TRANSPOWER

North Island 400 kV Upgrade Project

Investment Proposal

Executive Summary and Introduction

1 Introduction

This document sets out Transpower's proposed investment comprising a 400 kV high voltage alternating current (HVAC) transmission line between Otahuhu and Whakamaru in the upper North Island, for assessment by the Electricity Commission under Part F of the Electricity Governance Regulations 2003 ("EGRs"). Transpower has determined that the expenditure on the proposed investment is "reasonably prudent or necessary" to meet Transpower's current grid reliability standards by the year 2010 in the Auckland and North Isthmus regions.

Transpower is making this submission under the transitional provisions in view of the tight timeframes involved with the Project in order to (among other things) trigger the Commission's process for consideration of the proposal. It is recognised that the Commission is moving towards implementing the new grid upgrade plan ("GUP") process, that some aspects of it are presently being consulted on within the industry, and that finalisation of the basis of the GUP is not expected for some months.

Transpower requests that the Commission now commence the process which is outlined in Rule 16 for the consideration of its submission.

Although the Submission is necessarily made under the transitional provisions, Transpower has, to the extent possible, included in the Submission the same level of detail and analysis that would be required under a GUP application.

Transpower will be submitting a full GUP to the Commission later in 2005 after the Statement of Opportunities (SoO) has been finalised and other regulatory issues surrounding the contents and nature of the GUP have been determined. This Project will be included in that GUP.

2 Approval Sought

Transpower seeks approval from the Electricity Commission under Rule 16 of Section III of Part F for all expenditure on the following:

- Investigation and initial design of the proposed investment;
- Acquisition of property rights for the proposed investment;
- Acquisition of designation and resource consents for the construction of the proposed investment;
- Design, procurement, construction and commissioning of the overhead transmission lines, substations and underground cables forming part of the proposed investment;
- Dismantling of existing transmission lines that are required to be removed as the result of the proposed investment, and consequential system reinforcement.

The proposed investment is the construction of a 400 kV transmission interconnection between the existing Whakamaru and Otahuhu substations, including:

- A 400 kV, double circuit, steel lattice tower, overhead transmission line of approximately 200 km from Whakamaru substation to a new underground cable transition station near Ormiston Road (south of Otahuhu substation).
- A 400 kV, double circuit, underground cable from the underground cable transition station into Otahuhu substation with a route length of approximately 9 km.
- Two new 400/220 kV interconnector transformers and associated substation works at Whakamaru substation.
- Two new 400/220 kV interconnector transformers and associated substation works at Otahuhu substation.
- Dismantling the Arapuni to Pakuranga 110 kV transmission line in part or full (depending on final outcome of route) and reinforcement of system where appropriate.

3 Summary of Analysis

This submission concludes that Transpower's proposed investment is "*reasonably prudent or necessary to meet Transpower's current grid reliability standards*" on the following basis:

(a) There is a need for additional supply capacity into the Auckland and North Isthmus region by 2010 as set out in Part II of the submission.

(b) There are no generation alternatives committed in the Auckland and North Isthmus region that would defer or avoid the need for transmission investment.

(c) There are no other alternatives to transmission that are reasonably likely to occur in the Auckland and North Isthmus region and would defer or avoid the need for transmission investment as set out in Part III.

(d) The proposed investment is the best economic transmission option based on a national benefit analysis as set out in Part IV.

(e) Environmental impacts have been taken into account in determining the proposed investment as set out in Part IV.

4 Proposed Investment Process

The processes required to implement the proposed investment are as follows:

Investigation Process

The investigation process has included all engineering and system planning work to identify the need for investment, identify all possible transmission and non transmission alternatives and to select a preferred solution to provide long term security of supply into the upper North Island.

This process also includes environmental, property and engineering work required to investigate and select the preferred route corridor and investigate and select two 500m wide routes within that route corridor. It also includes consultation on the preferred routes and the preparation of the documentation required to lodge notices of requirement (in respect of the designation process).

Environmental Statutory Process

The environmental statutory process includes securing designation and resource consents for the construction of the 400 kV transmission line and underground cables between Otahuhu and Whakamaru and the construction of 400 kV substations at Otahuhu and Whakamaru. Regional Council resource consents may also need to be secured.

Property Rights Acquisition Process

The property rights acquisition process will commence once a final route is announced. Transpower will then need to identify the property rights required (i.e., property purchases, leases, licences, and easements) and undertake good faith negotiations with property owners to secure these property rights along the selected route.

Transpower will seek to use the compulsory acquisition processes within the Public Works Act where good faith negotiations fail.

Engineer/Procure/Construct Process

This process will include all the detailed engineering design, procurement of all equipment, construction and commissioning of the project.

5 Timing

Transpower has concluded in Part II of this submission that the proposed investment is required to be commissioned by 2010 to ensure Transpower's grid reliability standards can continue to be met in the upper North Island.

A project of this magnitude would normally be expected to take a period of eight years from initial mobilisation to final commissioning. Transpower has identified that the proposed investment is required by May 2010 therefore all major project milestones are critical to the successful implementation of the proposed investment.

The critical dates required to be met to avoid delays to the commissioning of the proposed investment are:

- registration of interest in transmission line construction: August 2005
- lodgement of the notice of requirement: 13 April 2006
- commencement of compulsory acquisition process for property rights (if required): 14 April 2006
- commencement of tender process for the Engineering, Procurement, Construct contract: 10 April 2006

6 Establishing the Need for New investment

Part II of Transpower's submission demonstrates the need for the proposed investment by analysing demand and generation forecasts against Transpower's current grid reliability standards. The analysis concludes that there is a risk of electricity demand not being supplied into the upper North Island from 2010 and that new investment is required to maintain security of supply into the region.

Transpower's needs analysis draws on a number of key inputs including forecast electricity demand, electricity generation scenarios, grid reliability standards and the capability of the existing and proposed power system.

7 Options for Meeting the Investment Need

In concluding the proposed investment is the preferred solution, Transpower undertook an analysis of all transmission options and alternatives to transmission (including generation and demand side management) to meet the demand identified as being required in the upper North Island from 2010.

Transmission Options

Transpower's high level assessment of transmission options against technical, economic and environmental criteria showed that only 220 kV and 400 kV AC overhead transmission options are credible options to meet the need identified in Part II.

The following transmission options have been considered and assessed by Transpower in Part III:

- 220 kV development
- 330 kV development
- 400 kV development
- 500 kV development
- Classic HVDC development
- HVDC Light development
- Undergrounding

Alternatives to Transmission

Transpower issued a Request for Information (RFI) to determine the potential alternatives to transmission. Transpower assessed all alternatives offered through this RFI process and concluded that generation plant designed to operate at peak load times is the sole alternative to transmission which would avoid or defer the need for the proposed investment and/or have a reasonable likelihood of proceeding. This option is analysed as part of the economic analysis of transmission options and non transmission alternatives.

8 Cost Benefit Analysis

The cost benefit methodology used to assess the proposed investment is set out in Part IV of this submission. Transpower considers that this cost benefit methodology is consistent with the Electricity Commission's Grid Investment Test. The cost benefit analysis demonstrates the following conclusions.

A long run development plan for the transmission network at 400 kV is more economic than continuing with incremental augmentation at 220 kV. The expected net market benefit of a 400 kV development plan over a 220 kV development plan is estimated at $133 million. Therefore 400 kV is the most economic choice for the main backbone voltage of the National Grid.

There are substantial benefits in implementing transmission augmentation when compared to a "do nothing" alternative which allows only for that generation anticipated in Transpower's or the Electricity Commission's draft generation scenarios to be established.

The proposed investment has a substantially higher expected net market benefit than the best case transmission alternative of a diesel fired peaking plant. The expected net market benefit (cost) of a diesel fired peaking plant ranges between -$130 and -$240 million.

In summary the proposed investment based on the construction of a 400 kV double circuit transmission line between Whakamaru and Otahuhu is the most economic alternative to provide long run security of supply into the upper North Island and satisfies the requirements of the Grid Investment Test.

9 Project Costs

Transpower is seeking Electricity Commission approval under the transitional provisions of Part F for all costs incurred by Transpower in the implementation of the proposed investment. The estimated order of magnitude of costs for Transpower's proposed investment including transmission works, property and project management is approximately $460 million.

Part V contains the estimated capital costs to the proposed investment. Transpower has submitted cost estimates in good faith and expects to be able to recover actual costs reasonably incurred in relation to the approved project through the transmission pricing methodology. The costs contained in this document are estimates only.

Category	Item	Cost $m (2005 Real)
Investigations	Preliminary engineering, environmental and property work to establish preferred route and lodge NoR.	20
Property	Acquisition of property rights	97
Environmental	Acquisition of designations and resource consents	11
Transmission works	400 kV line Whakamaru to Otahuhu	120
	Substations – Otahuhu	66
	– Whakamaru	33
	Cable	84
Dismantling	Arapuni to Pakuranga Line	4
Project Management		25
Total		460

10 Environmental Impacts

In undertaking its analysis of the proposed investment, Transpower has analysed the environmental impact of transmission options.

The Area Corridor, Route Easement (ACRE) process being followed by Transpower in determining a final route for the proposed 400 kV transmission line meets the requirements of the Resource Management Act in terms of sustainable management of resources. The ACRE process is not intended as a basis for environmental comparison between transmission options, but is intended to ensure that potential adverse environmental effects of the 400kV option are appropriately avoided, remedied or mitigated. For the sake of completeness, in undertaking its analysis of the proposed investment pursuant to this investment proposal, Transpower has analysed the broader environmental parameters that make one transmission option more preferable than another.

11 Documentation

There are five parts to Transpower's investment proposal, together with this Executive Summary and Introduction. They are as follows:

Section	Content
Part I – Project Description and Project Plan	Describes the 400 kV project and sets out the project plan.
Part II – Establishing the Need for New Investment	Describes the transmission planning inputs including demand forecasts, generation scenarios and the existing transmission system. These inputs form part of the analysis that demonstrates the need and timing for the proposed investment.
Part III – Analysis of Options for Meeting the Investment Need	Identifies and analyses the transmission options and alternatives to transmission investment to meet the identified need for investment
Part IV – Cost Benefit Analysis	Sets out the cost/benefit analysis methodology and the associated results of the economic analysis.
Part V – Project Costs	Sets out the cost estimates of the proposed investment.

There are also a number of supporting documents that underpin this investment proposal. They are referred to where appropriate in the main Parts to this document:

Appendix A – List of Supporting Documentation

NO.	REPORT NAME	DATE
1	Request for Information Paper	September 2004
2	Grid Development Plan – 400 kV Option (Part I: Scenario 1,2 & 3)	February 2004
3	Grid Development Plan – 400 kV Option (Part II: Scenario 4 & 5)	May 2005
4	Grid Development Plan – 220 kV Option (Part I: Scenario 1,2 & 3)	February 2004
5	Grid Development Plan – 220 kV Option (Part II: Scenario 4 & 5)	May 2005
6	North Island 400 kV Project – Main Transmission System Planning Criteria	March 2005
7	North Island 400 kV Project – Planning Assumptions – Demand and Generation Forecasting	April 2005
8	Security of Supply into the Upper North Island – Comparison of High Voltage Direct Current and High Voltage Alternating Current Grid Upgrade Alternatives	May 2005
9	System Vision Investigation – Grid Vision (Technical Feasibility). 330 / 400 kV Transmission Line Upgrade Study. Analysis of costs and Practicality of upgrading two existing 220 kV lines to 330 kV Operation.	August 2003
10	North Island 400 kV Project - Monte Carlo Analysis of Auckland Area Thermal Plant Availability	March 2005
11	Comparison of the Reliability of a 400 kV underground Cable with an Overhead Line for a 200 km Circuit	2005
12	Peer Review of Choice of Voltage for Development of the New Zealand Grid	February 2004
13	Security of Supply into Auckland – Review of System Capacity Limitations	March 2005

T R A N S P O W E R

North Island 400 kV Upgrade Project

Investment Proposal

Part I – Project Description and Project Plan

1 Summary

Part I introduces the proposed investment and sets out:

- the technical description of Transpower's proposed investment;
- the various processes required to implement the proposed investment; and
- the expected timeframes of undertaking each process.

The four key processes required to be undertaken to complete the proposed investment are:

investigations including preliminary environmental, property and engineering work;
environmental including securing designations and consents;
acquisition of property rights; and
engineering, design, equipment procurement, construction.

Transpower has concluded in Part II of this submission that the proposed investment is required to be commissioned by 2010 to ensure Transpower's grid reliability standards are met in the upper North Island. The timeframes are tight for each of the above processes if the commissioning date is to be achieved.

The critical dates required to be met to avoid delays to the commissioning of the proposed investment are:

registration of interest in transmission line construction: **August 2005**

- lodgement of the notice of requirement: **13 April 2006**
- commencement of compulsory acquisition process for property rights if required: **14 April 2006**
- commencement of tender process for the engineering, equipment procurement and construction contract: **10 April 2006**

2 Project Description

2.1 General

The proposed investment is the construction of a 400 kV transmission interconnection between the existing Whakamaru and Otahuhu substations, including:

- A 400 kV, double circuit, steel lattice tower, overhead transmission line of approximately 200 km from Whakamaru substation to a new underground cable transition station near Ormiston Road (south of Otahuhu substation).
- A 400 kV, double circuit, underground cable from the underground cable transition station into Otahuhu substation with a route length of approximately 9 km.

- Two new 400/220 kV interconnector transformers and associated substation works at Whakamaru substation.
- Two new 400/220 kV interconnector transformers and associated substation works at Otahuhu substation.

Dismantling and removal all of the Arapuni to Pakuranga 110 kV line (providing the preferred western route is confirmed in mid July), making good the affected land and consequential works at Pakuranga.

A schematic diagram of the proposed investment is included in Appendix I-A.

2.2 400 kV Overhead Transmission Line

The 400 kV overhead transmission line will run from Whakamaru substation to a new underground cable transition station near Ormiston Road. The cable transition station will connect the overhead line to underground cables and will require the construction of a small station yard to enclose the works. The transition station is approximately 9 route kilometres south of Otahuhu substation.

2.2.1 Design Parameters

The anticipated key design parameters for the 400 kV overhead transmission line are as described in Table 2-1:

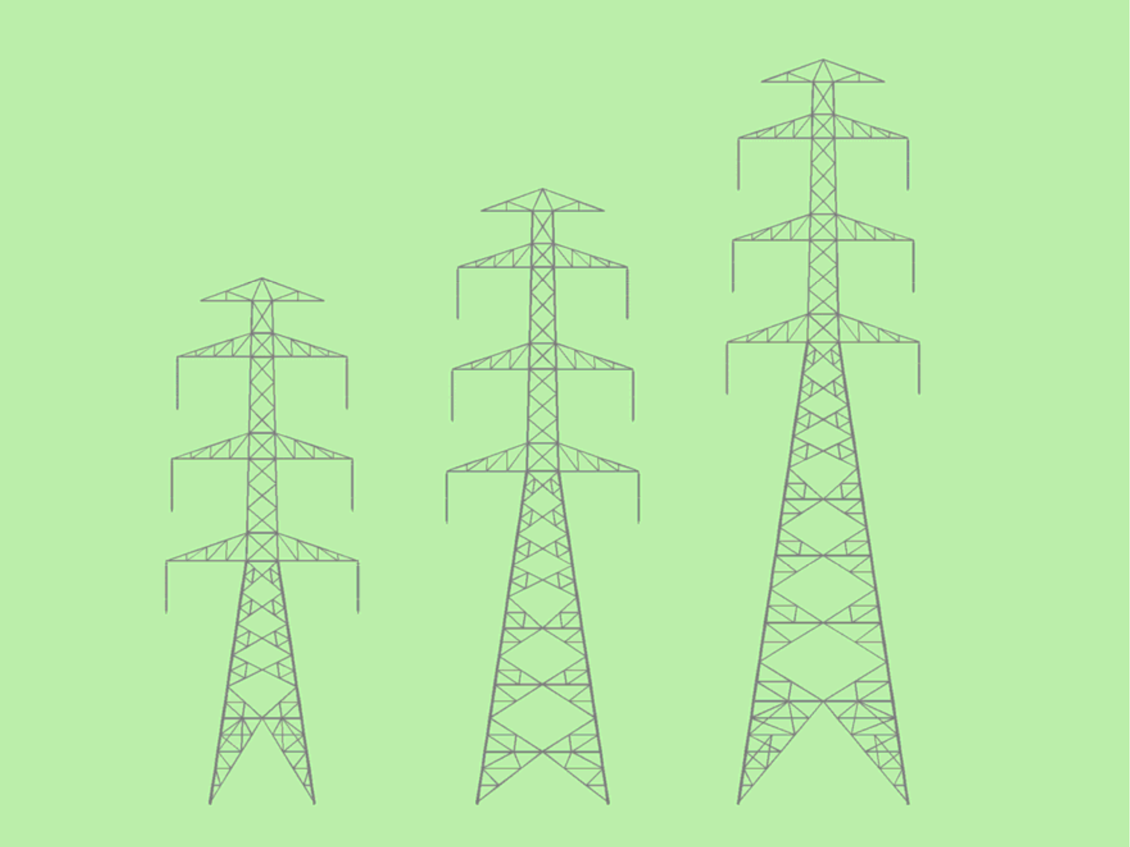
Item	*Value*
Number of Circuits	2
Route Length	200 km
Line Rating	1200 MVA
Max Operating Temp	50 Deg C
Nominal System Voltage	400 kV
Conductors	Twin conductors @ 460mm spacing
Earthwire System	Twin earthwires: 1-OPGW and 1-SC/AC
Structure types	Double circuit lattice steel Tower types – Standard Suspension, Angle Heavy Suspension, Light Strain, Heavy Strain/Dead End
Maximum Electric Field Strength	In accordance with ICNIRP[1] Guidelines
Maximum Magnetic Flux Density	In accordance with ICNIRP Guidelines
Audible Noise Level	45dBA (±1 dBA)
Radio Frequency Interference (RFI)	Compliance with NZS6869:2004
Easement Width	Minimum width based on Audible Noise. Maximum width based on Conductor Swing. Minimum width of 65 m

Table 2-1: Key Design Parameters of 400 kV Overhead Line

---

[1] ICNIRP - International Commission on Non-Ionizing Radiation Protection

Typical tower outlines are as follows, with the likely proportion of each type detailed underneath.



Short Tower (46m) (40%) Medium Tower (55m) (55%) Tall Tower (67m) (5%)

Figure 2-1: Typical 400 kV Suspension Towers General Outline

2.2.2 Transmission Line Route Options

Transpower is currently consulting with the public on two route options (Western and Eastern) for this 400 kV overhead transmission line using the ACRE (Area, Corridor, Route, Easement) process, described further in an appendix to Part III of this submission.

On 14 May 2005 Transpower publicly announced an interim decision to select the Western Route (with minor modifications). Transpower and is continuing with consultation on this interim decision. In mid July 2005 Transpower will announce its final decision on which of these two routes is preferred, and will commence detailed investigations, along with landowner negotiations, to define an easement centreline by 1 December 2005.

The western route largely follows the existing 110 kV transmission line between Arapuni and Pakuranga. If this route was chosen, the Arapuni-Pakuranga 110 kV transmission line would be removed in its entirety. If the eastern route was chosen, Transpower would retain the southern section of the existing line from Arapuni to Karapiro, but would remove the section from Karapiro to Pakuranga.

The two routes that are currently being consulted on are shown in the map in Appendix IB.

2.3 400 kV Underground Cable

The proposed investment includes a 400 kV, double circuit, underground cable from the underground cable transition station into Otahuhu substation with a route length of approximately 9 km.

2.3.1 Design Parameters

The anticipated key design parameters for the 400 kV underground cable are as described in Table 2-2 below:

Item	Value
Number of circuits	2
Number of cables per circuit	3 x single phase cables
Route length	9 km
Installation method	Direct burial or in ducts as required
Depth of burial	1.5 m, nominal
Distance between cable circuits	> 3m
Circuit rating	1000 MVA continuous
Rated voltage	420 kV
Conductor material and size	Copper 2500 sq mm
Insulation	XLPE or SCFF
Metal sheath	Aluminium
Oversheath	PVC or HDPE
Method of sheath bonding	Crossbonded
Maximum Electric field strength	Zero - Except at terminations in a restricted area where a limit of 10 kV/ m will apply. In accordance with ICNIRP Guidelines
Maximum Magnetic Flux Density	In accordance with ICNIRP Guidelines
Radio frequency interference	To comply with NZS 6869

Table 2-2: Anticipated Key Design Parameters of 400 kV Underground Cable

2.3.2 Environmental and Property

Transpower considered obtaining designations under the Resource management Act and securing of property rights for a 400 kV overhead transmission line through high-density residential and commercial areas into Otahuhu would create significant environmental, property, political and financial risks to project success. It would also be likely to lead to unacceptable time delays in the project. The environmental process followed has identified that, due to these reasons, the closest distance that the 400 kV overhead line can approach to Otahuhu substation is 9 route kilometres.

An overhead line to underground cable transition station is planned to be constructed at this point, near Ormiston Road in South Auckland.

The cables would exit this transition station and, where possible, be direct buried in public roads all the way into Otahuhu substation.

Under existing legislation Transpower has no rights to place cables in roadways at voltages above 110 kV. Transpower would therefore need to seek a licence and consents from the Manukau City Council (MCC) for the cable route.

2.4 400/220 kV Substations

The proposed investment includes two new 3-phase, 500 MVA, 400/220 kV interconnector transformers at Whakamaru substation and two new 3-phase, 500 MVA, 400/220 kV interconnector transformers at Otahuhu substation to terminate the 400 kV line and provide interconnection to the existing transmission system.

The switching arrangement for the new 400 kV substations at Otahuhu and Whakamaru will be breaker and a half configuration.

2.4.1 Design parameters

The anticipated key parameters for the 400/220 kV substations are as provided below in Table 2-3:

Item	Value
Substation Type	400 kV (OTA): Outdoor Air Insulated Switchgear 400 kV (WKM): Outdoor Air Insulated Switchgear 220 kV (OTA): Indoor Gas Insulated Switchgear
Substation switching arrangement	400 kV (OTA): 1 ½ breaker 400 kV (WKM): 1 ½ breaker 220 kV (OTA): 1 ½ breaker
Diameters	400 kV (OTA): 2 400 kV (WKM): 2 220 kV (OTA): 3
System voltage	220 kV and 400 kV Nominal 245 kV and 420 kV Maximum
No. of transformers	2 at each site
Transformer rating	500 MVA, 400/220 kV, 3-phase
No. of shunt reactors	2 (one on each circuit)
Shunt reactor rating at Otahuhu	50 Mvar, 400 kV, 3-phase

Table 2-3: Anticipated Key Design Parameters for 400/220kV Terminal Stations

2.4.2 Whakamaru Substation

A new substation site will be developed at Whakamaru to accommodate the new 400/220 kV interconnection facilities and will provide for future 400 kV expansion if required. The new 400/220 kV substation will be constructed adjacent to the existing 220 kV substation to provide physical separation from the existing switchyard. A 220 kV tie line will be established to connect the output of the 400/220 kV interconnector transformers to the existing Whakamaru 220 kV bus.

The new substation will be designed to provide the necessary number of connections at 400 kV to the two new circuits and interconnector transformers. Provision will be made for the site to be expanded to connect up to eight 400 kV circuits in the future if required. Initially there will be no 220 kV bus as the interconnecting transformers will be connected back to the existing Whakamaru 220 kV bus.

Transpower plans to use outdoor air insulated switchgear at Whakamaru substation.

2.4.3 Otahuhu Substation

A new 400/220 kV substation will be constructed at Otahuhu substation within the boundary of Transpower's existing substation and ancillary facilities.

In order to provide diversity of supply at Otahuhu substation, the 400/220 kV interconnector transformers will be connected to a new 220 kV busbar which is physically separate from the existing 220 kV bus. The existing 220 kV circuits from Otahuhu to Henderson and Penrose will be rearranged so that these key loads are supplied from both the existing and new 220 kV busses to achieve this diversity. Provision will also be made so that other key loads can be supplied from the extended 220 kV substation in the future. The new and existing sections of the 220 kV substations at Otahuhu will be interconnected by two tie-lines.

Transpower plans to use outdoor air insulated switchgear for the 400 kV termination and gas insulated switchgear for the new 220 kV substation at Otahuhu substation.

3 Project Plan

There are a significant number of activities and processes that need to be completed prior to, and during, the physical construction of the proposed investment. These form part of Transpower's project plan and are as follows:

3.1 Investigation Process

The investigation process has included all engineering and system planning work to identify the need for investment, identify all possible transmission options and non transmission alternatives and to select a preferred solution to provide long term security of supply into the upper North Island.

This process also includes environmental, property and engineering work required to investigate and select the preferred route corridor and investigate and select two 500m wide routes within that route corridor. It also includes consultation on the preferred routes and the preparation of the documentation required to lodge notices of requirement (in respect of the designation process).

3.2 Environmental Process

Since October 2004 Transpower has been following a public consultation process to gather information to assist in determining which of two 500 m wide route options will be selected as the preferred option.

An interim decision on a preferred route was announced on 14 May 2005, and the public have been provided with a summary of the consultation process undertaken and the data, on which Transpower based its decision. The public has been invited to give submissions to Transpower (either written or oral) on this interim decision. Once these submissions have been reviewed Transpower will make its final decision on which (500 metre wide) route is preferred.

The final easement centre-line will be confirmed by December 2005. A Notice of Requirement (NoR) will be lodged with all the affected District Councils by April 2006 to designate the easement (minimum 65 metres wide). Regional consent applications will also be lodged with the Regional Councils at the same time.

Public notification of the NoR is anticipated to occur in July/August 2006, allowing the public a one-month period to make submissions to councils on the NoR and accompanying Assessment of Environmental Effects (AEE).

The councils will be required to consider Transpower's proposal, as well as any public submissions when holding hearings on the proposed designation some time from October 2006. From this point, councils respond back to Transpower with their recommendations. The estimated timing for councils' recommendations is February 2007. Transpower must then consider the councils' recommendations, and decide whether to accept these in full or in part, and advise the councils accordingly. This process is likely to be resolved by March 2007. From this point, any person who made a submission during the original council hearings, or the councils themselves, can appeal Transpower's decision to the Environment Court (within 3 weeks of receiving the decision). A one-year timeframe has been estimated to resolve all Environment Court appeals, resulting in final statutory approval in March 2008.

3.3 Property Rights Acquisition Process

Following the determination of the preferred route, the property acquisition process will commence, in early July 2005. Negotiations in good faith will be the key objective. It is anticipated that there will be a number of landowners where negotiations in good faith will not produce a result. In the event this occurs, Transpower as a Requiring Authority will seek to use the compulsory acquisition processes within the Public Works Act where good faith negotiations fail.

3.4 Engineer/Procure/Construct Process

This process will include all the detailed engineering design, procurement of all equipment, construction and commissioning of the project.

The project will be split into several implementation packages to provide programme flexibility, and to align the individual implementation packages with their related risks to ensure that these risks are placed where they are best managed. In general terms the implementation packages will all be “design/build” and there are likely to be four basic packages covering:

- The 400 kV overhead transmission line
- The 400/220 kV interconnecting transformers and associated substation works at OTA and WKM (including the overhead to underground transition station)
- The 400 kV underground cable
- The dismantling of relevant existing transmission lines.

The 400 kV overhead transmission line is the project critical path, and this is therefore the implementation package that will be most intolerant of project delays. In order to ensure that Transpower is able to secure the best engineering solution and commercial arrangement it intends to seek an international registration of interest (ROI) no later than early August 2005. The ROI process will involve the receipt of detailed submissions, their evaluation, face to face interviews, reference checking (technical and commercial), and short listing.

It is planned that short listed tenderers be asked to bid for an engineering, procurement and construction contract on 10 April 2006. The contract is planned to be awarded no later than 6 November 2006.

3.5 Critical Timeframes and Milestones

A project of the proposed investment’s magnitude would normally be expected to take a period of eight years from initial mobilisation to final commissioning. Transpower has identified that the proposed investment is required by May 2010 therefore all major project milestones are critical to the successful implementation of the proposed investment.

A summary of key milestones for each process is set out below and further highlighted in the bar chart in Figure 3-1.

3.5.1 Environmental & Property

- Preferred Route Announced: mid July 2005
- Easement Centre Line Confirmed: December 2005
- Notice of Requirement (NoR - for a designation under the RMA) Lodged with Councils: April 2006
- Designation Granted: March 2008
- Property Rights Secured: September 2008

3.5.2 Engineer/Procure/Construct

- Commencement of Registration of Interest & Short List: 1 August 2005
- Commencement of Tender/Evaluation/Negotiation Process for Design/Procure/Construct: 10 April 2006
- Commencement of Design/Procure/Construct Process: 6 November 2006
- Final Commissioning: 27 May 2010

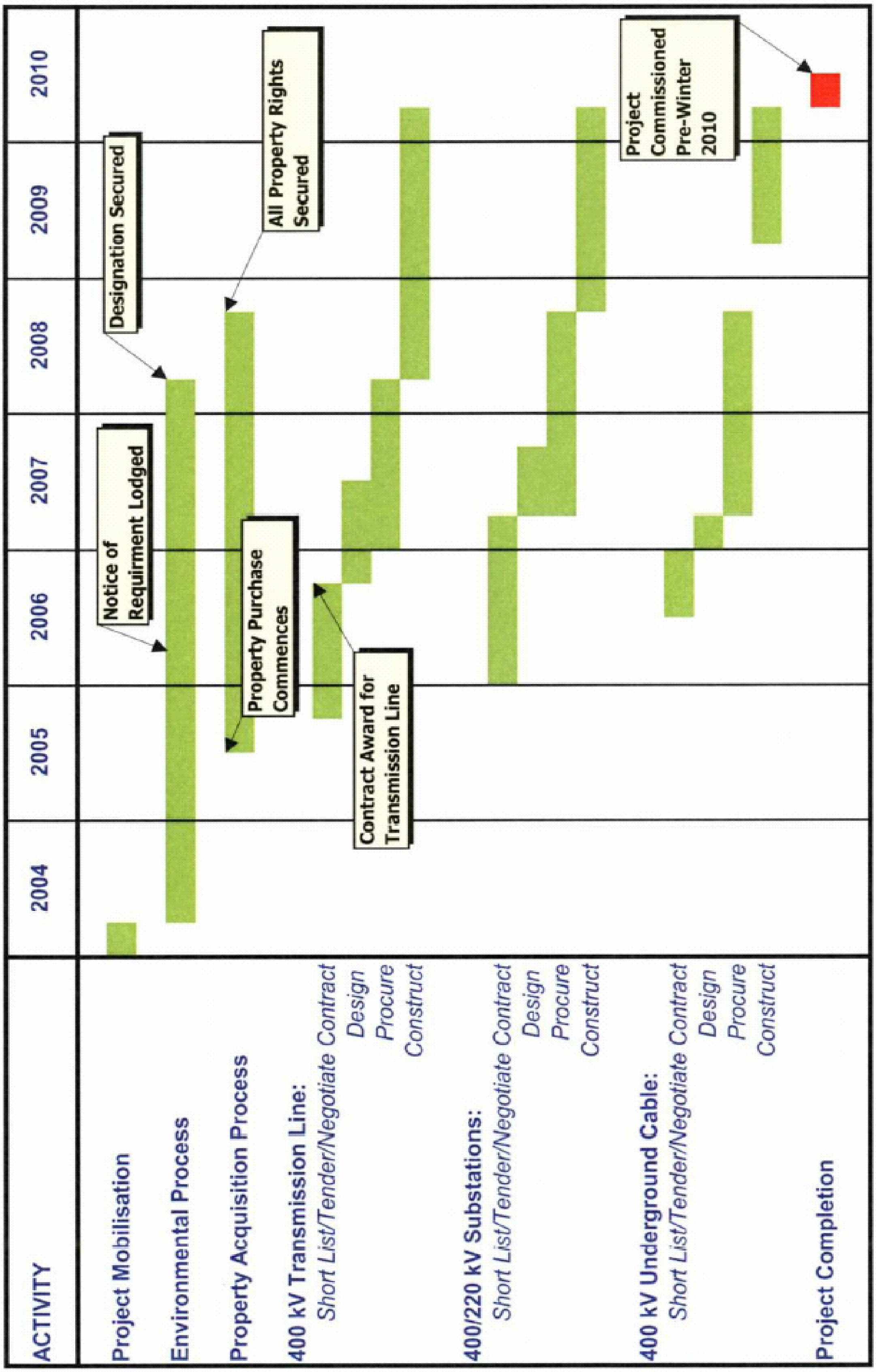
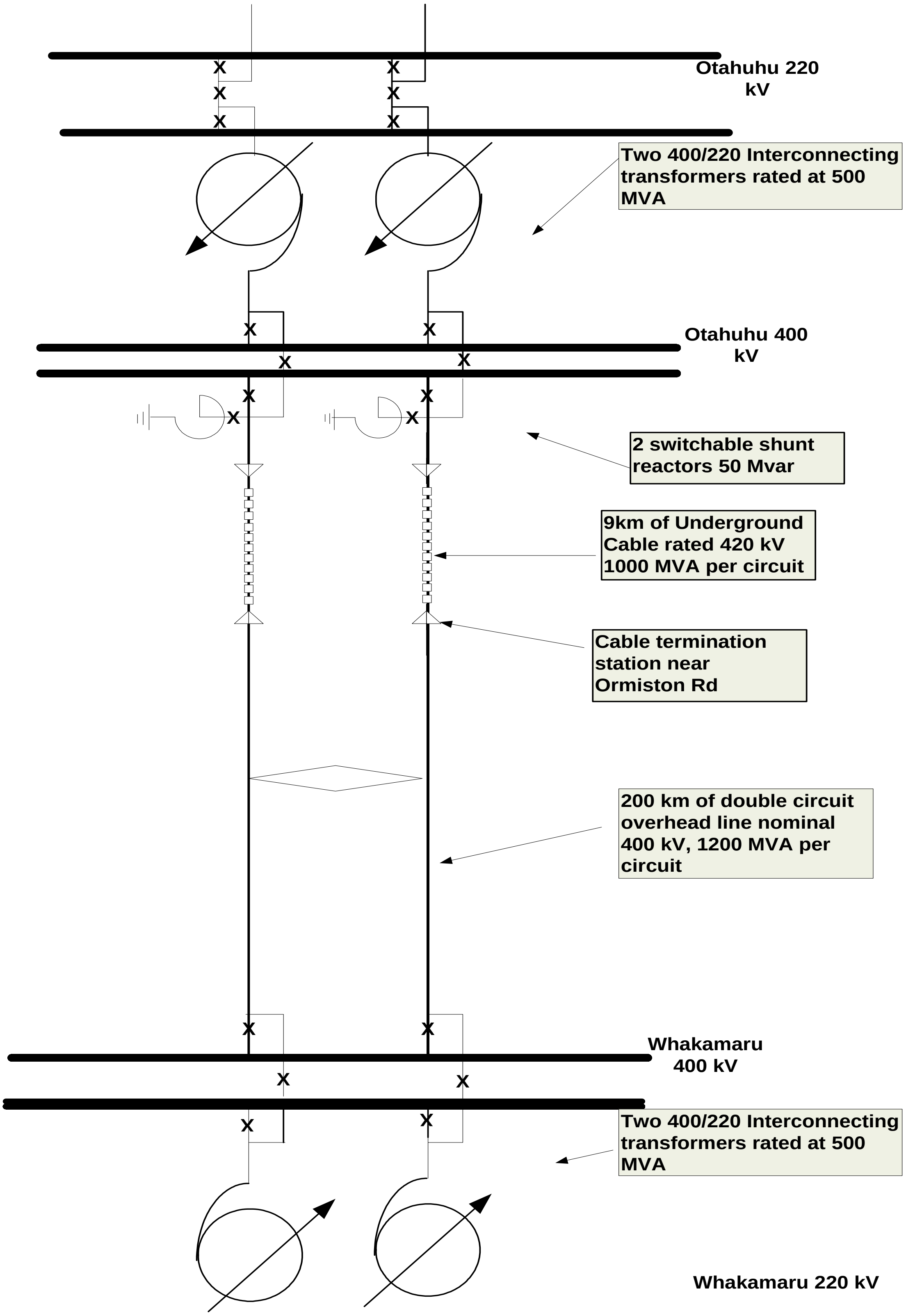
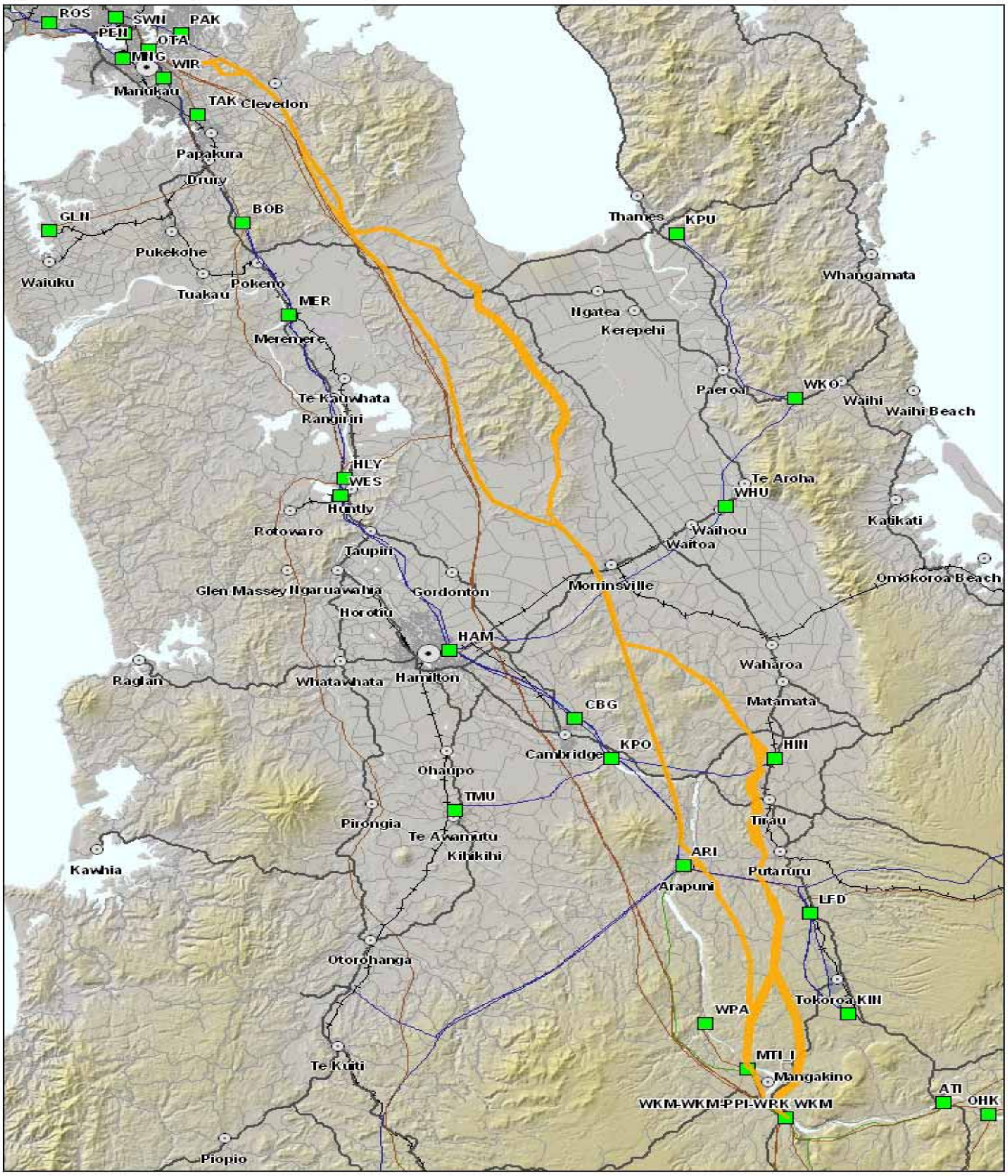


Figure 3-1: Key activity timeline

Appendix IA - Transmission Schematic of Project (Simplified)



Appendix IB - Map of Route Options



Appendix IC - North Island 400 kV Grid Upgrade Project Critical Path Timeline

Date	Action	Comment
31 May 2005	Lodge submission with Electricity Commission	Triggers EC process
15 July 2005	Commence "good faith" property rights acquisition negotiations	EC approval required prior to TP commitment to significant expenditure
13 April 2006	Lodge NoR Commence compulsory property rights acquisition	Requires Minister of Lands approval. Will almost certainly require unfettered approval by EC before Minister "sign off"
3 Nov 2006	Award "Construction" contract	Needs to be conditional on designations and certainty of property rights acquisition. If there is uncertainty about the recovery of the cost of the risk of cancellation/delay then TP shareholders will need to underwrite.
28 Mar 2008	Designation granted Start "Field" construction	Requires designations to be granted and property right acquisition certainty to be in place (ie section 23 PWA)
25 Sept 2008	Property Rights secured	
27 May 2010	Commission 400 kV project	

TRANSPOWER

North Island 400 kV Upgrade Project

Investment Proposal

Part II – Establishing the Need for New Investment

1 Summary

Part II of Transpower's submission demonstrates the need for the proposed investment by analysing demand and generation forecasts against Transpower's current grid reliability standards. The analysis concludes that there is a risk of electricity demand not being supplied into the upper North Island from 2010 and that new investment is required to maintain security of supply into the region.

Transpower's needs analysis draws on a number of key inputs which are described below and are contained in section 2 to 5 of this Part II:

a) *Forecast electricity demand (section 2)*

Demand forecasts (including sensitivity analysis) are developed for all grid exit points in the upper North Island. These demand forecasts are based on the Electricity Commission's national electricity demand forecast for the next 40 years.

b) Forecast electricity generation (section 3)

Five generation scenarios are used to identify existing generation and the range of possible future generation in the upper North Island region.

c) Grid Reliability Standards (section 4)

The transmission planning criteria sets out Transpower's current grid reliability standards (noting its consistency with the Electricity Commission's grid reliability standards).

d) Existing and Proposed Power System (section 5)

The parameters of the current power system including generation capacity and reliability and transmission limits.

2 Forecast Electricity Demand

Transpower has developed demand forecasts for each grid exit point to enable it to undertake the power system analysis required to determine the need for investment and to complete the economic analysis of transmission and non-transmission alternatives. This section sets out the basis on which the demand forecasts were developed for the upper North Island.

2.1 Electricity Demand Growth Forecasts

Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis of creating the necessary demand forecasts for the power system analysis. This national forecast is set out in Figure 2-1.

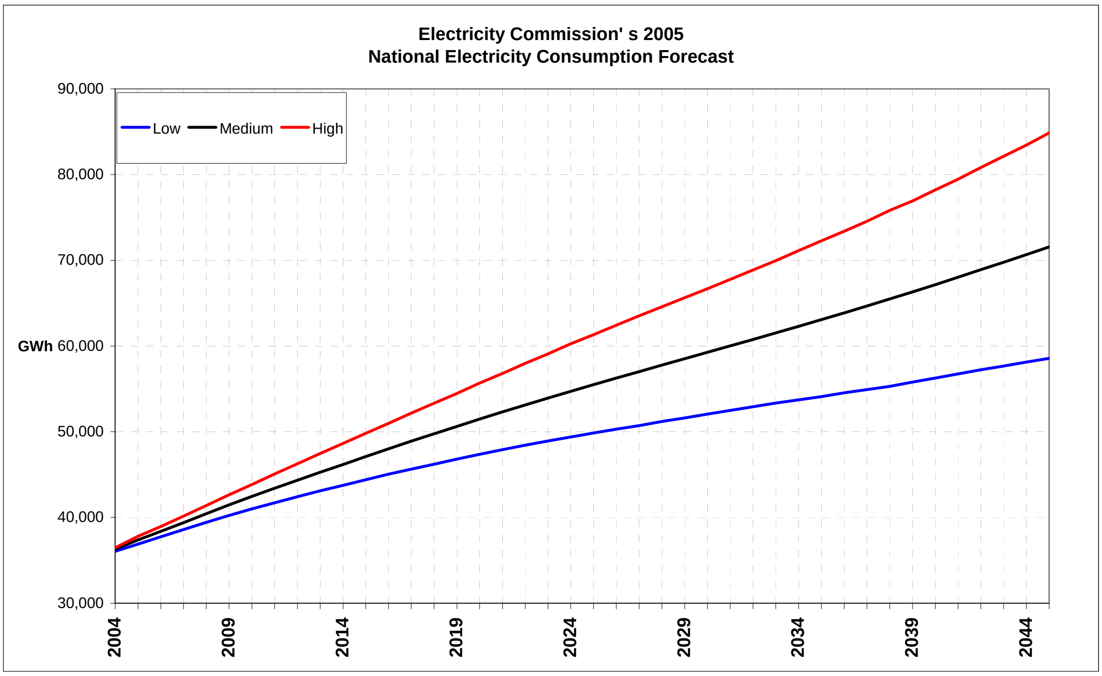


Figure 2-1: National Electricity Consumption Forecast

2.1.1 Regional Allocation Methodology

Transpower used the national electricity consumption forecast to derive a forecast of the half hourly average peak demand known as the After Diversity Maximum Demand (or ADMD) at all grid exit points by using a regional allocation methodology, as shown in Figure 2-2. The ADMD forecast is derived by using the following factors:

- Allocation of national demand across all regions
- A review of the historical peak demand
- An assessment of distributed generation uptake.

The allocation of national growth in demand to regions was completed on the basis of forecast of regional population growth. Regional growth projections were obtained from Statistics New Zealand.

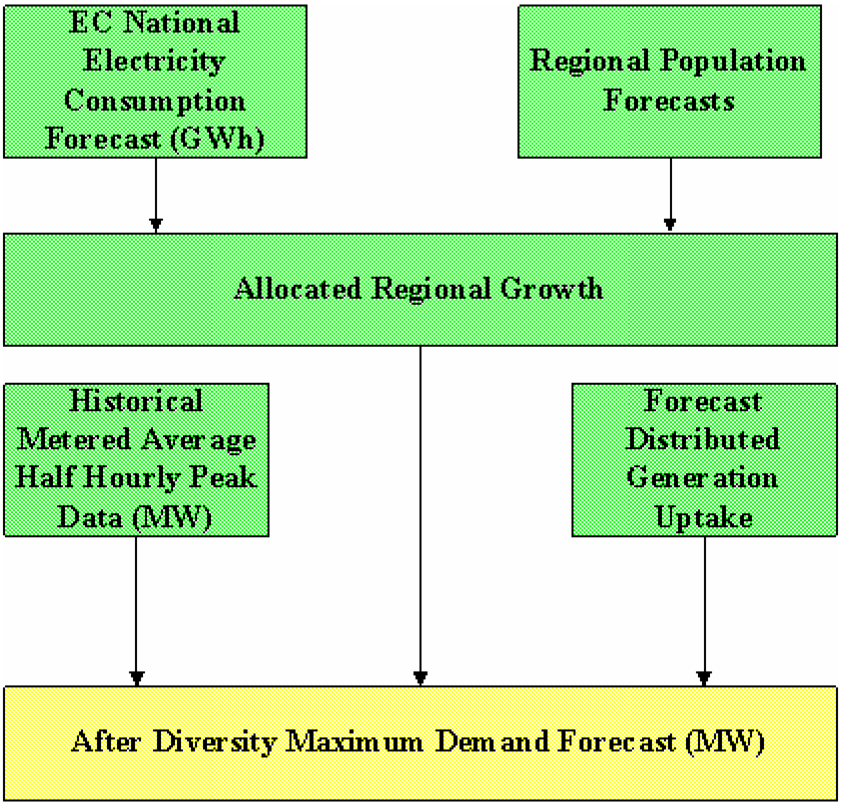


Figure 2-2: High Level Process for Deriving Transpower's After Diversity Maximum Demand Forecast

2.1.2 Small Scale Distributed Generation

The national electricity consumption forecast, is a forecast of gross electricity consumption, including that delivered from the grid and supplied locally from small scale distributed generation. Transpower plans on the basis of the load that needs to be supplied from the grid and consequently, Transpower's regional demand forecast is derived including an implicit assumption about the uptake of small scale distributed generation in the future. The expected contribution from local small scale distributed generation has been deducted from the gross consumption forecast at grid exit point level.

