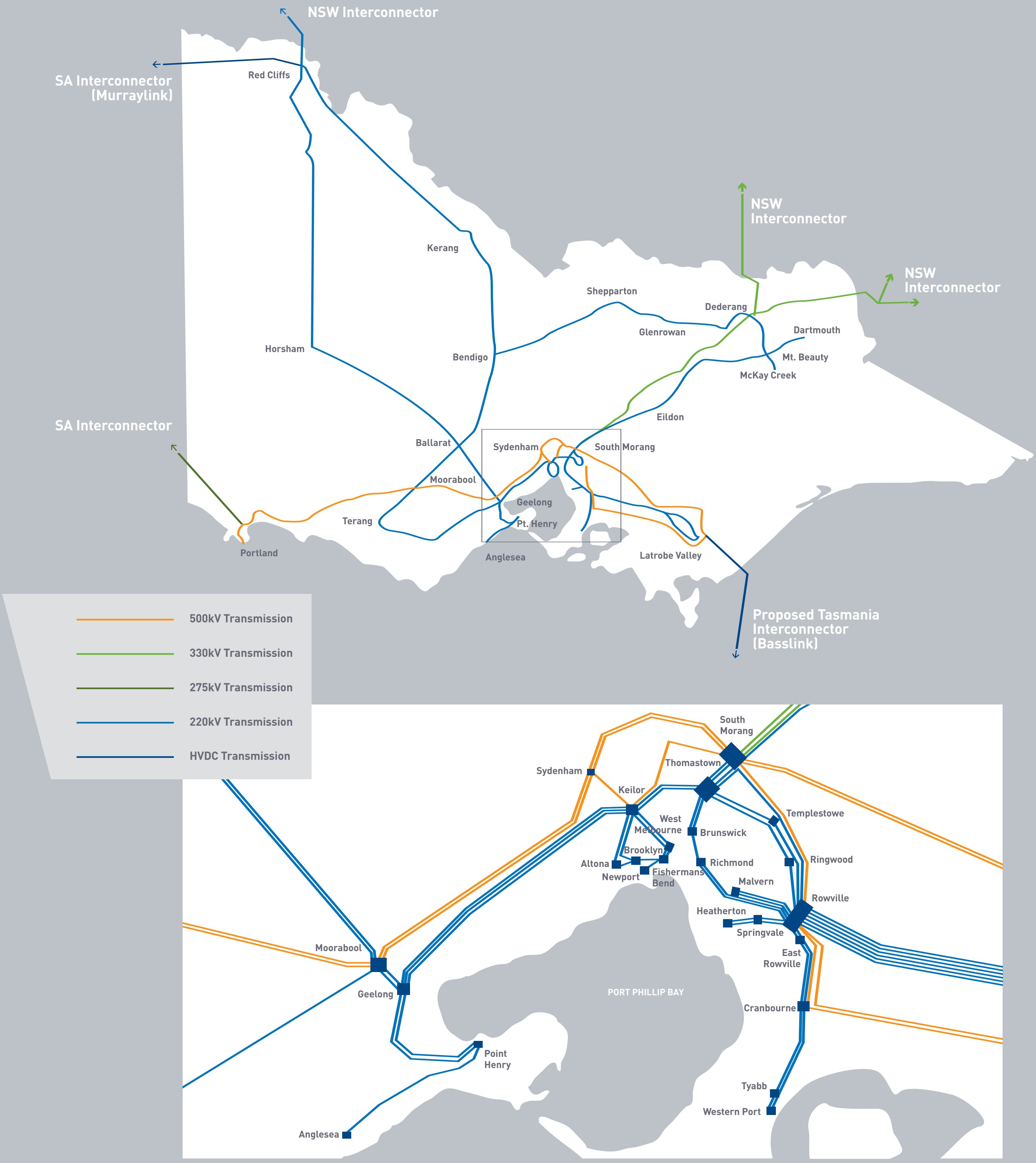
2005

ELECTRICITY ANNUAL PLANNING REPORT

VENCorp


NSW Interconnector
SA Interconnector (Murraylink)
Red Cliffs
Kerang
NSW Interconnector
NSW Interconnector
Shepparton
Dederang
Glenrowan
Dartmouth
Horsham
Bendigo
Mt. Beauty
McKay Creek
SA Interconnector
Eildon
Ballarat
Sydenham
South Morang
Moorabool
Geelong
Pt. Henry
Terang
Portland
Anglesea
Latrobe Valley
Proposed Tasmania Interconnector (Basslink)
500kV Transmission
330kV Transmission
275kV Transmission
220kV Transmission
HVDC Transmission
South Morang
Sydenham
Thomastown
Keilor
West Melbourne
Templestowe
Brunswick
Brooklyn
Altona
Newport
Fishermans Bend
Richmond
Ringwood
Malvern
Rowville
Heatherton
Springvale
Moorabool
East Rowville
Geelong
PORT PHILLIP BAY
Cranbourne
Point Henry
Tyabb
Western Port
Anglesea

2005

DISCLAIMER

VENCorp's role in the Victorian electricity supply industry includes planning and directing augmentation of the shared transmission network. As part of that function, the National Electricity Code and the Victorian Electricity System Code require VENCorp to publish this report on the load forecasts and adequacy of the electricity transmission system to meet the medium and long-term requirements of Victorian electricity consumers.

