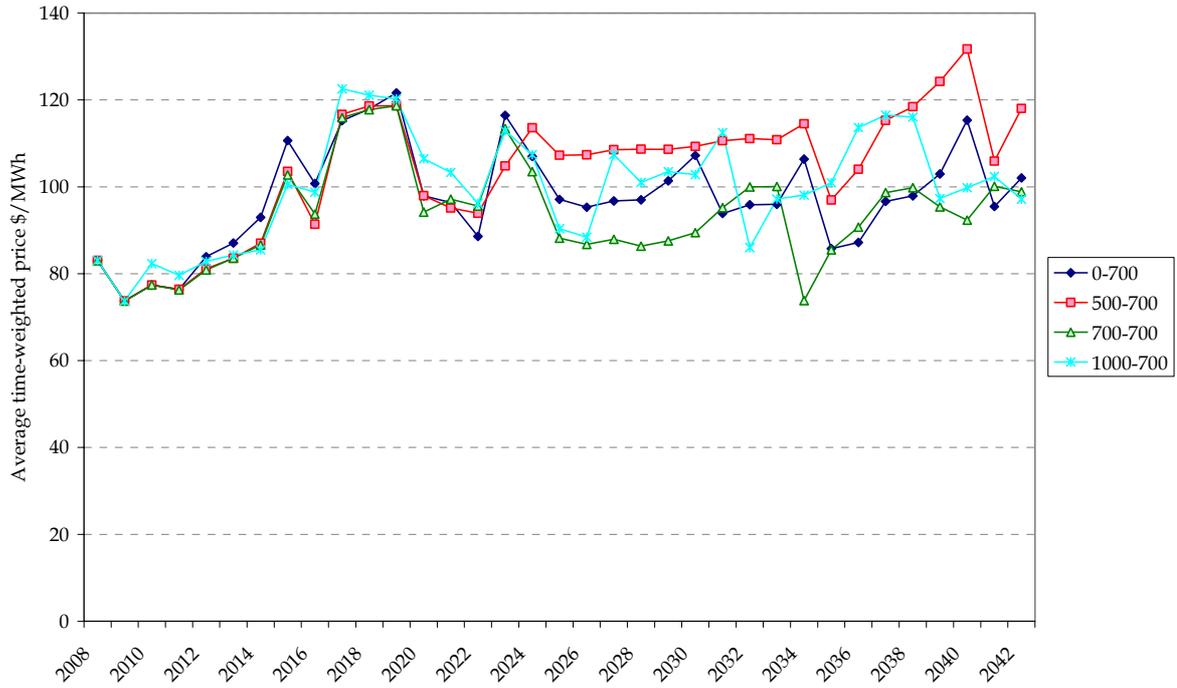
The figures below show the North Island and South Island nodal price projections (at Penrose and Islington) for the 90% renewables by 2025 scenario with medium demand growth, based on the Nash-Cournot game.

This analysis indicates that, in the 90% renewables by 2025 scenario, prices in the North island are projected to rise from their current levels of around \$80/MWh to between \$90 and \$120/MWh from around 2015, reflecting fuel price increases and carbon price increases. The variability in pool price under each augmentation alternative is largely driven by changes in the generation technologies selected by the capacity expansion plan. Similar variability and relativities are observed in prices projected assuming perfect competition.