A forecast of the uptake of small scale distributed generation is made based on projected technology and electricity production costs under various manufacturing and commercial conditions (e.g. available sources of energy, industrial work patterns). An industry profile is used to assess those applications where distributed generation may be cost effective compared to grid delivered electricity. Small scale distributed generation is projected to increase from its estimated current uptake of 4% to a level equivalent to 5% of the total forecast peak demand by the end of the forecast period (2046).

2.1.3 Annual Demand Variations and Establishing a Baseline

While demand in the upper North Island has trended upwards over time, there can be substantial fluctuations year on year from an expected average. These variations may be caused by effects such as ambient temperature changes. In the case of a city such as Auckland, it is usual to expect a temperature related demand sensitivity of approximately 25 MW per °C for variations of typical winter temperatures (i.e. 50 MW for 2°C). This is illustrated in Figure 2-3 which shows the volatility of the demand observed during the period 1997 – 2004 with actual demands varying as much as +/-40 MW from the average trend line.

In order to establish a reasonable starting point for demand forecasting, a baseline for the peak demand forecast was derived using the trend of actual average half hourly metered information between 1997 and 2004. This approach contrasts with one which assumes the base demand as the peak demand observed during one particular year which may over or underplay the impact of random variations in the annual peak demand.

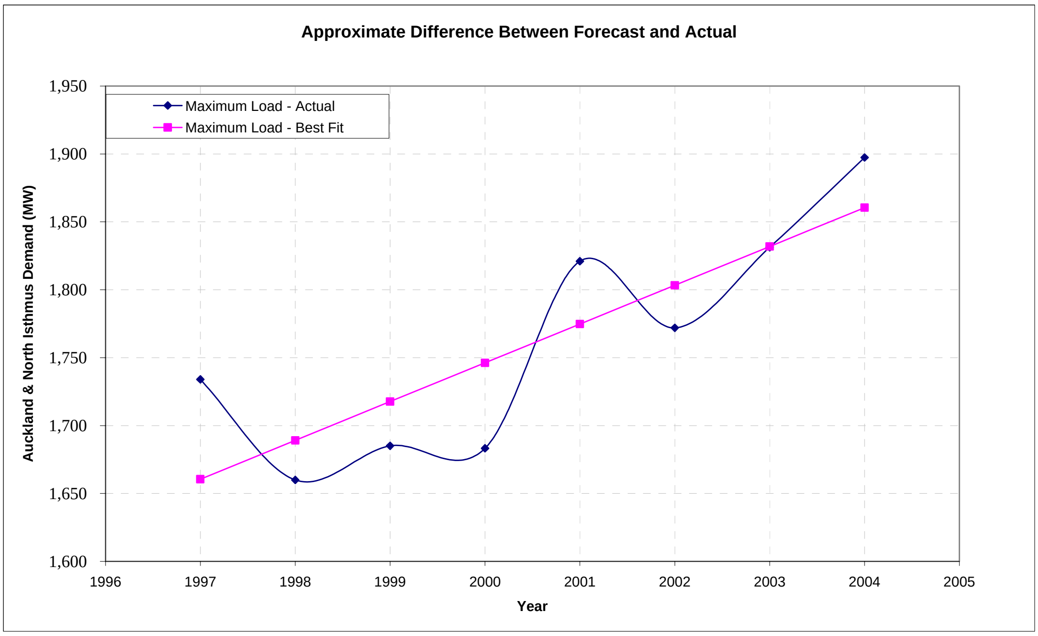


Figure 2-3: Difference Between Forecast Trend and Actual Demand

2.1.4 Average Half Hourly ADMD Forecast

Another key assumption in the projections for the base demand scenario is that the rate of growth in peak demand matches the rate of growth in gross electricity consumption.

The resulting ADMD forecast is a forecast of the half hourly average peak demand, as opposed to a forecast of the instantaneous peak demand. This difference is discussed in more detail in Section 2.1.5.

The upper North Island region encompasses the area north of Bombay. Figure 2-4 shows the average half hourly ADMD forecast for the upper North Island regions.

A complete table of low, medium and high forecast data for the combined regions can be found in Appendix II-A. The load forecasts show that annual peak demand in the region by 2010 will be approximately 2265 MW under a medium growth forecast and 2345 MW under a high growth forecast.

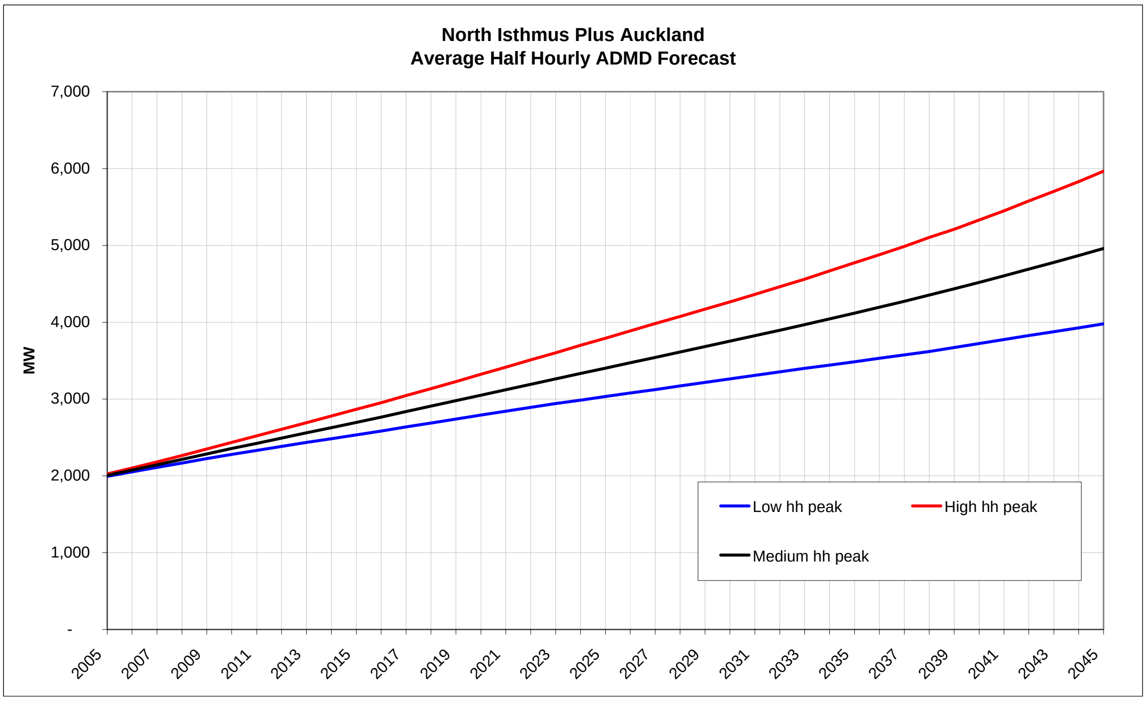


Figure 2-4: Upper North Island Forecast Half Hourly Average Peak Demand

2.1.5 Instantaneous ADMD Forecast

Transpower considers that it is prudent to base load forecasting methods upon actual system demand as opposed to half hourly average metered demand data as this provides a more stable basis for forecasting. Metering is a reliable source of information and is correlated with electricity billing practices. However, these forecasts only provide a long term view of half hourly average demands and do not take into account the short term volatility, (e.g. instantaneous variations in the load) or the medium term volatility (e.g. variations due to unexpected seasonal changes) of grid exit point requirements.

Short-term, or instantaneous demand varies within the “half hourly average” figure and in the case of the greater Auckland area and north regions, variations of ±50 MW are common. This is illustrated in Figure 2-5, which shows the actual instantaneous system demand, as represented by metered data, for a typical Winter’s day. The instantaneous peak demand, in the upper North Island region can be 50 MW higher than the average metered data.

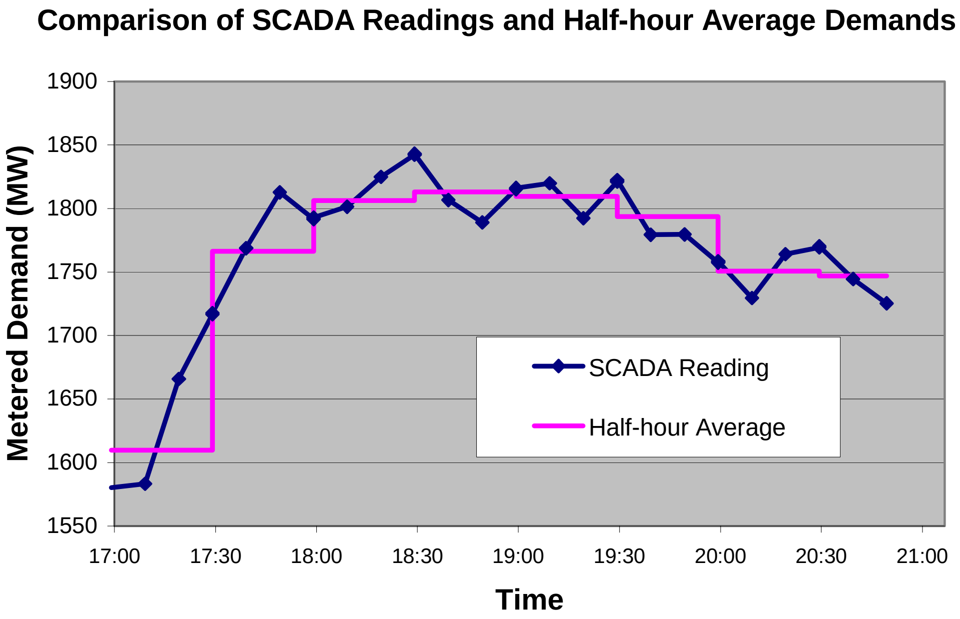


Figure 2-5: Metered Data versus Half Hourly Average Demand Comparison

2.1.6 Electricity Commission Comparison

The Commission has recently published its regional peak demand forecast in the draft Statement of Opportunities. The methodology the Commission has employed is almost identical to Transpower's with the following key differences:

1. The Commission does not assume a future uptake of distributed generation;
2. The Commission has used a different base year to Transpower from which to forecast.

Nevertheless, both approaches by the Commission and Transpower deliver consistent outcomes.

The chart below compares the following:

1. The Commission's peak demand forecast which excludes any assumption about future distributed generation;
2. Transpower's demand forecast excluding any uptake of future distributed generation;
3. Transpower demand forecast used in the transmission planning assumptions outlined in this proposal. The forecast includes an assumption about the uptake of distributed generation in the future.

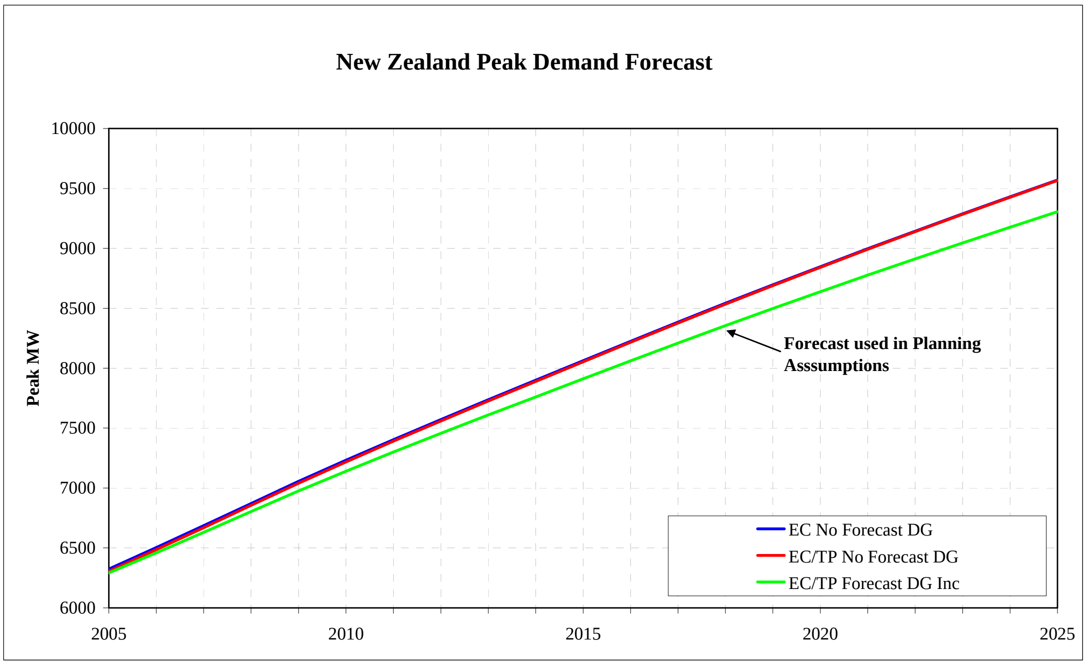


Figure 2-6: Commission and TPNZ Peak Demand Forecast Comparison

The above chart shows that on a “like for like” basis, ie excluding any assumption about distributed generation uptake, there is no material difference between the Commission’s forecast and the forecast Transpower used for its planning analysis.

Transpower also considers that the differences between the demand forecast used in this analysis and the Commission’s demand forecast, (which is slightly higher), are immaterial to both the outcomes of the need for and timing of new investment and the economic analysis.

Further information on this process can be found in the supporting document: “North Island 400 kV Project Planning Assumptions – Demand and Generation Forecasting.”

2.1.7 Demand Forecast Summary

In summary, the demand forecast utilised for this submission has been based on the following:

- The Electricity Commission’s national consumption forecast.
- A conversion of the national forecast to regional forecasts.
- A baseline starting forecast for 2005 based on average growth over the last seven years.
- An allowance for the effect of year by year demand fluctuations from the baseline forecast (40 MW) and the effect of average metered demand versus actual demand (50 MW) by the addition of 90 MW to the baseline forecast.

Figure 2-7 shows the instantaneous peak demand forecast (as the dashed line) which has been derived from the above process and has been used in this submission. Appendix II-A provides a detailed table of the year by year demand forecast from 2005 until 2045.

Further information on this process can be found in the supporting document titled, “North Island 400 kV Project Planning Assumptions – Demand and Generation Forecasting”.

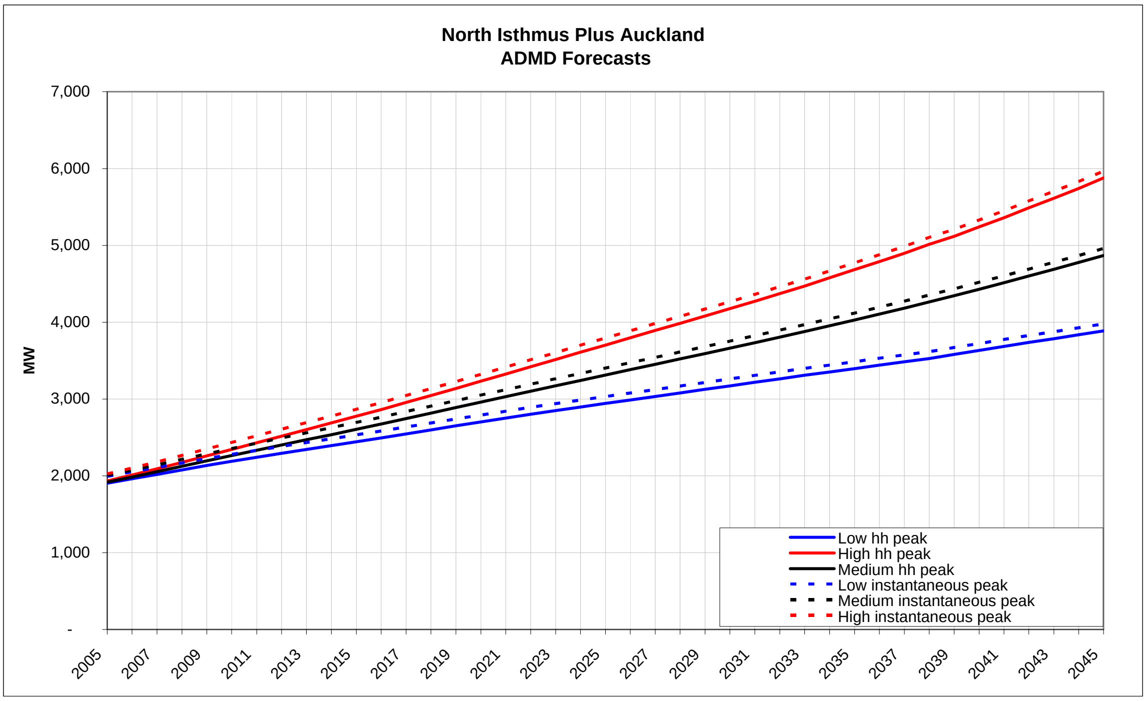


Figure 2-7: Upper North Island Average Half Hourly Forecast Demand

3 Generation Scenarios

Transpower has developed five generation scenarios to identify the range of possible generation forecasts in the upper North Island region over the next 40 years.

The generation scenarios contained within this submission are based on a set of generation scenarios developed by Transpower over the period 2003 – 2004 and have been modified where additional information has become available. These generation scenarios were used for assessing the robustness of Transpower's grid upgrade alternatives against a range of future generation developments.

The type and location of generation capacity was determined by the scenario, eg Scenario 1 assumed the majority of new North Island generation was located in:

- areas where there is a high probability of further gas being discovered, ie Taranaki, East Coast North Island;
- areas on the main gas transmission network, ie Huntly, Otahuhu;
- areas where there is a high probability of new gas fired co-generation stations such as Marsden.

Generation requirements were established, at five yearly intervals, assuming a 1-in-20 dry year requirement i.e. sufficient generating plant is available to ensure that a dry year (modelled as whenever hydro reserves fall below 300 GWh of generation) only occurs once every twenty years on average.

Transpower's 2003 - 2004 generation scenarios are regarded as suitable for this analysis as they reflect current knowledge of New Zealand's energy supplies and include sufficient generation to meet the electricity consumption forecast detailed in Section 1.

Scenario 1 – Unconstrained inputs ("Burn Gas")
Scenario 1 reflects an environment where there are no resource constraints. In this scenario, gas is plentiful and cheap, and the first choice of input for electricity generation. It is assumed that gas is only available for generation in the North Island. The HVDC is constrained to its existing capacity in this scenario, limiting the amount of North Island based gas-generated electricity that can be transmitted to the South Island. Some gas reserves have been discovered off the coast of Canterbury, but these are not commercial and are not supported by existing infrastructure. Generation in the South Island is provided through a mix of hydro generation and coal. Limited wind and geothermal generation have been included as has limited hydro in the North.

Scenario 2 – Gas constrained ("Burn Coal")
Scenario 2 portrays a future where significant gas is not found, but where coal is an acceptable and attractive alternative. It is assumed that existing gas generation will be retained, either as gas or an alternative fuel type, in its current location. The location selected for new coal-based generation depends on the island it is located in. In the North Island coal generation has been located at, or close to, major port facilities or near known coal reserves in the Waikato area. In the South Island coal generation has been located at, or close to, known coal reserves. This scenario also introduces more wind generation in the North Island than in Scenario 1, to reflect a marginal response associated with anticipated higher costs in the North Island.

Scenario 3 – Carbon constrained ("Renewables")
This scenario reflects a future in which carbon fuels such as gas and oil are uneconomic due to a combination of resource availability, and carbon constraints or taxes imposed as a result of environmental policy. Generation is provided mainly through a mix of hydro, wind, geothermal, and biomass. In order to provide the quantities of generation required, it is assumed that significant hydro development remains viable despite local environmental issues. In later years significant amounts of new biomass based generation are introduced in order to meet North Island demand, given the assumed HVDC constraint.

Scenario 4 – Carbon constrained and HVDC unconstrained ("Southern Hydro")
This scenario is similar to Scenario 3 in that it reflects a future where generation is primarily provided through renewable sources. In this case though, it is assumed that the HVDC capacity is unlimited so as to enable transport of electricity from hydro sources in the South to the North Island. The intent of this is to provide a scenario with a larger proportion of hydro-generation in the South Island, as opposed to Scenario 3 where the HVDC constraint results in biomass renewables being installed in the North Island to meet demand.

Scenario 5 – Reduced South Island Demand ("Reduced South Island Demand")
In Scenario 5, South Island demand is reduced, in steps, by 200 MW in 2015, 2019 and 2023 so that by 2023, a total of 600 MW of demand has been dropped in the South Island. Given that the HVDC link is assumed to remain constrained to its current limit of 1,040 MW North and 620 MW South, the extent of new North Island capacity was capped by how much was required to meet forecast peak demand in the North Island. Therefore, the reduction in new generation capacity to be installed mainly occurs in the South Island.

Table 3-1 shows the new installed generation capacity in each region under the five generation scenarios.

Scenario 1 - Additional New Generation Capacity Installed														
MW	N. Isthmus	Auckland	Waikato	BOP	Hawke Bay	Taranaki	Central	Wellington	WstCst	Nelson	SthCant	Canterbury	Otg/ Slnd	**Total**
2010	32	393	440	-	-	18	-	22	-	-	-	60	294	1,258
2015	32	393	618	-	119	399	-	22	212	-	-	120	371	2,285
2020	32	929	618	-	119	399	-	379	212	-	-	120	448	3,254
2025	270	1,226	618	-	119	815	-	591	365	-	-	239	448	4,692
2030	570	1,226	840	-	357	815	244	591	365	-	-	239	686	5,934
2035	808	1,226	1,118	278	357	815	244	591	365	-	-	239	686	6,728
2040	808	1,226	1,790	278	357	815	661	591	365	-	-	239	686	7,816

Scenario 2 - Additional New Generation Capacity Installed														
MW	N. Isthmus	Auckland	Waikato	BOP	Hawke Bay	Taranaki	Central	Wellington	WstCst	Nelson	SthCant	Canterbury	Otg/ Slnd	**Total**
2010	399	-	440	-	-	18	-	22	119	-	-	-	200	1,198
2015	982	-	618	-	-	18	-	22	119	-	-	200	200	2,159
2020	982	-	975	-	357	18	-	22	119	-	-	200	498	3,171
2025	1,280	-	1,570	36	393	18	244	234	476	-	-	200	664	5,115
2030	1,577	-	1,792	36	393	18	488	234	476	-	-	200	1,021	6,236
2035	1,577	-	2,070	202	393	18	488	234	476	-	-	200	1,021	6,680
2040	1,577	-	2,378	202	393	368	488	234	595	-	-	200	1,498	7,933

Scenario 3 - Additional New Generation Capacity Installed														
MW	N. Isthmus	Auckland	Waikato	BOP	Hawke Bay	Taranaki	Central	Wellington	WstCst	Nelson	SthCant	Canterbury	Otg/ Slnd	**Total**
2010	32	393	440	-	-	18	-	22	62	88	-	62	181	1,298
2015	204	393	696	36	113	18	-	22	62	165	-	217	588	2,514
2020	204	393	696	66	383	166	441	22	262	165	77	371	858	4,104
2025	307	473	898	305	454	226	640	446	262	319	77	371	1,012	5,788
2030	393	473	1,009	342	514	374	762	446	262	627	385	483	1,134	7,202
2035	512	473	1,287	509	715	374	821	446	262	627	385	622	1,174	8,205
2040	512	592	1,769	564	953	493	940	565	262	781	385	622	1,174	9,611

Scenario 4 - Additional New Generation Capacity Installed														
MW	N. Isthmus	Auckland	Waikato	BOP	Hawke Bay	Taranaki	Central	Wellington	WstCst	Nelson	SthCant	Canterbury	Otg/ Slnd	**Total**
2010	32	393	440	-	-	18	-	22	62	-	275	92	-	1,334
2015	204	393	518	-	78	18	-	22	62	77	529	92	585	2,577
2020	204	393	518	31	334	166	441	22	292	77	606	246	854	4,184
2025	247	473	696	31	359	166	640	422	292	390	606	246	1,470	6,038
2030	333	473	807	68	359	314	762	422	292	698	914	359	1,745	7,546
2035	333	473	1,084	235	382	314	762	422	292	698	914	497	2,245	8,652
2040	333	473	1,448	290	382	314	762	422	292	1,006	1,452	497	2,553	10,225

Scenario 5 - Additional New Generation Capacity Installed														
MW	N. Isthmus	Auckland	Waikato	BOP	Hawke Bay	Taranaki	Central	Wellington	WstCst	Nelson	SthCant	Canterbury	Otg/ Slnd	**Total**
2010	70	357	357	50	-	-	30	22	-	29	-	62	200	1,177
2015	145	357	624	50	-	381	103	72	-	121	-	62	335	2,250
2020	145	379	624	127	250	531	353	122	-	121	-	62	335	3,049
2025	295	509	884	294	450	531	653	322	-	204	-	62	410	4,613
2030	647	509	1,034	353	450	556	653	322	-	204	-	62	460	5,250
2035	766	509	1,502	353	569	675	712	441	-	204	-	201	783	6,716
2040	766	628	1,921	464	688	675	712	441	-	466	-	201	783	7,746

Table 3-1– New Generation Capacity by Region

Full details of the generation scenarios can be found in the Transpower document: “North Island 400 kV Project Planning Assumptions – Demand and Generation Forecasting”.

3.1 Summary of Generation in the Auckland and North Isthmus region

The power system analysis and associated economic analysis is sensitive to the capacity and timing for new generation investment in the upper North Island, as this local generation reduces the benefits of new transmission augmentation. Figure 3.1 illustrates the cumulative total of local generation included in the Auckland and North Isthmus region for each scenario.

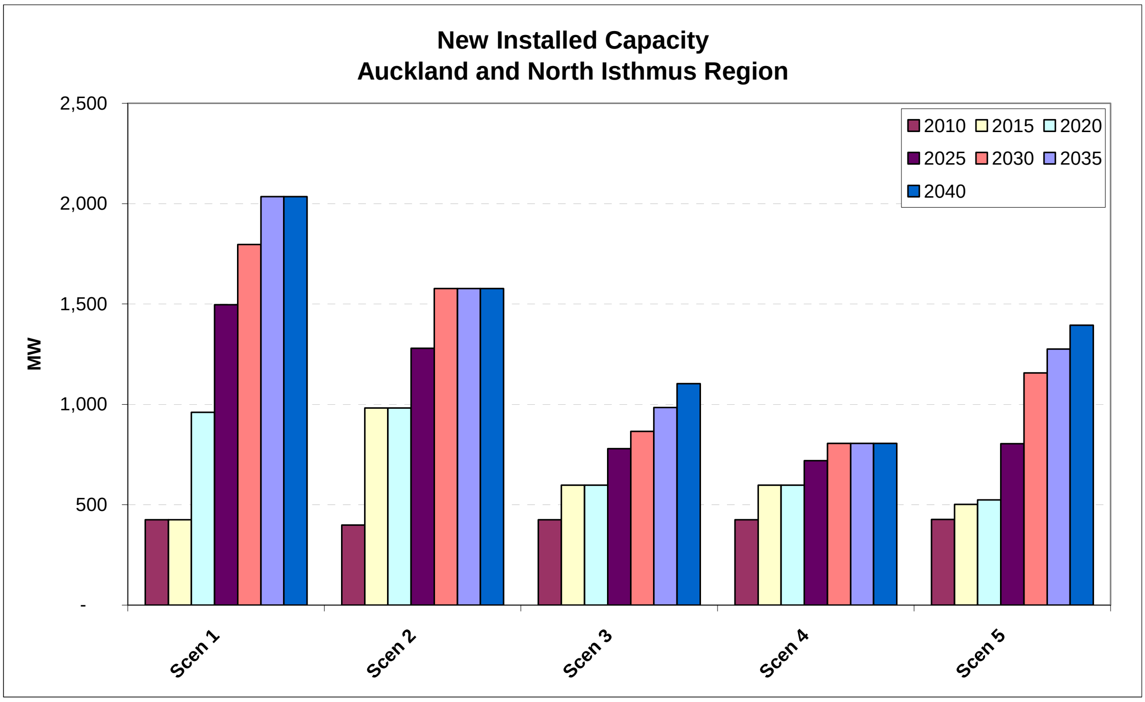


Figure 3-1: Upper North Island New Installed Generation Capacity per Scenario – Transpower version

Further information on the forecast generation for each grid exit point under each scenario can be found in the Transpower document: "North Island 400 kV Project Planning Assumptions – Demand and Generation Forecasting".

3.2 Comparison with Electricity Commission's Generation Scenarios

While broadly consistent in terms of scenario type, the generation scenarios used by Transpower contain some differences to those that have been recently published for consultation by the Electricity Commission in their Statement of Opportunities.

The amount of local generation included in each of the Electricity Commission's scenarios is set out in Figure 3.2. The comparison shows that Transpower's scenarios all contain more generation in the upper North Island than scenarios published by the Electricity Commission. Transpower's scenarios therefore provide a harder economic test for the proposed 400 kV line between Whakamaru and Otahuhu. This is because any generation north of Auckland relieves (or delays) the requirement for transmission reinforcement from the south. Transpower's scenarios therefore provide for less unserved energy[1] forecast in the economic analysis.

Transpower therefore considers that the differences between the scenarios used for this analysis and those published by the EC for consultation are not material to the outcomes of the economic analysis set out in Part IV.

---

[1] The key benefit of new transmission augmentation in the National Benefit test methodology is the avoidance of unserved energy, valued at $20,000 MWh.

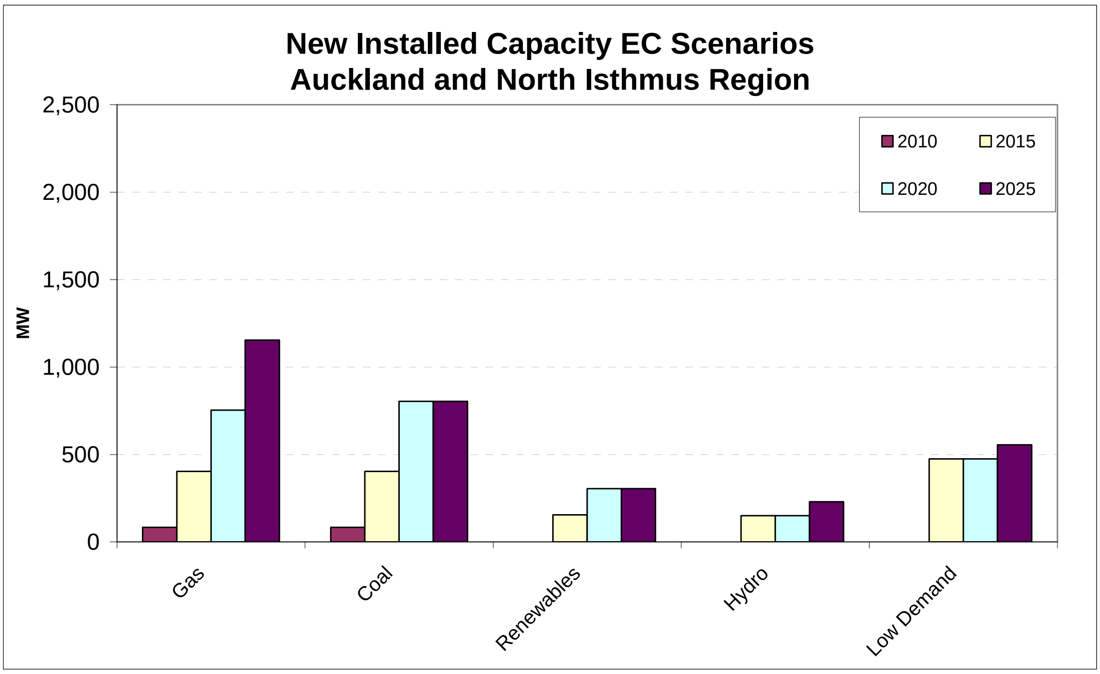


Figure 3-2: Upper North Island New Installed Generation Capacity per Scenario - Electricity Commission Version

4 Grid Reliability Standards

The transitional provisions of Part F require that the proposed investment is “reasonably prudent or necessary to meet Transpower’s current grid reliability standards”. Transpower’s current grid reliability standards form the basis of its transmission planning criteria. Transpower uses the criteria to justify the requirement for a new transmission investment from a planning perspective.

Under Transpower’s transmission planning criteria, the main interconnected transmission system supplying upper North Island regions is designed to maintain an N-1 security criterion, meaning that the system is in a secure state with all transmission facilities in service and in a satisfactory state following a single contingency. These standards are consistent with the real time standards for system operation applied by the system operator under Part C of the Electricity Governance Regulations.

The single contingencies considered under the N-1 criterion are:

- loss of a single transmission circuit
- loss of a single generating unit
- loss of a single bus section (for new transmission builds only)
- loss of an interconnecting transformer
- loss of a single reactive component, e.g. capacitor bank or SVC

Transpower’s current transmission planning criteria are consistent with the new Grid Reliability Standards (GRS) that were published by the Electricity Commission in May 2005.

A copy of Transpower’s transmission planning criteria, against which the proposed investment is analysed, is available in the document titled “North Island 400 kV Project – Main Transmission System Planning Criteria.

5 Existing and Proposed Power System

5.1 Existing Generation within the upper North Island

The generation that can be assumed to be reasonably available within the region is determined by two factors:

- The installed capacity of the generation
- The availability of the generation plant for dispatch

For the purposes of determining system adequacy, only the existing and committed generation plant in the region have been considered. The plants' availability is affected by two factors:

- reliability of the generation plants leading to plant capacity reduction due to the unplanned outages and
- the operating restrictions on the plants due to availability of the fuel resources and/or the constraints placed on the operation of the plants.

5.1.1 Capacity of the Generation Plant

Electricity generation in the North Island is a mix of thermal power from Huntly, Stratford and Otahuhu power stations, hydro power from the Waikato River and central North Island stations and geothermal power from Wairakei, Ohaaki and Mokai stations.

The combined installed generation capacity in the upper North Island is 1947 MW. A break down of this figure is given in Table 5-1.

Generating Station	Installed Capacity MW
Glenbrook[2]	55
Otahuhu CC	365
Southdown	122
Huntly[3]	1405
TOTAL	**1947**

Table 5-1: Generation in Upper North Island Regions

Generation from Huntly in the table includes the existing coal/gas fired steam generation plant of capacity 4x250 MW, the gas turbine plant (P40) of capacity 1x40 MW and the new generation (e3p) presently being built by Genesis, of estimated capacity 1x365 MW. It is expected that the new gas fired single shaft combined cycle generation plant will be in service by 2007.

---

[2] For cogeneration plants, the average monthly dispatch is assumed

[3] Generation from power plants at Huntly is included in the table above because, while it is located in the Waikato region, its relative proximity to the Auckland region (compared to generation near Whakamaru), means that it does have an effect on supply security.

Transpower is aware that at least two other significant generation projects have been suggested, by Contact and Mighty River Power at Otahuhu and Marsden Point respectively. These projects have not been reflected in the assessment of the adequacy of the existing system as they are still some way from being committed or confirmed. However generation to this effect has been included in all of Transpower's generation scenarios so the impact of this plant on the economics of the proposed investment has been considered.

5.1.2 Availability of the Generation Plant

The supply security of the regional load is dependent on two critical factors, reliability of the generation in the area and the secure transmission capacity into the region. By 2010, all the major generating plants available in the region will be thermal plants. The largest units will be the single shaft, single generating unit, combined cycle generating plants at Otahuhu and Huntly (exceeding 350 MW/unit) followed by the four gas/coal fired steam units at Huntly (250 MW/unit). Such thermal plant has a substantially lower level of availability and reliability than transmission equipment. Therefore an assessment has been completed on the likely level of actual generation that can be reasonably and prudently assumed to be available.

Historically, a failure of one of the major plant items (e.g. unit transformers or boilers) results in a long repair time. Assuming the average failure rates of the similar machines reported in international literature, the assessed plant availability in the region (including Huntly) is shown in Figure 5-1. Detail of the assessment of generator availability is described separately in the report: "North Island 400 kV Project – Monte Carlo Analysis of Auckland Area Thermal Plant Availability"".

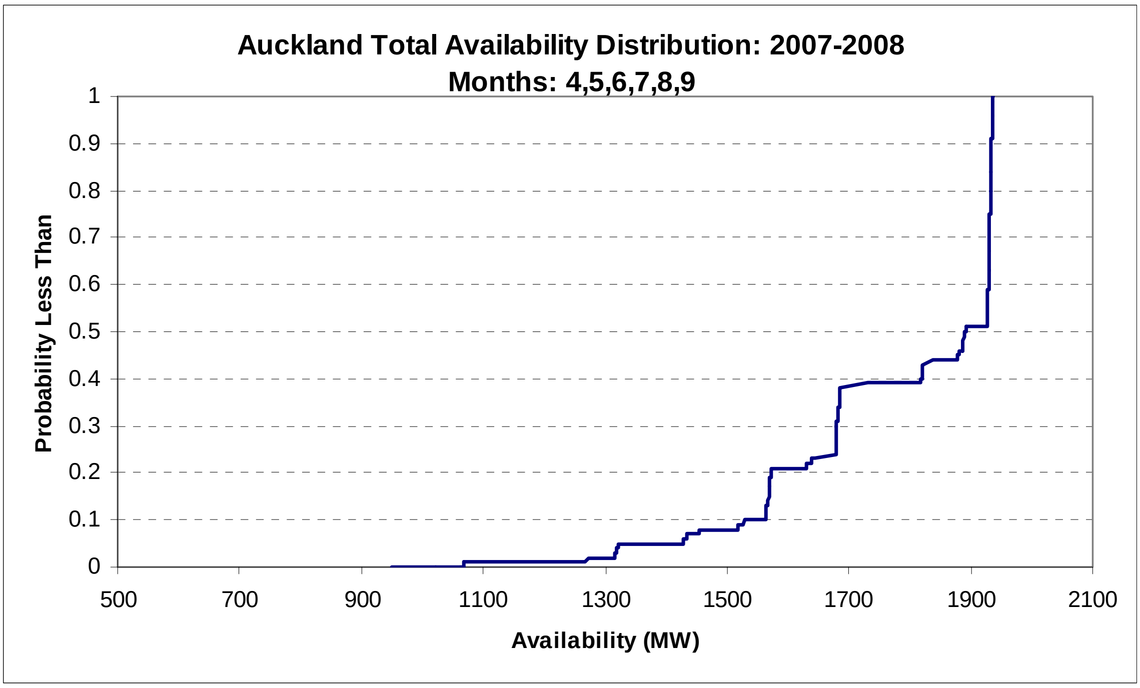


Figure 5-1: Cumulative probability of the availability of generation in the Auckland area between April and September being less than a given maximum generation

The figure shows that of 1947 MW total installed capacity, the actual amount of generation that can be expected to be available in the region is likely to be less than 1500 MW for approximately 10% of the time due to forced outages. Similarly, generation is likely to be less than 1600 W for approximately 20% of the time.

Because the unavailability of synchronous condensers has not been taken into account, the availability of generating stations and the synchronous condensers (when considered together) to provide the reactive support required by the region will be even smaller than the availability of the generating plant considered alone.

A reasonable and prudent system planning process must take into account the fact that thermal generation cannot always be available for injection into the grid. Therefore, the unavailability of a major generating plant in the region during and following any single credible contingency event has been taken into consideration in assessing the transmission capability into the region.

5.2 Existing North Island Transmission Grid

The North Island grid includes a number of core 220 kV circuits, and the HVDC bi-pole link linking the South and North Islands. Power transfer is normally from south to north.

The transmission system used for the analysis is the network as at 1 January 2005, together with the projects identified as "committed" as outlined in the Transpower publication "Future of the National Grid – Transmission Plan Summary (December 2004)."

During various outages, the transmission capacity of the grid to supply power to North Island regional loads may be subject to practical limitations. The major factors limiting power transfer capability are thermal capacity, voltage instability, and transient instability due to heavy circuit loading and distances between generation and load. Further details of existing transmission limits which affect transmission capacity are available in Transpower's System Security Forecast as published in December 2004.

5.2.1 Auckland Regional Transmission System

Figure 5-2 shows a schematic representation of the transmission grid supplying the upper North Island regions.

The Auckland region is supplied mainly over a number of 220 kV and 110 kV lines from the Waikato region to the south, including:

- the double circuit 220 kV Stratford-Taumarunui-Huntly-Otahuhu line,
- the double circuit 220 kV Whakamaru-Otahuhu C line,
- the single circuit 220 kV Whakamaru-Otahuhu A&B lines.
- the double circuit 110 kV Arapuni-Hamilton-Bombay-Otahuhu line, and
- the double circuit 110 kV Arapuni-Pakuranga line[4]

The region north of Auckland is supplied from Otahuhu via the following 220 kV circuits:

- the double circuit 220 kV Otahuhu-Henderson line (with one circuit passing through Southdown)
- the double circuit 220 kV Henderson-Marsden A line

The planned and committed transmission upgrades, which have a significant impact on transmitting power to the upper North Island region are summarised in Table 5-2.

---

[4] Presently the two circuits are bonded and operated as a single circuit. Transpower intends removing this line from service as part of this proposed investment.

Figure 5-2: The Upper North Island Region and Transmission Schematic

Grid Upgrade Project	Post Upgrade Capacity	In-Service Date
Thermal upgrade of 220 kV Otahuhu – Penrose circuits 5&6	469/492 MVA (Sum/Win)	2006
Thermal upgrade of 220 kV Huntly – Otahuhu circuit 1	614/671 MVA (Sum/Win)	Completed
2 x 50 MVAr 110 kV shunt capacitors at Penrose substation	50 Mvar (1x 50 Mvar is a replacement unit)	2006
1 x 50 MVAr 110 kV shunt capacitor at Hepburn Road sub station	50 MVAr	2006
Thermal upgrade of 110 kV Bombay - Otahuhu circuits 1 & 2	92/101 MVA (Sum/Win)	2005

Table 5-2– Committed tactical transmission upgrades assumed in the system adequacy analysis

5.2.2 Voltage Support in the Auckland Region

Presently, there is a total reactive capacity of 630 Mvar connected to the grid and approximately an additional 240 Mvar of capacity connected to the distribution substations in the Auckland region.[5] While the capacitors connected to the distribution substations improve the power factor of the connected load to approximately 0.975, the capacitors connected to the transmission system are mainly used for compensating the reactive power loss in the transmission circuits. At present, two of the Otahuhu synchronous condensers have been contracted to provide 2x33 Mvar dynamic reactive support in addition to the grid connected capacitors.

In order to maintain voltage stability in the region up until 2010, the following additional reactive power support set out in Table 5-3 (in addition to that outlined in Table 5-2) is required to be available during the period 2006-2010.

Location	Capacity	Year
Otahuhu (Synchronous Condensers)	1x33 + 2x50 Mvar	2006
Marsden (Synchronous Condensers)	1x80 Mvar	2006
Otahuhu (Capacitor Bank)	1x100 Mvar	2009
Albany (Static Var Compensator)	+/- 100 Mvar	2008

Table 5-3: Additional Static and Dynamic Voltage Support Anticipated in the Region Prior to 2010

5.2.3 Further Grid Augmentation within the Greater Auckland Area

Transpower has developed tentative plans for long range development of the core grid in the greater Auckland area to ensure that the required level of reliability will be maintained for conveying the additional power delivered from Otahuhu to grid exit points in Auckland and north beyond 2010.

These developments mainly involve reinforcement of connections from Otahuhu to Penrose, from Otahuhu to Mt Roskill, from Otahuhu to Pakuranga and from Otahuhu to Henderson at 220 kV and are shown schematically in Appendix II-C.

This submission does not include a request for approval of expenditure on these further developments as grid reliability investments. This will be the subject of a separate submission.

6 Assessment of Transmission Capability

6.1 Introduction

This Section details the analysis undertaken by Transpower to assess the adequacy of the upper North Island transmission system. Transpower assessed the capability of the transmission system in terms of its ability to meet the forecast demands and remain within the current grid reliability standards for a range of credible power system contingencies specified in those standards. A key issue highlighted in this analysis is that there is no single absolute system limitation. Transmission system limitations are dependent primarily on generation

---

[5] A list of grid connected capacitors in the upper North Island regions is provided in Appendix II-B

and transmission equipment availability. Therefore, the system limits into Auckland will vary substantially throughout the year as equipment (particularly generation plant) is made unavailable for a range of reasons whether they are planned or unplanned outages, due to market conditions or weather (hydrological) conditions.

6.2 Methodology

In order to capture the wide range of potential power system conditions and their associated impact on system adequacy, sensitivity analysis was performed to test the robustness of the power system to sustain satisfactory operating conditions under a range of events that can be reasonably expected to occur.

A large number of power system analysis studies were completed to identify the limitations on power supply into the Auckland area including:

- Power flow analysis to identify thermal limits into the region, i.e. the point at which assets may become overloaded due to contingent events on the system.
- Voltage stability analysis to identify voltage collapse limits into the region, i.e. the point at which the upper North Island regions are at risk of voltage collapse and consequential total or partial loss of supply to the upper North Island regions.
- Transient stability analysis to identify stability limits into the region, i.e. the point at which sections of the power system separate from the bulk of the national grid system leading to cascade failure of that section of the power system supplying the upper North Island regions.

The following potential transmission system limitations may come into play:

- Thermal Limitations
- Voltage Stability Limitations
- Transient (Angle) Stability Limitations

6.3 Power Flow Analysis

All power system equipment has thermal limitations which are set by the physical design of plant. Cascade failure due to thermal overload may occur when overloaded equipment fails, placing a higher burden on the remaining in-service equipment, which may then continue to fail in a cascade fashion.

The thermal capacities of the relevant 220 kV transmission circuits are set out in Table 6-1[6].

---

[6] There are different thermal limits for summer and winter operation recognising the effect of ambient temperature on the actual operating temperature of the conductors

Circuit	Summer Rating (MVA)	Winter Rating (MVA)
Otahuhu-Whakamaru-1&2	202	246
Otahuhu-Whakamaru-3	403	491
Hamilton-Whakamaru 1	403	491
Hamilton-Huntly 1	403	491
Huntly-Otahuhu 1[7]	614	671
Huntly-Otahuhu 2	694	764
Glenbrook-Huntly 1 and Glenbrook-Otahuhu 1	694	764

Table 6-1: Thermal Ratings of the 220 kV circuits supplying the Upper North Island

Under normal operating conditions (i.e. when the inter-island power flow is from south to north), the Otahuhu - Whakamaru circuits transfer power generated in the central North Island hydro and geothermal stations as well as a proportion of hydro power generated in the South Island, into Auckland and further north. In contrast, the Huntly-Otahuhu circuits are mainly used for transferring the power generated from the thermal power stations in Huntly and Stratford.

The power that reaches Otahuhu via all the existing 220 kV circuits is transferred within the region and northwards through a network of 220 kV and 110 kV circuits. While some of the circuits used for transferring power further north are heavily loaded (e.g. Otahuhu – Henderson circuits), they do not have a direct bearing on the thermal loading of the transmission circuits transferring power to the region from the south.

The actual thermal loading of the circuits supplying Auckland is dependent on the demand in the region, local generation and the availability of the transmission circuits (i.e. having anticipated any unplanned outages). In particular, in determining the thermal limitations, the consideration of security of supply to loads under the following conditions is important:

- The limitations during the outage of one transmission circuit when a reasonable level of generation is not available in the Auckland region itself. Any deficiency of generation within the region needs to be met with transmission from the south and therefore the loading of the transmission circuits will increase.

- The limitations during the outage of one transmission circuit when a reasonable level of generation is not available from Huntly. Any deficiency of generation from Huntly, which would have transferred to the Auckland region via the Huntly-Otahuhu circuits, now needs to be met using transmission from Whakamaru to Otahuhu. Consequently there is an increase in the loading of the Otahuhu-Whakamaru circuits.

The generation available in the immediate Auckland area amounts to approximately 540 MW from three stations, including a single shaft combined cycle power station of capacity 365 MW in Otahuhu. By 2010, the generation available from Huntly will amount to approximately 1400 MW, including the generation from the combined cycle e3p power station of 365 MW. Consequently, the existing transmission circuits need to provide sufficient thermal capacity for supplying the upper North Island when a generating station such as Otahuhu B or a large

---

[7] Thermal upgrading of the Huntly – Otahuhu section of Otahuhu – Whakamaru C line in 2005 April has increased the line rating from 402/492 MVA to 614/671 MVA.

generating unit at Huntly is out of service for planned or unplanned outages. (Note: planned outages involving extensive maintenance and unplanned outages due to plant failure could last from several hours to several months).

Figure 6-1 and Figure 6-2 illustrate the relationship between generation injection from Huntly and the loading on the Otahuhu-Whakamaru circuits 1 and 2 and the Huntly –Otahuhu circuit 1, to be expected by 2010 winter and summer respectively. An increase in generation from Huntly increases the thermal loading of Huntly-Otahuhu circuit 1 and reduces the loadings on Otahuhu-Whakamaru circuits 1 and 2 for the worst case N-1 contingent events. These are Otahuhu-Whakamaru circuit 3 outage for Otahuhu-Whakamaru 1 and 2 overloading and Huntly – Takanini – Otahuhu for the Huntly – Otahuhu circuit 1 overloading.

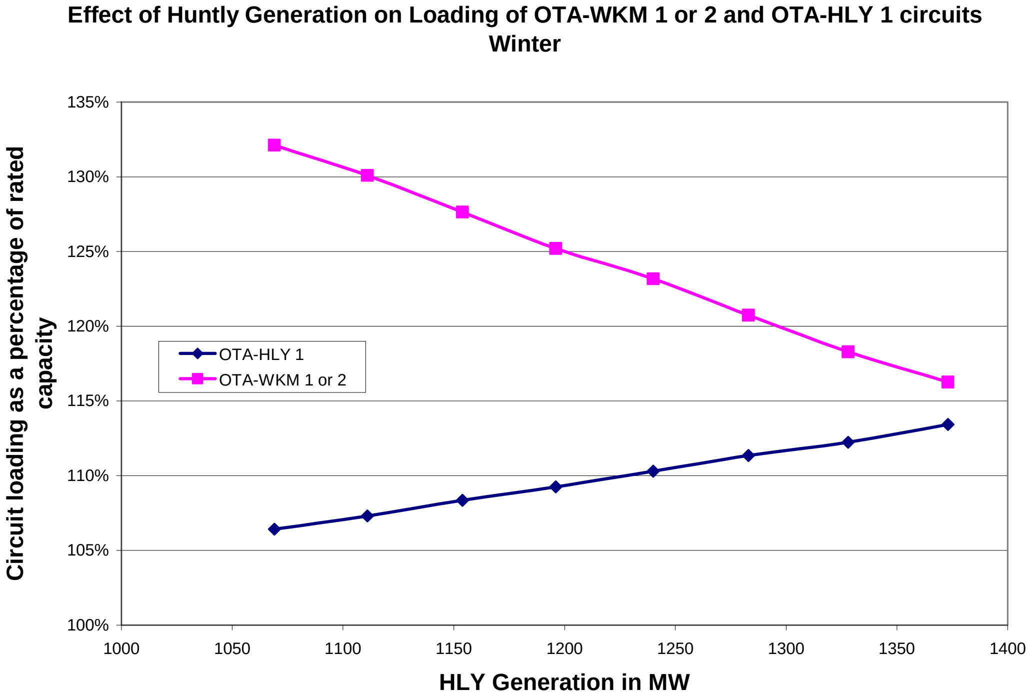


Figure 6-1: Relationship between Huntly generation and loading of Huntly-Otahuhu and Whakamaru –Otahuhu circuits (Winter power flow).

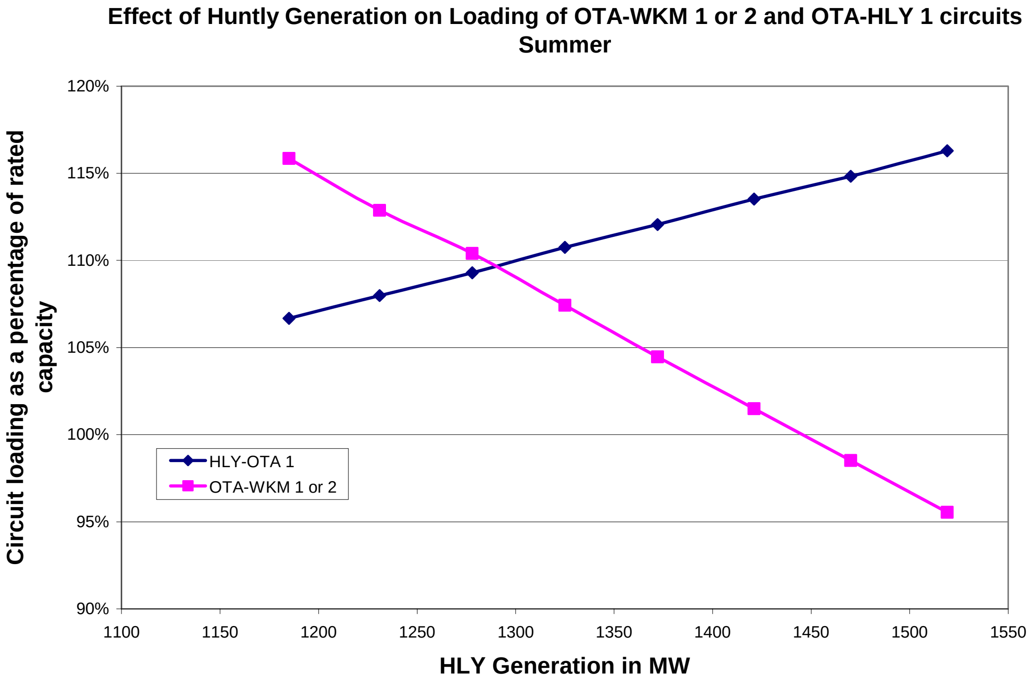


Figure 6-2: Relationship between Huntly generation and loading of Huntly-Otahuhu and Whakamaru –Otahuhu circuits (Summer power flow).

It is clear from the above results that the thermal limitations on the major 220 kV circuits supplying Auckland is a concern by 2010, especially if any major generation in Auckland is out of service during peak load times. The Otahuhu – Whakamaru circuits 1 and 2 may be able to be to be thermally upgraded to provide a modest increase in thermal capacity, however detailed investigations to determine how much additional capacity can be extracted are not yet complete. The Huntly – Otahuhu circuits have recently been thermally upgraded, therefore, the thermal capacity of these particular lines is already at its maximum point.

6.4 Voltage Stability Analysis

The maximum power that can be transferred over a transmission link may also be limited by the voltage stability performance of the system.

Voltage instability is a known mode of cascade failure of power systems. Voltage stability analysis has been completed to determine maximum power transfer limits for transmission planning. The methodology and the results are set out in this section.

The power transfer limit into Auckland for voltage stability is dependent on a number of factors namely:

- The impedance of the transmission system including lines and transformers.
- The quantity of demand supplied, including its power factor.
- The real and reactive power capability of generation connected to the power system particularly in (or near) Auckland.
- The reactive power compensation (static and dynamic) available in the region

The voltage stability analysis has been completed in two stages. The first being "static" analysis which provides a view of how the system will perform in the absence of external disturbances. The second being "dynamic" analysis which models how the system will behave in response to disturbances such as faults on the transmission grid.

It is important to model both static and dynamic behaviour of the power system as this provides a more thorough test of potential system conditions that may lead to total or partial failure of supply. The voltage stability limit is determined by the lesser of the two limits resulting from this analysis. Dynamic analysis is widely considered to be more relevant as it provides simulations of the expected behaviour of the power system over a period of time rather than a single "snapshot" as provided by static analysis. Dynamic analysis generally delivers lower power transfer limits than static analysis.

6.4.1 Static Analysis

Static analysis has been performed to provide a snapshot of the system conditions that occur at or near the point of voltage collapse and to indicate what measures might be adopted to avoid operation of the transmission grid at or near the point of voltage collapse.

The results of the static analysis illustrated in Figure 6-3 show that the steady state limit can be increased up to a practical limit by the installation of increasing amounts of static capacitors. However, the effectiveness of the additional capacitors decreases as the total extent of the capacitors installed increases to a point where further capacitors have no material effect.

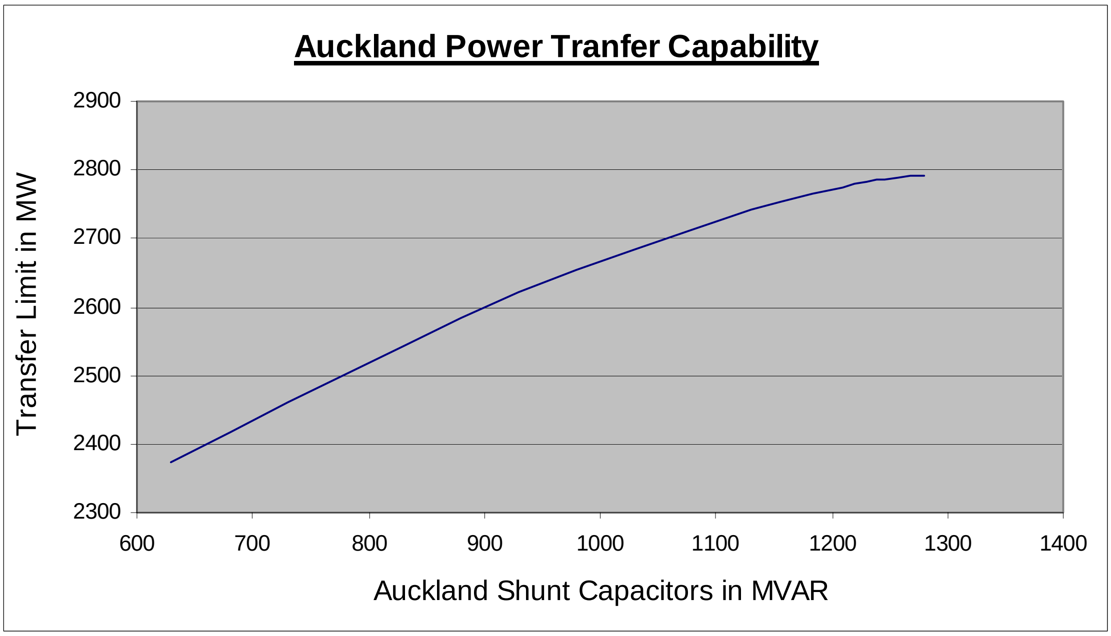


Figure 6-3: Variation of the maximum power transfer limit with grid connected reactive compensation.

6.4.2 Dynamic Analysis

Dynamic analysis was performed to analyse the performance of the power system over time, in particular how the power system would respond to simulated events or disturbances such as transmission faults. These "dynamic voltage stability limits" depend on the dynamic performance of a power system which has many uncertainties, and hence the voltage stability limits can be nothing more than informed estimates.

A detailed discussion of the factors involved in the estimation of dynamic voltage stability limits is set out in Appendix II-D attached.

The dynamic voltage stability limit for supplying the upper North island demand through the core grid is critically dependent on the generation as well as on the reactive power compensation, locally available within the region.

The amount of local generation that is installed and operating at any particular time in upper North Island is doubly significant in the estimation of the dynamic voltage stability limits for the supply of power over the core grid to the south of Auckland. If generating plant is out of service, the available quantum of local power will be reduced requiring additional power to be imported over the heavily loaded transmission grid and, in addition, the region will be deprived of an important source of dynamic reactive power support.

Figure 6-4 below illustrates the effects of the availability of local generation and reactive power support (dynamic and static) in the estimation of the dynamic voltage stability limit for the core grid supplying the upper North Island from the south.

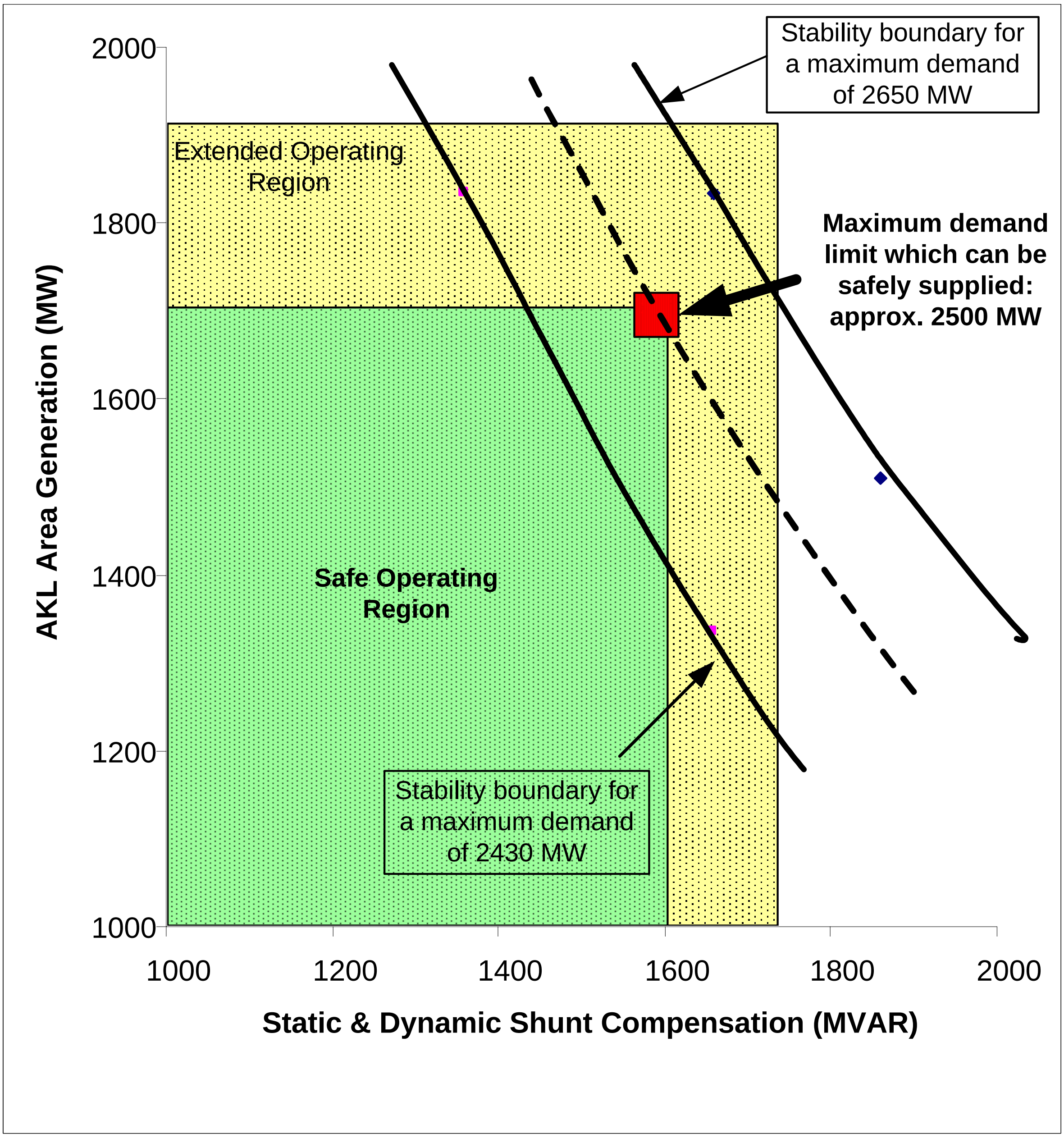


Figure 6-4: Estimation of the Dynamic Voltage Stability Limit for the Core Grid Supplying the upper North Island from the South

The figure shows that the dynamic voltage stability limit depends upon the extent of local generation operating in the upper North Island and the extent of reactive voltage support installed in the Auckland area.

The extent of local generation is limited by the capacity of the plant that is installed and serviceable at any particular time. The maximum extent of the reactive power support (static and dynamic) that can be usefully installed in the Auckland area is limited by the potential onset of cascading voltage collapse near the dynamic voltage stability limit for the grid. The installation of further reactive voltage support will reduce the voltage controllability of the power system even if the reactive power support is in the form of static var compensators (SVC's).

As discussed, heavy reactive compensation of the power system is not desirable due to operating inflexibility. Section 5.1 shows that no more than 1700 MW of generation in the upper North Island regions (including Huntly) can be reasonably assumed to be available more than 60% of the time.

Table 6-2 demonstrates the sensitivity of the controllers, when the region is heavily shunt compensated. The results show that a slight variation of the reactive power output from the dynamic reactive power sources (e.g. generators) needs to be compensated by a large quantity of static reactive sources (i.e. capacitor banks) in order to maintain the system stability.

Auckland plus Northern Isthmus load level (MW)	OTC generator initial output (MVAR)	VAR compensation required in Auckland area for loss of OTC (MVAR)	
		Dynamic (SVC + synchronous condensers)	Static shunt capacitors
2640	0	390	1270
2640	-40 (i.e. absorbs VARS)	390	1070

Table 6-2: Reactive power requirements of heavily shunt compensated Auckland system. (Negative Vars represent that the generator is operating at a leading power factor)

The above example confirms that, while the transmission system is capable of supplying the Auckland and North Isthmus demand up to approximately 2650 MW with very heavy shunt reactive compensation in the region (note: total dynamic and static reactive compensation required in the above example is approximately 1500 – 1700 MVAr), the power system operation becomes very sensitive to the reactive power variations. Such increased sensitivity to reactive or real power variations is a clear indication of the power system operation nearing the unstable operation region. Therefore, operating the power system with increased level of reactive compensation above approximately 1500 – 1600 MVAr can not be considered to be prudent and would carry with it significant operational risk of cascade failure.

The figure shows that while it is theoretically possible to supply a total demand of 2650 MW in the upper North Island regions, this would require:

- the acceptance of significant risks in relation to the quantum of generating plant actually operating in the region;
- an extremely high level of reactive voltage support; and
- an inherently high risk of cascading voltage collapse.

The above figure shows that taking this into account and making due allowance for the uncertainties in the estimation of the dynamic voltage stability limit, a upper North island load of 2500 MW would be approximately the maximum load that can be securely supplied using the existing grid assets (including the transmission upgrades and reactive power support planned to be installed prior to 2010). It should be noted that in the real time operation of the power system, the system operator would subtract a stability margin off this figure such that the system was not operated right up to the point of possible voltage collapse. This margin is 5% of the total demand.

6.4.3 Transient Stability Analysis

Another limitation to power transmission is the ability to operate the synchronous machines (generators as well as motors), in the sending system and the receiving system, in synchronism under all the operating conditions and to survive a credible contingency event. As described in Section 5.1, there is some local generation in the Auckland region itself and the remaining regional load has to be supplied from the generation at Huntly, and Waikato and Taranaki regions.

Transient stability is significantly influenced by the electrical characteristics of the transmission system between the sending and the receiving regions. Simulation studies have shown that, a large amount of generation can not be transferred to the Auckland region from the south (e.g. from Taranaki) due to the electrical characteristics of the transmission paths, Taranaki - Huntly-Auckland and Taranaki - Bunnythorpe - Whakamaru - Auckland.

Figure 6-5 shows the large disturbance instability of the power system following a three phase fault at Stratford 220 kV bus and cleared by opening a Stratford to Huntly circuit.

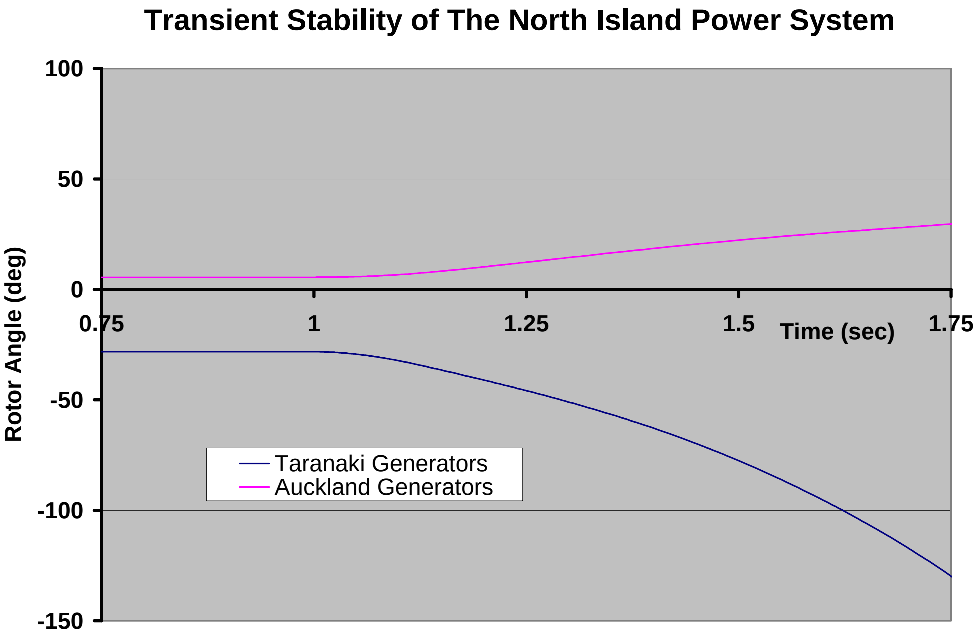


Figure 6-5: Loss of transient stability between Taranaki and Auckland generation

The figure shows that following a fault on a Stratford to Huntly circuit, the generators in Taranaki region would lose synchronism with respect to the generators in the Auckland region, under an operating condition with high Taranaki generation and the load in the Auckland region about 2500 MW.

This instability will pose a significant constraint for transferring power from Taranaki to Auckland and is significantly influenced by the transmission impedance of the SFD-HLY lines. Because of this constraint, during an outage of a generating unit in the Auckland area, significant generation from Taranaki could not be transferred to Auckland without taking an unacceptable risk of a cascading shut-down of the upper North Island. The constraint upon Stratford generation means that additional generation would have to be made up from the generation from Huntly, Waikato, the central North Island and (if possible) increasing the power transfer from the South Island over the HVDC. Make up power from all or any of these sources conspire to increasing the loading the Whakamaru to Otahuhu lines thus pushing the upper North Island region closer to its thermal overload and dynamic voltage stability limits.

7 Timing of Grid Augmentation

Section 6 detailed how the transmission capacity of the existing transmission system (including committed and anticipated grid augmentation) can be limited by the thermal capacity, voltage stability or the transient stability of the transmission system. While, at present, the transmission system is operated close to these stability and capacity limits, the increasing demand in the upper North Island region will cause a rapidly escalating risk of a cascade failure of supply.

The voltage stability limit is dependent on the local generation available in the region (including the generation from Huntly) and the level of reactive power compensation in the region. While increasing the reactive compensation in the region can further increase the transmission capacity, this is achieved only through greater economic costs and significant technical risks. Further, the reliability of the thermal generating units in the region is such that it can not reasonably be assumed that more than approximately 1700 MW generation will be available on a sustainable basis in the region by 2010.

The analysis summarised in the form of Figure 6-4 demonstrated that the maximum demand for the upper North Island regions that can be reliably and securely met without major augmentation of the grid is approximately 2500MW, which is the point at which voltage collapse of the system was modelled...

Figure 7-1 shows the peak demand forecast of the Auckland region overlaid with this transmission limit. (The demand shown in the figure represents the actual demand that can be safely supplied from the grid allowing for a stability margin of 5%). The existing transmission system with increased level of reactive power compensation and significant constraints on the operation of the generators (in order to manage the associated operational risks) is just adequate for supplying the medium forecast load until 2010.

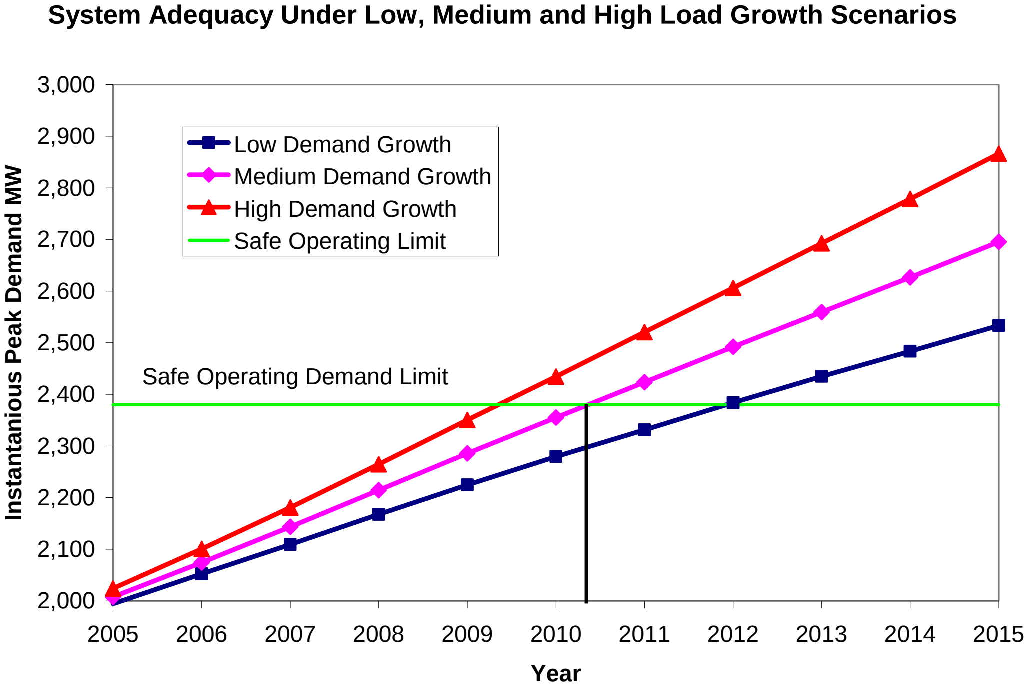


Figure 7-1 System Adequacy for supplying the upper North Island load.

The figure also shows that under a high demand growth scenario, the capacity of the existing transmission grid for supplying the upper North Island demand is only adequate up to 2008. Under such a scenario, it would be difficult to meet the 2009 -2010 demand without taking significant operating risks. Under a low growth scenario, supply security to the Auckland region can be provided until approximately 2012.

Appendix II-A: Forecast of Upper North Island Demands

Forecast Upper North Island Half Hourly Average Maximum Demands						
	Average Half Hour ADMD Forecast			***Instantaneous Peak ADMD Forecast***		
Year	***Low(MW)***	***Medium (MW)***	***High (MW)***	***Low(MW)***	***Medium (MW)***	***High (MW)***
2005	1,904	1,918	1,934	1,994	2,008	2,024
2006	1,962	1,984	2,011	2,052	2,074	2,101
2007	2,019	2,053	2,091	2,109	2,143	2,181
2008	2,078	2,124	2,175	2,168	2,214	2,265
2009	2,135	2,196	2,260	2,225	2,286	2,350
2010	2,190	2,265	2,345	2,280	2,355	2,435
2011	2,241	2,334	2,431	2,331	2,424	2,521
2012	2,294	2,402	2,516	2,384	2,492	2,606
2013	2,345	2,470	2,602	2,435	2,560	2,692
2014	2,394	2,537	2,689	2,484	2,627	2,779
2015	2,443	2,605	2,776	2,533	2,695	2,866
2016	2,494	2,674	2,863	2,584	2,764	2,953
2017	2,546	2,746	2,956	2,636	2,836	3,046
2018	2,597	2,818	3,046	2,687	2,908	3,136
2019	2,651	2,889	3,137	2,741	2,979	3,227
2020	2,701	2,960	3,232	2,791	3,050	3,322
2021	2,751	3,031	3,325	2,841	3,121	3,415
2022	2,801	3,102	3,421	2,891	3,192	3,511
2023	2,850	3,173	3,513	2,940	3,263	3,603
2024	2,896	3,243	3,611	2,986	3,333	3,701
2025	2,943	3,312	3,702	3,033	3,402	3,792
2026	2,988	3,382	3,797	3,078	3,472	3,887
2027	3,032	3,452	3,894	3,122	3,542	3,984
2028	3,080	3,522	3,985	3,170	3,612	4,075
2029	3,126	3,592	4,081	3,216	3,682	4,171
2030	3,172	3,663	4,175	3,262	3,753	4,265
2031	3,218	3,734	4,272	3,308	3,824	4,362
2032	3,263	3,806	4,372	3,353	3,896	4,462
2033	3,310	3,879	4,471	3,400	3,969	4,561
2034	3,352	3,953	4,578	3,442	4,043	4,668
2035	3,395	4,028	4,684	3,485	4,118	4,774
2036	3,442	4,105	4,788	3,532	4,195	4,878
2037	3,485	4,183	4,897	3,575	4,273	4,987
2038	3,527	4,263	5,014	3,617	4,353	5,104
2039	3,581	4,345	5,119	3,671	4,435	5,209
2040	3,632	4,428	5,240	3,722	4,518	5,330
2041	3,684	4,514	5,360	3,774	4,604	5,450
2042	3,737	4,601	5,489	3,827	4,691	5,579
2043	3,786	4,689	5,614	3,876	4,779	5,704
2044	3,838	4,778	5,740	3,928	4,868	5,830
2045	3,887	4,869	5,877	3,977	4,959	5,967

Appendix II-B: Network Connected Capacitor Banks in the Auckland Region

Substation	Voltage (kV)	Capacitor (MVAR)
Kaikohe	11	20
Albany	110	50
Albany	11	60
Henderson	11	60
Henderson	220	75
Otahuhu	220	100
Otahuhu	110	100
Otahuhu	11	90
Penrose	220	75
	Total	**630**

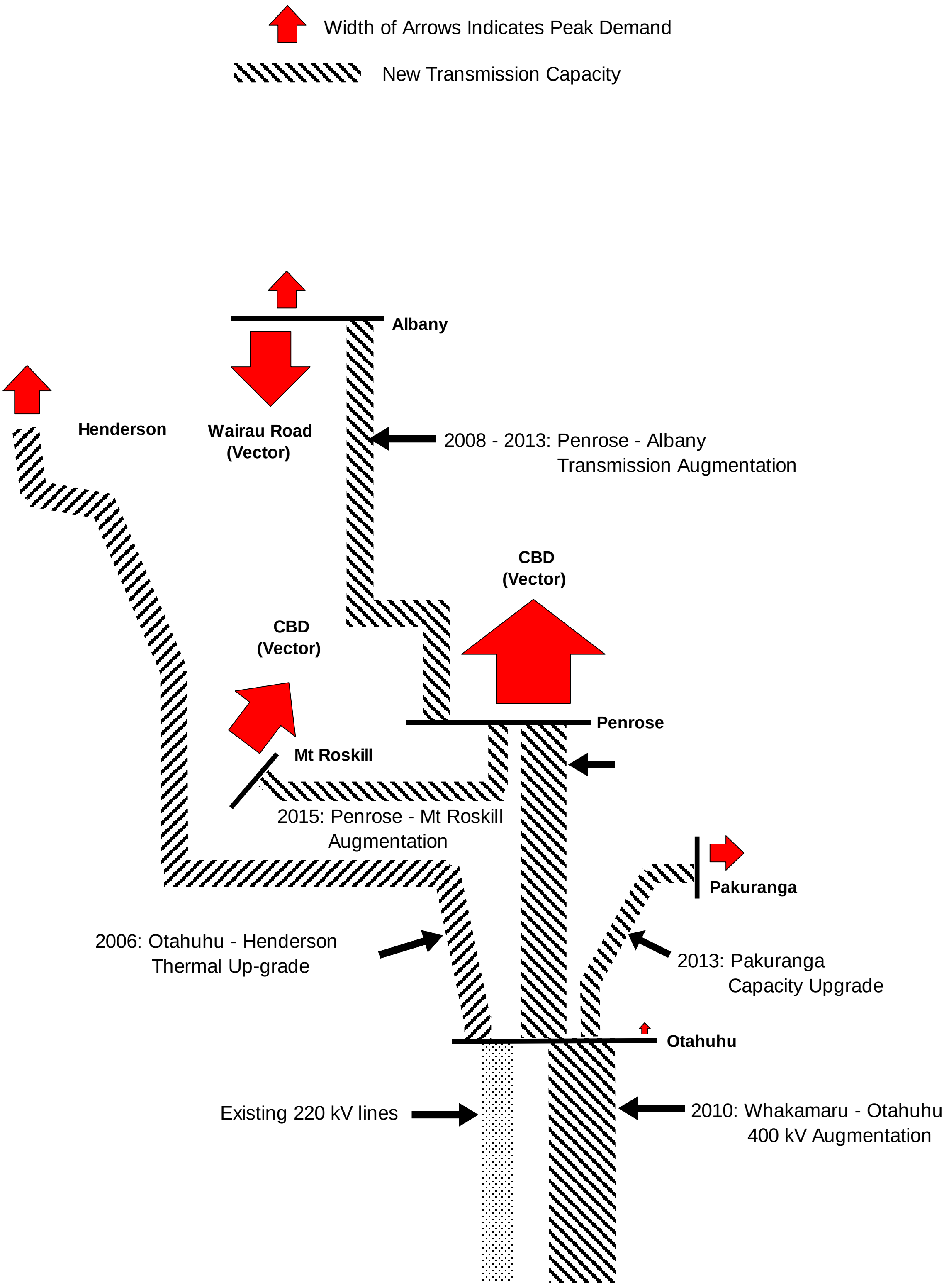
Table B-7-1: Capacitors connected at Transmission busses. 11 kV capacitors connected to tertiaries of interconnecting transformers

GXP	Voltage (kV)	Capacitor (MVAR)
Wairu Rd.	33	48
Albany	33	9
Dargaville	11	2
Henderson	33	12
Hepburn Rd.	33	22
Kensington	33	1
Mangere	33	3
Maungatapere	33	2
Maungaturoto	33	2
Otahuhu	22	9
Pakuranga	33	6
Penrose	33	66
Penrose	110	15
Mt Roskill	22	3
Mt Roskill	110	15
Takanini	33	6
Wellsford	33	6
Wiri	33	15
	Total	**240**

Table B-7-2: Distribution capacitors aggregated at their respective Grid Exit Points (GXP)

Appendix II-C: Anticipated Grid Reinforcement in the Greater Auckland Area

INTEGRATION OF AUCKLAND AREA DEVELOPMENT WITH 400 kV GRID AUGMENTATION



Appendix II-D: Estimation of Dynamic Voltage Stability Limits

Power system voltage stability limits depend upon the variation of the system voltage during this period immediately following a disturbance. Generally, following a power system fault, the system voltage reduces momentarily and then recovers over a period of 1 – 3 seconds (Figure D-1).

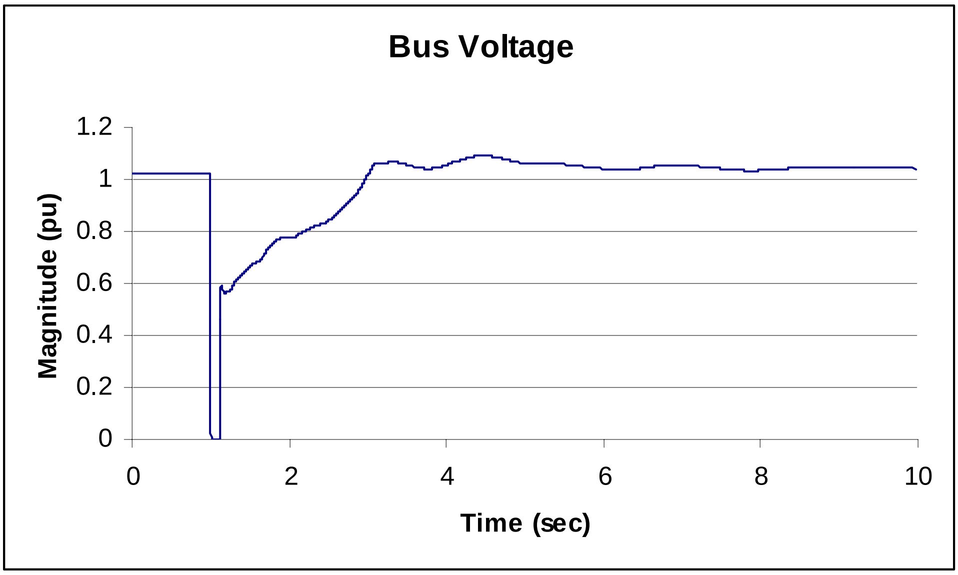


Figure D-1: Variation of the system voltage following a fault at Otahuhu 220 kV bus

The variation of the system voltage interacts with the connected loads and generators in the following manner during the transient period:

- The reduction of the system voltage contributes to the reduction in demand in three ways
  - (i). reduction in power consumed by the power output of the passive loads such as electrical lighting, heaters, etc
  - (ii). dropping off of the loads, especially the motor loads, as a result of magnetic contactor dropping off or due to the operation of protection relays
  - (iii). reduction in the power consumed by the motor loads which remain connected to the grid

- Reactive compensation provided by capacitors connected to the grid is proportional to the square of the system voltage. Hence, during transient voltage reductions, the reactive power compensation provided by the capacitors is significantly reduced resulting in a transient decrease in the overall power factor of the connected load.

  This decrease in load power factor contributes to a reduction in the dynamic voltage stability limit.

- The power output of the motors is proportional to the square of the system voltage Therefore at reduced voltages, the power output of the motor loads reduces, resulting in motors decelerating and in some instances stalling. The stalled motors and the motors which are operating at below their nominal speed consume a significant amount of reactive power and therefore decreases the overall power factor of the connected load. This decrease in load power factor contributes to reducing further the dynamic voltage stability limit.

- The generators, synchronous condensers and static var compensators (SVCs) increase reactive power output as a means of restoring the system voltage. This action effectively improves the power factor of the combined load at the receiving end. However, in estimating dynamic voltage stability limits, it is necessary to take into account that this plant will have physical limitations upon its ability to contribute to voltage support depending upon its installed capacity.

  The limitations upon this plant contribute to reducing further the dynamic voltage stability limit.

The typical performance of the power system components which have a significant impact on the estimation of the dynamic voltage stability limit of the power system are shown in the following figures D-2 and D-3. The figures show the variation of the reactive power compensation by the capacitors, reactive power consumed by the motor loads and reactive output of the generators, during the transient disturbance.

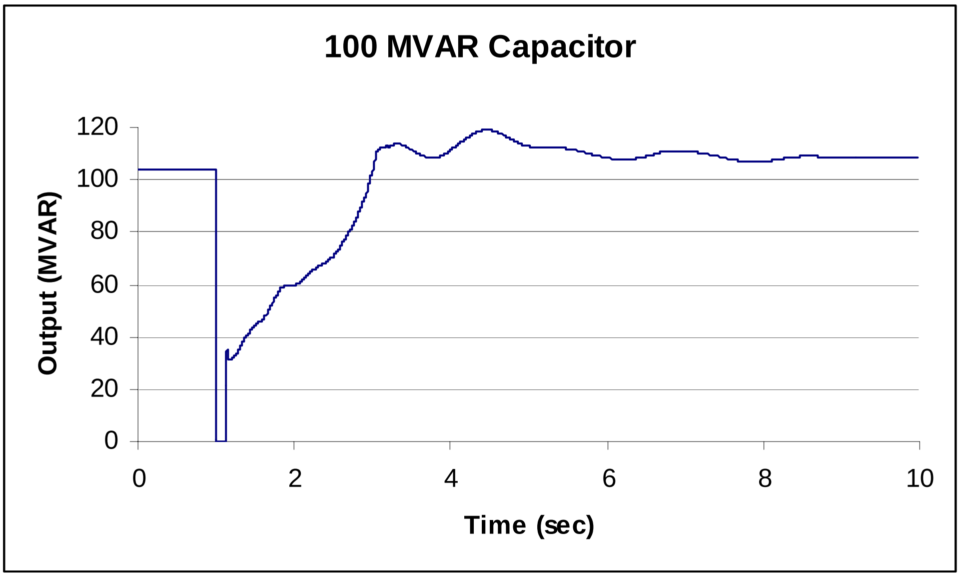


Figure D-2: Variation of reactive power compensation provided by a 100 MVAr capacitor bank at Otahuhu.

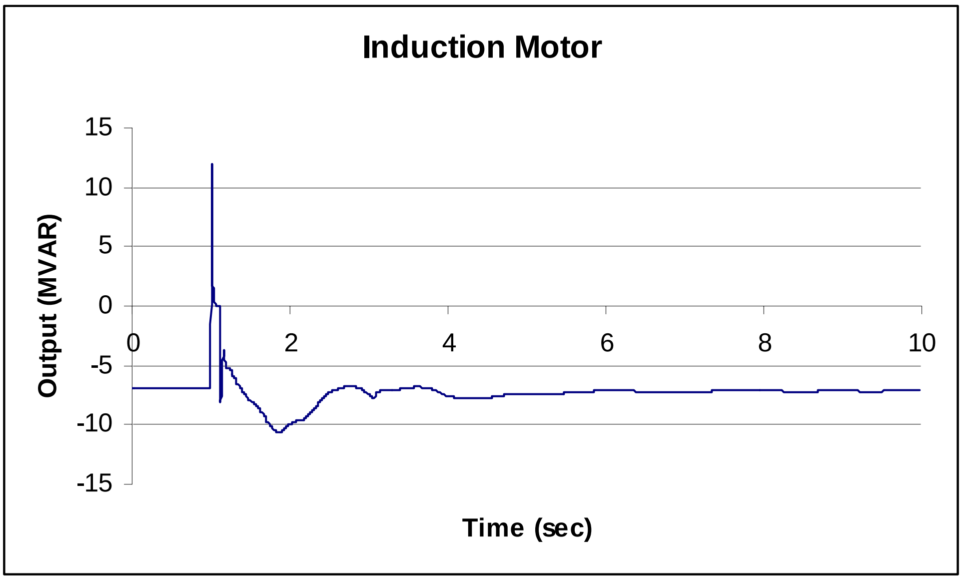


Figure D-3: Variation of reactive power consumed by a 20 MVA motor load. (note: reactive power consumed by the motor is shown as negative)

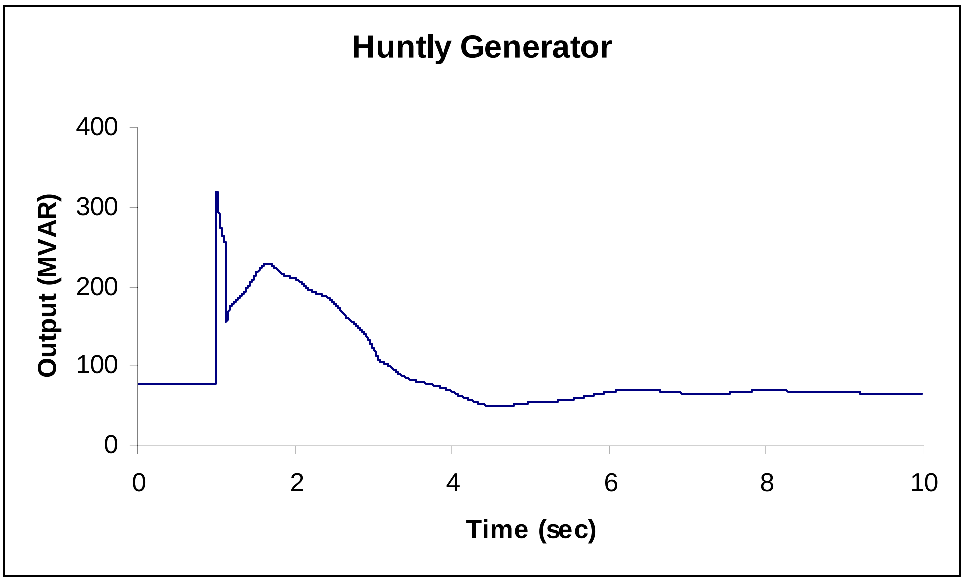


Figure D-4: Variation of reactive power output from a 250 MW generating unit at Huntly, operating at 100% power output.

As shown above, the performance of the power system and the connected loads following a power system disturbance is complex and its impact on the voltage stability is normally assessed by using simulation studies. In general, the power system performance during disturbances results in a dynamic voltage stability limit significantly less than that voltage stability limit that would be estimated using a simplistic static analysis.

TRANSPOWER

North Island 400 kV Upgrade Project

Investment Proposal

Part III – Analysis of Options for Meeting the Investment Need

1 Summary

Part III contains an analysis of all transmission options and alternatives to transmission (including generation and demand side management) to meet the demand identified as being required in the upper North Island from 2010.

The transmission options and alternatives for transmission which are determined by Transpower as being credible options are then assessed against the proposed investment from an economic perspective (such analysis being contained within Part IV).

Transmission Options

Transpower's high level assessment of transmission options against technical, economic and environmental criteria showed that only 220 kV and 400 kV AC overhead transmission options are credible options to meet the need identified in Part II.