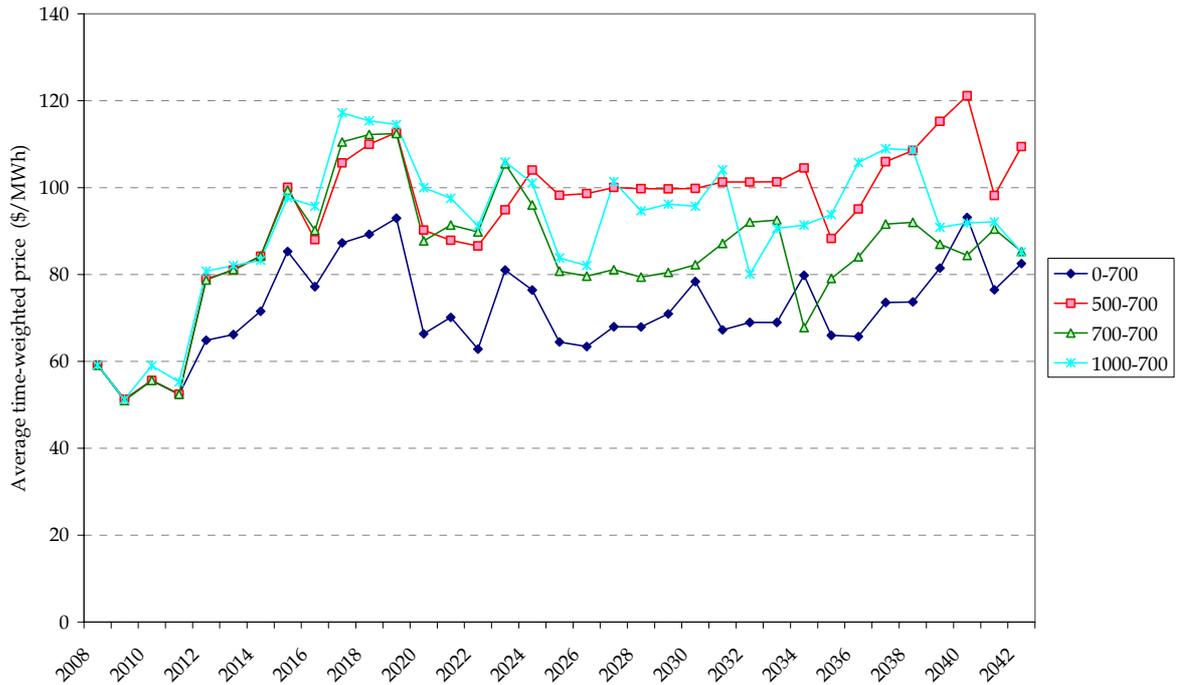
South Island prices follow a similar pattern. The greater spread in South Island prices between the various options reflects the price differential between the two islands, and hence the degree of congestion on the HVDC link.

The table below shows the annual average price differential between the North Island and South Island for the same nodes and scenario. Increasing the capacity of the HVDC link reduces the price differential between the NI and the SI, with the price in the SI typically increasing more than the decrease in price in the NI.

North Island nodal price (Penrose), 90% renewables by 2025, medium demand



South Island nodal price (Penrose), 90% renewables by 2025, medium demand

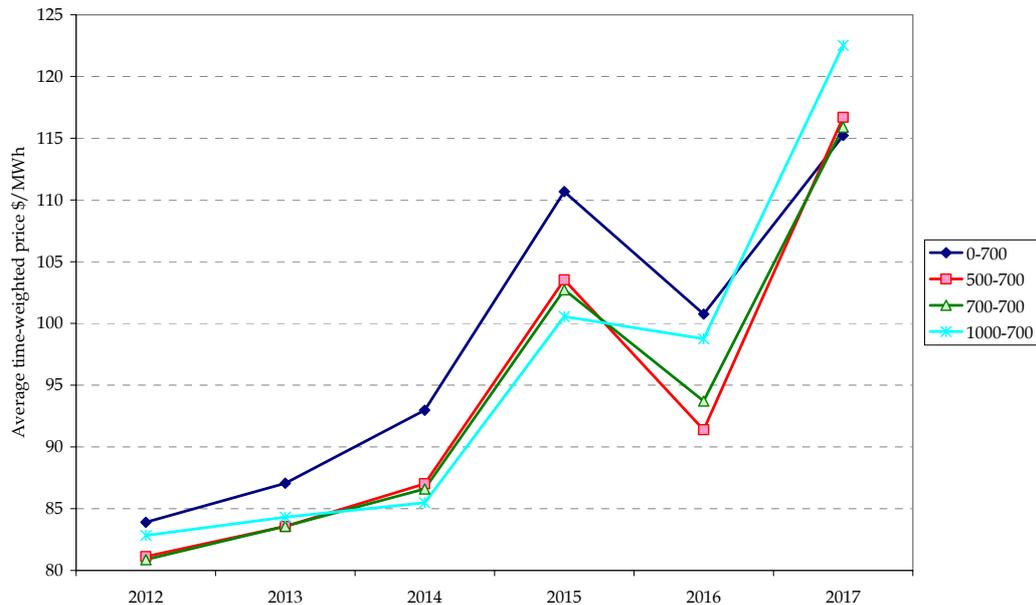


Price differential between North and South islands, 90% renewables by 2025, medium demand

HVDC option	Average annual price differential post augmentation (\$/MWh)
0-700	25.9
500-700	8.0
700-700	6.6
1000-700	6.3

Investing in a 700 MW Pole 1 replacement will increase the price in the South Island by 20% on average (\$15/MWh), relative to the South Island price if no replacement link is built. The North Island price decreases over time, relative to the North Island price without replacement, with an average decrease of 4%. For the first five years after replacement of Pole 1, the impact of HVDC augmentation on North Island price is most noticeable, with average North Island prices reducing as shown below. Beyond 2017, variations in capacity expansion plans swamp any clear relationship between North Island price and the size of the HVDC link.