The following transmission options have been considered and assessed by Transpower in this Part III:

- 220 kV development
- 330 kV development
- 400 kV development
- 500 kV development
- Classic HVDC development
- HVDC Light development
- Undergrounding

Alternatives to Transmission

Transpower issued a Request For Information to determine the potential alternatives to transmission. Transpower assessed all alternatives offered through this RFI process and concluded that peaking plant is the sole alternative to transmission which would avoid or defer the need for the proposed investment and/or have a reasonable likelihood of proceeding.

2 Assessment Criteria

The criteria that Transpower has considered in assessing all transmission and non transmission options are:

- ***System Security*** *– Whether the power supply to the upper North Island meets an N-1 security standard in accordance with Transpower's security standard given the assumed demand and generation forecasts as set out in this submission.*
- ***Asset Availability*** *– The availability of the various power system components forming an essential part of the proposed development.*

- ***Economic Benefit** – The net present value of the benefits that accrue from the transmission option less all estimated capital and operating costs.*
- ***Environmental Feasibility** – The feasibility of development options given environmental constraints. The details of this assessment criteria are in Appendix III-A.*
- ***Timing** – The ability of the proposed development to be delivered by 2010.*
- ***Flexibility** – The ability of the proposed development to be harmoniously used together with the existing grid assets and future grid upgrades for meeting the future demand growth and generation developments.*

3 Transmission Options

Transpower has assessed a range of transmission options that it considers are capable of providing the necessary the power transfer capacity to the upper North Island. In summary this assessment includes:

- High voltage alternating current (HVAC) options at 220 kV, 330 kV, 400 kV and 500 kV.
- High voltage direct current (HVDC) transmission options at 350 kV, 500 kV and HVDC light.
- The use of overhead transmission lines and or underground cables for HVAC and HVDC applications.

The commitment to a new voltage level for the core grid is a strategic decision involving the entire national grid and a decision on the appropriate voltage for grid reinforcement between Whakamaru and Auckland needs to be considered in that light.

3.1 HVAC power transmission options

There are two broad development paths for HVAC transmission, namely:

- Continuing with future grid development using 220 kV assets – in other words maintaining the maximum voltage for New Zealand's core grid at 220 kV.
- Selecting a new maximum voltage (e.g. 330 kV, 400 kV or 500 kV) which would be introduced as appropriate in the North and South Island transmission systems.

All transmission proposals, including the use of higher voltages for the core grid, would require the continued use of 220 kV for other parts of the grid where it is economic to do so.

In assessing the preferred future transmission voltage, Transpower has analysed future possible grid developments under several generation scenarios and a medium confidence load growth forecast. Of the HVAC options, the 220 kV and 400 kV alternatives were ranked has the best two HVAC solutions and the results are compared in detail in this section. A summary of the rationale for not following a development path with maximum transmission voltage of 330 kV and 500 kV are also included.

3.2 HVDC power transmission options

Two generic HVDC transmission options to increase the power transfer levels into Auckland were investigated. These options were:

- A bulk HVDC power transfer option connecting South Island generation and transferring this directly to Auckland.
- The establishment of a short 200 km HVDC link between Whakamaru and Otahuhu which is interconnected into the HVAC system at each end.

There are also two main choices of HVDC technology that are applicable to high voltage power systems. HVDC power transmission requires the conversion of power to HVDC using power electronic devices. Bulk electricity is then transferred at HVDC through overhead lines or underground cables (or a combination). An inversion process then converts HVDC power back to HVAC power at the receiving end. Two means of converting the AC power to DC are presently available and are considered as possible options:

Classical HVDC	• High voltage, high power, thyristor-based power conversion technology. • Power transmission could be by way of overhead line or underground cable.
HVDC Light	• Relatively new, medium voltage (150 kV), transistor-based power conversion technology. • With the current technology, power transmission possible only by underground cable

3.3 220 kV HVAC Development Plan

The following sections describe the future development of the grid under different generation scenarios, if 220 kV is retained as the maximum transmission voltage.

As electricity demand increases, regional transmission connections and supply transformers will become increasing overloaded and will require reinforcement. For the purposes of this analysis, the focus is on the core transmission network and therefore regional upgrades have been added to the power flow models as necessary to remove overloading problems. While these solutions have not been optimised, they are not considered material to the analysis of the core grid.

In this section a number of stages have been developed to group the necessary grid upgrades into discrete steps. Stage 1 represents grid upgrades which are planned to take place approximately from 2010 to 2015, stage 2 are developments up from 2015 to 2020, and stage 3 are developments beyond 2020.

It should be noted that the high-level development plans in this section are based on system planning studies. Detailed studies are required to confirm optimal location and sizing of some reactive power investments and detailed engineering work is still required to confirm feasibility and the appropriateness of the type of solution employed. For example where an existing line is proposed for upgrading by installing duplex conductors the existing towers may not be strong enough and they may require replacement. Furthermore, where two single circuit lines are proposed for duplexing, a single double circuit line may be built instead.

3.3.1 Grid Developments Before 2010

A number of tactical transmission upgrade projects are planned for implementation in the North Island before 2010. A summary of these projects is given in the Transpower publication: Future of the National grid – Transmission Plan Summary 2004. These projects are summarised in Appendix III-B.

Before 2010, the transfer capability into Auckland will be increased by a combination of thermal upgrades of key transmission lines and increasing the level of reactive power compensation in the region. After 2010, the power transfer into the Auckland region will be mainly constrained by a voltage stability limit and the benefits of installing more reactive compensation become limited as set out in Part II of this submission. At this point Transpower considers that a major step change in transmission investment is required.

3.3.2 220 kV Grid Development Plan for Generation Scenario 1 (Gas) from 2010-2040

The lines to be newly built or upgraded with duplex conductors under Generation Scenario 1 (gas) at different stages are:

Stage	Transmission Line
1	Construct a 220 kV double circuit line Whakamaru to Auckland.
	Upgrade 220 kV Tokaanu – Whakamaru A&B lines to duplex conductor.
	Upgrade 220 kV Bunnythorpe – Haywards A&B lines to duplex conductor.
	Auckland cross Isthmus reinforcement with new 220 kV circuit (cable or overhead).
	Construct a 220 kV double circuit line Wairakei - Atiamuri - Whakamaru in duplex zebra. String one circuit only.
2	Upgrade the 220 kV double circuit Stratford - Taumarunui – Te Kowhai - Huntly line to duplex conductor.
	New double circuit 220 kV –Taumarunui - Whakamaru line.
	New double circuit 220 kV Stratford – Whakamaru line.
	Upgrade the 220 kV Bunnythorpe – Tokaanu - Whakamaru lines to duplex.
	New double circuit 220 kV Bunnythorpe – Redclyffe line. String one circuit only.

3	String second circuit of 220 kV Wairakei – Atiamuri – Whakamaru line.[1]
	Upgrade Atiamuri – Tarukenga A line with duplex conductor.
	New single circuit 220 kV Hamilton - Huntly line.
	Possibly dismantle 220 kV Otahuhu – Whakamaru A&B lines[2].
	New switching station near Huntly.

Table 3-1: 220 kV Grid Development Plan 2010-40 for Generation Scenario 1

In stage 1, the thermal upgrades and a new 220 kV double circuit line will be needed to supply the Auckland load.

The existing HVDC link is also assumed to be upgraded to 1400 MW capacity by the end of 2010. The associated core grid HVAC developments include upgrading the existing 220 kV single conductor Hayward – Bunnythorpe A&B lines and Tokaanu - Whakamaru A&B lines with duplex conductors (for increased HVDC transfer to the South Island during low hydro periods, and increased northwards transmission respectively).

In stage 2, upgraded and new lines will be required out of the Taranaki region to Taumarunui, Huntly and Whakamaru to facilitate unconstrained dispatch of generation in the Taranaki region to Auckland.

Additional new lines are also required to dispatch the generation from the Bunnythorpe region and south (including HVDC import) to areas north of Whakamaru.

Augmentation in stage 2 will need to be followed in stage 3 by reinforcement of the 220 kV grid for the transfers into Hamilton, into Bay of Plenty and through the Wairakei ring.

The new switching station near Huntly is to connect the increased generation from Huntly to the Otahuhu – Whakamaru lines.

The ultimate grid augmentation plan for a 220 kV transmission system for Scenario 1 is shown in Figure 3-1.

---

[1] At this stage it may be possible to dismantle the existing lower capacity single circuit Wairakei – Ohakuri – Atiamuri – Whakamaru line.

[2] Towards the end of the planning horizon for this scenario there is a large increase in generation capacity in the Auckland area, so the capacity of the Otahuhu – Whakamaru A&B lines may not be required. As these lines will be old, they could be considered for dismantling.

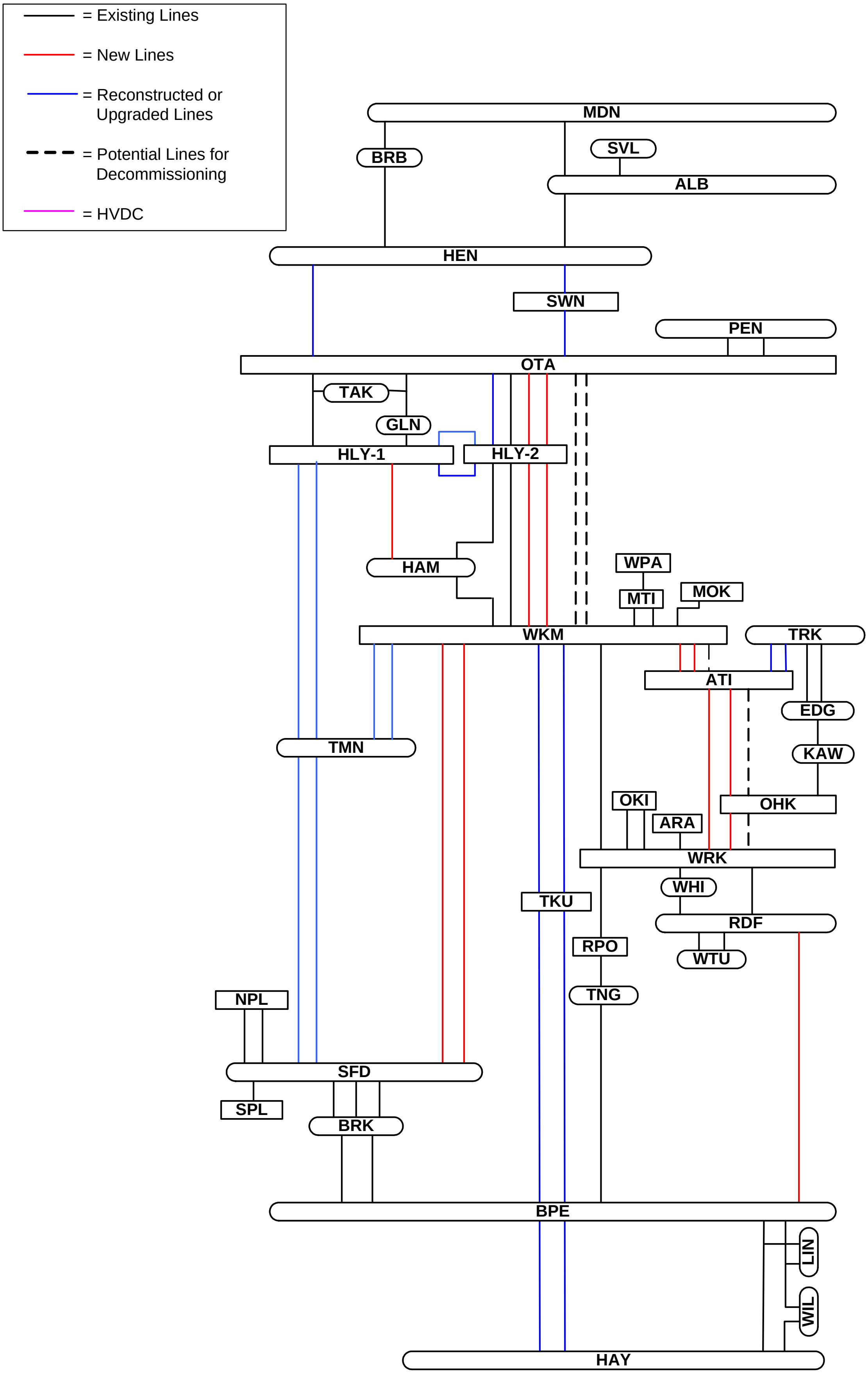


Figure 3-1: 220 kV grid configuration for Generation Scenario 1 at 2040

3.3.3 220 kV Grid Development Plan for Generation Scenario 2 (Coal) from 2010-2040

The new lines to be built and those that are to be upgraded with duplex conductors under Generation Scenario 2 (coal) are given below:

Stage	Transmission Line
1	Construct a 220 kV double circuit line Whakamaru to Auckland.
	Upgrade 220 kV Tokaanu – Whakamaru A&B lines to duplex conductor.
	Upgrade 220 kV Bunnythorpe – Haywards A&B lines to duplex conductor.
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead).
	Construct a 220 kV double circuit line Wairakei - Atiamuri - Whakamaru in duplex zebra. String one circuit only.
2	Upgrade double circuit 220 kV Bunnythorpe – Whakamaru line to duplex conductor.
	New double circuit 220 kV Bunnythorpe – Redclyffe line. String one circuit only.
3	Upgrade Atiamuri – Tarukenga A line with duplex conductor.
	String second circuit of the 220 kV Wairakei – Atiamuri – Whakamaru line[3].
	Upgrade the 220 kV double circuit Stratford - Taumarunui – Te Kowhai - Huntly line to duplex conductor.
	New double circuit 220 kV Taumarunui – Whakamaru line.

Table 3-2: 220 kV Grid Development Plan 2010-40 for Generation Scenario 2

In stage 1, the thermal upgrades and a new 220 kV double circuit line will be needed to supply the Auckland load. The existing HVDC link is assumed to be upgraded to 1400 MW capacity by the end of 2010. The associated core grid AC developments include upgrading the existing 220 kV single conductor Hayward – Bunnythorpe A&B lines and Tokaanu - Whakamaru A&B lines with duplex conductors (for increased HVDC transfer to the South Island during low hydro periods, and increased northwards transmission respectively).

For stage 2, the upgraded and new lines from Bunnythorpe are for the new generation in the Bunnythorpe and south regions to supply the load to the north.

For stage 3, the upgraded and new lines from Stratford to Taumarunui, Huntly and Whakamaru are principally due to the new generation at Stratford and south of Bunnythorpe, and for voltage stability to the Auckland area. The second Wairakei – Atiamuri – Whakamaru circuit is for the new generation in the Wairakei area, and to supply the Bay of Plenty load. The ultimate grid augmentation plan for a 220 kV transmission system for Scenario 2 is shown in Figure 3-2.

---

[3] At this stage it may be possible to dismantle the existing lower capacity single circuit Wairakei – Ohakuri – Atiamuri – Whakamaru line.

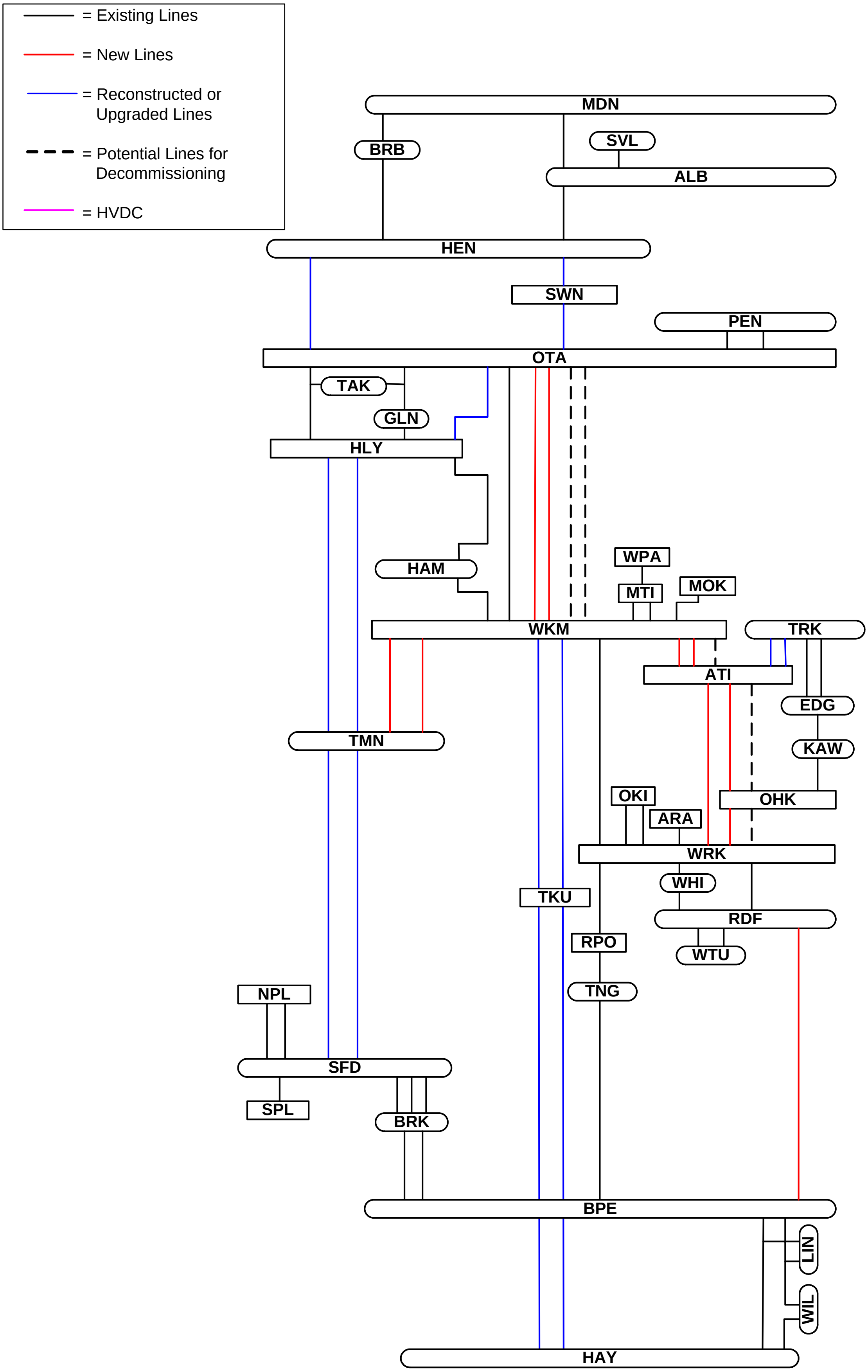


Figure 3-2: 220 kV grid configuration for Generation Scenario 2 at 2040

3.3.4 220 kV Grid Development Plan for Generation Scenario 3 (Renewable) from 2010-2040

The lines to be newly built or upgraded with duplex conductors under Generation Scenario 3 (renewables) at different stages are:

Stage	Transmission Line
1	Construct a 220 kV double circuit line Whakamaru to Auckland.
	Upgrade 220 kV Tokaanu – Whakamaru A&B lines to duplex conductor.
	Upgrade 220 kV Bunnythorpe – Haywards A&B lines to duplex conductor.
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead).
	Construct a 220 kV double circuit line Wairakei - Atiamuri - Whakamaru in duplex zebra. String one circuit only.
2	Upgrade double circuit 220 kV Bunnythorpe – Tokaanu - Whakamaru line to duplex conductor.
	New double circuit 220 kV Bunnythorpe – Redclyffe line. String one circuit only.
3	String second circuit of 220 kV Wairakei – Atiamuri – Whakamaru line[4].
	New double circuit 220 kV Whakamaru – Auckland line.
	Upgrade the 220 kV double circuit Stratford - Taumarunui – Huntly line to duplex conductor.
	New double circuit 220 kV Taumarunui – Whakamaru line.
	New single circuit 220 kV Hamilton – Huntly line.
	New double circuit 220 kV Whakamaru – Otahuhu line[5].
	New double circuit 220 kV Whakamaru – Otahuhu line.

Table 3-3: 220 kV Grid Development Plan 2010-40 for Generation Scenario 3

In stage 1, the thermal upgrades and a new 220 kV double circuit line will be needed to supply the Auckland load.

The existing HVDC link is assumed to be upgraded to 1400 MW capacity by the end of 2010. The associated core grid AC developments include upgrading the existing 220 kV single conductor Hayward – Bunnythorpe A&B lines and Tokaanu - Whakamaru A&B lines with duplex conductors. (for increased HVDC transfer to the South Island during low hydro periods, and increased northwards transmission respectively).

---

[4] At this stage it may be possible to dismantle the existing lower capacity single circuit Wairakei – Ohakuri – Atiamuri – Whakamaru line.

[5] It is assumed that the Otahuhu – Whakamaru A&B line routes would each be used for a new double circuit line. Alternatively, these lines could be duplexed, in which case one less double circuit line is required.

For stage 2, the upgraded and new lines from Bunnythorpe are for the new generation in the Bunnythorpe and south regions to supply the load to the north.

In stage 3 upgrades for the transfers into Hamilton, into Bay of Plenty and through the Wairakei ring, will be as per generation scenarios 1 and 2.

For this scenario very little new generation is projected in the region North of Whakamaru. Therefore, significant reinforcements will be required in stage 3 between Whakamaru-Otahuhu, in addition to the double circuit line built in stage 1.

The ultimate grid augmentation plan for a 220 kV transmission system for Scenario 3 is shown in Figure 3-3.

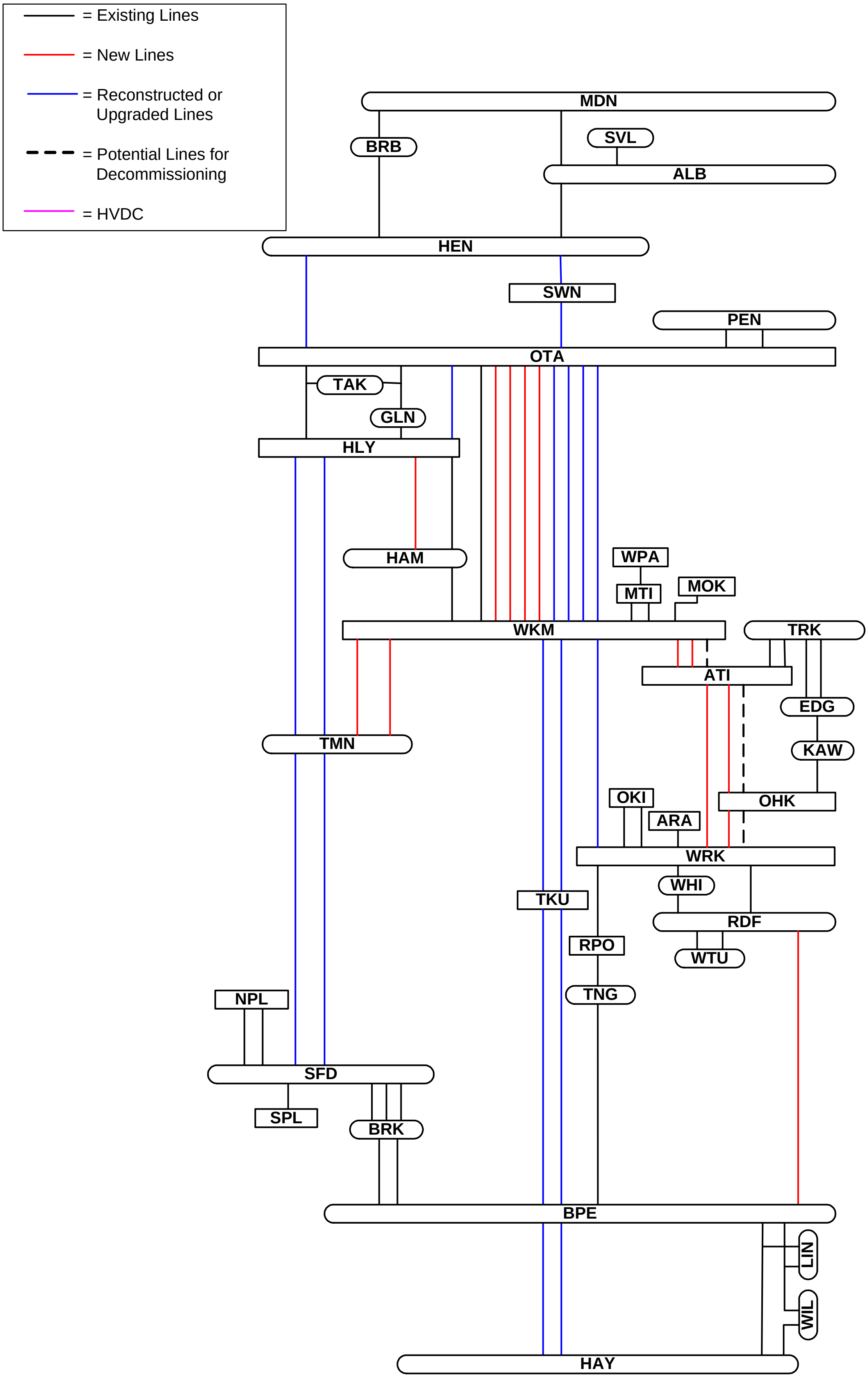


Figure 3-3: 220 kV grid configuration for Generation Scenario 3 at 2040

3.3.5 220 kV Grid Development Plan for Generation Scenario 4 (Southern Hydro) from 2010-2040

The new lines to be built and those that are to be upgraded with duplex conductors under Generation Scenario 4 (hydro) are given below:

Stage	Transmission Line
1	Construct a 220 kV double circuit line Whakamaru to Auckland.
	Upgrade 220 kV Tokaanu – Whakamaru A&B lines to duplex conductor.
	Upgrade 220 kV Bunnythorpe – Haywards A&B lines to duplex conductor.
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead).
	Construct a 220 kV double circuit line Wairakei - Atiamuri - Whakamaru in duplex zebra. String one circuit only.
2	New HVDC link of capacity 600 MW from the South Island into Auckland[6].
	Upgrade Atiamuri – Tarukenga line to duplex conductor.
3	Construct a new 220 kV double circuit line Whakamaru to Auckland.
	Upgrade the new HVDC link from 600 MW to 1200 MW.
	String second circuit of 220 kV Wairakei – Atiamuri – Whakamaru line[7].

Table 3-4: 220 kV Grid Development Plan from 2010-2040 for Generation Scenario 4

In stage 1, the thermal upgrades and a new 220 kV double circuit line will be needed to supply the Auckland load.

The existing HVDC link is assumed to be upgraded to 1400 MW capacity during the period 2010 - 2015. The associated core grid AC developments include upgrading the existing 220 kV single conductor Hayward – Bunnythorpe A&B lines and Tokaanu - Whakamaru A&B lines with duplex conductors. (for increased HVDC transfer to the South Island during low hydro periods, and increased northwards transmission respectively).

An increasing generation deficit develops in the North Island from 2010 onwards, primarily caused by a large increase in load and a lack of new generation in the Auckland and Northland region. With the upgrade of the existing HVDC, this deficit can be supplied until 2020, at which point n-1 security under generation contingencies can no longer be maintained.

For stage 2, a new HVDC link is assumed to be built from the South Island directly to Auckland. It is built in two stages, and is required to import power from the South Island directly to the major load centre in Auckland. Reinforcement of the 220 kV grid into the Bay of Plenty by duplexing Atiamuri - Tarukenga will also be required.

---

[6] The HVDC link is based on transmission capacity requirements only. The link must be such that it provides 600 MW reliable supply capacity to the Auckland region. Security considerations may require an arrangement, such as a double bipole.

[7] At this stage it may be possible to dismantle the existing lower capacity single circuit Wairakei – Ohakuri – Atiamuri – Whakamaru line.

For stage 3, the new HVDC link to Auckland is upgraded to 1200 MW to provide for additional load growth in the Auckland area. A new double circuit line is also required from Whakamaru to Auckland for transferring power from the new generation developments around Whakamaru and south of Whakamaru.

The ultimate grid augmentation plan for a 220 kV transmission system for Scenario 4 is shown in Figure 3-4.

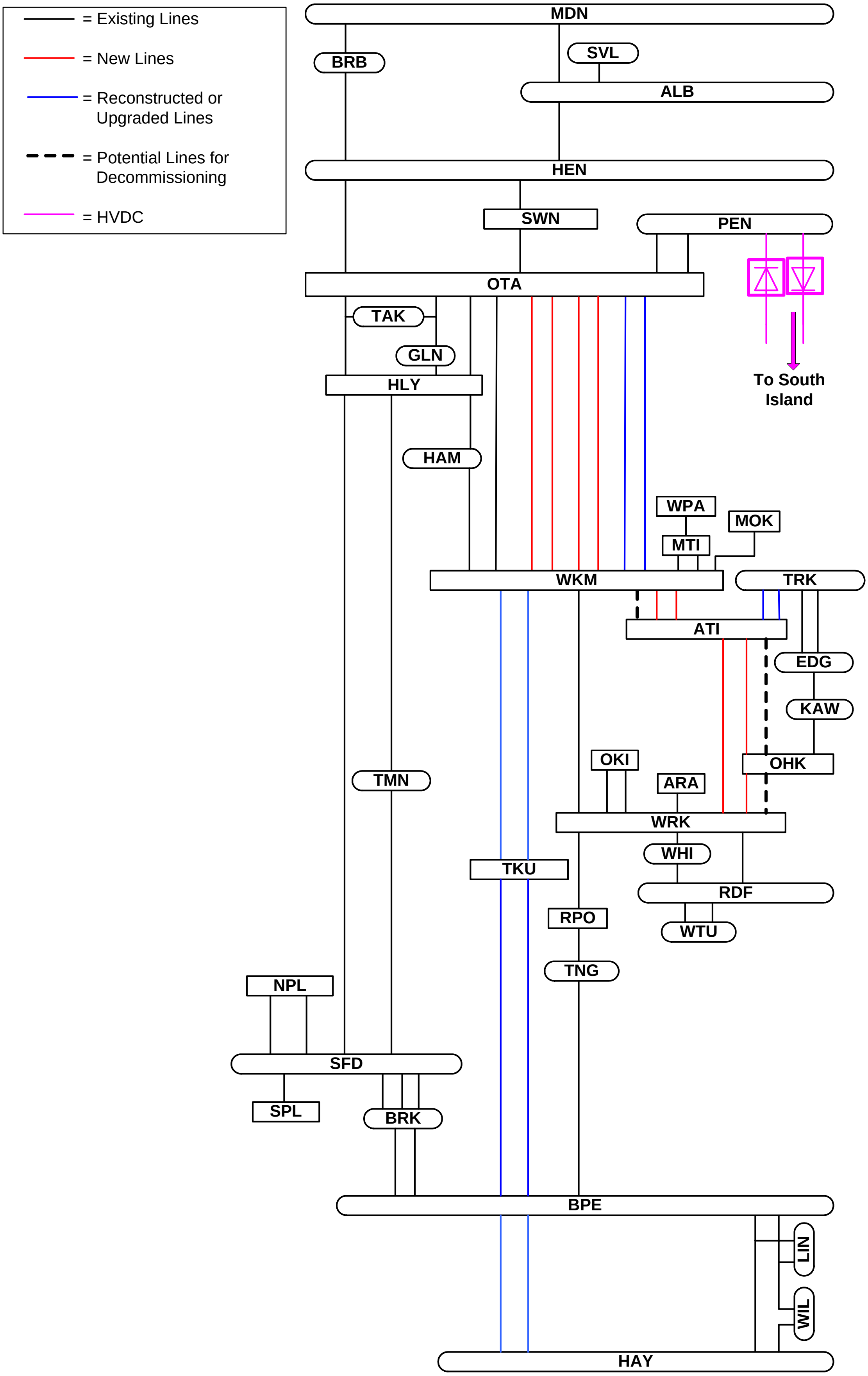


Figure 3-4: 220 kV grid configuration for Generation Scenario 4 at 2040

3.3.6 220 kV Grid Development Plan for Generation Scenario 5 (Reduced Demand) from 2010-2040

The new lines to be built and those that are to be upgraded with duplex conductors under Generation Scenario 5 (reduced demand) are given below:

Stage	Transmission Line
1	Construct a 220 kV double circuit line Whakamaru to Auckland.
	Upgrade 220 kV Tokaanu – Whakamaru A&B lines to duplex conductor.
	Upgrade 220 kV Bunnythorpe – Haywards A&B lines to duplex conductor.
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead).
	New 220 kV double circuit Whakamaru-Atiamuri-Ohakuri-Wairakei line.
2	Connect second circuit on Otahuhu-Whakamaru C line into Huntly.
	Upgrade Bunnythorpe-Tokaanu circuits to duplex conductor.
	Upgrade Bunnythorpe-Tangiwai-Rangipo circuits to duplex conductor.
	Connect Bunnythorpe-Tokaanu circuits into Rangipo.
	Upgrade Rangipo-Wairakei circuits to duplex conductor.
3	Upgrade 220kV Otahuhu - Whakamaru A and B lines to duplex conductor.
	Upgrade Atiamuri – Tarukenga A line to duplex conductor.
	Connect second circuit of Otahuhu-Whakamaru C line into Hamilton.
	New 220 kV double circuit Otahuhu - Whakamaru line.
	Upgrade existing Wairakei-Whakamaru A line to duplex conductor.

Table 3-5: 220 kV Grid Development Plan 2010-2040 for Generation Scenario 5

In stage 1, the thermal upgrades and a new 220 kV double circuit line will be needed to supply the Auckland load. A new double circuit line between Wairakei and Whakamaru is also required for transferring the generation from south of Bunnythorpe.

The existing HVDC link is assumed to be upgraded to 1400 MW capacity during the period 2010. The associated core grid AC developments include upgrading the existing 220 kV single conductor Hayward – Bunnythorpe A&B line and Tokaanu - Whakamaru A&B line with duplex conductors. (for increased HVDC transfer to the South Island during low hydro periods, and increased northwards transmission respectively).

In stage 2, the Otahuhu-Whakamaru C line is connected into Huntly to increase the transmission capacity due to increased generation at Huntly. The Huntly-Stratford circuit is connected into Taumarunui to ease voltage problems during a contingency with new generation at Stratford. The Bunnythorpe-Tokaanu circuits are connected into Rangipo to improve sharing between the three circuits north of Bunnythorpe for high HVDC transfer.

Other developments in this stage include duplexing the existing 220 kV Bunnythorpe-Tokaanu A&B lines and the Bunnythorpe-Wairakei A line to meet the increasing transfer requirement in the corresponding regions.

In stage 3, the Otahuhu-Whakamaru A&B is upgraded to relieve grid constraints from south of Otahuhu. The Otahuhu-Whakamaru C line is connected into Hamilton to increase transmission capacity into the Waikato region and relieve constraints on the existing Hamilton-Whakamaru circuit during low Huntly generation. A new 220 kV circuit between Otahuhu-Whakamaru will be constructed to relieve the constraints between Otahuhu and Whakamaru. Reinforcement of the 220 kV grid into Bay of Plenty, and between Whakamaru and Wairakei, is also required.

The ultimate grid augmentation plan for a 220 kV transmission system for Scenario 5 is shown in Figure 3-5.

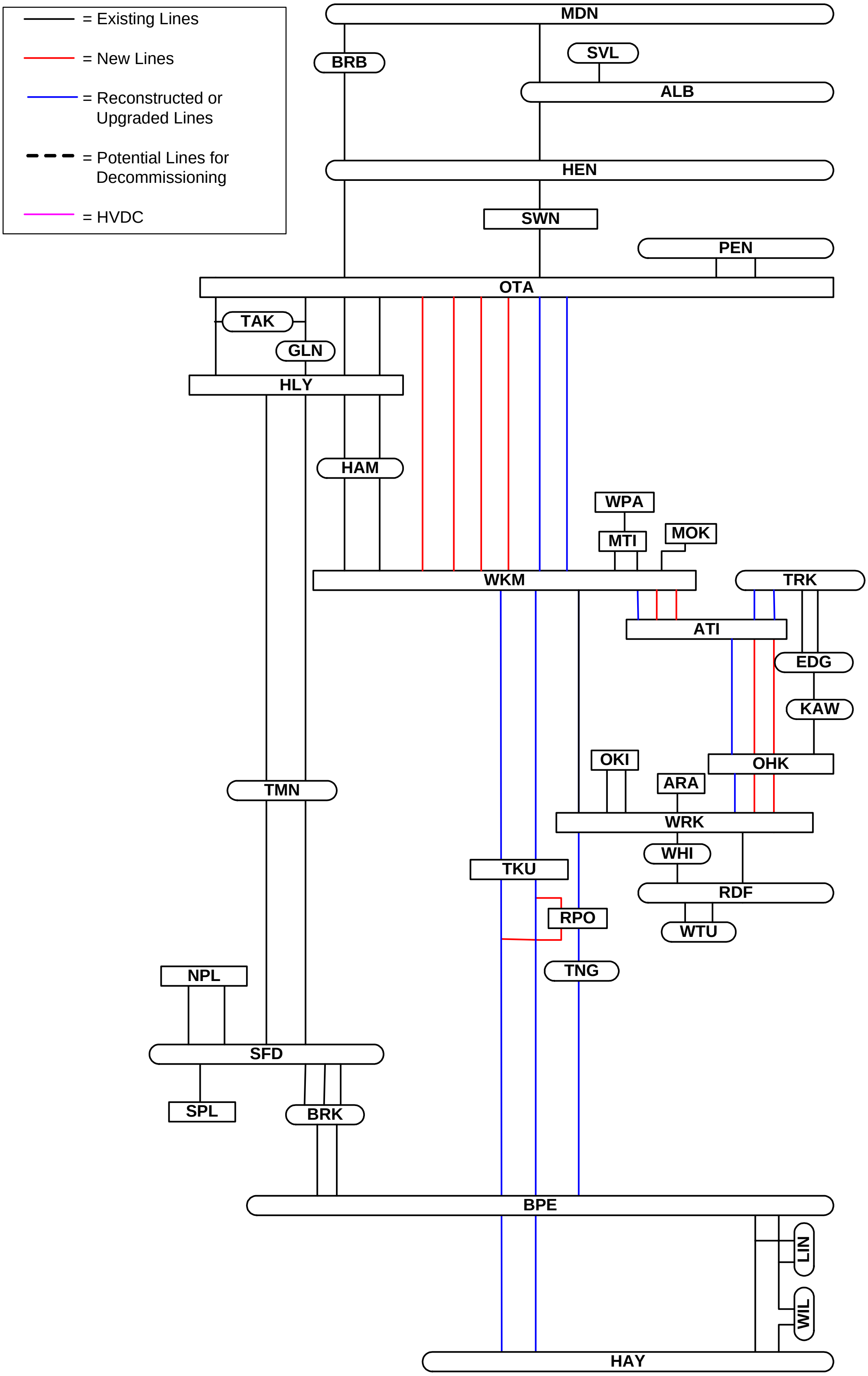


Figure 3-5: 220 kV grid configuration for Generation Scenario 5 at 2040

3.4 Assessment of 220 kV HVAC Grid Upgrade Plan

3.4.1 System Security

The proposed 220 kV HVAC grid development plan can be planned and implemented to meet Transpower's current grid reliability standards.

3.4.2 Asset Availability

Table 3.6 shows the historical availability of the HVAC assets. The availability of the new overhead 220 kV transmission assets is expected to be similar or better than the existing 220 kV transmission assets, which is an acceptable level of performance.

Year	33/50/66	110kV	220kV	Total
1999 / 00			99.7%	99.2%
2000 / 01	98.4%	98.6%	99.6%	98.9%
2001 / 02	99.2%	98.9%	99.4%	99.1%
2002 / 03	99.1%	98.6%	99.3%	98.9%
2003 / 04	99.2%	98.7%	99.4%	99.0%

Table 3-6: Historical Availability of HVAC Assets

3.4.3 Flexibility

All 220 kV transmission development plans allow flexibility for future expansion of the grid, depending on the future generation developments and load growth.

3.4.4 Environmental Consideration of 220 kV Options

Power transfer capabilities of transmission systems increase as the system voltage increases. Consequently, continuing with a 220 kV grid development strategy will result in the greatest number of new transmission lines to be constructed between major generation facilities and load centres across the country (when compared to other higher voltage options).

While 220 kV transmission line tower heights are lower than the other high voltage upgrade options, it is considered that the benefit of lower tower heights is substantially outweighed by the need to establish more transmission line routes to connect the major load centres to generation.

System losses are also highest for a 220 kV development plan when compared to higher voltage choices. This brings forward the need for investment in generation when compared to higher voltage (lower loss) alternatives.

In summary, when assessed over a 30-40 year period, a 220 kV development plan is considered to cause the greatest overall environmental impact. This is based on this development plan having the largest number of new transmission lines which cause greatest disruption to land use and have a wider impact on communities over greater areas the other higher voltage options.

3.4.5 *Economic Analysis*

The detailed economic analysis of this plan is contained in Part IV of this submission. In summary the 220 kV development plan is has a national benefit assessed as $133 million lower than the 400 kV development plan.

3.4.6 *Conclusion*

A 220 kV HVAC development plan to cater for the needs of New Zealand's demand growth would provide satisfactory security of supply outcomes. However a 220 kV development plan would require the highest number of new transmission lines to be build especially between Whakamaru and Auckland, when assessed against all generation scenarios. Given the difficulty in obtaining transmission corridors for building new lines, and considering the adverse environmental impact, the ability to implement such a plan in the long term is a concern. This option is also substantially more expensive in national benefit terms than moving to a higher system voltage choice such as 400 kV.

Transpower does not consider that a "no investment" outcome is a viable long term choice for New Zealand as the amount of energy forecast to be unserved would have massive consequences for the country as a whole. For this reason the 220 kV option has been considered as the base case against which the economic benefits of the other options are tested.

3.5 400 kV HVAC Development

The following sections describe the future development of the grid under different generation scenarios, if the maximum transmission voltage for new core grid transmission is increased to 400 kV. The 400 kV developments would be focussed in the transmission corridors where significant power transfer is expected to take place in the future. Development of the grid at 220 kV and 110 kV will also continue in areas of the network with lower power transfer requirements.

In this section a number of stages have been developed to group the necessary grid upgrades into discrete steps. Stage 1 represents grid upgrades which are planned to take place approximately from 2010 to 2015, stage 2 are developments up from 2015 to 2020, and stage 3 are developments beyond 2020.

It should be noted that the high-level development plans in this section are based on system planning studies. Detailed studies are required to confirm optimal location and sizing of some reactive power investments and detailed engineering work is still required to confirm feasibility and the appropriateness of the type of solution employed. For example where an existing line is proposed for upgrading by installing duplex conductors the existing towers may not be strong enough and they may require replacement. Furthermore, where two single circuit lines are proposed for duplexing, a single double circuit line may be built instead.

3.5.1 *Development Plans before 2010*

A summary of the grid upgrade projects which are expected to be implemented in the North Island Power System before 2010 are given in the Transpower publication: Future of the National grid – Transmission Plan Summary 2004. For conciseness, the salient upgrade projects are summarised in Appendix III-B.

Before 2010, the transfer capability into Auckland is increased by thermal upgrades of lines and increasing the level of reactive power compensation in the region. After 2010, the power transfer into the Auckland region will be mainly constrained by a voltage stability limit and no further significant transmission capacity can be provided by thermal upgrades or reactive compensation. Further increase in transmission capacity will require building new transmission lines especially between Auckland and Whakamaru.

3.5.2 400 kV Grid Development Plan for Generation Scenario 1 (Gas) from 2010-2040

The new lines to be built and those existing lines to be upgraded with duplex conductors under this generation scenario are shown below in Table 3-7:

Stage	Transmission Project
1	New 400kV double circuit Otahuhu – Whakamaru line
	New 220 kV double circuit Wairakei – Atiamuri – Whakamaru line (string one side only)
	Duplex 220 kV Tokaanu – Whakamaru A&B lines
	Duplex 220 kV Bunnythorpe – Haywards A&B lines
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead)
2	New 400 kV double circuit Bunnythorpe – Whakamaru line
	New 400 kV double circuit Stratford – Whakamaru (new) line
	New 220 kV Tokaanu-Taumarunui line[8]
	Tap Rangipo 220 kV bus onto Bunnythorpe-Tokaanu 220 kV A&B lines
3	Duplex 220 kV Atiamuri – Tarukenga A line
	String second side of 220 kV Wairakei – Atiamuri – Whakamaru double circuit line
	Connect 400 kV double circuit line constructed in stage 1 into Huntly
	Bond 220 kV Otahuhu – Whakamaru C line to create a single circuit

Table 3-7: 400 kV Grid Development Plan 2010-2040 for Generation Scenario 1

In stage 1 a new double circuit 400 kV line will be required between Otahuhu and Whakamaru, to relieve grid constraints from south of Otahuhu. 400 kV substations will be required at Otahuhu and Whakamaru to provide interconnection to the 220 kV grid. Other developments in this stage include duplexing the existing 220 kV Hayward – Bunnythorpe A&B lines and Tokaanu – Whakamaru A&B lines and building a new double circuit line between Wairakei and Whakamaru to meet the increasing transfer requirement in the corresponding regions. Reinforcement of the grid across the Auckland Isthmus will be completed with a new 220 kV cable or

---

[8] This development assumes that the Stratford-Taumaranui-Huntly line and Tangiwai-Rangipo section of the Bunnythorpe-Tokaanu A&B lines are decommissioned. However, the need fro decommissioning will be assessed closer to the time depending on the condition of the asset and the generation developments (especially wind generation) in the region.

overhead line to increase the transfer capability to the North Isthmus and Northland regions.

In stage 2, the 400 kV network will be extended south to Bunnythorpe from Whakamaru and west to Stratford to allow generation from Taranaki region and Bunnythorpe south (including HVDC import) to areas north of Whakamaru. This development will allow the existing 220 kV Stratford – Taumarunui and Huntly – Taumarunui line, the Tangiwai – Rangipo section of the Bunnythorpe – Tokaanu A&B lines, and the entire Bunnythorpe – Wairakei line to be decommissioned.[9] New 400 kV substations at Bunnythorpe, Stratford will also be built in this stage.

In stage 3 the 400 kV line built in stage 1 will need to be diverted to Huntly power station by constructing a short section of 400 kV double circuit line for transporting generation from Huntly. Reinforcement of the 220 kV grid into Bay of Plenty and through the Wairakei ring will also be required.

The ultimate augmentation plan based on 400 kV option for Scenario 1 is shown in Figure 3-6

---

[9] The need for decommissioning will be assessed closer to the time depending on the condition of the asset and the generation developments (especially Wind Generation) in the region.

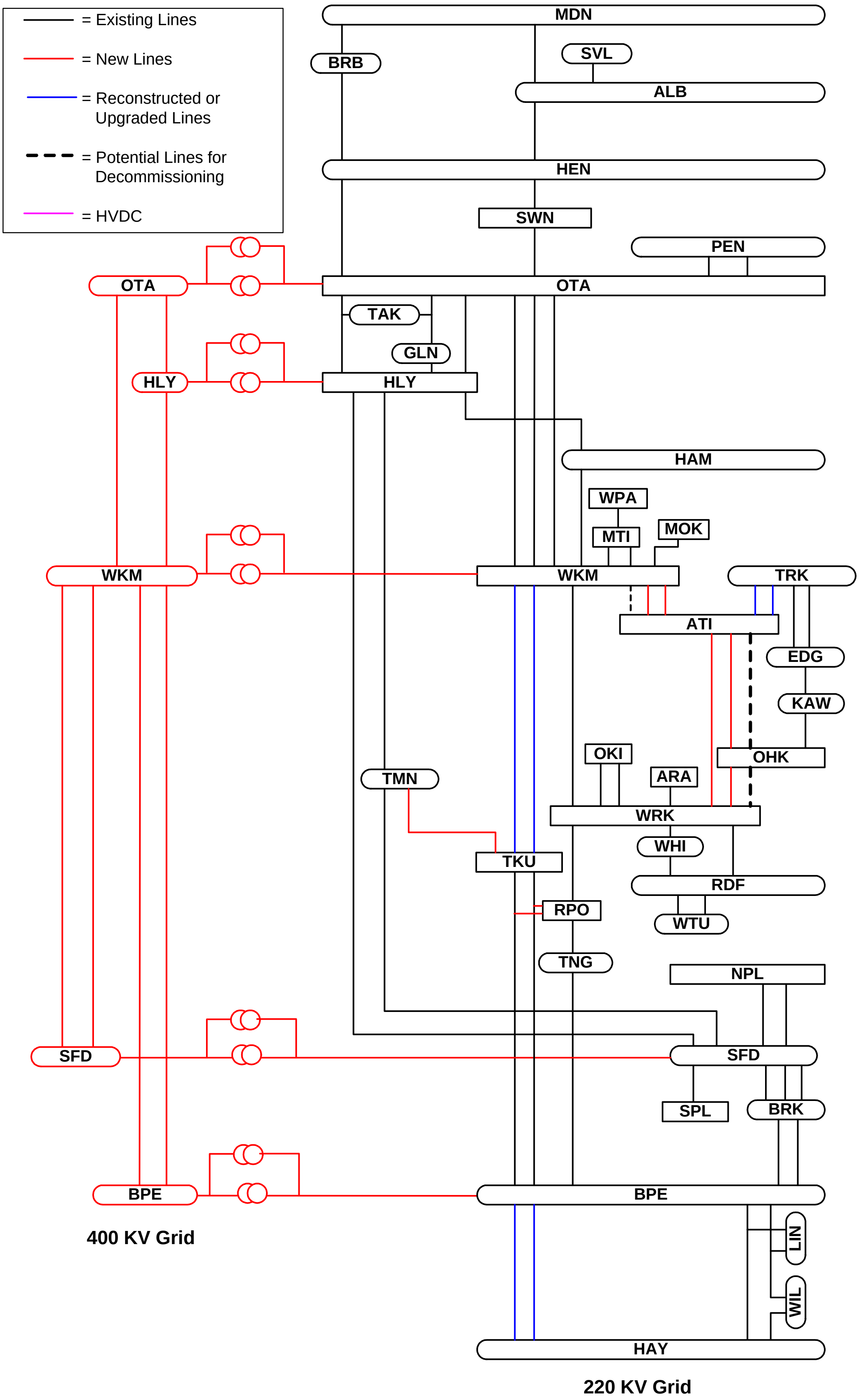


Figure 3-6: 400 kV Grid Development Plan for Generation Scenario 1 at 2040

3.5.3 400 kV Grid Development Plan for Generation Scenario 2 (Coal) from 2010-2040

The new lines that are to be built and those existing 220 kV lines that are to be upgraded to duplex conductors for this generation scenario are shown below:

Stage	Transmission Project
1	New 400kV double circuit Otahuhu - Whakamaru line
	New 220 kV double circuit Wairakei – Atiamuri – Whakamaru line (string one side only)
	Duplex 220 kV Tokaanu – Whakamaru A&B lines
	Duplex 220 kV Bunnythorpe – Haywards A&B lines
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead)
2	New 400 kV double circuit Bunnythorpe – Whakamaru line
	Tap Rangipo 220 kV bus onto Bunnythorpe-Tokaanu 220 kV A&B lines
3	Duplex Atiamuri – Tarukenga A line
	String second side of 220 kV Wairakei – Atiamuri – Whakamaru double circuit line
	Connect 400 kV double circuit line constructed in stage 1 into Huntly

Table 3-8: 400 kV Grid Development Plan 2010-2040 for Generation Scenario 2

The gird development plan in stage 1 is identical to the one developed for Generation Scenario 1.

However, the new 220 kV circuits between Stratford –Whakamaru (new) required in stage 2 for Scenario 1 are not required in this scenario. This is because the new generation in the Taranaki region for Generation Scenario 2 is much less than that for Generation Scenario 1 and therefore the capacity requirement between Stratford and Whakamaru is significantly reduced.

The grid augmentation required in stage 3 is mainly for reinforcing the transfer into the Bay of Plenty and through the Wairakei ring. Also the 400 kV line built in stage 1 will need to be diverted to Huntly power station by constructing a short section of 400 kV double circuit line for dispatching generation from Huntly.

The ultimate augmentation plan based on 400 kV option for Scenario 2 is shown in Figure 3-7.

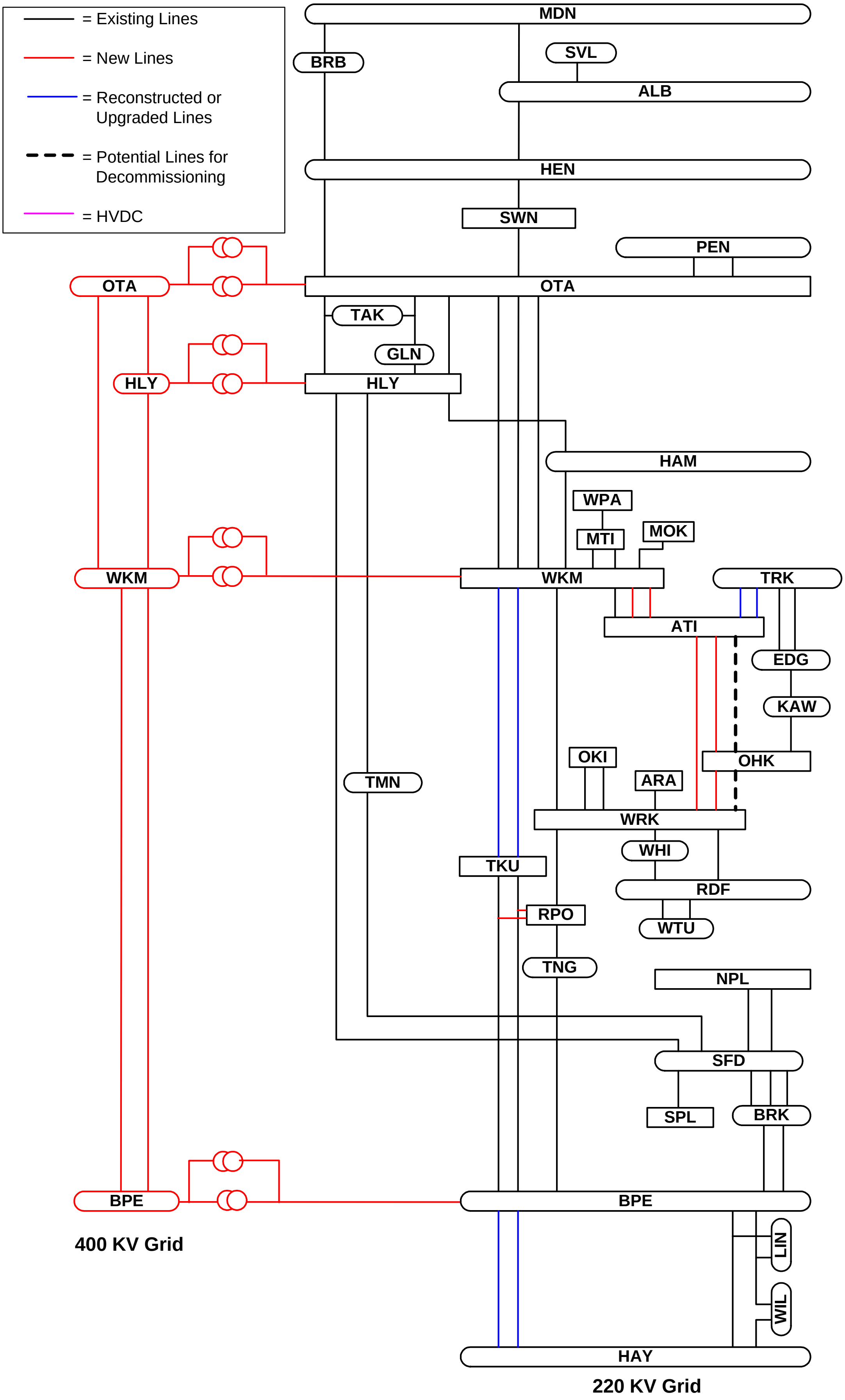


Figure 3-7: 400 kV Grid Development Plan 2040 for Generation Scenario 2

3.5.4 400 kV Grid Development Plan for Generation Scenario 3 (Renewables) from 2010-2040

For Generation Scenario 3, the new lines to be constructed and the 220 kV lines that are to be upgraded to duplex conductors are shown below:

Stage	Transmission Project
1	New 400kV double circuit Otahuhu – Whakamaru line
	New 220 kV double circuit Wairakei – Atiamuri – Whakamaru line (string one side only)
	Duplex 220 kV Tokaanu – Whakamaru A&B lines
	Duplex 220 kV Bunnythorpe – Haywards A&B lines
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead)
2	New 400 kV double circuit Bunnythorpe – Whakamaru line
	Tap Rangipo 220 kV bus onto Bunnythorpe-Tokaanu 220 kV A&B lines[10,11]
3	New 400 kV double circuit Whakamaru – Pakuranga
	String second side of 220 kV Wairakei – Atiamuri – Whakamaru double circuit line
	New 220 kV double circuit Taumarunui-Whakamaru line
	Connect 400 kV double circuit line constructed in stage 1 into Huntly
	New 220 kV single circuit Whakamaru – Wairakei line
	Bond 220 kV Otahuhu – Whakamaru C line to create a single circuit

Table 3-9: 400 kV Grid Development Plan (Generation Scenario 3)

The stage 1 grid augmentation plan for this scenario is identical to those developed under scenarios 1 & 2. Similarly, stage 2 development is identical to that developed under Scenario 2.

In stage 3, a second double circuit 400 kV transmission line from Whakamaru to Auckland will have to be constructed. This is because in Generation Scenario 3, very little new generation is projected north of Whakamaru compared with generation scenarios 1 and 2. Consequently, more transmission capacity into Auckland will be required compared with other generation scenarios. Additional 220 kV lines will be required into Bay of Plenty via the Wairakei ring, similar to the requirement under scenarios 1 and 2. The 400 kV line built in stage 1 will need to be diverted to Huntly power station by constructing a short section of 400 kV double circuit line for dispatching generation from Huntly. The Huntly-Otahuhu section of the existing 220 kV Otahuhu - Whakamaru C line could be decommissioned in this stage.[12] Also in

---

[10] This development assumes that the Tangiwai – Rangipo section of the Bunnythorpe – Tokaanu A&B lines are decommissioned.

[11] The need for decommissioning will be assessed closer to the time depending on the condition of the asset and the generation developments (especially wind generation) in the region.

[12] The need for decommissioning will be assessed closer to the time depending on the condition of the asset and the generation developments (especially wind generation) in the region.

stage 3, a new small section of 220 kV line from Taumarunui to Whakamaru will need to be built.

The ultimate augmentation plan based on 400 kV option for Scenario 3 is shown in Figure 3-8.

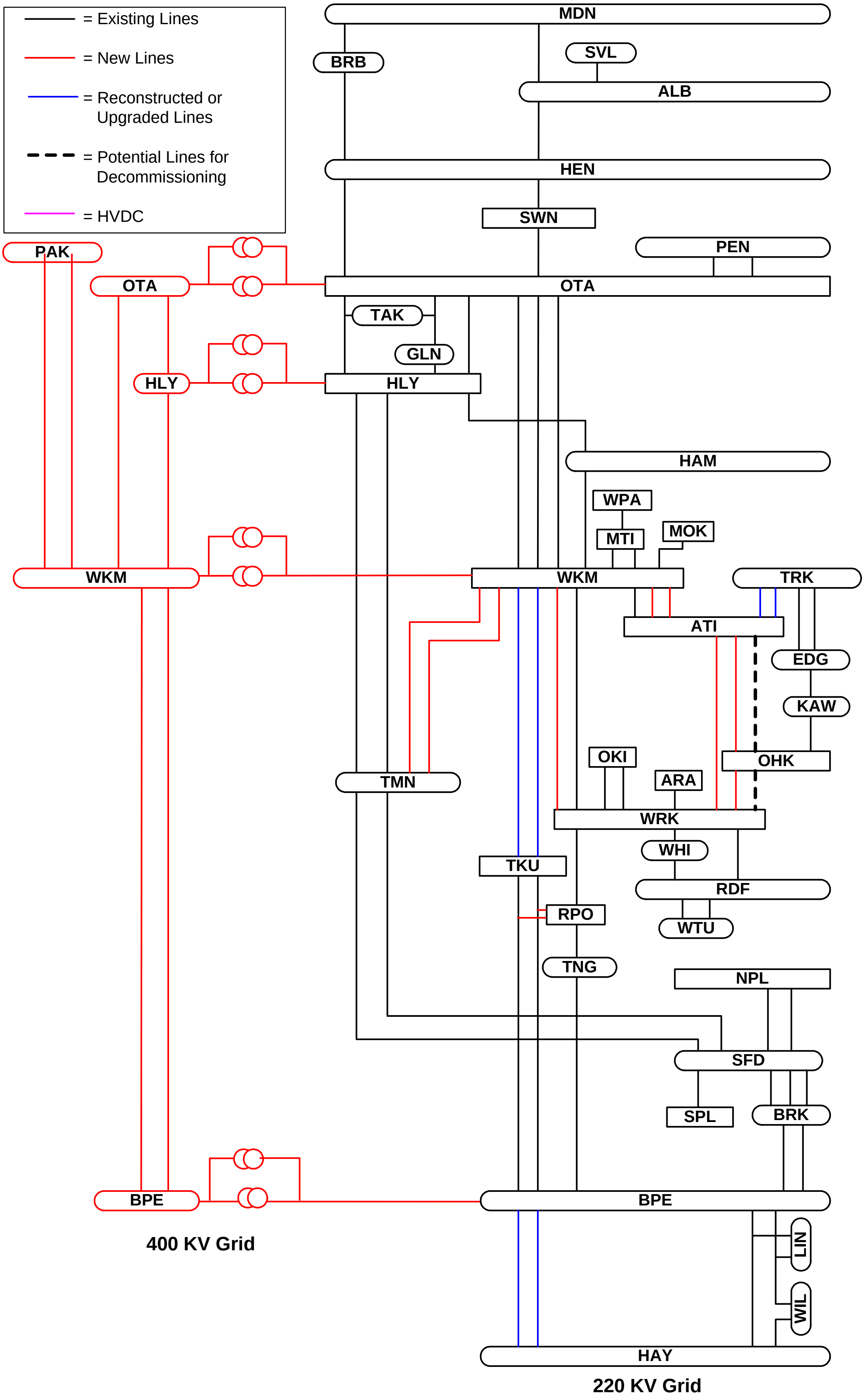


Figure 3-8: 400 kV Grid Development Plan 2040 for Generation Scenario 3

3.5.5 400 kV Grid Development Plan for Generation Scenario 4 (Southern Hydro) from 2010-2040

The major projects, new lines that are to be built and those existing 220 kV lines that are to be upgraded from single conductor to duplex conductors for this generation scenario is shown below:

Stage	Transmission Project
1	New 400kV double circuit Otahuhu - Whakamaru line
	New 220 kV double circuit Wairakei – Atiamuri – Whakamaru line
	Duplex 220 kV Tokaanu – Whakamaru A&B lines
	Duplex 220 kV Bunnythorpe – Haywards A&B lines
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead)
2	New HVDC link of capacity 600 MW from the South Island into Auckland
	Duplex 220 kV Atiamuri – Tarukenga A line
3	Upgrade the capacity of new HVDC to Auckland from 600 to 1200 MW
	New 220 kV double circuit Otahuhu – Penrose line

Table 3-10: 400 kV Grid Development Plan (Generation Scenario 4)

The stage 1 grid augmentation plan for this scenario is identical to those developed under scenarios 1, 2 & 3.

In this generation scenario there is an increasing generation deficit in the North Island from 2010 onwards. With the upgrade of the capacity of the existing inter-island HVDC link to 1400 MW, this deficit can be supplied up to a point where n-1 security under generation contingencies can no longer be maintained. In stage 2 of this upgrade plan, a new HVDC link is required to import power from the South Island. This link is planned to inject power directly into Auckland. Reinforcement of the 220 kV grid into Bay of Plenty and through the Wairakei ring will also be required.

In stage 3 of this grid augmentation plan, the capacity of the new HVDC link between the South Island and Auckland will have to be increased. This is once again driven by insufficient generation capacity in the North Island for ensuring the supply security. The 220 kV grid between Otahuhu and Penrose will have to be reinforced to cater for the increased demand north of Otahuhu.

The ultimate augmentation plan based on 400 kV option for Scenario 4 is shown in Figure 3-9.

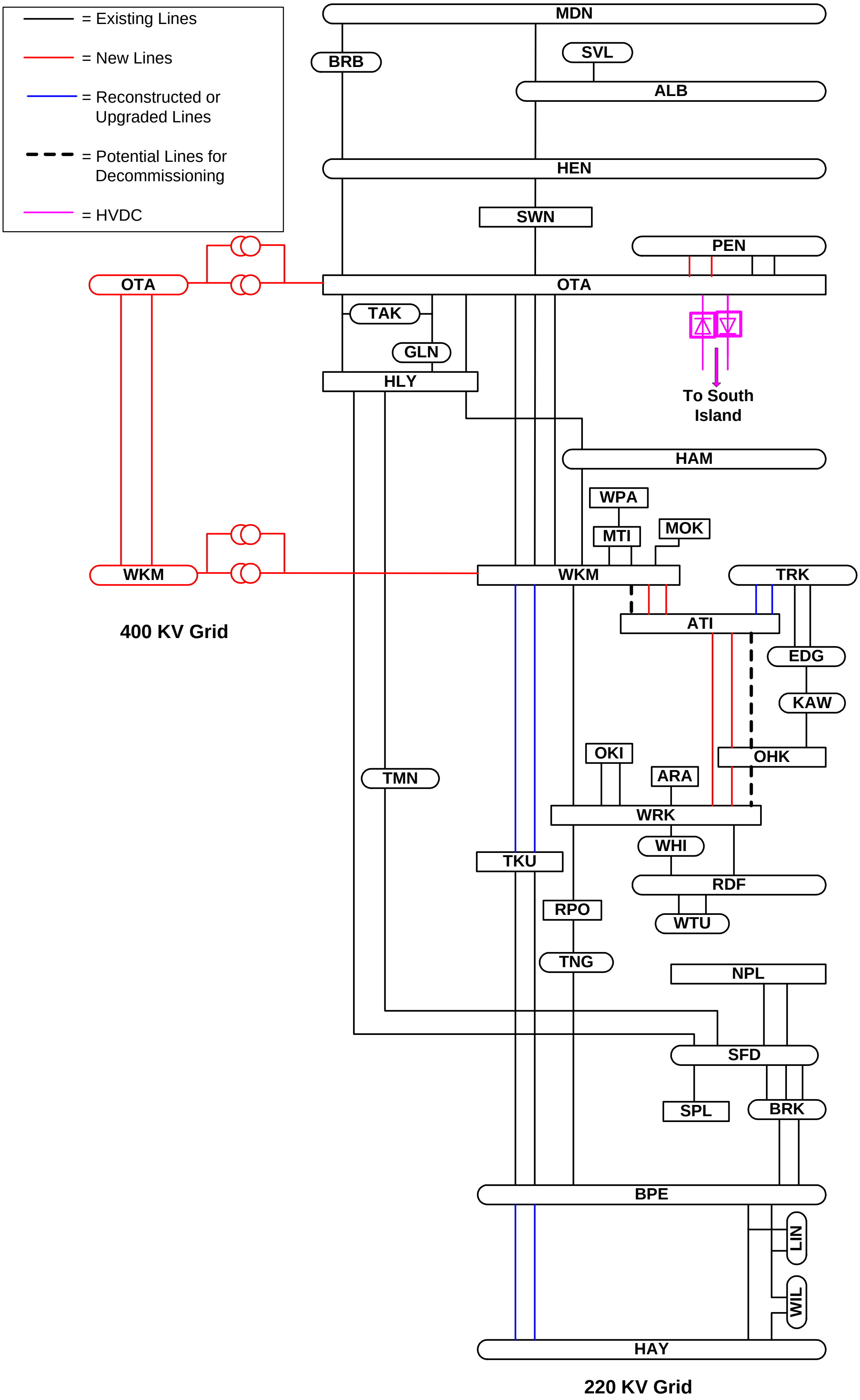


Figure 3-9: 400 kV Grid Development Plan 2040 for Generation Scenario 4

3.5.6 400 kV Grid Development Plan for Generation Scenario 4 (Reduced Demand) from 2010-2040

The major projects, new lines that are to be to be built and existing 220 kV lines that are to be upgraded from single conductor to duplex conductors for this generation scenario is shown below:

Stage	Transmission Project
1	New 400kV double circuit Otahuhu - Whakamaru line
	New 220 kV double circuit Wairakei –Ohakuri-Atiamuri – Whakamaru line
	Duplex 220 kV Tokaanu – Whakamaru A&B lines
	Duplex 220 kV Bunnythorpe – Haywards A&B lines
	Auckland cross isthmus reinforcement with new 220 kV circuit (cable or overhead)
2	Loop in one circuit of Otahuhu-Whakamaru 400 kV line at Huntly
	Tap the 220 kV Huntly-Stratford circuit at Taumarunui
	Duplex 220 kV double circuit Bunnythorpe-Tokaanu . Tap Rangipo 220 kV bus onto Bunnythorpe-Tokaanu A&B lines
	Duplex 220 kV Bunnythorpe-Tangiwai-Rangipo section of Bunnythorpe-Wairakei A line
	Duplex 220 kV Rangipo-Wairakei section of Bunnythorpe-Wairakei A line
3	Duplex 220 kV Atiamuri-Tarukenga A line
	Duplex 220 kV Wairakei-Ohaaki-Atamuri circuit

Table 3-11: 400 kV Grid Development Plan 2040 for Generation Scenario 5

The stage 1 grid augmentation plan for this scenario is identical to those developed under scenarios 1-4.

In stage 2 one circuit of the 400 kV line built in stage 1 will need to be diverted to Huntly power station by constructing a short section of 400 kV double circuit line. This will be required for dispatching the increased generation from Huntly and the Taranaki region. Increased Taranaki generation under this scenario necessitates sectionalising the 220 kV Huntly-Stratford circuit by tapping at Taumarunui. It is necessary to strengthen the system between Bunnythorpe and Whakamaru. Rangipo is tapped onto the two Bunnythorpe-Tokaanu circuits and the capacity of the three circuits out of Bunnythorpe is increased.

In stage 3, increased Wairakei generation results in the requirement for reinforcements of the 220 kV grid into Bay of Plenty and through the Wairakei ring.

The ultimate augmentation plan based on 400 kV option for Scenario 5 is shown in Figure 3-10.

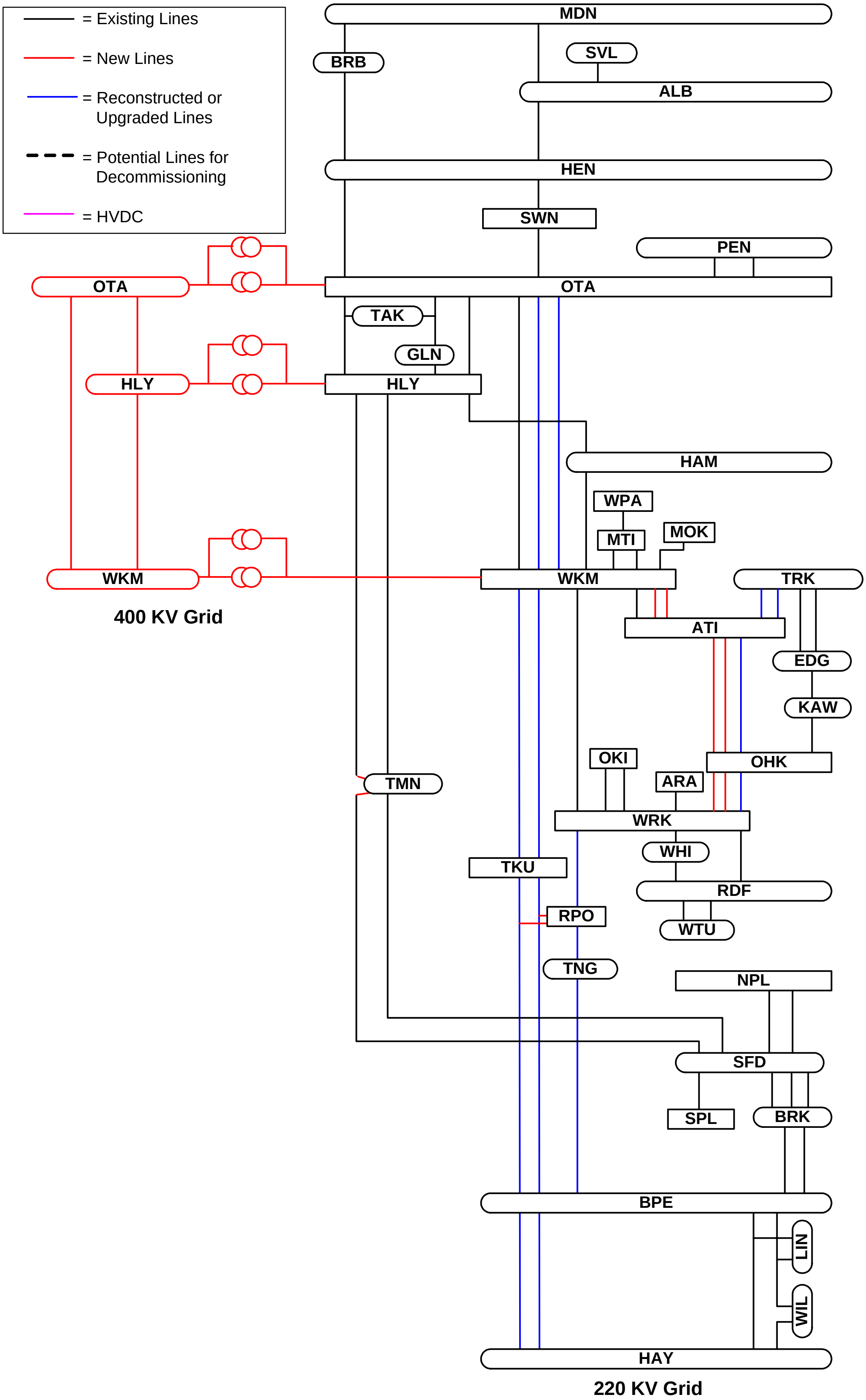


Figure 3-10 400 kV Grid Development Plan 2040 for Generation Scenario 5

3.6 Assessment of 400 kV HVAC Grid Upgrade Plan

3.6.1 System Security, Asset Availability and Flexibility

The 400 kV grid upgrade plan can be constructed to deliver equivalent outcomes to the 220 kV option when assessed against System Security and Asset Availability criteria. The flexibility of the 400 kV option to cater for a range of possible future demand and generation patterns is also equivalent to the 220 kV option. The criteria that provide a point of difference between 220 kV and 400 kV options are therefore environmental and economic.

3.6.2 Environmental Consideration of 400 kV Options

The 400 kV option, when compared to 220 kV or 330 kV options, will require substantially fewer new transmission lines to be constructed over the study period out until 2040. With fewer line routes required for 400 kV transmission, the environmental impact of transmission corridors, particularly those entering Auckland city will be better contained than continuing with 220 kV developments.

While tower heights are clearly a sensitive issue for communities, on balance Transpower considers that there are environmental benefits of having fewer high capacity lines with higher towers as opposed to more low capacity lines with lower height towers.

The choice of 400 kV as the main backbone voltage also reduces system losses substantially. The average difference in peak system losses between 220 kV and 400 kV development plans, across all five generation scenarios at 2040 is estimated as 50 MW.

3.6.3 Conclusions

A development plan based on introducing a 400 kV HVAC backbone into the transmission system will meet the needs of New Zealand’s demand growth across a range of possible generation futures.

A 400 kV network will provide satisfactory security of supply outcomes and would require substantially fewer new transmission lines to be constructed, particularly into the high demand growth areas such as the upper North Island.

With fewer lines established in corridors of high power transfer, the environmental impact of a 400 kV development plan will be lower than that of an equivalent capacity 220 kV development plan.

Finally, a 400 kV HVAC development plan is expected to deliver substantially higher national benefits due to lower capital costs and lower transmission losses than a 220 kV development, as detailed in Part IV of this submission.

3.7 330 kV HVAC Development

This option considers adopting 330 kV as the main core grid voltage for the future long term development of the New Zealand transmission system, augmenting the transmission capacity of the present 220 kV system.

This option retains many parts of the network at 220 kV, especially where generating stations are already connected at that voltage or for regional supply only. The 220 kV network will also be retained where the expected transmission along the corridor is substantially small and does not warrant upgrading to a higher voltage.

One major driver as well as the attraction of the 330 kV option was the perceived possibility of physical modification of the existing 220 kV transmission lines to be operated at 330 kV. However, detailed investigations showed that significant rebuild is required for such a conversion and in many cases it is not practical to convert 220 kV lines for operation at 330 kV. The issues that make upgrading the existing 220 kV lines to 330 kV impractical are:

- The foundations will have to be strengthened or replaced as existing foundations are inadequate for the heavier loading required for 330 kV lines.
- If existing towers are to be re-used, a large number of temporary by-pass lines will have to be built while existing towers are modified or relocated and new conductors are installed to maintain security of supply.
- The existing 220 kV flat-top towers have insufficient strength to sustain the loads associated with a major upgrade of capacity. The lines would be limited in their current carrying capacity which in turn forces the choice of more, lower capacity lines as opposed to fewer high capacity lines. The existing clearance levels of the 220 kV lines are also likely to be insufficient to cater for 330 kV operation.
- Some of the existing tower steel is more than 50 years old. Even though these towers may be reused, it is likely that ageing and distortions while in service will increase the cost of recycling. Further, the compatibility of the strength of steel used in the old towers with modern tower designs needs to be re-assessed.
- All of the above points confirm that reusing the existing tower line infrastructure for 330 kV in infeasible and that the lines would need to be rebuilt to cater for a standard 330 kV performance specification.
- Long continuous line outages will be required during the course of conversion, with the associated risk that electricity supply to customers will be interrupted.
- Any such upgrades would not be able to be achieved under Transpower's existing use rights under the Electricity Act 1992. Therefore the 330 kV option offers no advantage in terms of avoiding the need to acquire property rights and consents under the Resource Management Act for rebuilding the existing towers.

Preliminary costing studies have shown that there would be no cost advantage in upgrading existing lines to 330 kV compared with construction of new lines at 330 kV.

3.7.1 System Security, Asset Availability and Flexibility

System Security, Asset Availability and Flexibility of the 330 kV option will be similar to that discussed in Section 3.3, 220 kV HVAC Development.

3.7.2 Environmental Consideration of 330 kV Options

This option provides similar advantages as the 400 kV option in terms of the number of routes required, and will limit potential adverse effects to a defined transmission easement, at least in the short term. However, over a long time period, 330 kV development will naturally require greater transmission routes than 400 kV development. Increase in the operating voltage to 330 kV from what is currently being used (i.e. 220 kV) is also likely to raise community concern and opposition.

3.7.3 Conclusion

330 kV AC was only initially considered as an option because it was perceived that the existing 220 kV lines could be easily converted to 330 kV AC operation.

Subsequent investigations showed that upgrading of the 220 kV lines for 330 kV operation essentially require the lines to be rebuilt. Furthermore there is no cost advantage for rebuilding the existing lines when compared to constructing a new line. If new lines are to be built, the past experience and high level economic analysis have shown that the new voltage to be migrated should be approximately twice the present voltage. Hence 330 kV is considered to be too low to deliver long run benefits, for adoption as the new core grid transmission voltage.

Because of the above reasons, it was concluded that 330 kV will not provide a suitable transmission option for long term upgrade of the transmission grid.

3.8 500 kV HVAC Development

Transpower has carried out detailed assessment of the viability of using 500 kV as the next voltage level for the long term development of the New Zealand high voltage grid, augmenting the capacity of the existing 220 kV grid.

Experience shows that, if there is a need to migrate to another system voltage, the next system voltage level should be about twice the existing voltage level. With the current principal transmission voltage in New Zealand being 220 kV, this suggests voltages of either 400 kV or 500 kV. The ultimate choice is a function of a number of factors including, the distance over which power transfers are required and the load density.

The electricity demand in North Island accounts for two thirds of the demand of New Zealand[13] and about one third is consumed in Auckland alone. Over the 40 year planning period, transfers on a number of corridors will require reinforcement depending on the assumed generation. The forecast corridor transfers are shown in Figure 3-11. Figure 3-11 also shows typical transfer capabilities of circuits at 220 kV, 400 kV and 500 kV although these may vary slightly depending on the choice of conductor and overhead line configuration[14] (ref: Peer review of choice of voltage for development of the New Zealand Grid).

---

[13] The remaining one third of the demand is associated with the South Island with a large proportion consumed in Christchurch.

[14] “Peer Review of Choice of Voltage for Development of the New Zealand Grid”– PB Power February 2004.

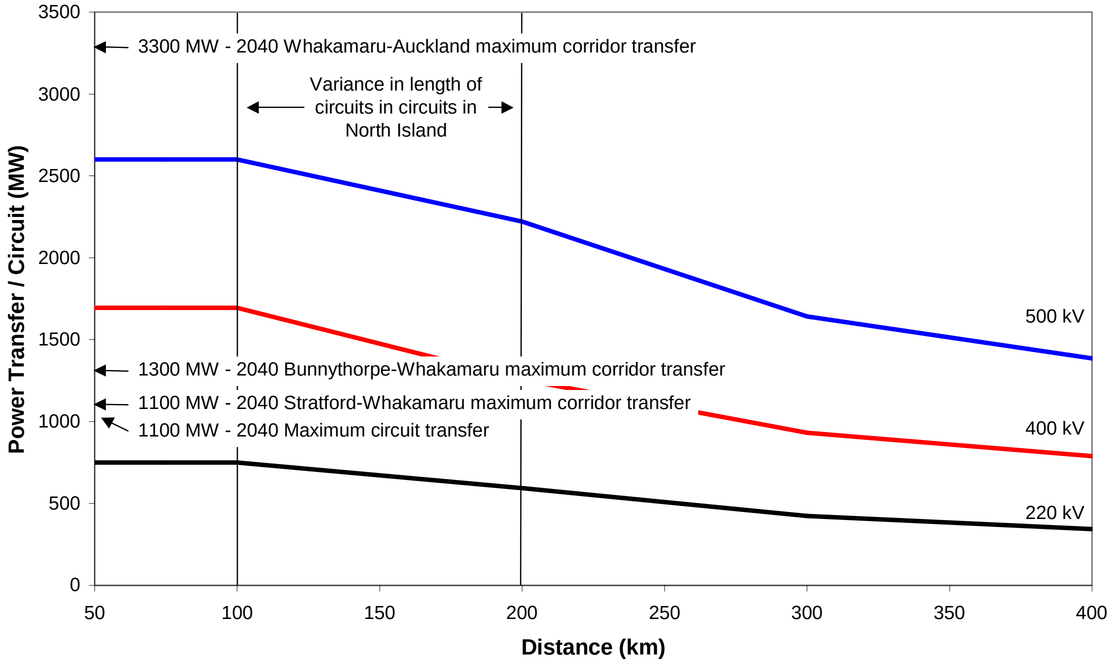


Figure 3-11 North Island - transfer capability at various voltage levels compared to expected corridor and circuit transfers.

In the North Island, the Whakamaru-Otahuhu, Bunnythorpe-Whakamaru and Stratford-Whakamaru corridor transfers are forecast to increase to approximately 3,300 MW, 1,300 MW and 1,100 MW respectively over the planning period. The number of additional circuits required to secure these transfers under contingency conditions is shown in Table 3-12.

Corridor	220 kV	400 kV	500 kV
Whakamaru-Otahuhu	8	4	3
Bunnythorpe-Whakamaru	4[15]	2	2
Stratford-Whakamaru	4[16]	2	2

Table 3-12 Requirements for additional circuits to secure corridor transfers by 2040

Therefore, while there may be an argument for the introduction of 500 kV to accommodate transfers from Whakamaru-Otahuhu, the capacity would be overly high for transfers required in the Bunnythorpe-Whakamaru and Stratford-Whakamaru corridor. High level economic analysis has also shown that 500 kV development options will yield lower economic benefits compared to 400 kV developments.

---

[15] Comprises 2 x Bunnythorpe-Whakamaru circuits and 2 x Bunnythorpe-Rangipo circuits

[16] Comprises 1 new double circuit and 1 rebuilt double circuit with heavier construction

3.8.1 System Security, Asset Availability and Flexibility

System Security, Asset Availability and Flexibility of the 500 kV option will be similar to that discussed in Section 3.3, 220 kV HVAC Development.

3.8.2 Environmental Consideration of 500 kV Options

Capacity is considerably in excess of that required to meet reasonable transmission requirements and will result in increased tower heights and easement area (to accommodate EMF levels). This option provides similar advantages as the 400kV option in terms of the number of routes required, and will limit potential adverse effects to a defined transmission easement. Overall effects within this easement will be greater than the 400kV option, without any real advantage.

3.8.3 Conclusions

The capacity offered by the 500 kV transmission lines, while under some generation scenarios would be suitable for high power transmission corridors, the utilisation would be small for many line corridors considered with the planning horizon until 2040. Hence 500 kV is not considered as the preferred voltage for future development of the New Zealand transmission system.

3.9 HVDC Link between South Island and Auckland

Transpower operates an HVDC link between Benmore in the South Island and Haywards in the North Island. Equipment forming the HVDC link includes:

- Converter stations at Haywards and Benmore. These stations convert electricity between HVAC and HVDC;
- Overhead transmission lines between Benmore and Fighting Bay in the South Island and Oteranga Bay and Haywards in the North Island.
- Undersea cables between Fighting Bay and Oteranga Bay which are laid across the Cook Strait.

The HVDC link is “bi-polar” which means that the power transferred between the North and South Islands can be transmitted through one or two HVDC poles. Pole 1 of the HVDC link was commissioned in 1964 and consists of mercury-arc converters. Pole 2 was commissioned in 1992 and is constructed using newer thyristor technology. The mercury-arc pole is nearing the end of its economic and physical life and is due for replacement within the next ten years. Therefore, the most viable option for extending the HVDC link to Auckland is to decommission pole 1 at Haywards, construct a new HVDC transmission line from Haywards to Auckland and establish a new HVDC pole in Auckland. The new HVDC pole from Benmore to Auckland would be rated at 350 kV and 700 MW in order to match the existing thyristor based pole 2 at Haywards.

The HVDC link between the South Island and Auckland was assessed as follows:

3.9.1 System Security

The HVDC alternative would provide up to 700 MW of “non-firm” additional transmission capacity into the Auckland area. This capacity must be regarded as non-firm because loss of the HVDC line from Benmore to Auckland (via

Haywards) or failure of a single converter pole at either Auckland or Benmore will result in the complete loss of 700 MW of power transfer into Auckland. This does not provide a grid augmentation alternative comparable with the preferred HVAC transmission option of 400 kV which would provide approximately 1000 MW of firm capacity (1000 MW on each circuit, with a total capacity of 2000 MW[17]) into Auckland.

The critical concern regarding HVDC augmentation is its inability to transport power into Auckland during dry year periods in the South Island. Historically, during dry years, power transmission through the HVDC link from the South Island to the North Island reduces significantly. For extended periods during dry years, power flows are often north to south. Figure 3.18 shows the HVDC transfer southward during a period of low hydro inflows in 2001 in the South Island (indicated as negative power flows). If southward power flows across the HVDC link occur at the time of high system demand, as evidenced in 2001, then an HVDC upgrade will provide no security of supply enhancement to the Auckland region during dry years.

It is not considered a feasible grid augmentation option to implement a transmission alternative that will not meet the peak demand requirements of a region under a realistic generation scenario (in this case, dry year conditions). Therefore, even if an HVDC alternative was implemented, HVAC grid augmentation into Auckland would still be required to provide a secure power supply. For this reason, HVDC augmentation between the South Island and Auckland was not considered to be a realistic transmission alternative to solve the security of supply concerns into the upper North Island.

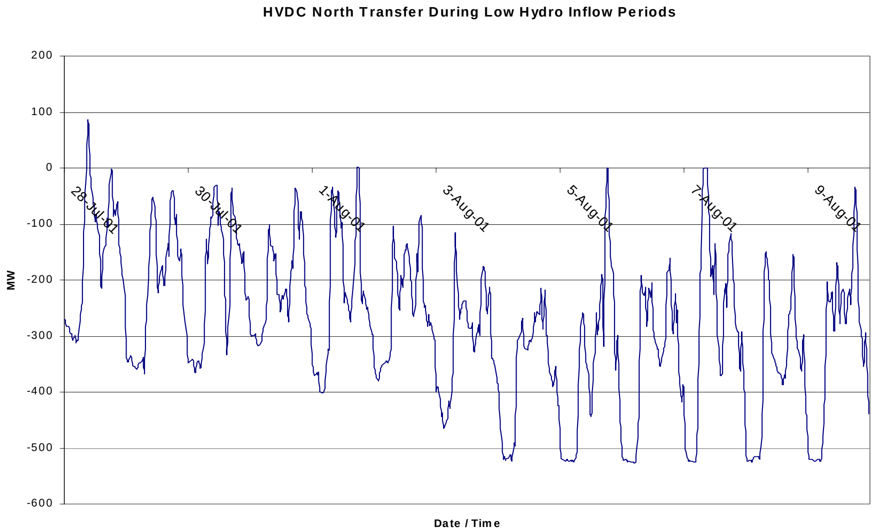


Figure 3-12: HVDC Power flows during a typical dry year (2001)

---

[17] While a new double circuit 400 kV line will provide 1000 MW of firm and 2000 MW of total thermal capacity, voltage stability limitations will reduce the actual power transferable into Auckland to a lesser quantity. The actual quantity will depend on the generation and reactive support that is established in the area.

3.10 HVDC Link between Whakamaru and Otahuhu - Classical Configuration

In consideration of HVDC as an alternative to HVAC transmission between Otahuhu and Whakamaru, Transpower assessed a number of HVDC transmission configurations of differing operating voltages and transfer capacities. The most suitable HVDC option is a 350 kV link which could provide a secure and reliable supply with 1000 MW of firm capacity. The link would consist of a double bi-pole arrangement with each pole of the two converter stations (one at Whakamaru and the other at Otahuhu) rated to 500MW.

The choice of a 350 kV HVDC pole design rated at 500MW would allow the use of proven technology. Modular designs with this rating are available from a number of manufacturers and would likely be offered at competitive prices.

The double bi-pole option was assumed to be implemented in two discrete stages.

Stage 1

- Completion of the entire transmission line and the short length of underground cable within Auckland urban area.
- Installation of 1000 MW, 350 kV bi-pole converter stations, at Whakamaru and Otahuhu.

Stage 2

- The ultimate design would be achieved by installing another 1000MW, 350 kV bi-pole converters, at Whakamaru and Otahuhu. This would augment the capacity of the HVDC link to1000 MW of firm capacity.

This ultimate design which includes the independent operation of two bi-poles between Whakamaru and Otahuhu is shown in Figure 3-13.

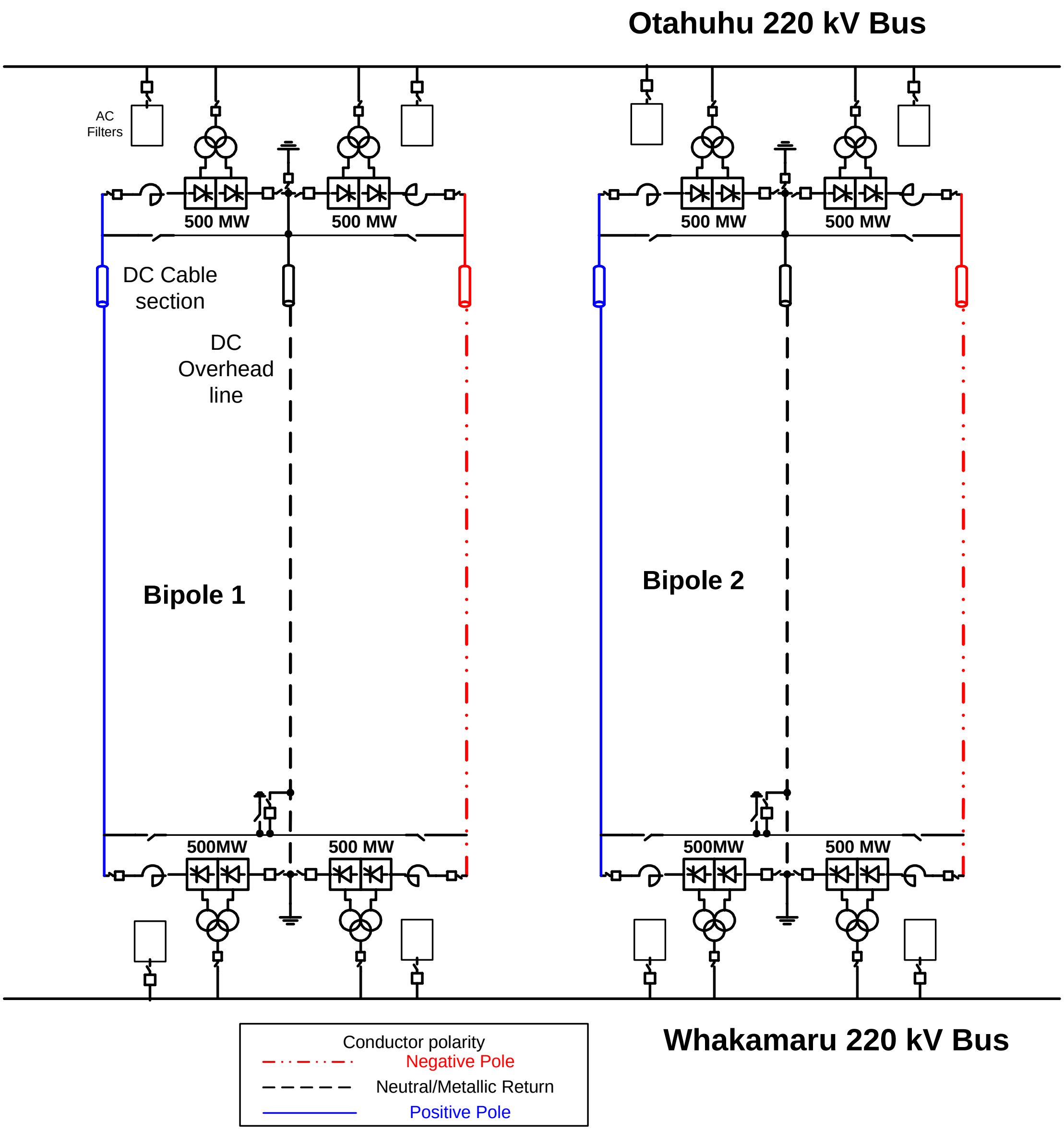


Figure 3-13: Schematic for 350 kV HVDC Transmission Link Between Whakamaru and Otahuhu

Establishing a 350 kV double bipole HVDC link between Whakamaru and Auckland was assessed follows:

3.10.1 System Security

The HVDC option described above provides sufficient capacity to maintain supply security into the Auckland region in a level comparable to that provided by all HVAC transmission options.