North Island nodal price (Penrose) immediately after augmentation, 90% renewables by 2025, medium demand



Overall, there is a transfer of wealth from consumers to generators in the SI, and from generators to consumers in the NI, upon the building of the replacement link.

B.3 Conclusion

Although, the results of the competition benefit analysis are inconclusive, the consumer benefit analysis demonstrates that, in general, competitiveness is increased with a replacement Pole 1 and that competitiveness increases as the replacement link size increases.

Overall, there is expected to be a transfer of wealth from consumers to generators in the South Island, and from generators to consumers in the North Island, upon the building of the replacement link. The analysis suggests replacement of Pole 1 is likely to result in benefits to consumers.

This analysis does not include sensitivity analysis, which would improve the robustness of the results. The trends, however, do indicate that replacing Pole 1 of the HVDC link will enhance the competitiveness of the New Zealand electricity market and the benefits to consumers.

Appendix C

Since publishing its proposed GIT analysis for consultation, Transpower has refined and updated the scope and estimated costs for the options in light of further available information. As a result, Transpower's GIT analysis has used slightly different costs to those used in its proposed analysis.

The tables below set out the works to be undertaken in the Base Case and under each short list option with the estimated costs associated with each stage of the Base Case and each option. The cost items for Option 2 are (a) items in the Proposal and (b) modelled projects, i.e., investments that Transpower expects are likely to occur but for which Transpower is not seeking cost recovery as part of this Proposal.

These tables update the information in Appendix A to Attachment B – Databook to the Consultation Paper (see Volume 2).

These costs are reproduced in the companion spreadsheet “Final HVDC GIT results.xls”, along with the streaming of these costs. For the Electricity Commission, this spreadsheet is available on the enclosed CD. For others, the spreadsheet is available at <http://www.gridnewzealand.co.nz/n282,110.html>.

The GIT analysis set out in Attachment A to this document has used the expected costs listed below. Expected costs are the estimated capital costs plus a contingency for scope accuracy. This contingency is to allow for unexpected variations in the design scope and an allowance, based on experience, for items not considered in the design.

Table 10-1 Base Case development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	<p>Electrode and HVDC transmission line works for continuous mono-polar operation, and replacement of cable terminal bushings</p> <p>Refurbishment and unit connection of three Haywards Synchronous condensers</p> <p>Low order harmonic filter at Haywards</p> <p>Seismic strengthening at Haywards and Benmore sites</p>	55
Stage 2	Pole 2 valve base electronics and control system replacement	25
Total		80

Table 10-2 Option 1 (500 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	<p>New 500 MW, 350 kV, converter pole terminating at Benmore and Haywards including new Pole 1 and Bipole control system</p> <p>Pole 2 valve base electronics and control system replacement</p> <p>Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW</p> <p>Seismic strengthening and AC switchyard development for 500 MW option at Benmore and Haywards</p> <p>Electrode and HVDC Transmission line works for 500/700 MW operation, and replacement of cable terminal bushings</p> <p>Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10</p>	388
Stage 2	New condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 60 MVar	29
Total		417

Table 10-3 Option 2 (700 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	<p>New 700 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems</p> <p>Pole 2 valve base electronics and control system replacement</p> <p>Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW operation</p> <p>Seismic strengthening and AC switchyard development for 700 MW option at Benmore and Haywards</p> <p>Electrode and HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings</p> <p>Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10</p>	445
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVAR	34
Stage 3	<p>Additional filters suitable for 1400 MW operation</p> <p>Add one new HVDC submarine cable rated, 350 kV, 500 MW</p>	125
Total		604

Table 10-4 Option 3 (1000 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	<p>New 1000 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems</p> <p>Pole 2 valve base electronics and control system replacement</p> <p>Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW</p> <p>Seismic strengthening and AC switchyard development for 1000 MW option at Benmore and Haywards</p> <p>Electrode refurbishment for 1000/700 MW operation.</p> <p>HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings</p> <p>Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10</p>	547
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVAR	34
Stage 3	Additional filters suitable for 1400/1700 MW operation	125

Add one new HVDC submarine cable rated, 350 kV, 500 MW

Stage 4	New synchronous condenser C12 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVA	71
	HVDC Transmission Line works for BEN-HAY 1000/700 MW bipole operation	
Total		777