3.10.2 Asset Availability

Considering the transmission lines in isolation (i.e. apart from the terminal equipment), the double bi-pole HVDC transmission line is likely to have an equivalent availability to that offered by the proposed 400 kV HVAC transmission line.

However, the AC-DC-AC converter stations do not provide the same reliability as 400/220 kV HVAC transformers. Converter stations are inherently complex and contain a large number of components which can contribute to partial or total converter station failure. Further, there are a significant number of items common to both poles of an HVDC bi-pole scheme, leading to increased risks of common-mode failures.

In summary, the HVAC system will provide an overall higher level of asset availability and therefore system reliability into the Auckland region. While HVDC remains a potential fit for purpose solution, the risks of reduced reliability - in particular converter station failure - must be taken into consideration in the decision making processes.

3.10.3 Economic Benefit

Because of the high capital investment required for HVDC converter stations, development of the converter capacity in several stages as described above will provide significant economic benefits.

However, even with the staged development, when the net present value of the HVDC versus HVAC costs are considered, the HVDC solution is found to be significantly more expensive compared to the HVAC options.

3.10.4 Environmental Feasibility

The DC option operates at 350 kV and thereby offers similar advantages to the 330 and 400 kV AC voltage options in terms of the overall number of transmission line routes. Tower numbers are also likely to be similar.

Although both the AC and DC options will be required to comply with ICNIRP guidelines pertaining to electric and magnetic fields, overall levels from DC lines enable reduced height of towers compared to equivalent voltage AC options. Visual effects (and associated effects on tourism and recreational values), although subjective, would arguably be less than the AC option.

The DC technology also requires increased density of structures at Whakamaru and Otahuhu, with associated effect on local amenity. Adverse effects of such termination structures are site specific and can most likely be mitigated within existing industrial landscapes at Whakamaru and Otahuhu sites.

3.10.5 Timing

HVDC systems are inherently complex and need to be designed carefully, taking into account the variability of the operating conditions and the dynamic performance of the connected power system. Typically, the lead time for construction, form the time of awarding the contracts, ranges from 3 to 4 years. However, the developments are also associated with significant pre-tendering technical investigations and therefore the total lead time required would be in the order of 5 – 6 years.

Therefore, if HVDC developments are to be used for providing the supply security to the Auckland region by 2010, investigation and construction time needs to be significantly compressed. Such expediency will result in significant commercial and technical risks to the development project.

3.10.6 Flexibility

HVDC options provide less flexibility for future grid expansion and will continue to be associated with higher level of capital investments compared to the HVAC options.

One significant disadvantage of the HVDC options is that, once an HVDC link is established, the opportunities for “tapping off” (i.e connecting) at different points in order to accommodate future grid developments become very limited. At present, it is the generally accepted view that HVDC transmission linking more than three terminals is not technically sound. While a point-to-point HVDC link can be augmented at a significant cost to make a three terminal link for tapping off at a single point between its original terminals, it does not allow for any further tapping off.

In a future with deregulated generation investments, whose locations are significantly uncertain, such a limitation in the flexibility of making new connections to the grid is a significant concern.

3.10.7 Conclusions

Overall, the adoption of an HVDC transmission backbone would deliver a more expensive, less reliable and relatively inflexible transmission system in the long run than a National Grid supported by an interconnected HVAC transmission network. More details of this analysis are contained in the supporting document titled “Comparison of HVDC and HVAC Grid Upgrade Alternatives – May 2005”.

3.11 HVDC Link between Whakamaru and Otahuhu – HVDC Light Configuration

This option uses voltage sourced converters consisting of insulated gate bipolar transistors (IGBT) as switching devices rather than thyristors. The power handling capability of IGBTs is not as large as thyristors and with present technology the Pole capacity is limited to a maximum of about 330MW.

At present technology limitations also require underground cable(s) for the entire length of transmission link.

Similar to HVDC Classical option the transmission capacity of HVDC light option can be increased in several stages. The circuit configurations for a two stage development are shown in Figure 3-14.

HVDC Light also has the advantage over the HVDC Classic option that converter stations are more compact due to the reduced size of filters. However, the disadvantages are that converter losses are much higher due to higher switching frequencies compared to classic HVDC, and the higher transmission losses due to a lower DC operating voltage.

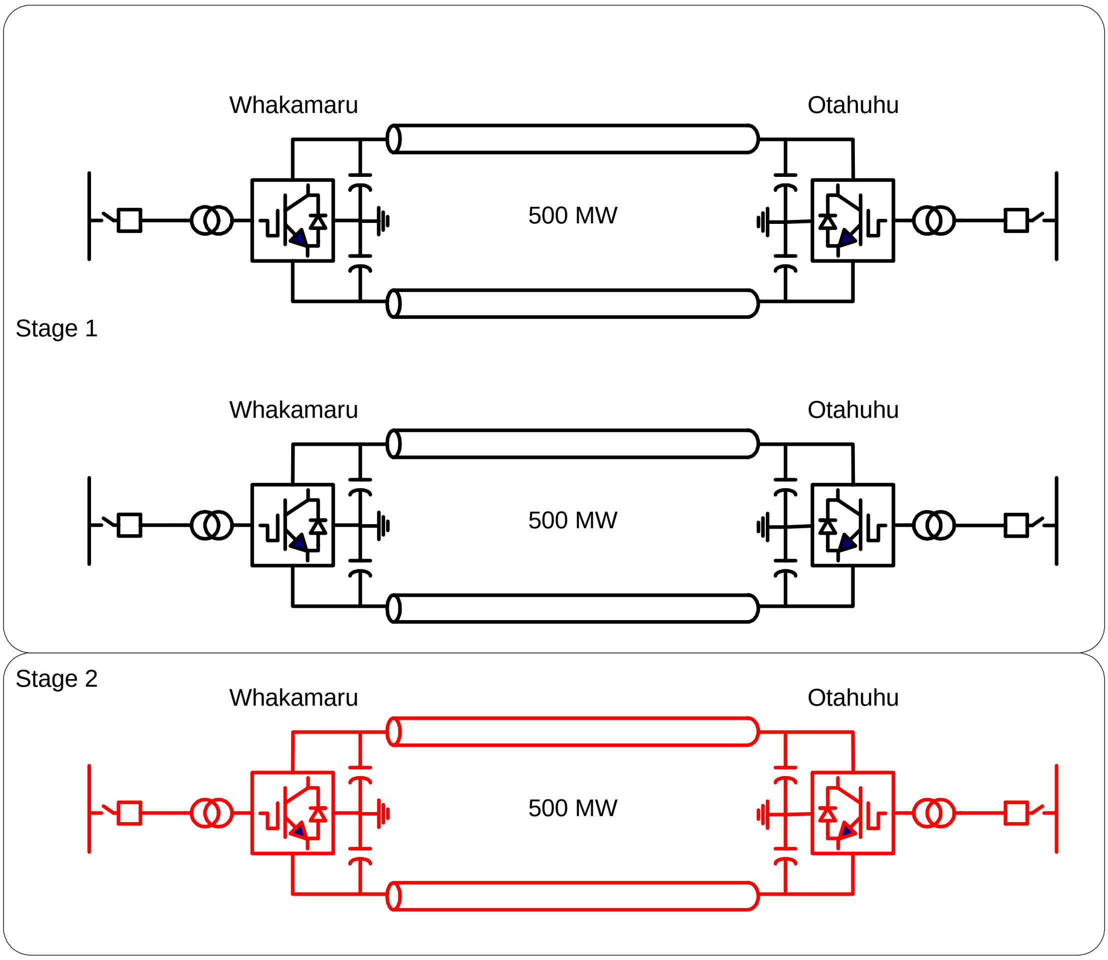


Figure 3-14: Circuit Configuration Stages 1 & 2 HVDC Light Transmission System 1000 MW Firm

Stage 1

- Installation of 2 x 500 MW converters in year 2010

Stage 2

- Installation of 1 x 500 MW as required under the corresponding generation scenarios.

Establishing a HVDC Light between Whakamaru and Auckland was assessed follows:

3.11.1 System Security

The HVDC light option configuration as shown in the above figure will provide (n-1) security to the Auckland load, at a level of reliability similar to that provided by the HVAC options.

3.11.2 Asset Availability

With the present state of technology, the HVDC Light option can only work with underground cables and the maximum operating voltage is below 200 kV thus requiring many cables. This means total undergrounding with multiple cables and multiple routes.

Underground land based cables are not as reliable as overhead lines options due to the large number of joints in land cables and the substantial mean time to repair any cable failures. The number of joints is high due to the practical length of cable sections that can be transported and installed using vehicles in New Zealand in roads. Furthermore, fault location and repair times would generally be higher than for overhead conductors.

3.11.3 Environmental Impact

The HVDC Light option is visually very attractive due to the entire length of line being undergrounded. Converter stations can be compact (as compared with the Classic HVDC options). This means that the land area required for the converter stations may be less than for the classic HVDC options.

Potential adverse impacts of HVDC light option are similar to other underground cables, including earthworks and vegetation removal during the construction phase, and longer term requirements to maintain areas along the cable length free of vegetation.

3.11.4 Timing

Implementation of the HVDC Light option will require a typical of 28-36 months to complete, from the date of issuing a contract. A full length cable solution will involve an easement acquisition process and cable installation, which will likely to take a longer time than the construction of overhead transmission lines.

3.11.5 Future Flexibility

HVDC light can be applied as a new link at any time in the future. However to meet N-1 security levels and a level of reliability comparable to the HVAC options it is probable that any new link to another location would need to be duplicated. This increases costs, and given the already high cost of converters, cables and losses make it unlikely that new HVDC Light links would be attractive.

3.11.6 Economic Benefits

The cost of HVDC Light transmission development must consider the cost of undergrounding the cables over the total length of the route. The cost of supply of HVDC light cables is estimated to be in the order of $224 million per 500 MW HVDC Light link. The installation cost is expected to be more than the cable cost since trenching rather than ploughing would be needed. Thus for three HVDC Light links, the total installed cost of cables and converters would be approximately over $2.1 billion.

3.11.7 Conclusion

Overall, the adoption of an HVDC light transmission backbone would deliver a very expensive and unreliable transmission system in the long run than a National Grid supported by an interconnected HVAC transmission network.

3.12 Underground Transmission Options

Extra high voltage (EHV) cables are increasingly being used worldwide to supply electrical power for large cities and metropolitan areas. This is due to the increasing difficulty in obtaining overhead transmission line routes through high density built up areas. Other special reasons include, entry to substations, crossing other overhead lines, safety reasons at airports, land value enhancement and social/environmental concerns which require undergrounding.

Transpower has investigated a range of issues associated with partial or complete undergrounding of the proposed 400 kV AC transmission link between Whakamaru and Otahuhu substations.

3.12.1 Reliability

The reliability of the underground cable systems (for 220 kV and above) was investigated and compared with the overhead transmission in terms of expected performance including failure rates, outage times and availability due to forced outages.

If the present grid availability is to be maintained then the failure rates and outage times for 400 kV links would have to be to be equal to or better than those for the existing 220 kV lines.

There is a very high level of uncertainty in the estimation of the failure rates for 400 kV cables because of the small number of circuit kilometres installed and recent changes in technology with the introduction of XLPE type cables at this voltage. Repair times for faults on cables, joints and terminations are much longer than for overhead lines and at best will take between 10 and 19 days. This assumes that the contracting cable jointers would be immediately available from overseas, that spares were immediately available in New Zealand and the site is accessible and fault easily located.

Even with optimistic assumptions on failure rates and outage durations the availability of a 400 kV cable circuit will be significantly worse than for an overhead line when transmission over long distances is concerned. The expected levels of reliability are far too low to consider a complete underground cable system between Whakamaru and Otahuhu is a feasible transmission option.

3.12.2 Economic Benefit

Financial cost of underground transmission between Otahuhu – Whakamaru would be significantly expensive compared to overhead transmission. The costs would be in approximately 10:1 ratio. The costs are further increased by the need to provide intermediate stations at approximately 50 km intervals along the cable route for cable charging current compensation.

Operation and maintenance of such an underground cable system will depend on availability of skilled cable jointers and specialised equipment. Therefore, operating costs would also be significantly higher compared to overhead transmission.

3.12.3 Environmental Feasibility

The environmental impacts of underground cables are most obviously associated with short term effects during the construction phase. These include earthworks, vegetation removal and general construction nuisance. Longer term effects are limited to the need to maintain areas without vegetation along the cable length. Selection of a cable route that avoids sensitive ecological and social environments is equally relevant to cable locations as overhead lines. As with overhead cables, public exposure to electrical and magnetic fields will be required to comply with ICNIRP guidelines.

While, the visual impact of underground transmission is minimal, easements need to be maintained throughout the route and loss of use of land (at least partially) can not be avoided.

3.12.4 Timing

There would be a longer lead time in manufacturing and procuring long lengths of cable. Availability of skilled cable jointers and specialised equipment for installation will also slowdown the progress of the project compared to building an overhead line.

Therefore, it is unlikely that an underground installation can be completed in time (i.e. 2010) for ensuring the security of supply to Auckland load.

3.12.5 Flexibility

Compared with overhead lines, operational issues associated with cable transmission such as, the need to match compensation with load and harmonic impedance resonance problems exacerbated by the higher capacitance of cables, could significantly limit the operational flexibility of a long underground transmission system compared to overhead transmission.

3.12.6 Conclusion

A review of available information and advice from its consultants confirm Transpower’s views that installing underground cables at 400 kV AC from Whakamaru to Otahuhu is not a technically fit-for-purpose solution. The reliability of the underground cable route is far less than what is required for a high security backbone of the core grid.

The cost of undergrounding will also be substantially higher than overhead. Transpower estimates that underground cabling would be approximately ten times the cost of overhead line.

3.13 Summary of Transmission Options

The following summarises the results from the assessment of transmission options:

220 kV AC

220 kV HVAC development could meet the future demand growth in the North Island and would be a credible approach for the future long term development of the core transmission grid in the North island. However, 220 kV development would require a number of transmission lines to be build, especially between Whakamaru and Auckland under some generation scenarios. Given the difficulty in obtaining transmission corridors for building new lines, and considering the environmental impact, the ability to implement such a plan in long term is a concern.

330 kV AC

Conversion of the existing 220 kV lines to operate at 330 kV will require significant changes to the construction of the existing towers, foundations and replacement of the existing conductors. Significant outages would also be required which would place security of supply to the upper North Island at risk. On this basis conversion of existing lines is considered impractical and new lines would be required to be constructed to carry any new 330 kV infrastructure. If new lines are to be built, system studies have shown that the increase in voltage does not provide a substantial change in the number of additional lines required, particularly into the upper North Island. Transpower therefore considers that migration of the core network to 330 kV is too low for to provide sufficient technical and economic benefits to warrant further consideration.

400 kV AC

400 kV HVAC development could meet the future demand growth in the North island and would be a credible approach for the future long term development of the core transmission grid in the North island. A 400 kV development option would enable the future core grid transmission requirements to be met using substantially fewer lines than 220 kV and 330 kV options.

500 kV AC

500 kV HVAC development could meet the future demand growth in the North island and would enable the future core grid transmission requirements to be met using only a few lines. Although 500 kV is a viable transmission voltage it provides significant transmission capacity in excess of that required for most of the transmission corridors in the North Island within the planning horizon. Furthermore it has no advantages over a 400 kV solution but it has a number of disadvantages. Consequently, 500 kV is not considered as the preferred voltage for future development of the New Zealand transmission system.

HVDC

An HVDC link was considered as a transmission alternative to high voltage AC options, but the lower reliability, the inflexibility for future developments and higher costs of the HVDC make the high voltage AC options a more suitable option.

Underground Cables

A review of available information and advice from its consultants confirm Transpower’s views that installing long lengths of high voltage underground cables from Whakamaru to Otahuhu is not a technically fit-for-purpose solution. The reliability of the underground cable route is far less than what is required for a high security backbone of the core grid and the cost of undergrounding will also be substantially higher than an overhead option.

4 Alternatives to Transmission

The EGRs define the term “alternatives to transmission” as:

“ :*alternatives to investment in the grid, including investment in local generation, energy efficiency, demand-side management and distribution network augmentation…”*

Transpower has considered the following four broad categories of alternatives to transmission as part of its analysis of the proposed 400kV AC investment:

- electricity substitutes
- generation alternatives
- energy efficiency alternatives
- demand-side management alternatives

These four categories are described below:

4.1 Electricity substitutes

Natural gas reticulation is an example of an electricity substitute.

On a smaller scale (e.g. by increasing domestic reticulation) gas could defer transmission, but in some situations (e.g. when building a new industrial plant) gas could be used instead of transmission. To be considered as a feasible transmission alternative for the upper North Island, Transpower notes that future gas supplies would need to be certain and gas transmission infrastructure would need to be augmented to deal with the significant increase in volume. Future gas supplies are not certain and there are no committed projects to switch consumers from electricity to gas, so Transpower considers that this cannot be relied upon as a transmission alternative.

Transpower has neither the information nor expertise to properly evaluate natural gas reticulation, or other electricity substitutes. Therefore they are not discussed further in this document.

4.2 Generation Alternatives

The potential for large scale base-load generation plant to be a transmission alternative is assessed by considering the market development scenarios. For more specific generation proposals, Transpower used a Request for Information (RFI) process to obtain details of proposals directly from the industry. More detail on the RFI is included in Section 4.5.

The market development scenarios include various views of the major base-load generation plant that may develop in the future, including in the upper North Island.

Because the scenarios have been developed to represent the extremes of likelihood, it is assumed that at least some of them reflect the maximum amount of new generation that is likely to appear in the upper North Island. The market development scenarios include the following new generation:

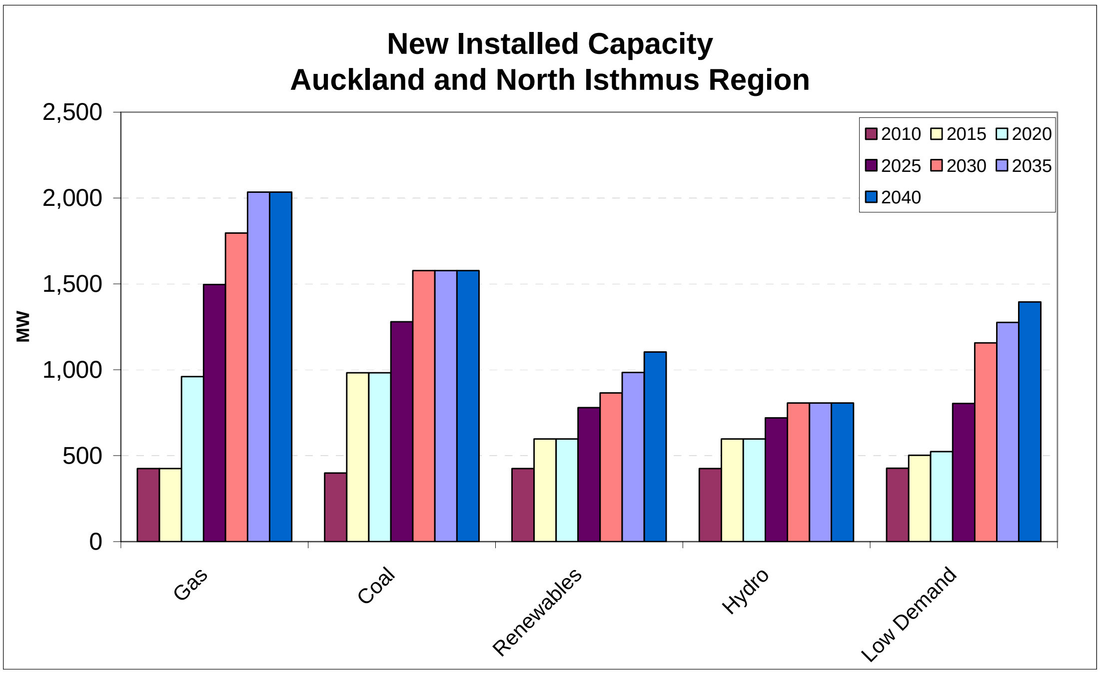


Figure 4-1: Cumulative new generation in the upper North Island

As a first step, the amount of demand growth that is forecast to be unserved in the upper North Island was calculated. The following assumptions were made in the calculations:

- Demand growth is between the low and high growth estimates
- The maximum load capability in the Auckland region is 2285MW
- New generation is commissioned according to the market development scenarios and is available for dispatch at a de-rated capacity to allow for planned maintenance outages, in the case of thermal plant 84% of installed capacity rating was assumed and in the case of wind generation35% of installed capacity rating was assumed to be available.

This results in the following estimates of unserved energy for each market development scenario:

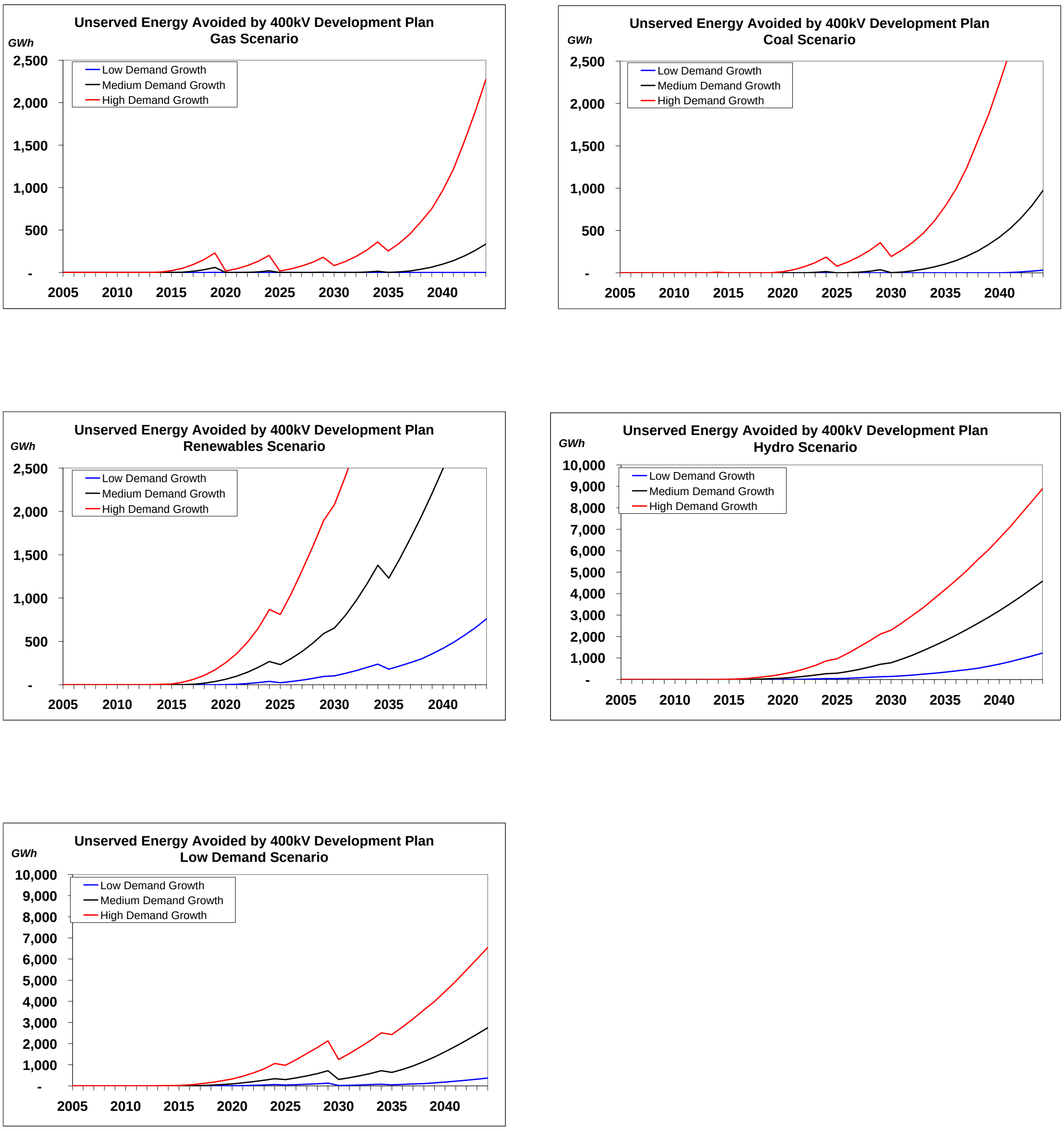


Figure 4-2 – Graphs of unserved energy per market development scenario

As can be seen, there is unserved energy in all of the scenarios, indicating that there is insufficient new generation emerging in the upper North Island to meet the forecast demand growth.

Accepting that the market development scenarios represent reasonable extremes of the potential new generation in the area, it can be concluded that large scale base-loaded generation has already been considered as part of the analysis and cannot be considered as a transmission alternative as well. This conclusion is also tested economically in Section 1, where the cost of installing new transmission to avoid the unserved energy is compared to the value of the unserved energy itself.

As a comparison, the same calculations have been undertaken using the Electricity Commission’s market development scenarios, as published in their draft Statement of Opportunities[18]:

---

[18] Initial Statement of Opportunities, Draft for consultation, May 2005

Their market development scenarios include the following new generation:

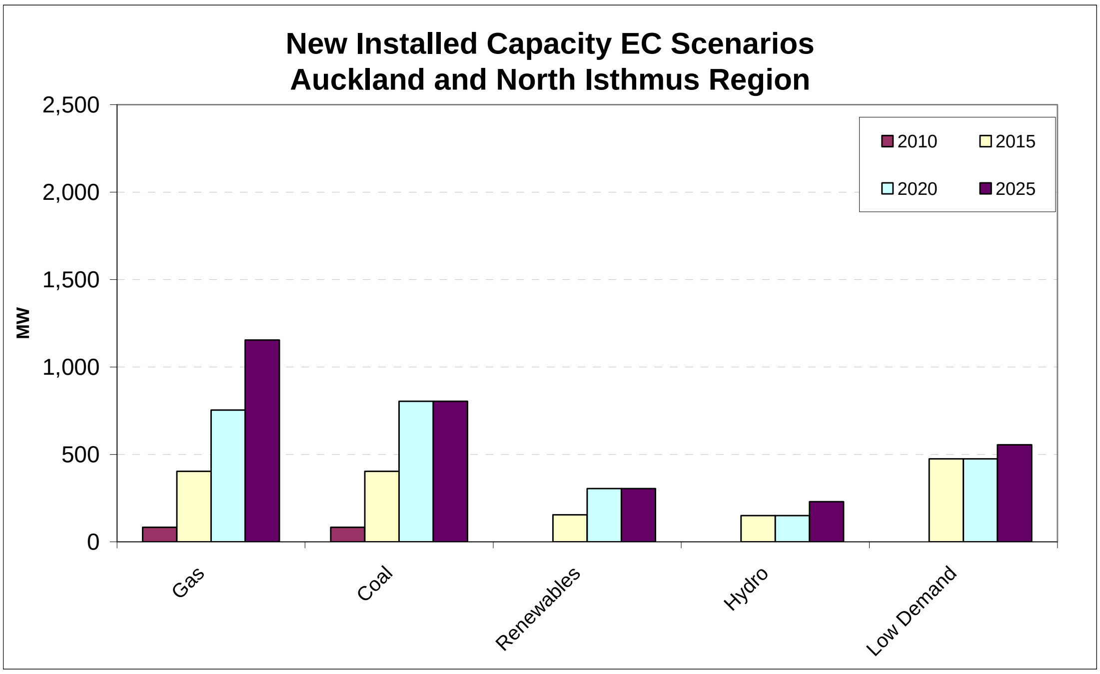
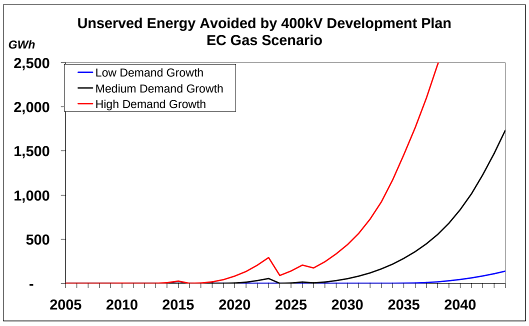
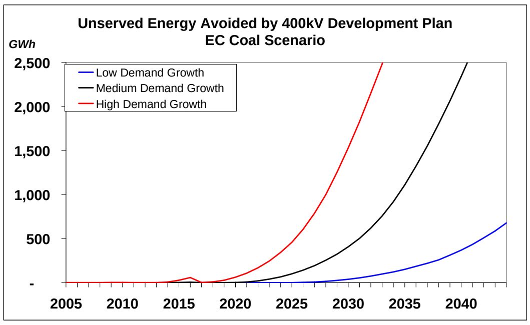
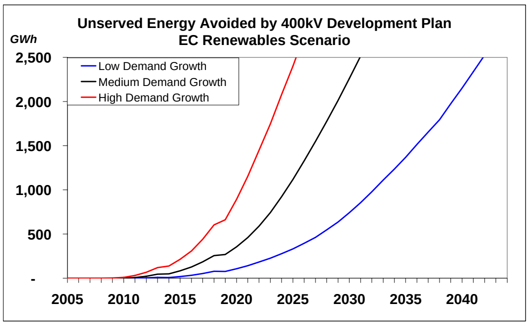


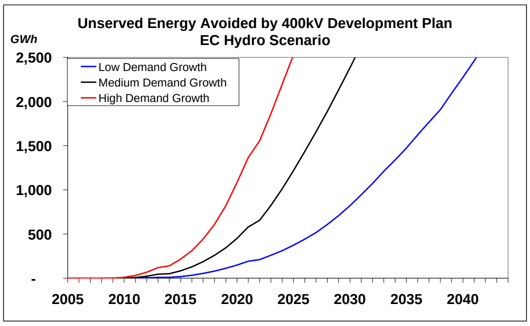
Figure 4-3: Cumulative new generation in the upper North Island in the Electricity Commission scenarios

This new generation results in the following estimates of unserved energy for each of the Electricity Commission's market development scenarios:









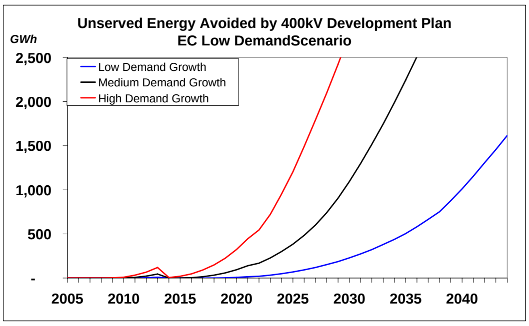


Figure 4-4: Graphs of unserved energy per market development scenario for the Electricity Commission's scenarios

As can be seen, the Electricity Commission scenarios reflect even less new generation appearing in the upper North Island than the Transpower scenarios and the same conclusion can also be drawn i.e. that large scale base-loaded generation cannot be considered as a transmission alternative as it has already been considered in the analysis.

4.3 Energy Efficiency Alternatives

Energy efficiency as an alternative to transmission is taken into account by sensitising demand forecasts. Energy efficiency initiatives tend to lower demand overall, and this is already captured in Transpower's demand forecasting models (see Part II). If energy efficiency initiatives are more economic than transmission, the expected net market benefit for low demand growth would be negative.

4.4 Demand Side Management Alternatives

Demand-side management alternatives are initiatives that take place on the distribution side of the power system. They are not otherwise captured in Transpower's analysis and together with generation proposals they have formed the subject of a Request for Information that Transpower sought from the electricity industry.

4.5 Request for Information document

Transpower's approach to determining the alternatives to transmission that have a reasonable likelihood of occurring, was to issue a Request for Information (RFI) document, seeking information on potential alternatives to transmission from interested parties.

The document was published in September 2004. A full copy of that document is available as a supporting document to this proposal.

In brief the RFI:

- described the regulatory requirement for considering alternatives to transmission
- described the process to be followed
- outlined the existing transmission system
- listed the existing generation in the upper North Island
- outlined Transpower's demand forecasts for the upper North Island
- described Transpower's grid planning criteria
- provided information on the energy shortfall and seasonality requirement that alternatives to transmission would need to meet in order to defer investment in transmission
- listed the criteria that transmission alternative proposals would be assessed against

4.5.1 Submissions received in reply to the RFI

A summary of the submissions received in reply to the RFI is included in the table below. To maintain confidentiality requested by some proposers, the submissions have been generalised. The table includes a list of the types of proposal received and the potential peak MW reduction on load if the proposal were implemented.

Alternatives to transmission	Approximate potential peak MW reduction (*)
Energy efficiency alternatives	
Range of general demand reduction initiatives that promote more efficient use of electricity.	150-300 MW
Peak Demand Management Programmes	
Demand bidding & communication programmes to target peak demand reductions.	150-250 MW
Generation alternatives	
Peaking and base load plant.	150 MW

(*) as estimated by the submitters

Table 4-1: Summary of submission types received in reply to the RFI

4.5.2 Application of initial screening process

The submissions were initially evaluated using a set of screening criteria developed by Transpower. These screening criteria supplanted the criteria outlined in the RFI document and served to eliminate several of the submissions which would not be useful as alternatives to transmission in practice.

The screening criteria require that, in order to be evaluated further, a transmission alternative must:

- result in peak MW load savings
- have reasonably guaranteed peak MW load savings

- defer the need for transmission investment by 12 months or more

The basis for these criteria is discussed below.

4.5.2.1 Would the proposal result in peak demand savings

Transmission is planned and implemented in a way that it enables demand to be met during peak load times. Any transmission alternative must therefore deliver a reduction in the peak demand required to be delivered by the transmission system during these critical peak load times.

For example, alternatives that offer general energy savings but do not reduce the peak demand on the transmission system were not considered as viable transmission alternatives as they do not provide the same peak loads in an area may occur on a daily basis between 7:00-7:30 am and 6:30-7:00 pm. An alternative which reduces load at say, midday, but which does not reduce the load during peak times, would not defer the need for transmission and therefore is not considered further.

Some of the proposals are based on demand reductions at off-peak times and as such they cannot be considered transmission alternatives in this case.

4.5.2.2 Are the peak demand savings reasonably guaranteed

One of Transpower's primary planning concerns is ensuring the transmission network will deliver a secure supply of electricity, in accordance with Transpower's transmission planning criteria, during times of peak demand.

In that regard, only those transmission alternative proposals where the forecast peak MW load savings can be reasonably guaranteed, were considered further.

Peaking generation plant, is an example of a transmission alternative which would meet this need. Presuming it is contracted as a transmission alternative, Transpower would advise the generator when to run, hence (reliability of the generating plant aside), Transpower can guarantee the peak MW load savings would be made.

Some of the transmission alternative proposals rely on demand response to price signals, which may reduce demand at peak times, but may not, depending on the preferences of the consumers concerned. On a particularly cold day, for instance, consumers may decide to consume "normal" levels of energy, irrespective of the cost and hence the peak MW load savings would not be realised. The peak MW load savings are too uncertain to reply upon from a security of supply point of view and therefore they cannot be considered alternatives to transmission.

4.5.2.3 Would the transmission alternative defer the need for transmission investment by one year or more

In the context of a six year transmission project, only those proposals that provide a substantial deferral of transmission plans can be considered as viable alternatives to transmission. With the risks that are associated with the current project timetable, only those proposals that defer the need for transmission investment by one year or more were considered further.

Application of the screening criteria resulted in the following outcome:

Transmission alternatives	Are there peak MW savings	Are the peak MW savings certain	Defer transmission for 12 months or more
Energy efficiency alternatives			
Range of general demand reduction initiatives that promote more efficient use of electricity.	?	?	×
Peak Demand Management Programmes			
Demand bidding & communication programmes to target peak demand reductions.	?	?	?
Generation alternatives			
Plant targeted at generating at during peak load times.	✓	✓	✓

Table 4-2: Application of Screening Criteria to Alternatives to Transmission

Energy efficiency initiatives were ranked low due to the fact that the initiatives could not provide reasonable certainty of providing the necessary demand reductions at time of peak load which is required for transmission investment deferral. The implementation path also is unclear and is reliant on consumers adopting certain technology and then continuing to use that technology for the long run.

Peak demand management initiatives were considered more likely to deliver the demand reductions at the time that they are required to defer transmission investment. However the implementation of such a system is unclear in terms of the quantity of benefits available and whether these would continue to be available during peak load times year on year. Transpower has commissioned work from independent consultants to investigate the feasibility and implementation strategy for such a system.

Therefore only the generation plant designed to operate at peak load times met the screening criteria and was considered further using cost/benefit analysis in Part IV of this submission.

4.6 Alternatives to Transmission Summary

According to the market development scenarios developed both by Transpower and the Electricity Commission, there is insufficient new generation emerging in the upper North Island to meet the forecast demand growth. On the basis that these scenarios capture the reasonable extent of generation possible in the region, additional large scale base-loaded generation cannot be considered as a realistic transmission alternative.

Transpower assessed the potential transmission alternatives not reflected in the market development scenarios, using a RFI process. Of the alternatives offered through the RFI process, only generation peaking plant is considered viable and further analysis is undertaken on peaking plant, using cost/benefit analysis, in Part IV of this submission.

Appendix III-A – Environmental Analysis & Process

Each of the transmission options will require a new transmission line extending from Whakamaru to Otahuhu, as well as substation investment at each termination location. This will require resource consents and designating the length of the route pursuant to the Resource Management Act 1991 (RMA). Potential adverse environmental effects of such a project are varied and may include, amongst others:

- Safety and health effects (associated with electric and magnetic fields)
- Social effects (disruption to communities).
- Property values (financial costs resulting from social effects – this issue is considered separately)
- Visual effects
- Effects on tourism and recreational values
- Impact on sites of ecological significance or heritage value
- Effects on cultural values
- Effects on existing infrastructure – including transmission lines and roads.
- Impact on land use (including disruption to agricultural activities as a result of the establishment of new structures).

Until a final centre-line of the preferred transmission route is known, it is not possible, or appropriate to identify the full environmental effects of each transmission option. Analysis of the preferred option is considered in detail during the Resource Management Act process, it is not expected to be relitigated outside that framework.

Transpower has developed the Area, Corridor, Route and Easement (ACRE) process which will be utilised to identify (through analysis) the final line easement location and any other mitigation measures to best manage adverse environmental effects of a transmission solution.

The model is designed to enable Transpower to secure designations and property rights for any new-build grid augmentation in a robust framework that meets the legislative requirements of the key statutes – the Resource Management Act (RMA), the Electricity Act and the Public Works Act (PWA) while also incorporating best environmental practice. The key stages of ACRE are noted below:

A = Identification of study 'Area' and environmental/social/engineering constraints and opportunities analysis mapping
C = Identification and confirmation of alternative 'Corridors' (500m to 5 kilometre wide corridors) ranking and selection of preferred corridor
R^{i} = Selection and evaluation of alternative 'Routes' within the confirmed corridor and public presentation (for consultation)
R^{ii} = Route confirmation following consultation.
E = Identification and confirmation of 'Easement' centre-line and designation boundaries (including ongoing consultation)
D = Documentation – preparation of full documentation and notices of requirement and resource consent application.
S = Statutory – lodgement of notices of requirement and resource consent applications, Council hearings, Transpower decision, Environment Court

appeal process, (if required), and mediation, leading to confirmation (or otherwise of designation.

The model is generic and is readily adaptable to the various transmission options (220, 330, 400 kV etc.).

Detailed environmental analysis of each of the Area, Corridor and Route stages for the 400 kV option is available as separate reports. They provide the justification for identification of the two route options currently being consulted on, and more latterly the preferred interim route decision.

When deciding between transmission options, it is, however, possible to identify and assess broader environmental parameters that make one transmission option more preferable than another. For example, lower capacity lines will require greater numbers of transmission lines to transfer electricity. Furthermore, options that are able to utilise the location of existing transmission lines or substations within a similar envelope of environmental effects[19] (visual, acoustic, social, ecological etc.) are more preferable than options which require a new 'greenfield' location.

Site specific impacts of the various transmission options can be evaluated, to a limited extent, on the basis of average tower height. Tower height determines visual impact and also provides a useful proxy for potential impacts on site-specific issues identified above. Tower height is a function of compliance with electric and magnetic field limits contained in ICNIRP guidelines. It will, therefore, also provide an indication of the likely perceived health concerns of the transmission option.

In this section, for each transmission option, the environmental effects are considered on the basis of potential visual effects and the likelihood of any additional lines within the foreseeable future. This analysis is presented for comparative purposes only. It merely attempts to outline the primary differences between each transmission option to enable the extent to which mitigation will be required, and thus the potential for securing environmental approvals and associated costs (both of mitigation, and any further investigations). In so doing, it is noted that visual effects (and each of the other issues previously identified) are subject to the environment within which they are located and thus not absolute. It is not possible to draw any firm conclusions from this analysis until RMA processes are resolved.

---

[19] The options identified do not provide opportunity for this scenario and are not considered further.

Appendix III-B North Island Tactical Transmission Upgrade Project Summary

A number of tactical transmission upgrade projects are planned to be implemented in the North Island before 2010. A summary of these projects is as follows:

Region	Grid Upgrade Project	Capacity	Description
Auckland and North Isthmus	Increase the operating temperature of the Huntly - Otahuhu section of Otahuhu - Whakamaru C 220 kV line	671/614 MVA	Reduces constraints on Huntly Generation and increase thermal capacity into Auckland
	Thermal upgrade of Otahuhu - Whakamaru A&B lines	323/293 MVA	Increases the thermal capacity into Auckland
	Thermal upgrade of 220 kV Otahuhu-Penrose 5&6 circuits	492/469 MVA	Increase the capacity of the existing 220 KV Otahuhu-Penrose 5&6 circuits
	Thermal upgrade of 220 kV Otahuhu-Henderson circuits	984/938 MVA	Increases the capacity of both existing 220 KV Otahuhu-Henderson circuit
	Shunt capacitors at Penrose 110 kV	2x50 Mvar	Increases the transfer limit until the Huntly E3P unit is commissioned in 2007
	Shunt capacitor at Hepburn Road 110 kV	1x50 Mvar	Increases the transfer limit until the Huntly E3P unit is commissioned in 2007
Wellington	Increase the operating temperature of the Bunnythorpe- Haywards A&B 220 kV line	335/307 MVA	Increase transfer south to Haywards from 640/760 MVA to 920/960 MVA
Central North Island	Increase the operating temperature of the Tokaanu - Whakamaru A&B 220 kV lines	335/307 MVA	Increases the thermal limit between the Central North Island and the bay of Plenty region
	Thermal upgrade of the Rangipo-Wairakei 1	370/333 MVA	Increases the thermal limit between the Central North Island and the bay of Plenty region
	Thermal upgrade of the Wairakei-Pohipi-Whakamaru 220 kV circuits	448/421 MVA	Increases the transmission capacity in Wairakei ring
	Thermal upgrade of the Bunnythorpe-Tokaanu 1&2	335/307 MVA	Increases thermal limit of the Central North Island core grid corridor

North Island 400 kV Upgrade Project

Investment Proposal

Part IV – Cost Benefit Analysis

TABLE OF CONTENTS

1 Summary

This Part IV sets out the cost benefit methodology used to assess the proposed investment. This methodology is consistent with the Electricity Commission's Grid Investment Test. The cost benefit analysis demonstrates the following conclusions.

A long run development plan for the transmission network at 400 kV is more economic than continuing with incremental augmentation at 220 kV. The expected net market benefit of a 400 kV development plan over a 220 kV development plan is estimated at $133 million. Therefore 400 kV is the most economic choice for the main backbone voltage of the National Grid.

There are substantial benefits in implementing transmission augmentation when compared to a "do nothing" alternative which allows only for that generation anticipated in either Transpower's or the Electricity Commission's draft generation scenarios to be established.

The proposed investment has a substantially higher expected net market benefit than the best case transmission alternative of a diesel fired peaking plant. The expected net market benefit (cost) of a diesel fired peaking plant ranges between -$130 and -$240 million.

In summary the proposed investment based on the construction of a 400 kV double circuit transmission line between Whakamaru and Otahuhu is the most economic alternative to provide long run security of supply into the upper North Island and satisfies the requirements of the Grid Investment Test.

2 Cost/benefit analysis approach

The cost/benefit approach used for this analysis is consistent with the Grid Investment Test as required for investment proposals submitted to the Electricity Commission under the Grid Upgrade Plan provisions of Part F of the Electricity Governance Rules.

2.1 *Defining the base case*

Transpower's current Grid Reliability Standards specify a deterministic criterion which is widely used by electricity transmission businesses in many parts of the world.

The Grid Reliability Standards require that Transpower maintain the core grid to an N-1 standard as discussed in Part II of this submission. Under this criterion, it is necessary only to compare developments which are technically feasible and will, at a minimum, satisfy the deterministic standard.

This contrasts with the purely economic approach which would require a value to be ascribed to unserved load. Using such an approach, the base case would include market development scenarios which include expected new generation and which reflect expected demand growth, but which do not include new transmission development (that is a "do nothing" base case). The economic justification for transmission development would then depend upon maximising the economic benefit of the proposed new transmission investment by reducing the extent of the unserved load in the particular region under consideration.

In developing its generation scenarios, Transpower assumes that new generating capacity will continue to be installed to meet electricity requirements throughout New Zealand. The generation scenarios are intended to provide Transpower with a basis for proposing grid augmentation for a range of plausible generation developments.

The base case for analysis of the transmission options implicitly assumes that sufficient generating capacity will be installed to meet the overall standard of a 1 in 60 year severity of a “dry year”.

Since 220 kV is the current core grid voltage, the base case used for this analysis includes expected demand growth, expected new generation, and continued development of the grid at 220 kV to satisfy the Grid Reliability Standards for each of the nominated generation scenarios.

2.2 Costs considered

All costs included in the cost/benefit analysis are estimates in 2005 New Zealand dollars i.e. they do not account for inflation and a “real” discount rate is used. However, special provision is made for the assumption that the costs of acquiring property rights and easements will escalate at 1% above the average inflation rate.

Since the cost/benefit analyses are all comparisons of technically feasible alternatives (including alternatives to transmission development such as distributed generation) only those costs which vary between the cases need to be included in any comparisons. The costs of maintaining the existing grid, for instance, are not included because they remain unchanged whichever case is being analysed.

The costs included in the analysis are summarised in this section. Part V of this submission provides further information about the estimated costs for the proposed 400 kV reliability investment.

2.2.1 Capital costs

The capital costs for the transmission options comprise estimates of the cost to design, purchase and construct new transmission assets (eg transmission towers, conductors, substation equipment). The approach used to determine these cost estimates and their estimated range over which the results are sensitised, is described in section 3.

For alternatives to transmission, publicly available cost information has been used and the source is referenced.

2.2.2 Operating and maintenance costs

Costs in this category are estimates of the costs of operating and maintaining either the transmission assets or alternatives to transmission relevant to each case.

2.2.3 Dismantling costs

Dismantling costs are the estimated costs of dismantling and removing assets that are no longer required. These costs are “net”, being the cost of dismantling less any scrap value realised from the sale of recovered material.

2.2.4 Property and easement costs

These are the costs of securing the property rights needed for new or altered transmission assets, or alternatives to transmission. These costs include the costs of purchasing land and easement rights.

2.2.5 Approval process costs

These are the legal and administrative costs of obtaining approval for the proposed reliability investment. The costs include satisfying the requirements of the Resource Management Act 1991, the Electricity Act 1992, the Public Works Act 1981 and other relevant legislation.

2.2.6 Project management costs

These are the costs associated with project managing the build of new assets. A standard value of 8% has been used, which includes a mixture of Transpower’s internal and external costs.

2.3 Benefits or costs evaluated

The following benefits or costs which are relevant to the comparison of alternatives have been considered in completing the cost/benefit analysis:

2.3.1 Avoidance of unserved energy

Differences in the level of unserved energy between the base case and each scenario have been quantified in MWh where relevant. The unserved energy has been calculated taking into account the generation available in each of the generation scenarios. Unserved energy has been valued at $20,000 MWh.

2.3.2 Energy loss differences

Any investment in transmission augmentation will generally reduce the extent of energy losses. The reduction in losses is a benefit which is quantified and valued.

Transpower has applied different values for such loss reduction recognising that transmission augmentation may serve to carry base load power flows or incremental power flows. Base-load loss differences are valued using the long run marginal cost which includes a capital cost for additional generating plant that would be required to make-up for the losses incurred. Incremental, or peak load loss differences are valued using the short run marginal cost of the marginal generation plant[1].

---

[1] Marginal plant is based upon the predominant mix of new thermal plant in the particular scenarios considered and is assumed to be gas fired in Scenario 1, coal fired in Scenario 2 and the average cost of gas and coal is used in the other scenarios .

The costs of generation required to make-up the transmission losses differ depending upon the Generation Scenario and (depending on the Scenario) range from the generation cost based on gas to the cost of coal or oil fired generation. The costs used are sourced from a publicly available report prepared for the Electricity Commission by Parsons Brinckerhoff Associates, “Thermal and Geothermal Generation Plant Capabilities,” dated December 2004.

2.3.3 Differences in energy costs

Some transmission options or alternatives to transmission will enable different generation dispatch patterns. For example, relieving a transmission constraint may enable expensive thermal generation to be displaced by cheaper hydro or wind generation. Where such differences are material, the dispatch differences are derived, the variable costs of generation are calculated in each case (primarily fuel costs) and the cost difference is calculated. The variable costs of generation used are also sourced from Parsons Brinckerhoff Associates report referenced above.

2.3.4 Differences in carbon costs

The relieving of a transmission constraint may enable expensive thermal generation to be displaced by hydro or wind generation with a consequential reduction in the CO_2 burden. Where such differences are material, the dispatch differences are derived, the tonnes of CO_2 generated in each case are estimated and the cost difference is calculated using a value of $15 per tonne CO_2.

2.3.5 Differences in ancillary service costs

Some transmission options or alternatives to transmission may enable different levels of ancillary services to be required. For example, voltage stability is the limiting design factor in the Auckland area and different investments will require the purchase of more or less dynamic voltage support from existing synchronous condensers or generators. These differing amounts of voltage support requirement are estimated and costed at the average voltage support cost in Auckland for 2004.

2.3.6 Generation reliability value difference

Transmission assets typically provide approximately 99.0% reliability, and a grid designed to an N-1 standard is available and provides continuity of supply 99.99% of the time. Unplanned outages occur only 0.3% of the time, but on account of redundancy, failure of supply occurs only 0.01% of the time.

In contrast, generation assets are typically 85-90% reliable, with planned outages occurring 5-10% of the time and unplanned outages about 5% of the time. Generation can only approach the same level of service to consumers if multiple generators are built, or individual generators have multiple redundancy in their generating units. Where relevant, estimates are made of the amount of unserved energy that will accrue, as a result of the unreliability of each configuration of transmission and generation considered.

2.4 Other Assumptions

2.4.1 Timeframe

Transpower has also applied the technique that uses residual values to extend the analysis to consider 40 years of costs and benefits This is particularly relevant to HVAC transmission augmentation which will have an expected technical and economic life in excess of 50 years and there are significant benefits accruing after the first 20 years.

2.4.2 Discount rate

A pre-tax real discount rate of 7% consistent with the Electricity Governance Rules is used to determine the present value of future cash flows.

2.4.3 Weightings applied to generation scenarios

The generation scenarios will be given equal weighting (ie 20% each) in calculation of the expected net market benefit, consistent with the Electricity Governance Rules.

2.4.4 Competition Benefits

Competition benefits have not been calculated for the purposes of this analysis. This is not mandatory under the Electricity Governance Rules and, although there are likely to be some competition benefits accruing to the 400 kV HVAC augmentation proposal compared to local generation alternatives, Transpower does not have a suitably developed methodology to calculate these benefits.

2.5 Calculation of expected net market benefit

The approach Transpower uses to calculate the expected net market benefit is a net present value analysis. Rather than being the outcome of a static spreadsheet calculation, the expected net market benefit is calculated by a Monte Carlo simulation in which demand is varied between the low and high bounds of the demand growth forecasts.

Figure 2-1 illustrates 1000 demand paths produced from a typical Monte Carlo simulation:

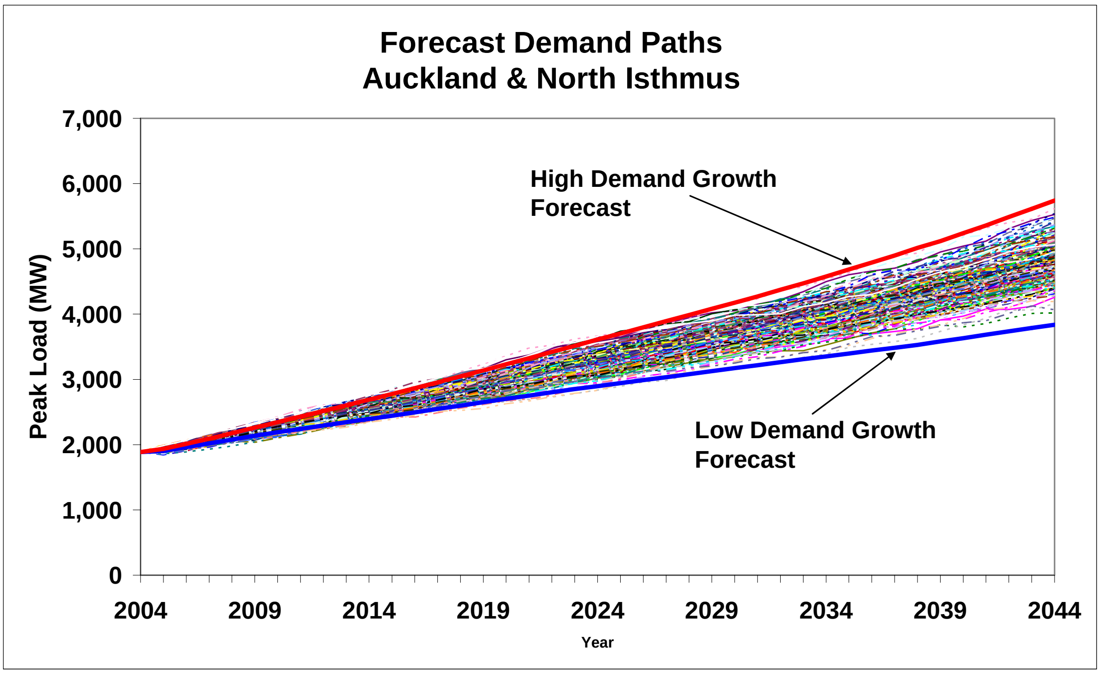


Figure 2-1 Illustration of demand paths from a Monte Carlo simulation

Transmission lines are large investments, with an economic life in excess of 50 years. There is considerable uncertainty when looking far into the future and in the particular case of transmission lines, uncertainty in:

- Future energy demands
- The location of new generation
- Technology changes that reduce the need for transmission.

Some transmission options and potentially alternatives to transmission include an inherent value, in that they include future investment flexibility to deal with uncertainty. For example, projects which are built incrementally in line with growth in demand reduce the possibility of overbuild, because later investments can be deferred or cancelled should demand growth not be as high as expected.

Transpower's approach to calculating expected net market benefit does not capture all of this inherent value, in that a separate calculation is made for each generation scenario, but it does capture the value attributable to the uncertainty in demand growth.

2.6 Sensitivity Analysis

Transpower has sensitised the list of variables shown in Table 2-1, being those that may have a material impact on the cost/benefit analysis:

Variable	Range
Discount rate – transmission	4% to10%
Discount rate – alternatives	7% to 10%
Value of unserved energy	$10K to $30K
Value of losses	- 50%to +50%
Probability market development scenarios	0% to 40% ea
Capital Cost:	-10% to +50%
Operating and Maintenance Cost	-30% to +30%

Table 2-1: Table of variables which will be sensitised

Demand is not sensitised due to the effect of demand varying between the low and high bounds of the demand growth forecasts already being reflected in the Monte Carlo technique which calculates expected net market benefits.

3 Cost Summary

This section summarises all of the transmission costs used in the cost / benefit analysis.

3.1 Development Plan Costs

The 220 kV and the 400 kV grid development plans have been built up for each generation scenario, as described in Part III, section 5 of this submission. The costs presented here relate only to those developments which are unique to each transmission option[2].

Table 3-1 below shows the total costs (expressed in 2005 dollars) as they would be incurred for the base case 220 kV development plan out to the year 2040. It should be noted that the Operation and Maintenance Costs (O&M) have been included in this table for the purpose of comparing one transmission option against another. Other overhead costs associated with grid augmentation such as statutory approvals, property acquisition and project management have been included for the same reason. The treatment of capitalised cost of Interest During Construction (IDC) is taken account of in the projected incidence of investment costs.

220 kV Development Costs	**$ million (2005)**					
Scenario Numbered ➡	**No.1**	**No.2**	**No.3**	**No.4**	**No.5**	**Av.**
Line + Cable capital costs	611	474	1,054	376	662	635
Substation capital costs	102	82	160	29	36	82
Property	451	363	732	194	402	428
O&M	83	56	97	21	15	54
Dismantling costs	4	4	4	4	4	4
Project Management Costs	99	80	162	49	88	96
Approval Costs	20	10	22	10	9	14
Total	**1,369**	**1,067**	**2,232**	**683**	**1,216**	**1,313**

Table 3-1: 220 kV Augmentation Plan Costs $million (2005)

Table 3-2 below shows the total costs (expressed in 2005 dollars) as they would be incurred for the proposed 400 kV development plan out to the year 2040. Similar qualifications apply to the cost estimates in this table as for Table 3-1 above so that they may be directly compared.

400 kV Development Costs	**$ million (2005)**					
Scenario Numbered ➡	**No.1**	**No.2**	**No.3**	**No.4**	**No.5**	**Av.**
Line + Cable capital costs	508	362	569	205	216	372
Substation capital costs	227	185	338	99	151	200
Property	248	199	320	97	105	194
O&M	106	84	126	46	54	83
Dismantling costs	4	4	4	4	4	4
Project Management Costs	79	60	99	33	38	62
Approval Costs	32	20	31	11	11	21
Total	**1,203**	**913**	**1,485**	**494**	**579**	**935**

Table 3-2– 400 kV Augmentation Plan Costs $million (2005)

Table 3-3 shows the present value of the total costs which are unique to the base case (220 kV) development plan, in 2005 dollars.

---

[2] If a grid augmentation is required at the same time in both the 220 kV and the 400 kV development plans, the costs have been excluded on the basis that they are not necessary to compare development plans. this is a widely used approach in carrying out economic comparisons.

220 kV Development Costs **Scenario numbered➡**	**Present value $ million (2005)** **No.1**	 **No.2**	 **No.3**	 **No.4**	 **No.5**	 **Av.**
Line + Cable capital costs	354	234	427	176	277	294
Substation capital costs	43	39	54	9	10	31
Property	265	186	326	98	195	214
O&M	17	12	18	4	2	11
Dismantling costs	2	2	1	2	2	2
Project Management Costs	60	44	72	30	41	49
Approval Costs	14	8	13	3	3	8
Total	**757**	**525**	**910**	**322**	**532**	**609**

Table 3-3 - 220 kV Development Plan Costs $million (discounted)

Table 3-4 below shows the present value of the total costs which are unique to the proposed (400 kV) development plan, in 2005 dollars.

400 kV Development Costs **Scenario numbered ➡**	**Present value $ million (2005)** **No.1**	 **No.2**	 **No.3**	 **No.4**	 **No.5**	 **Av.**
Line + Cable capital costs	302	231	308	153	159	231
Substation capital costs	122	105	154	73	98	110
Property	167	142	194	85	89	136
O&M	24	19	26	12	14	19
Dismantling costs	2	2	2	2	2	2
Project Management Costs	48	39	53	25	28	39
Approval Costs	21	15	19	10	10	15
Total	**686**	**553**	**757**	**361**	**401**	**552**

Table 3-4 – 400 kV Development Plan Costs $million (discounted)

As can be seen from Table 3-3 and Table 3-4 above, the 220 kV development plan is $378 million (on the average) more expensive than the 400 kV development plan on a straight dollar comparison, but on a present value basis, this reduces to $57 million (on the average).

3.2 Proposed 400 kV Investment Costs

The costs associated with the proposed 400 kV investment, ie the 400 kV double circuit line and underground cable from Whakamaru to Otahuhu, that are used for the purposes of the cost/benefit analysis, are shown in Table 3-5.

Item	**$million (2005)**
Line capital costs	205
Substation capital costs	99
Property	97
O&M	46
Dismantling costs	4
Project Management Costs	33
Approval Costs	11
Preliminary Design & Investigation	12
Total	**507**

Table 3-5 – 400 kV first investment costs

A further set of costs are calculated, which include an estimate of costs associated with facilitating transmission across Auckland to North Isthmus. These costs also need to be incurred to ensure the energy flowing through the proposed new 400 kV line can reach load in Auckland and the North Isthmus.

Item	**$million (2005)**
Line capital costs	407
Substation capital costs	99
Property	97
O&M	57
Dismantling costs	4
Project Management Costs	49
Approval Costs	11
Preliminary Design & Investigation	12
Total	**737**

Table 3-6 – 400 kV First Investment Costs Including Across Auckland Costs

4 “Do Nothing” analysis – Is large scale base-loaded generation an economic alternative to transmission?

Transpower has undertaken analysis has been undertaken to determine whether the new generation that is forecast to emerge in the Auckland/North Isthmus region according to the generation scenarios, substitutes for transmission, and whether building transmission as well has a positive expected net market benefit.

4.1 Costs

The costs included in the analysis are the base case costs ie the costs of the 220 kV development plan. A sensitivity is included using the costs of the 400 kV development plan.

4.2 Benefits

The avoidance of unserved energy at $20,000 per MWh dominates the benefits included in the economic analysis. While there are a number of other benefits attributable to the proposed investment these have not been quantified or included in the analysis because they are relatively insignificant as compared to the avoidance of unserved energy. For completeness these other benefits include:

- Energy loss differences
- Differences in energy costs
- Differences in carbon costs
- Differences in ancillary service costs
- Generation reliability value difference

Energy loss differences, differences in energy costs and differences in carbon costs, would together represent the cost of meeting the otherwise unserved energy and as such would be a negative benefit if transmission was built. However, even if an average generation cost were used for thermal plant, of 7.5 cents per kWh, this only equates to $75 per MWh.

Ancillary service costs may increase in view of the higher demand being served but even if they were as high as the average cost of transmission, which is highly unlikely, that would only equate to $75 per MWh.

Generation reliability value is not a significant factor either. The previously unserved energy will be served through transmission, with an estimated reliability of 99.99%. The generation reliability cost will be 0.001% of $20,000 per MWh, or $2 per MWh.

Therefore, even if all of these were summed together, the likely maximum they could add is $152 per MWh, hence it is considered unnecessary to reflect them in the analysis. Rather, sensitivity analysis is undertaken on the unserved energy cost, using a low cost of $10,000 per MWh.

4.2.1 Expected net market benefit

The expected net market benefit of building transmission, as a result of applying the above assumptions, is:

$ million (discounted) Scenario number ➡	**No. 1**	**No. 2**	**No 3**	**No. 4**	**No. 5**	**Average**
Line capital costs	354	234	427	176	277	294
Substation capital costs	43	39	54	9	10	31
Property	265	186	326	98	195	214
O&M	17	12	18	4	2	11
Dismantling costs	2	2	1	2	2	2
Project Management Costs	60	44	72	30	41	49
Approval Costs	14	8	13	3	3	8
TOTAL COSTS	**757**	**525**	**910**	**322**	**532**	**609**
Avoidance of unserved energy	4,625	10,491	74,281	90,976	56,293	47,333
Total Benefits	**4,625**	**10,491**	**74,281**	**90,976**	**56,293**	**47,333**
Net Market Benefit	**3,868**	**9,967**	**73,371**	**90,654**	**55,761**	
Expected Net Market Benefit						**46,724**

Table 4-1 Expected Net Market Benefit Per Scenario

4.2.2 Sensitivities

The expected net market benefit has been sensitised for uncertainty in the cost estimates and the unserved energy cost, with the following results:

$ million (discounted)	Sensitised value	Expected Net Market Benefit
Base case without sensitivity applied		**46,724**
Total Costs	-10%	46,785
Total Costs	+50%	46,420
Unserved energy cost	$10,000	23,058
Unserved energy cost	$20,000	46,724
Unserved energy cost	$30,000	70,391

Table 4-2: Expected Net Market Benefit Sensitised for Uncertainty

As a separate sensitivity, the 220 kV development costs have been replaced by the 400 kV development costs, with the following result:

$ million (discounted)	Sensitised value	Expected Net Market Benefit
Base case without sensitivity applied		**46,724**
Total costs reflecting 400 kV development plan		46,782

Table 4-3: Replacement of 220 kV Development Costs with 400 kV Development Costs

4.2.3 Conclusion

From this analysis it is clear that both the base case (220 kV HVAC) and 400 kV HVAC have a highly positive expected net market benefit in all generation scenarios. Therefore, it can be concluded that:

- there is not enough large scale base-loaded generation forecast to appear to the North of Auckland in any of the generation scenarios to avoid significant amounts of unserved energy and thus large scale base-loaded generation does not substitute for transmission, and

- it is economic to augment existing transmission into the area to avoid the forecast unserved energy, and

- there is no certainty that the generation included in the generation scenarios will go ahead early enough to have any material effect on the timing of grid augmentation.

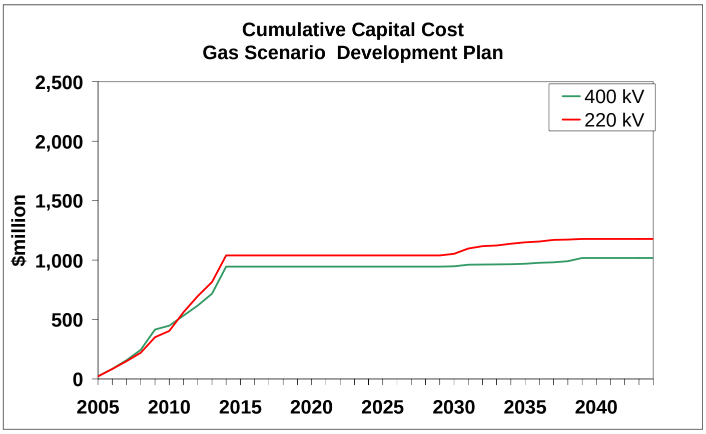
5 Cost benefit of 400 kV HVAC versus 220 kV HVAC

Previous studies have shown 400 kV HVAC to be the preferred technology from a wide range of alternative technologies including HVDC, for long-term development of New Zealand's national transmission grid. In this Section, Transpower compares a possible long-term grid augmentation plan using a 400 kV HVAC against a base case representing a "business as usual" case whereby the core grid elements continue to be designed and built to 220 kV HVAC.

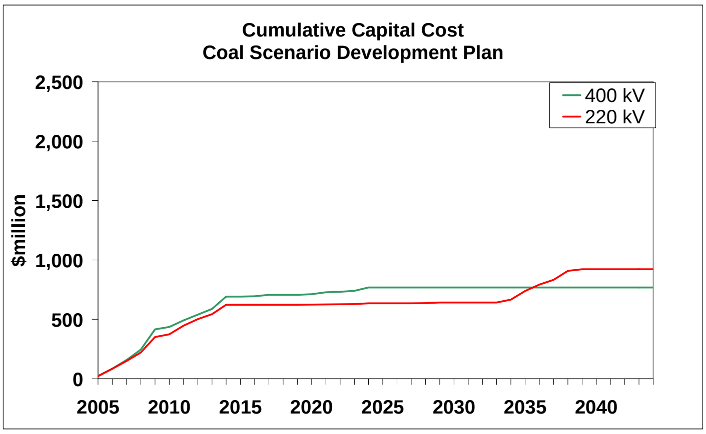
5.1 Capital Cost Summary

The following charts compare the cumulative capital costs associated with grid augmentation plans for the upper North Island development using 220 kV and 400 kV technology for each of Transpower's generation scenarios.

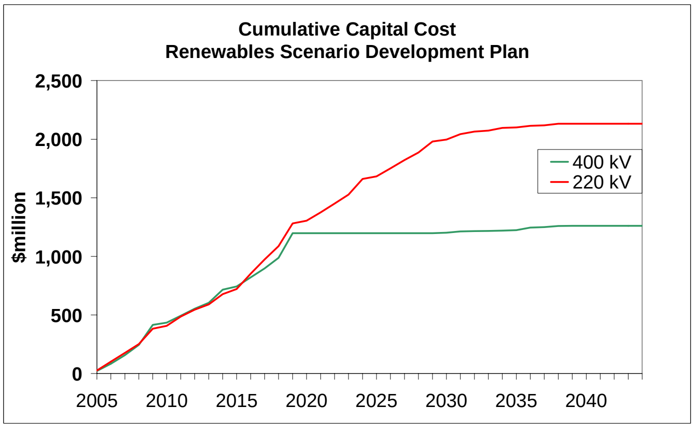
The costs shown in the charts below include line, substation, dismantling, property and approval costs only. They do not include operations and maintenance costs, transmission losses or project management costs.



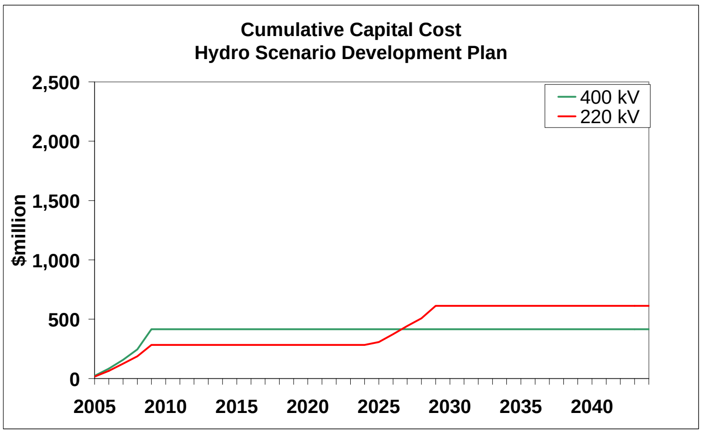
Scenario 1



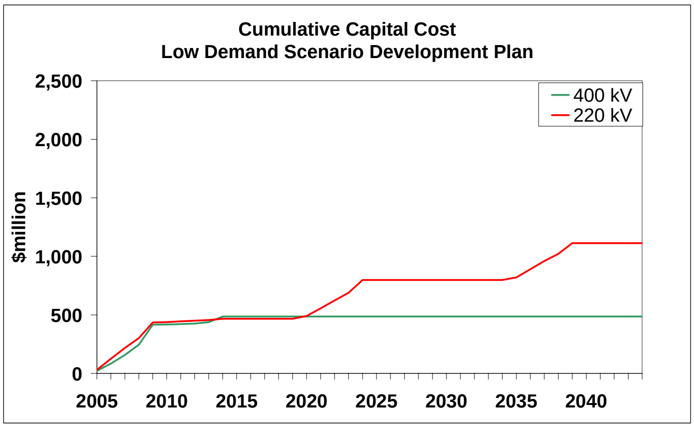
Scenario 2



Scenario 3



Scenario 4



Scenario 5

Figure 5-1:– Cumulative Capital Cost Summary

As the charts in Figure 5-1 above show, the cumulative capital cost for 220 kV is higher in all scenarios, although grid augmentation at 400 kV costs incurs higher initial costs which pay off in the medium term.

5.2 Cost/benefit analysis results

The results of the cost/benefit analysis are shown in table 5.1.

400 kV Advantage over Base Case $million (discounted)						
Scenario numbered ➡	**No. 1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Line capital costs	52	3	120	23	117	63
Substation capital costs	-79	-66	-101	-64	-88	-79
Property	98	43	132	13	106	78
O&M	-6	-7	-8	-8	-11	-8
Dismantling costs	0	0	-2	0	0	0
Project Management Costs	12	5	19	5	13	11
Approval Costs	-6	-7	-6	-7	-7	-7
Total Costs	**71**	**-29**	**153**	**-39**	**130**	**57**
Avoidance of unserved energy	0	0	0	0	0	0
Energy loss differences	95	75	105	18	85	76
Differences in energy costs	0	0	0	0	0	0
Differences in carbon costs	0	0	0	0	0	0
Differences in ancillary service costs	0	0	0	0	0	0
Generation reliability value difference	0	0	0	0	0	0
Total Benefits	**95**	**75**	**105**	**18**	**85**	**76**
Net Market Benefit 400 kV	**166**	**47**	**258**	**-21**	**215**	
Expected Net Market Benefit 400 kV						**133**

Table 5-1: Expected Net Benefit of 400 kV HVAC Augmentation of Supply to Auckland/North Isthmus Compared With 220 kV HVAC

The only material benefit that is applicable to the comparison of alternative transmission technologies dealt with in this section is the value of the lower transmission losses offered by the choice of a higher voltage level.

The value of transmission losses has been evaluated at the long run marginal cost (LRMC) of the most likely generation in each scenario, for example, gas fired in Scenario 1, coal fired in Scenario 2. Taken on average for all scenarios, the average value of losses is around $77/ MWh in 2020.

The analysis demonstrates that (on average) the 400 kV HVAC development option has an expected net market benefit of $133 million compared with the 220 kV HVAC base case development option.

Table 5-1 above, also shows that the 400 kV grid augmentation between Whakamaru and the Auckland/North Isthmus region is economically least attractive for Scenario 4. This scenario is based upon the assumption of extensive generation in the South Island in the short to medium term which would essentially be developed to supply loads in the North Island. This generation development in the South Island is assumed to be based upon new hydro resources being developed (Project Aqua plus other new hydro) but could equally be thermal generation based on the use of indigenous coal. It is also assumed that this development would take place within a reasonable period after the 400 kV augmentation of the grid supplying Auckland is completed.

If such large scale generation should develop, it is assumed that a new high capacity HVDC link would be established to deliver the new generation to a site near Auckland. If the HVDC terminal station is either in or near Auckland, the 400 kV development would have a low ongoing value for supply to Auckland and the North Isthmus which is reflected in the evaluation.

Equally well, the existence of the proposed 400 kV HVAC augmentation between Whakamaru and Auckland could be taken into account at the relevant future time and the HVDC terminated near Whakamaru where the availability of land and access is less likely to be and an issue than close to Auckland. If a terminal site to the south of Auckland is the preferred development in the future, the proposed 400 kV HVAC augmentation between Whakamaru and Auckland would have a substantial ongoing value which is not reflected in this scenario.

In reality, the possibility of a large scale generation in the South Island within a reasonable time-span which would warrant the construction of a major new HVDC link (rather than simply upgrading the existing link) seems to be of a low probability compared with the other generation scenarios that have been considered.

This points to the issues that may be introduced by taking a simple arithmetic average across all the generation scenarios. This approach assumes:

(i) that all scenarios have a similar likelihood of occurring with the result that a “unlikely” scenario could unduly bias the result, and

(ii) more importantly, it assumes that the outcome for any one particular scenario is equally acceptable in the context of future development of the national grid as it is for any other scenario.

This latter point is not considered in the Grid Investment Test. To put this point in the current context, the result of giving undue weight to scenario 4 was considered which would lead one to choose an extension of the 220 kV and the potential pitfalls of having to provide a further 220 kV line (or even migrate to 400 kV) some 10 years or so later if scenario 4 did not eventuate.

On the other hand, if this scenario was discounted as being the least likely, a decision in favour of 400 kV HVAC would leave the door open to the widest range of possible options including (as mentioned above) the possibility of siting a HVDC terminal station for a future HVDC link south of Auckland or even further south nearer Whakamaru. This has a very definite option value as suggested earlier in this Part IV but the possibility of putting a dollar value on such a future option has not been done in this instance as it is a difficult concept to give practical effect to.

If, for the reasons set out above, if scenario 4 is excluded from the calculation of the average of the expected net market benefit for the alternative scenarios, this increase the advantage of the 400 kV HVAC option over the “business as usual“ 220 kV option from $ 133 million to $ 172 million.

5.3 Development Plan Sensitivity Analysis Results

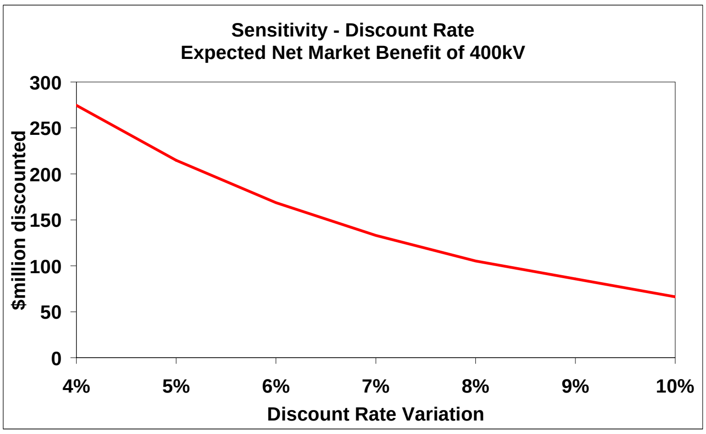
Table 5-2 shows the results of the various sensitivities applied to the cost benefit analysis set out in the previous section. The expected net market benefit is the weighted average of the 400 kV development plan over and above the base case across all five generation scenarios[3].

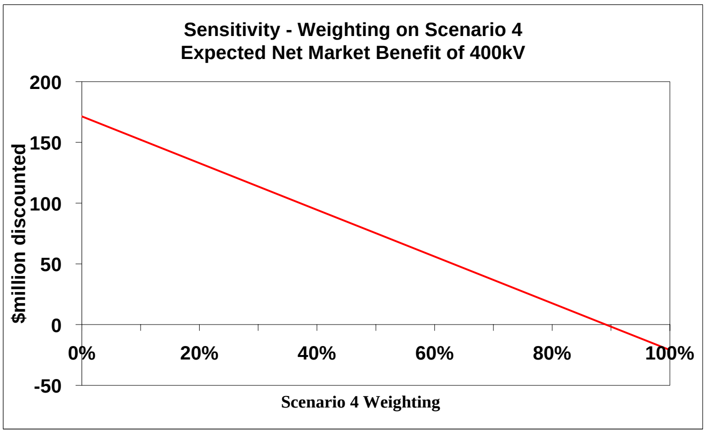
---

[3] The sensitivity results are the weighted average over all scenarios assuming that each scenario carries an equal weighting of 20%.

Expected Net Market Benefit $million (discounted)	
Sensitivity Factor	**Benefit**
Base case without sensitivity applied	133
4% discount rate	275
10% discount rate	66
Loss value + 50%	172
Loss value – 50%	95
0% weighting on Scenario 4	172
40% weighting on Scenario 4	95
Capital costs + 50%	169
Capital costs -10%	128
O & M costs + 30%	133
O & M costs - 30%	133

Table 5-2 – Sensitivity Results for Expected Net Market Benefit of 400 kV





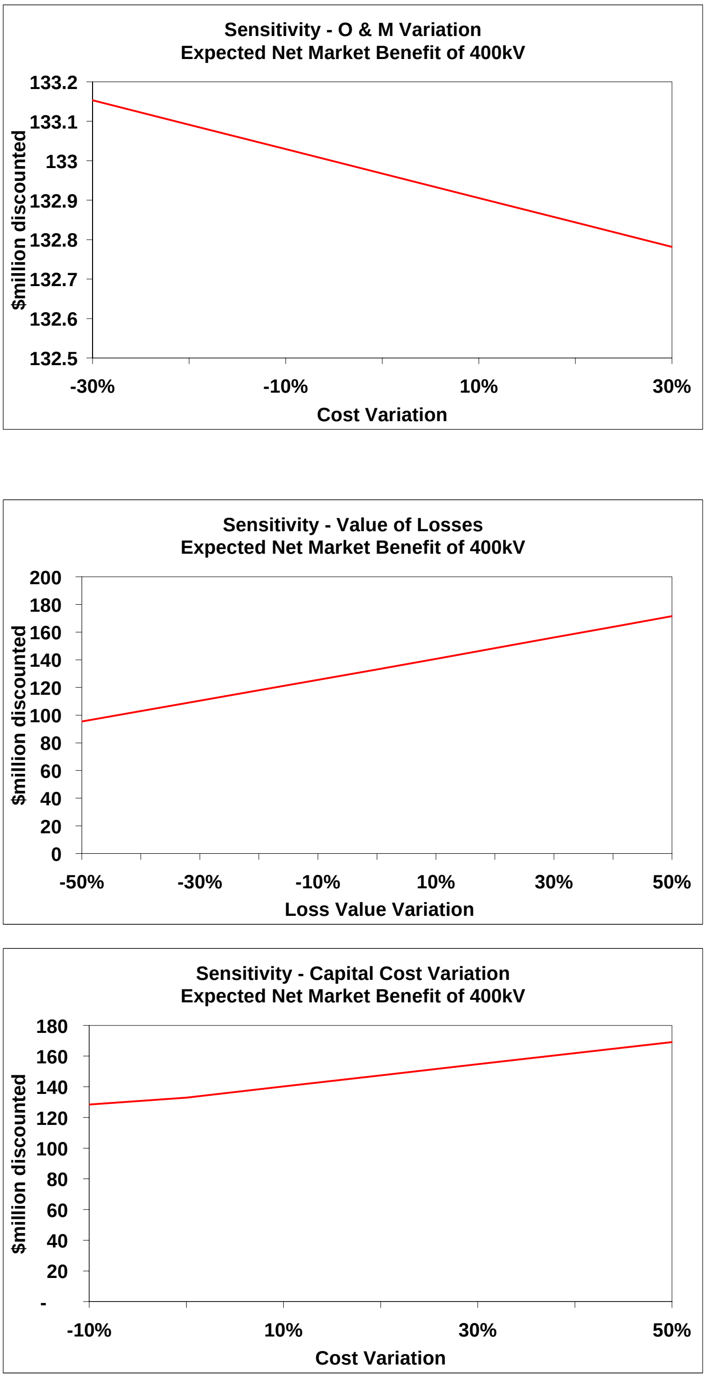


Figure 5-2: - Sensitivity Chart of Expected Net Market Benefit of 400 kV over Base Case

There is an economic advantage of the 400 kV investment over and above the base case in all of the sensitivity analysis.

Figure 5.2 shows that as the discount rate increases, the advantage of the 400 kV over the base case diminishes. However, even at the worst case of 10%, the advantage is still $66 million.

The analysis is fairly sensitive to the value of losses and this is to be expected given that this is a key point of difference in assessing the relative benefits of the project. However, it should be noted again, that even if the value of losses is decreased by 50% this would equate to an average marginal cost of generation of around $43/ MWh in 2025. This is less than the SRMC of a coal fired plant excluding any carbon tax. Transpower therefore considers that the loss figures used represent a reasonable view of their future value.

The weighting for Scenario 4 was also sensitised given that this is the scenario which favours the base case to the greatest degree. All other scenarios had an equal weighting applied. The significance of Scenario 4 and this sensitivity was discussed previously.

It was not considered necessary to sensitise the other scenarios as this would only provide different variations of positive expected net market benefit.

The cost sensitivities were applied to both the 400 kV and the 220 kV[4] total costs and since the 220 kV total costs are higher than the 400 kV total costs, the benefit of the 400 kV increases as the capital costs increase.

6 Expected Net Market Benefit of the proposed 400 kV HVAC grid augmentation

The Electricity Governance Rules provide that the *grid investment test*[5] is to be applied by the *Board* (the Electricity Commission) to review and approve *reliability investments* and *economic investments*.

Furthermore, *the grid investment test* (see Schedule F4 to Schedule II of Part F of the Electricity Governance Rules) states that:

4. “A *proposed investment* satisfies the grid investment test if the *Board* (now the Electricity Commission) is reasonably satisfied that :

   4.1. the *proposed investment* maximises the *expected net market benefit* compared with a number of *alternative projects* ;

   4.2. the *expected net market benefit* of the *proposed investment* is greater than zero; and

   4.3. if sensitivity analysis is conducted, a conclusion that a *proposed investment* satisfies clauses 4.1 and 4.2 is sufficiently robust having regard to the results of that sensitivity analysis.”

Whilst Transpower is making this submission in accordance with the transitional provisions of Part F, it notes that its economic analysis and methodology is consistent with that required under the Grid Investment Test.

This estimation of the expected net market benefit has been carried out and included in this submission for the sole purpose of assisting the Electricity Commission considering its position.

In seeking to establish the *net market benefit* for a particular grid augmentation, Transpower has to rely on an assumption that the generation scenarios included in the particular *market development scenarios* used to determine the *net market benefit* contain sufficient generating capacity to meet the electricity requirements of New

---

[4] It is considered unlikely that there would be a significant variation in the 400 kV costs which would not also be reflected in the base case costs, hence, the sensitivity was applied equally to both cases.

[5] The italicised terms defined in the Electricity Governance Rules

Zealand as a whole. Otherwise, there will be a concern that the results will contain an artefact arising from insufficient generation in the scenarios used. In developing its own generation scenarios, Transpower has been particularly careful to ensure that provision has been made for sufficient generation throughout New Zealand.

The expected net market benefit has been calculated by undertaking the same analysis as used for the "do nothing" analysis in section 4, but with the proposed 400 kV double circuit line from Whakamaru to Otahuhu only in service. In the "do nothing" base case, no transmission is built and there is a cost associated with unserved energy in the Auckland and North Isthmus regions.

The "present value" of unserved energy that would be avoided by the proposed *reliability investment* comprising a 400 kV double circuit line from Whakamaru to Otahuhu is calculated, and this is compared to the "present value" cost of the proposal.

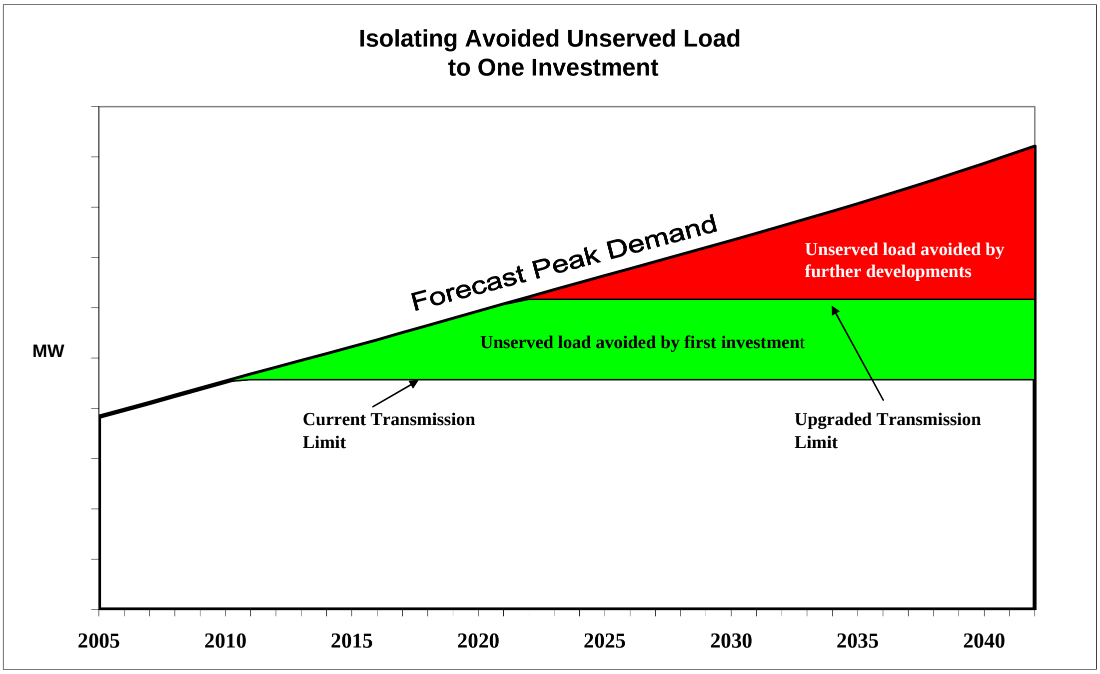


Figure 6-1: Illustration of Unserved Load Avoided by Initial 400 kV Investment

Figure 6-1 is an illustration of how unserved load can be isolated to one transmission investment. The avoided unserved load (MW) figure is the area shown in green which is the difference between the existing load capacity in Auckland and North Isthmus area and the future load capacity once the proposed investment has been built. The area in red is the unserved load that would be avoided by subsequent investments such as further grid augmentation or development of major generation in the Auckland area or north of Auckland.

The unserved energy associated with the proposed *reliability investment* is calculated separately for each market development scenario. In this analysis, the unserved energy figure used in the analysis is the average result over 1,000 demand paths lying between the maximum and minimum load forecast so that the results are robust for a range of load developments (effectively the "expected" unserved energy that will be avoided by building the first 400 kV investment).

In this analysis, the transmission option under consideration is the proposed 400 kV augmentation of the North Island grid between Whakamaru and Otahuhu and the expected net market benefit of this proposal is to be evaluated. Because it is common to all generation scenarios, the estimated present value cost of implementing the proposed investment as well as reinforcing the the 220 kV network across the Auckland Isthmus[6] is set separately in Table 6-1 below. Care should be taken in comparing this Table with the capital cost estimates shown elsewhere in this submission as the costs are “present valued” and also contain a 40 year estimate of the operation and maintenance costs of the proposal.

Table 6-2 below shows the results of the cost benefit analysis over all scenarios for the proposed investment including the necessary cross Auckland Isthmus 220 kV reinforcements. The average column shows the weighted average assuming each scenario carries an equal weighting of 20% each.

Present Value Costs of Building, Operating and Maintaining the Proposed 400 kV Reliability Investment	
	$million
Line + Cable capital costs	309
Substation capital costs	73
Property	85
Dismantling costs	2
Project Management Costs	38
Approval Costs	10
Operation & Maintenance	15
Preliminary Design & Investigatio	10
Total Costs	**542**

Table 6-1 - Present Value Cost of the Proposed Investment

Expected Net Market Benefit of Proposed 400 kV Reliability Investment for Transpower’s Generation Scenarios $million discounted						
Scenario Number ➡	**No.1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Avoidance of unserved energy	3,830	7,118	42,911	49,115	36,073	27,809
Less total cost of proposed 400 kV reliability investment	542	542	542	542	542	542
Net Market Benefit Proposed 400 kV Investment	**3,288**	**6,575**	**42,369**	**48,573**	**35,530**	
Expected Net Market Benefit Proposed 400 kV Investment						**27,267**

Table 6-2 – Expected Net Market Benefit of First 400 kV Investment

The average expected net market benefit assuming it is relevant to give all generation scenarios the same weight is $ 27,267 million.

---

[6] The investment costs to reinforce the Auckland isthmus are included because without this reinforcement, demand will not be able to be supplied at peak times to the North Isthmus and Northland. Therefore the in order for the proposed investment to be credited with serving the North Isthmus and Northland demand the cross Auckland reinforcement must be included.

Three conclusions may be drawn immediately from this Table 6-2 as follows:

(i) the numbers obtained from such an analysis are extremely large being many billions of dollars,

(ii) the range of the net market benefits is extremely large being from $3.3 billion to $48.6 billion,

The reason the numbers are extremely large is that the *net market benefit* is evaluated over a period of 40 years on the basis that the proposed *reliability investment* will not be built. Quite clearly, if the proposed *reliability investment* is not built and the national welfare suffers losses of the order of magnitude indicated in the above table, then some form of alternative development would likely take place to remedy the situation.

Transpower concludes the following from the numbers in Table 6-2:

(i) that Scenario 1 appears to be the least robust for the proposed reliability investment. This is because Scenario 1 includes a substantial amount of base load generation near Auckland or in the North Isthmus using gas as a fuel but this is dependent upon further discoveries of gas in commercial quantities and new gas transmission infrastructure. The postulated development does not provide for new generation in a time-frame that adversely affects the economic value of proceeding now with a 400 kV development but the availability of local generation reduces the quantum of unserved energy in the longer term.

(ii) that Scenario 4 is the most robust for the proposed reliability investment. This raises questions as it has been shown in Section 5 of this Part IV that for Scenario 4, the proposed 400 kV grid augmentation is the least attractive when compared with continued development of the 220 kV grid. The reason for this is that Scenario 4 has the least amount of generation in the immediate Auckland area and there is greater reliance in the longer term on the transmission grid south of Auckland to provide security of supply and minimise the unserved energy.

(iii) While the assumed termination of a new HVDC link from the South Island in or near Auckland diminishes the long term value of the proposed 400 kV grid augmentation, in the longer term with the new HVDC link in service, it is necessary to have the augmented transmission between Whakamaru and Otahuhu in service to continue to supply some 2000 MW into Auckland. It has been indicated earlier in this section that the 400 kV HVAC option would reduce transmission losses and minimise the use of easements to achieve this end.

6.1 400 kV Line Sensitivity Analysis Results

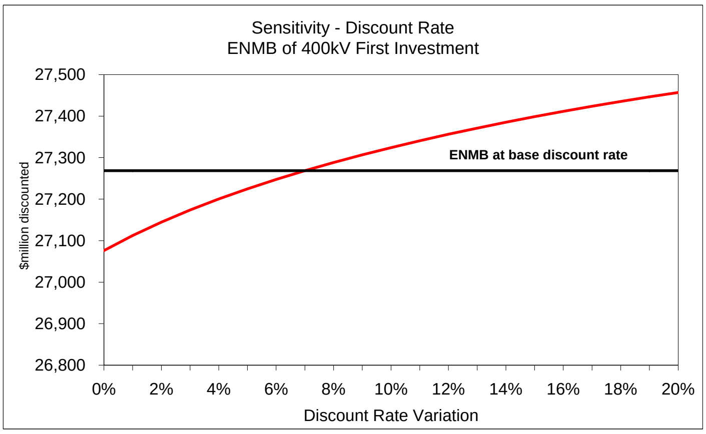
Table 6-3 and Figure 6.2 below shows the results of the various sensitivities applied to the cost/ benefit analysis. Table 6.3 shows the expected net market benefit of the 400 kV development plan over and above base case[7].

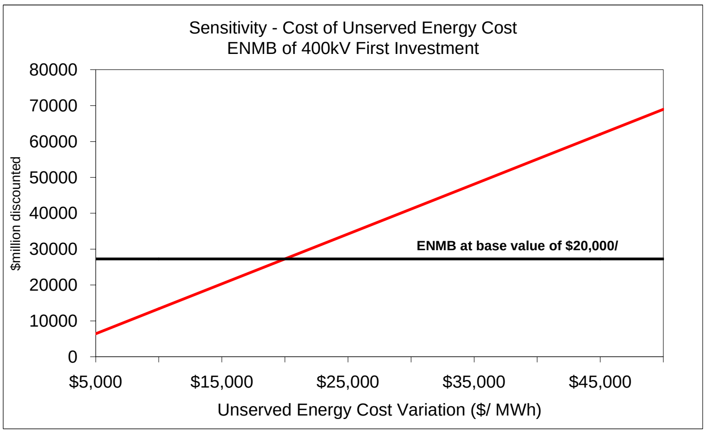
---

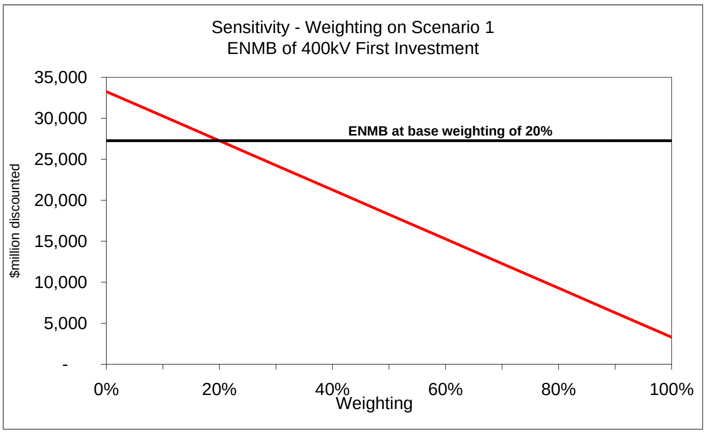
[7] Apart from the ‘weighting” sensitivity, the sensitivity results show the weighted average ENMB over all scenarios assuming that each scenario carries an equal weighting of 20%.

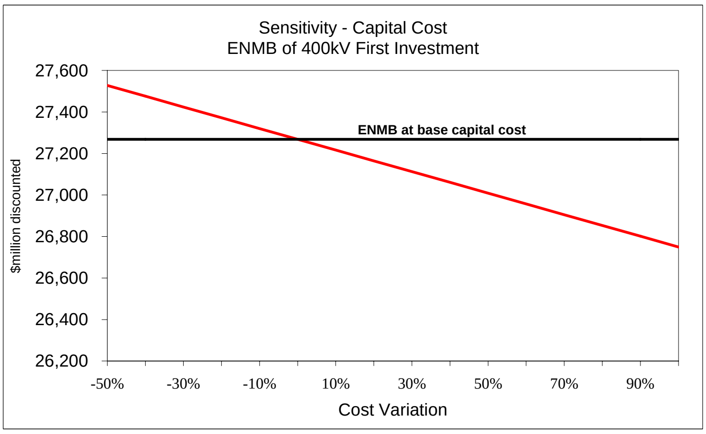
Expected Net Market Benefit - $million (discounted) Sensitivity	 Benefit
Base case without sensitivity applied	27,267
4% discount rate	27,200
10% discount rate	27,268
Unserved load value - $10,000/ MWh	27,324
Unserved load value - $30,000/ MWh	13,364
0% weighting on Scenario 1	41,173
40% weighting on Scenario 1	33,263
Capital costs + 50%	21,274
Capital costs -10%	27,009
O & M costs + 30%	27,320
O & M costs -30%	27,265

Table 6-3: Expected Net Market Benefit Against Various Sensitivities









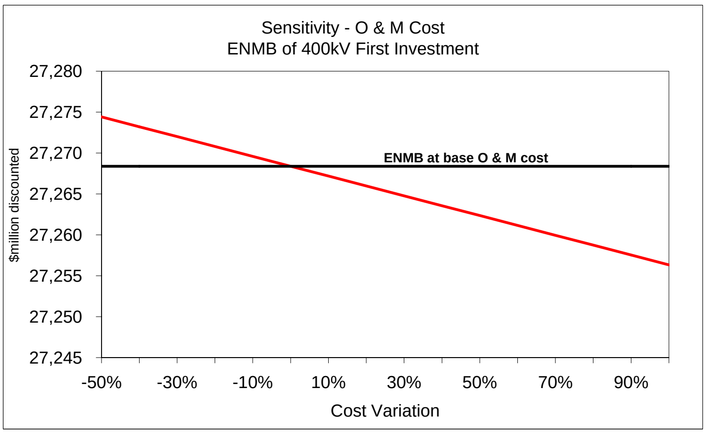


Figure 6-2: Sensitivities of the Initial 400 kV Investment

As expected when comparing the proposal to a base case of “no transmission”, any reduction in the discount rate will reduce the expected net market benefit of the proposal, however even at a rate of 4%, the expected net market benefit of is still $27,200 million positive.

Variations in the cost of unserved energy affects the expected net market benefit of most significantly of all the sensitivities, but again, even at the low value of $5,000/ MWh, the expected net market benefit of is still positive at $6,411 million.

The sensitivity around the weighting of the scenarios was tested on Scenario 1, which returns the lowest expected net market benefit of due to the significant amount of modelled generation in the Auckland/ North Isthmus region in this scenario. The weighting on all other scenarios is assumed to be equal when varying Scenario 1's weighting. At the extreme of raising this Scenario's weighting to 100%, the expected net market benefit of is still $3,289 million positive.

The cost sensitivities demonstrate that the analysis is robust against significant cost variations with very little variation around the base value - even if costs were to double the expected net market benefit of the proposal would still be in excess of $26 billion.

6.2 400 kV Line using the Electricity Commission's Scenarios

A sensitivity analysis has been undertaken using the Electricity Commission's generation scenarios which are currently under consultation as part of the draft Statement of Opportunities.

The Electricity Commission's scenarios all contain less generation in the upper North Island than Transpower's resulting in Transpower's scenarios providing a harder economic test for the proposed 400 kV line between Whakamaru and Otahuhu. This can be demonstrated by sensitising the economic analysis using the Electricity Commission's 2005 Generation Scenarios[8].

Given that there is substantially less assumed generation in the Auckland/ North Isthmus region under the Electricity Commission's scenarios than in the scenarios used in this analysis, the proposed investment will essentially avoid a larger proportion of the potential unserved energy. As a result the accrued benefits of the proposed investment will be higher.

Table 6-4 below shows the results of the economic analysis using the benefit of the avoided unserved energy under the Electricity Commission's generation scenarios. The average column shows the weighted average assuming each scenario carries an equal weighting of 20% each.

$million discounted						
Scenario Number ➡	**No. 1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Avoidance of unserved energy	13,086	32,207	97,375	101,838	58,263	60,554
Less total cost of proposed 400 kV reliability investment	542	542	542	542	542	542
Net Market Benefit 400 kV Investment	**12,544**	**31,665**	**96,833**	**101,295**	**57,720**	
Expected Net Market Benefit 400 kV Investment						**60,011**

Table 6-4: Expected Net Market Benefit of first 400 kV Investment under Electricity Commission Scenarios

As mentioned above, the benefit from avoidance of unserved energy is over twice that shown in the analysis using Transpower's generation scenarios. As a result, the

---

[8] For this exercise Transpower has used the generation scenarios published in the *"Initial Statement of Opportunities"* dated May 2005.

Expected Net Market Benefit is over twice that from using Transpower's scenarios, at $60,011 million.

7 Alternatives to transmission which may economically defer transmission

Section 6 concluded that building the proposed 400 kV double circuit line from Whakamaru to Otahuhu, in 2010, has a positive expected net market benefit, under a range of reasonable scenarios. This section considers whether there are any alternatives to transmission which might economically defer the need for transmission in 2010.

7.1 Request for Information document

As discussed in Part III of this report, Transpower's approach to the question of an alternative to transmission deferring the need for the grid augmentation, was to issue a Request for Information document seeking information on potential "transmission alternatives" (the term used in the Electricity Governance Rules).

Part III also describes the analysis of the submissions received in response to the Request for Information and identifies the following alternatives to transmission as qualifying for further consideration.

- Load Shedding Bidding programme targeting peak demand reductions
- Peaking generation plant, diesel fired
- Base-loaded generation plant, gas fired

7.1.1 Load Shedding Bidding Programme

Although there is potential for a load shedding bidding programme to deliver peak MW load savings, no programmes are known to operate at present. Hence, there is considerable uncertainty about whether such a programme could deliver the quantity of load and certainty required in the Auckland area to defer transmission with the required degree of confidence.

The proposal did not provide adequate information on these matters. Particular questions that would need to be resolved relate to the total amount of sheddable load in the Auckland area and the extent to which a Load Shedding Bidding Programme would compete for sheddable load already available for other purposes. If sheddable load in the Auckland area is a scarce resource, then introducing a load shedding bidding programme may just serve to push up the prices being asked for instantaneous reserve. Because of these uncertainties, and the lack of data, this scheme is not considered as a viable alternative to transmission at this stage.

However Transpower has sponsored an independent investigation of such a programme to assess its potential benefits and to develop a design and implementation strategy.

7.1.2 Generation plant

Only the diesel fired peaking plant and gas fired base-loaded plant generation proposals are considered as potential contenders from an economic perspective at this stage.

Cost/benefit analysis has been undertaken to determine whether the use of such alternatives to transmission would have a positive expected net market benefit.

The analysis does not take a view on the form of the arrangements that would need to be in place to enable such alternatives, but does assume that the contractual arrangements would mean that the generation would be available to be dispatched, as and when required by Transpower. The practical use by Transpower of local generating plant, particularly for the base-loaded generation, has not been considered as such a generator would be a participant in the overall energy bidding market and Transpower has no place there.

7.2 Approach to evaluate alternatives to transmission to defer transmission

Rather than consider the particular generation plants offered in the RFI, a more generic approach was taken, whereby diesel generation equivalent to 1, 2, 3 and 4 years worth of demand growth (assuming medium demand growth) was considered. The applicability of these results to the economics base-loaded generation are discussed separately.

Costs

The capital and operating costs used, were sourced from various sources including Parson Brinckerhoff Associates "Thermal and Geothermal Generation Plant Capabilities" report, dated December 2004 and East Harbour Limited's "Cost of Fossil Fuel Generating Plant" dated September 2002.

Diesel peaking plant MW	Capital cost $m/MW	Fixed costs $m/annum	Fuel costs $/MWh	Other variable costs $/MWh
1 year deferral	1.24	1.064	164.80	6.00
2 years deferral	1.16	2.128	164.80	6.00
3 years deferral	1.11	3.211	164.80	6.00
4 years deferral	1.03	4.351	164.80	6.00

Table 7-1: Diesel Peaking Plant Capital and Operating Costs

It is not clear what value should be assigned to the residual value of the diesel plant after 1, 2, 3 or 4 years use. The plant might either be scrapped entirely, or if constructed in such a way as to be moveable, it could be transported elsewhere for use. For the purposes of this analysis, the economics have been calculated assuming both no residual value and a 50% residual value.

Benefits

The primary benefit of deferring the 400 kV HVAC proposal past 2010 is that the capital cost of the 400 kV HVAC proposal is deferred. This equates to approximately a $ 22 million per annum saving on the capital cost of the whole project, or $ 17 million per annum saving if the property and easement costs are excluded.

Of the other benefits considered:

- Energy loss differences

- Differences in energy costs
- Differences in carbon costs
- Differences in ancillary service costs
- Generation reliability value difference

The first three were considered using SDDP[9] to determine an optimum national generation dispatch for each size of peaking generation. The model was optimised on a short run marginal cost basis for generation costs, rather than making assumptions about market participant bidding behaviour. This approach ensures that the dispatch results are minimum cost from a national perspective, as required by the Grid Investment Test.

By calculating the cost of the national dispatch in this manner, the differences due to the first three benefits above, are all captured.

Ancillary service costs are calculated assuming:

- Reserve costs will not vary. Reserves are purchased based on the largest single generating unit in each island. Although transmission constraints can result in "islanded" demand, reserves are not purchased to cover regional risks caused by such islanding.

- Voltage support costs will vary. It is assumed for the purpose of this analysis that demand met using peaking generation will not require voltage support, but that if the same demand is met using transmission, then voltage support will be required.Actual 2004 voltage support costs for Zone 1 are used as the forecast cost for future voltage support.

Generation reliability differences are calculated using the methodology previously described. The estimated unserved energy in the Auckland/North Isthmus area for each transmission/generation configuration is calculated and valued at $20,000 per MWh.

Results

The results are summarised in Table 7-2 below for the case where all of the costs associated with the proposed 400 kV gird augmentation (including property and easement costs) are deferrable.

Table 7-3 shows the corresponding result if the property costs are taken not to be deferrable.

---

[9] Stochastic Dual Dynamic Programme

$ million (discounted)	**Peaking plant 1 year deferral**	**Peaking plant 2 years deferral**	**Peaking plant 3 years deferral**	**Peaking plant 4 years deferral**
Total 400 kV cost deferred, Zero residual value for generation				
Capital cost generation[10]	52	98	140	177
Deferred transmission cost	22	43	63	81
National dispatch cost benefit	-19	-36	-50	-70
Voltage support cost benefit	0	-2	-4	-7
Generation reliability cost benefit	-35	-46	-48	-47
Residual value peaking plant	0	0	0	0
Total benefits	-32	-41	-39	-43
Expected net market benefit	**-84**	**-139**	**-179**	**-220**

Total 400 kV cost deferred, 50% residual value for generation				
Capital cost generation	52	98	140	177
Deferred transmission cost	22	43	63	81
National dispatch cost benefit	-19	-36	-50	-70
Voltage support cost benefit	0	-2	-4	-7
Generation reliability cost benefit	-35	-46	-48	-47
Residual value peaking plant	26	49	70	89
Total benefits	**-6**	**8**	**31**	**46**
Expected net market benefit	**-58**	**-90**	**-109**	**-131**

Table 7-2: Expected Net Market Benefit of Installing Diesel Fuelled Plant in the Auckland Area to Defer Transmission Augmentation Assuming Property & Easement Costs are Deferrable

---

[10] Note that these costs do not include land costs, installation costs, project management costs, etc, and so are not determined on the same basis as transmission . Neither do they include the cost of other infrastructure required eg noise abatement, diesel storage tanks, or a diesel pipeline.

$ million (discounted)	Peaking plant 1 year deferral	Peaking plant 2 years deferral	Peaking plant 3 years deferral	Peaking plant 4 years deferral
Partial 400 kV cost deferred, Zero residual value for generation				
Capital cost generation	52	98	140	177
Deferred transmission cost	17	31	45	58
National dispatch cost benefit	-19	-36	-50	-70
Voltage support cost benefit	0	-2	-4	-7
Generation reliability cost benefit	-35	-46	-48	-47
Residual value peaking plant	0	0	0	0
Total benefits	**-37**	**-53**	**-57**	**-66**
Expected net market benefit	**-89**	**-151**	**-197**	**-243**
Partial 400 kV cost deferred, 50% residual value for generation				
Capital cost generation	52	98	140	177
Deferred transmission cost	17	31	45	58
National dispatch cost benefit	-19	-36	-50	-70
Voltage support cost benefit	0	-2	-4	-7
Generation reliability cost benefit	-35	-46	-48	-47
Residual value peaking plant	26	49	70	89
Total benefits	**-11**	**-4**	**13**	**23**
Expected net market benefit	**-63**	**-102**	**-127**	**-154**

Table 7-3 - Expected Net Market Benefit of Installing Diesel Fuelled Plant in the Auckland Area to Defer Transmission Augmentation Assuming Property & Easement Costs are Not Deferrable

7.3 Sensitivities

The results for the most favourable case (ie the case with the highest expected net market benefits), where the total cost of the 400 kV AC proposal is deferred and the peaking plant has a 50% residual value, have been sensitised for uncertainty in the cost estimates and the benefit costs, with the following results:

$ million (discounted)	Sensitised value	Expected Net Market Benefit			
		Peaking plant 1 year deferral	Peaking plant 2 years deferral	Peaking plant 3 years deferral	Peaking plant 4 years deferral
Transmission cost	-10%	**-60**	**-94**	**-115**	**-139**
Transmission cost	0	**-58**	**-90**	**-109**	**-131**
Transmission cost	+50%	**-47**	**-68**	**-77**	**-90**
Generation cost	-30%	**-42**	**-61**	**-67**	**-78**
Generation cost	0	**-58**	**-90**	**-109**	**-131**
Generation cost	+30%	**-74**	**-119**	**-151**	**-184**

Table 7-4: Expect Net Market Benefit After Sensitivities Analysis of Peaking Plant

7.4 Conclusion

The expected net market benefit of installing diesel peaking generation and deferring the 400 kV HVAC proposal is negative under all conditions considered in the analysis. It is concluded that building the 400 kV AC proposal in 2010, rather than using alternatives to transmission to defer the proposal, is a robust investment.

8 Summary

The cost benefit analysis has demonstrated that, under a range of reasonable scenarios and sensitivities, building the proposed 400 kV double circuit line from Whakamaru to Otahuhu, in 2010, produces a positive expected net market benefit compared to “do nothing” and also that the 400 kV proposal has the highest expected net market benefit of the transmission options considered.

The analysis also demonstrates that the large scale base-loaded generation as set out in both Transpower’s and the Electricity Commission’s draft generation scenarios do not substitute for transmission. Furthermore the analysis shows that diesel fired peak generation plant is not an economic alternative to transmission.

Therefore, the cost/benefit analysis has demonstrated that the proposed augmentation of the grid between Whakamaru to Otahuhu at 400 kV and associated substation works in 2010, is economic and should be recommended.

This analysis is consistent with the Grid Investment Test required for such a Reliability Investment under the Electricity Governance Rules and demonstrates that the 400 kV proposal meets the requirements of that test.

North Island 400 kV Upgrade Project

Investment Proposal

Part V – Project Costs

1 Summary

Transpower is seeking Electricity Commission approval under the transitional provisions of Part F for all costs incurred by Transpower in the implementation of the proposed investment.

This Part contains the estimated capital costs of the 400 kV project. Transpower has submitted cost estimates in good faith and expects to be able to recover actual costs reasonably incurred in relation to the approved project through the transmission pricing methodology. The costs contained in this document are estimates only.

The estimated order of magnitude of costs for Transpower's 400 kV project including transmission works, property and project management is approximately $460 million.

Category	Item	Cost $m (2005 Real)
Investigations	Preliminary engineering, environmental and property work to establish preferred route and lodge NoR.	20
Property	Acquisition of property rights	97
Environmental	Acquisition of designations and resource consents	11
Transmission works	400 kV line Whakamaru to Otahuhu	120
	Substations – Otahuhu	66
	– Whakamaru	33
	Cable	84
Dismantling	Arapuni to Pakuranga Line	4
Project Management		25
Total		460

2 Background

The transitional provisions of Part F of the Electricity Governance Rules allows the Electricity Commission to approve expenditure which is reasonable and prudent to meet Transpower's current grid reliability standards.

Transpower has submitted cost estimates in good faith and expects to be able to recover actual costs reasonably incurred in relation to the approved project through the transmission pricing methodology.

If the actual project costs are greater than the estimated cost included in this submission and Transpower was unable to recover these costs, Transpower would incur an economic loss. Forecasting errors could lead to windfall losses and could deter efficient investment. While considerable effort is made to ensure estimated costs represent the expected efficient investment, inevitably such forecasts are subject to imperfect foresight.

It would therefore be inappropriate to establish a final set of project costs for recovery 5 years out from commissioning of an approved investment. Such an approach would create unacceptable commercial risks for Transpower, and for electricity consumers. Transpower does not believe it is the Government's intention that this be the case.

3 Approach to Estimating Costs

Current cost estimates are based on conceptual designs. It is envisaged detailed design for the 400 kV assets will be carried out under some form of "turnkey" or "engineer, procure and construct" contract. Costs will become more certain as the project progresses through its various stages, and as risks are mitigated as illustrated in **Figure 3-1** below.

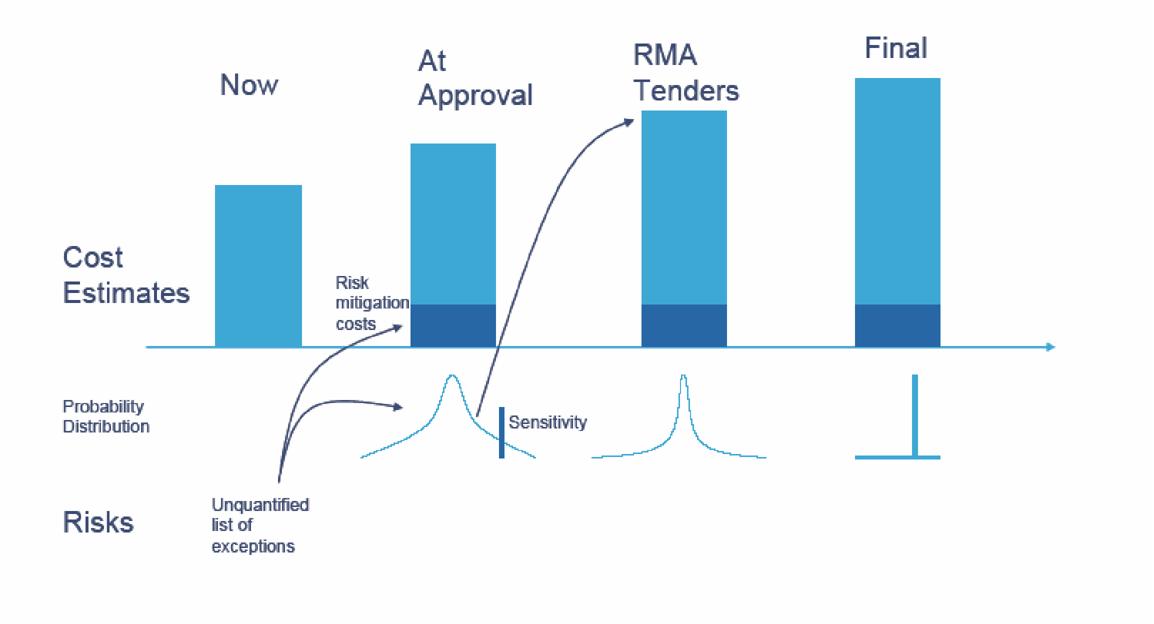


Figure 3-1: Relationship Between Project Stage and Accuracy of Cost Estimates

In estimating project costs Transpower's focus has been to establish an appropriate conceptual design for the capital equipment, preparing order of magnitude costs and identifying major sources of risk. Assumptions used in preparing cost estimates are discussed below.

As the project progresses scenario analysis techniques will be used to quantify expected variations, and establish a risk profile for the costings. This process will allow the refinement of risk mitigation strategies and the establishment of appropriate bounds for sensitivity analysis. For clarity, Transpower expects to be able to recover the costs of risk mitigation in addition to direct project costs.

A number of the cost risks (described below) relate to environmental costs and to specifics of market conditions and commercial requirements at the time tenders are let. It is clear that aspects of the costs cannot be finalised until the route is certain. For example, costs for cable trenching and foundations are sensitive to assumptions about soil depth and type. Approval of the project under the Resource Management Act and the letting of tenders will lead to increased engineering certainty and hence greater certainty over costs.

Subsequent to RMA approval and the letting of tenders, unavoidable circumstances may produce further variations in costs.

For clarity, operating and maintenance costs are not included in this Part in any detail as they do not form a part of the project capital costs. However, for completeness a description of the basis for estimating operating and maintenance costs has been included in Section 4.

4 Basis for Costs

This section sets out Transpower's basis for the cost estimates of each major component of the proposed investment. It also includes information on factors that have been specifically excluded from the estimates. Costs may vary from the estimates provided due to changes in the general assumptions (contained later in this Part), or to factors excluded from the cost estimates.

As discussed in the introduction to this part, costings for the preliminary design provided are subject to a high degree of uncertainty which will reduce as the project progresses.

4.1 Capital costs

4.1.1 Lines

The length of the transmission line has been assumed to be the proposed Western route which is approximately 200 km. The northern termination point is approximately 9 km (by cable route) south of Otahuhu. Variation to these lengths is possible once the final route is established.

Tower outlines and conductor selection are based on preliminary design criteria. Design criteria for transmission lines are discussed in Part I of this submission.

The number of towers and the composition of various different tower types are based on a preliminary tower spotting and are subject to finalisation of the alignment of the centre line as well as the suitability of individual tower positions.

The quantities of all other main materials such as insulators, conductor fittings, and foundations were derived from the tower quantities. The conductor lengths were based on the route length with a 3% allowance for sag and wastage.

Foundation installation rates are based on preliminary designs assuming average soil conditions over the whole route.

Exclusions:

Mitigation of step and touch voltages will be required for tower sites close to sensitive third party installations and other structures such as fences, sheds, swimming pools etc. Estimation of these costs is possible only after finalisation of tower sites.

Allowances for construction of new access tracks, bridges and upgrading of existing bridges/tracks can only be made after finalisation of tower sites.

4.1.2 Substations

Preliminary design of the NI 400 kV substations is based on the following key assumptions:

a) The 400 kV terminal stations will be located at Otahuhu and Whakamaru; and

b) A new and physically separate 220 kV switchyard extension is required at Otahuhu to provide diversity. This arrangement ensures that supply from the south into Otahuhu and supply from Otahuhu to key loads in the Auckland area are diversified across two physically separate “switchyards”.

The 400 kV terminal stations at Otahuhu and Whakamaru will be designed to facilitate future expansion for any of the identified future generation scenarios.

Exclusions:

Substation cost estimates exclude:

- Escalation of transformer costs due to high international demand;
- Required upgrading of bridges and roads for 400/220 kV transformer access;
- Upgrading transformers, buswork, circuit breakers, switchgear, protection systems, earthing, etc at existing substations for increased fault duty;
- Fault limiting equipment to ensure Distribution Companies’ equipment fault duty is not exceeded;
- Purchase of adjoining properties and additional substation land should this be necessary;
- Transitional configurations to allow for continuity of 220 kV power flow;

A transportation feasibility assessment has been made for the route from Port of Auckland to Otahuhu and Whakamaru for the 500 MVA 400/220 kV transformers. This assessment has identified a minimum of six bridges that must be analysed in detail to assess the cost to upgrade these bridges to allow the heavy haulage train to traverse the bridges. The worst case scenario is total replacement but strengthening or the use of bailey bridges may be feasible subject to specific investigation of each bridge. As the actual bridge strengthening requirements are unknown, costs have been excluded from the substation cost estimates.

4.1.3 Cable

Preliminary investigations have been carried out into suitable cable installation arrangements to determine corridor width required and identify potential cable routes between the transition station and Otahuhu substation. For the purpose of preparing cost estimates a length of 9 km was used.

To provide the required cable ratings, nominal trench dimensions of 1500mm wide by 2300m deep would be required with thermally controlled bedding/ backfill materials being required from the floor of the trench to just below the surface. This is a slightly “deeper than normal” burial depth to facilitate crossing of the trench alignment by other underground services and to increase the security of these important cables by reducing the likelihood of “dig ins” and damage caused by other service providers.

Exclusions:

Cable costs exclude:

- Additional costs to circumvent buried infrastructure
- Additional costs of special structures required to cross streams and the like.

4.2 Property Costs

4.2.1 Easements

Transpower's estimates of compensation for easements are based on the easement fee methodology for assessing compensation payable under the Public Works Act 1981. These are based upon analysis of market transaction data from 1 January 2003 for the broader area within which both the proposed east and west routes have been identified. The relationship between the rating value and sale price has been assessed and applied to the rating values for the identified properties to estimate the land value for each parcel of land.

The easement fee methodology has been successfully adopted in compensation assessments for a range of transmission line build and upgrade projects up to 220 kV lines, but has not been used on 400 kV lines. As a consequence Transpower has necessarily relied on increasing the compensation estimates, relative to the smaller transmission line developments, through an increase in the various factors that impact on land value e.g. increased corridors of effect and increased value loss factors. As a consequence of this and other limitations of the cost modelling Transpower has used the upper end range of the easement cost estimates.

From 2005 easement costs have been increased by 1% per annum to reflect movements in market prices in excess of inflation.

4.2.2 Environmental Costs

Costs have been estimated for securing a designation and resource consents pursuant to the RMA. These estimates are limited to Council processing costs, costs to Transpower of engaging specialist professional and legal advice, Transpower staff, and attending various hearings and court appeals. They do not attempt to allocate value to the environment or any environmental degradation resulting from the project.

Economic costs of securing environmental approvals are closely linked to the likely timeliness of securing designation. Where greater adverse environmental effects are likely to occur, there is an increased requirement for input from technical specialists, and additional consultation (to fully document and identify ways in which to mitigate adverse effects), reporting, compensation, and property negotiation periods. These commitments carry an additional economic cost.

4.3 Operating and Maintenance Costs

The operating and maintenance costs used in the Part IV economic analysis were estimated as:

- $300,000 per annum for new high voltage transmission lines

- 1% of capital cost for substation assets
- $750 per annum per circuit km of underground cable, i.e. $13,500 per annum for two 9km circuits.

5 Assumptions

The following general assumptions have been made in preparing capital cost estimates for this investment:

Cost of Plant and Materials

Material prices are based on budgetary prices obtained from manufacturers/suppliers for approximate quantities estimated from preliminary designs. They are exclusive of economies of scale for purchasing.

Cost of Labour

Installation rates are based on average wage rates and productivity levels in New Zealand and Australia on medium to large projects. Skilled Labour market conditions could dramatically change these estimated rates.

Real costs

Capital cost estimates are in 2005 NZ dollars. No allowance has been made for escalation of prices due to inflation or market conditions.

Project Management Costs

Internal and external project management costs have been assumed at 8% of overall project costs based on experience of large projects.

Allowances for detailed engineering and contractor's project management costs have been based on past experience and are subject to contract type (Engineer,Procure, Construct or Erect only) and market conditions at the time of tendering.

Project Financing Costs (Interest During Construction)

Project financing costs or interest during construction have not been included in the cost estimates. Instead, it has been assumed that these costs can be expensed during project implementation.

Exchange Rates

Budgetary costs have been obtained in the currency of origin and have been converted to $NZ using the 5-year forward exchange rates tabled below.

Currency	2010[1]
NZD/USD	0.5640
NZD/AUD	0.8558
NZD/EURO	0.4343
NZD/SEK	3.9749
NZD/CHF	0.6197
NZD/CAD	0.7286

---

[1] ANZ National Bank, 23 March 2005.

When determining a suitable spot foreign exchange rate for costing purposes, the current two year average spot rate is calculated for the applicable currency. This rate is compared to the current spot rate and the lower of the two rates is used as the ‘advised spot rate’. For future payments out to five years, the current forward foreign exchange points are applied to the ‘advised spot rate’.

These rates are updated on a quarterly basis, or if there is a significant movement in the underlying currency. This methodology is appropriate and is consistent with accepted market practice. It also ensures that future payments are priced off derived forward rates not spot rates.

Hedging

The cost of hedging exchange rates and commodity prices has been included in the cost estimates only to the extent that these are represented in forward rates and prices used to prepare the estimates. It has been assumed that any additional costs of hedging can be expensed during project implementation.

Project Time Frame

Costs have been prepared according to the Project Timeline outlined in Part 1. Delays in the project are likely to increase time dependant costs (most particularly project management and environmental approval costs) and to increase the risk associated with other cost estimates (particularly those affected by factors that vary over time such as exchange rates).

6 Summary of Cost Estimates

Table 6-1 below summarises the order of magnitude costs for the major components of the project.

Category	Item	Cost $m (2005 Real)
Investigations	Preliminary engineering, environmental and property work to establish preferred route and lodge NoR.	20
Property	Acquisition of property rights	97
Environmental	Acquisition of designations and resource consents	11
Transmission works	400 kV line Whakamaru to Otahuhu	120
	Substations – Otahuhu	66
	– Whakamaru	33
	Cable	84
Dismantling	Arapuni to Pakuranga Line	4
Project Management		25
Total		460

Table 6-1: Estimated Capital Expenditure for 400 kV Grid Augmentation from Whakamaru to Otahuhu

The timing of capital expenditures is shown in Figure 6.1. Initial expenditures are focused on the acquisition of a route, with expenditure in the final two years focused on major capital items and cable installation. Expenditure in the final year of the project amounts to 41% of total project costs.

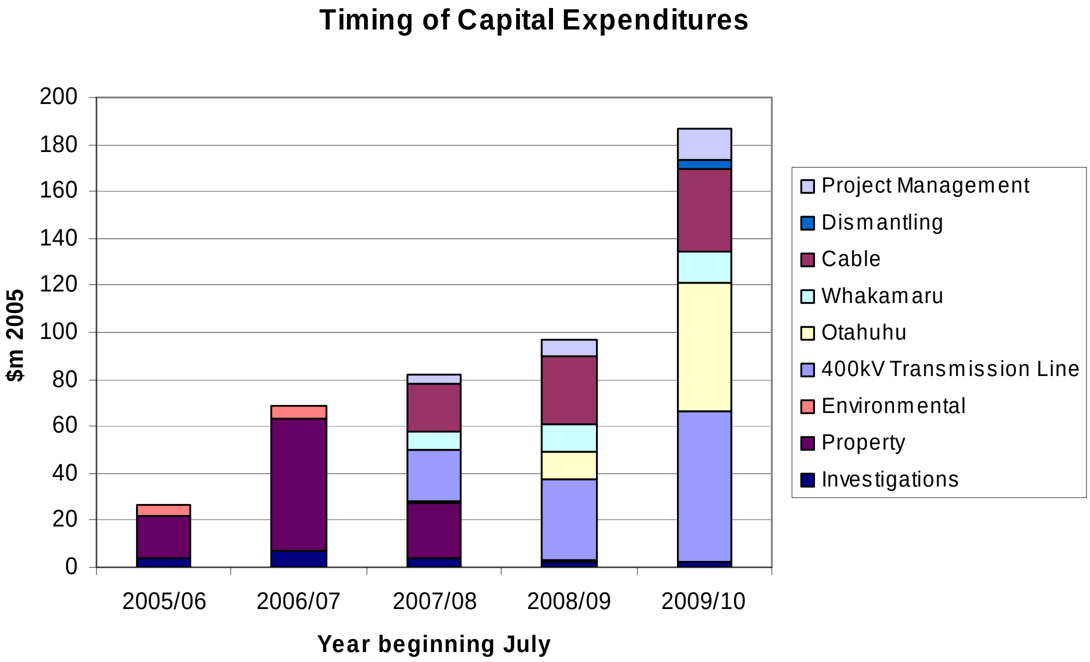


Figure 6-1: Anticipated Incidence of Expenditure on the Proposed 400 kv grid Augmentation project

7 Contingencies

The capital cost estimates provided in the earlier sections of Part V have been prepared to be consistent with the economic methodology described and applied in Part IV. As a consequence the costs differ from those ordinarily presented in business cases (and equally from the type of costs upon which revenue recovery might be based). Furthermore, the costs presented are based on preliminary design work and are order of magnitude costs.

The purpose of this section is to provide a bridge between the project capital costs, and those that might ordinarily be presented in a business case. They are, necessarily, indicative figures. As noted in Section 2, it is envisaged that detailed design for the 400 kV assets will be carried out under some form of "turnkey" or "engineer, procure and construct" contract. Such an arrangement is likely to have a bearing on, amongst other things the design, timing and currency of project expenditures, and therefore the scale of actual costs.

In short this analysis should not be seen as a substitute for the scenario based risk profiling which must take place during the next stage of project implementation.

7.1 Price Contingencies

7.1.1 Inflation Adjustment

Capital cost estimates been calculated in real (2005) dollars in order to maintain consistency with the real discount rate used in the calculation of expected net market benefits, to simplify the calculation of market benefits and costs and to provide greater transparency in the comparison of the proposed transmission investment with non-transmission investment options. The use of real or nominal costs should have no impact on the outcome of the economic analysis in expected net market benefit terms provided the treatment of inflation is consistent throughout the analysis.

Transpower wishes to recover the actual (nominal) costs of the proposed 400 kV investment. Even at modest rates of inflation over five years the difference between real and cost figures can be substantial. Nominal costs have been estimated by applying a 3% inflation rate to the expected expenditure programme. Given the expected timing of costs the difference between real 2005 dollars and nominal costs is approximately $39 million (or 8.6%). Figure 7-1 below shows the relative impact on major capital items.

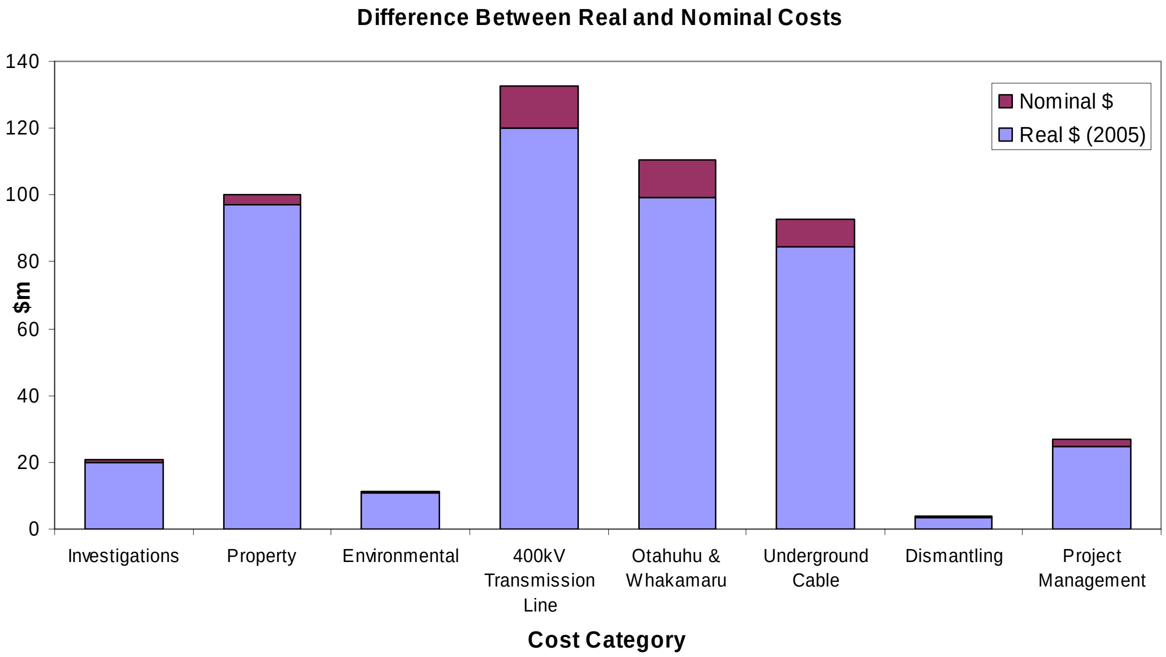


Figure 7-1: Estimated Capital Costs in Nominal Terms

7.1.2 Exchange Rate Adjustment

In preparing the capital cost estimates Transpower has used 5 year forward exchange rates to reflect the rates at which the foreign currency denominated components of the investment might be hedged.

Figure 7-2 shows the proportion of nominal capital costs denominated in the currencies of countries from which the capital works are expected to be sourced. Approximately 54% of the project costs are denominated in New Zealand dollars.

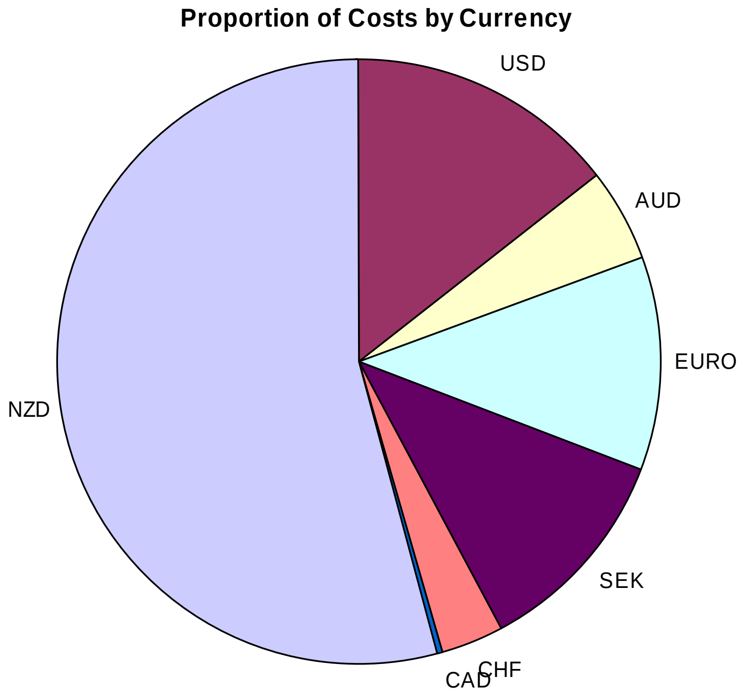


Figure 7-2: Proportion of Expenditure in Various Currencies

While the exchange rates used in preparing Tranpower's cost estimates are forward rates against which Transpower could hedge, it is important to understand the sensitivity of estimated costs to changes in the exchange rate assumptions.

As an alternative to the forward rates assumed in the capital cost estimates, the NZD was assumed to depreciate against the USD from 0.70 NZD per USD to 0.60 in 2010, with a similar level of depreciation against the other main currencies. Rates used in the sensitivity are shown in Table 7.1 below.

Exchange Rate	2005/6	2006/07	2007/08	2008/09	2009/10	2009/10 Cost Estimate Assumption
	Alternative Exchange Rate Assumption					
Nzd/usd	0.700	0.675	0.650	0.625	0.600	0.564
Nzd/aud	0.888	0.856	0.825	0.793	0.761	0.856
Nzd/euro	0.504	0.486	0.468	0.45	0.432	0.4343
Nzd/sek	4.585	4.421	4.257	4.094	3.930	3.975
Nzd/chf	0.766	0.738	0.711	0.684	0.656	0.620
Nzd/cad	0.814	0.784	0.755	0.726	0.697	0.729

Table 7-1: Alternative Exchange Rate Assumption

Adoption of the alternate exchange rate assumptions reduced the nominal capital cost of the 400 kV proposal by $6 million.

7.2 Interest During Construction

Interest during construction has been omitted from the capital cost estimates used in the economic analysis because it is not consistent with the measurement of national benefit[2].

Transpower wishes to recover the actual costs of the proposed 400 kV investment, including a return on capital invested during the commissioning of the project. As noted in Section 4, Transpower's preference is to recover these costs during implementation of the project. An estimate of the scale of nominal interest during construction costs implied by the preliminary cost estimates has been prepared, using a 10% pre-tax nominal discount rate[3]. This amounts to $64 million over the period of project disbursements.

7.3 Physical Contingencies

High level estimates of physical contingencies have been estimated for major components of the capital spend using Monte Carlo simulation, in conjunction with the estimates provided, and any information on the likely cost impact of exclusions identified in Section 3. Note however that these contingencies are not intended to cover variations in design or specification.

Lines

Approximately 5% of cases in the Monte Carlo simulation generated project costs higher than $144 million. Deducting from this the preliminary cost estimate of $120 million gives a physical contingency for transmission line costs of $24 million, or 20%. This figure must also be grossed up for inflation, exchange rate and interest during construction, producing a final contingency estimate of $28 million in nominal terms.

Substations

Approximately 5% of cases in the Monte Carlo simulation generated project costs higher than $115 million. Deducting from this the preliminary cost estimate of $99 million gives a physical contingency for substation costs of $16 million, or 16%. This figure must also be grossed up for inflation, exchange rate and interest during construction, producing a final contingency estimate of $17 million in nominal terms.

Underground Cable

Approximately 5% of cases in the Monte Carlo simulation generated project costs higher than $101 million. Deducting from this the preliminary cost estimate of $84 million gives a physical contingency for transmission line costs of $17 million, or 20%. This figure must also be grossed up for inflation, exchange rate and interest during construction, producing a final contingency estimate of $20 million in nominal terms.

---

[2] In a national cost/benefit framework the opportunity cost of an investment to society is represented though the discount rate. Interest during construction represents the opportunity cost of an investment to providers of funds, and is in essence a value transfer paid by beneficiaries to investors to ensure that the investment takes place. As a general principle such value transfers should net out of the economic analysis.

[3] This is consistent with the 7% pre-tax real discount rate applied in the economic test, adjusted for 3% inflation.

It should be noted that this contingency does not cover variation in the length of the underground cable.

Easements

Easement costs were prepared by a qualified external expert. To ensure consistency with the approach taken in preparing those estimates no allowance is made here for further contingent amounts.

7.4 Summary

Table 7-2 provides a summary of the various contingent amounts that have been discussed in this section.

	Real Cost excluding Contingencies $m 2005	Impact of Inflation $m	Exchange Rate Variation $m	Interest During Construction $m	Physical Contingency $m	Nominal Cost including Contingencies $m
Investigations	20	1		5		26
Property	97	3		33		133
Environmental	11	0		4		15
Lines	120	13	-1	8	28	167
Substations	99	11	-4	4	17	128
Underground Cable	84	8	-1	7	20	119
Dismantling	4	0		0		4
Project Management	25	2		3		30
Total	460	39	-6	65	65	622

Table 7-2: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $162 million. However interest during construction and inflation (which do not affect the economic merits of the project) represent $104 million of this difference. Physical contingencies are 14% of real capital costs, but it should be noted that these cover only a limited number of potential variations in project costs.

Transpower wishes to recover the actual costs of the proposed 400 kV investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be. However it would be inappropriate to establish a final set of project costs for recovery at this stage.