The purpose of the report is to provide information about VENCorp's assessment of the transmission system's likely capacity to meet demand in Victoria over the next ten years, and about VENCorp's plans for augmentation of the transmission network.

VENCorp has prepared this document in reliance upon information provided by, and reports prepared by, a number of third parties (which may not have been verified). Anyone proposing to use the information in this document should independently verify and check the accuracy, completeness, reliability and suitability of the information in this document, and the reports and other information relied on by VENCorp in preparing it.

This document also contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth scenarios, load growth forecasts and developments in the National Electricity Market. These assumptions may or may not prove to be correct.

The document also contains statements about VENCorp's plans. Those plans may change from time to time without notice and should therefore be confirmed with VENCorp before any action is taken based on this document.

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EXECUTIVE SUMMARY

VENCorp is the provider of shared electricity transmission network services in Victoria, and has responsibilities under various legal and regulatory instruments to plan and direct the augmentation of the shared transmission network within Victoria. As such, VENCorp is registered as the Transmission Network Service Provider for the shared transmission network in Victoria under the National Electricity Code. This Annual Planning Report examines the adequacy of the Victorian transmission network to meet the long term requirements of Victorian industry participants and provides the first step in VENCorp's consultation with interested parties in relation to possible future transmission network augmentation. Information relating to the generation supply and demand balance in Victoria is addressed in NEMMCO's Statement of Opportunities.

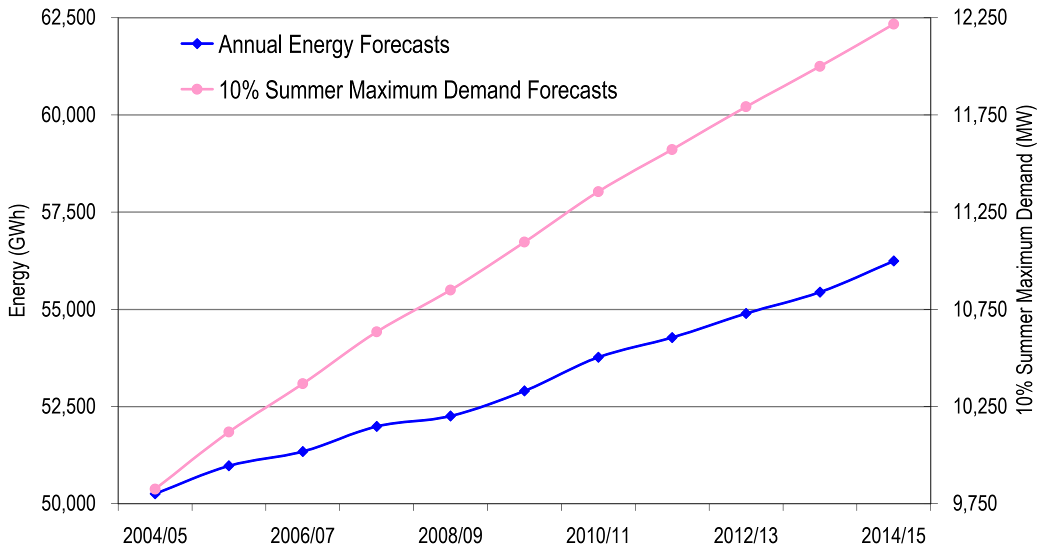
Energy/Demand Forecasts

VENCorp engaged the National Institute of Economic and Research to update forecasts of annual energy and summer and winter maximum demand, for the next 10 years from 2005/06 to 2014/15 based on three economic growth scenarios.

The following table and chart summarise the forecasts for the medium economic growth scenario. The summer and winter maximum demand forecasts are based on the 10% probability of exceedence temperature standards, which are exceeded not more than 1 in every 10 years.

	2005/06	2009/10	2014/15	Average Growth 2005/06 to 2009/10	Average Growth 2009/10 to 2014/15
Victorian GSP Growth (Medium Growth Scenario)	2.6%	2.3%	3.0%	2.3%	2.8%
Forecast Annual Energy (GWh)	50,976	52,901	56,247	1.0%	1.2%
Forecast 10% Summer Maximum Demand (MW)	10,119	11,097	12,218	2.5%	1.9%
Forecast 10% Winter Maximum Demand (MW)	8,111	8,687	9,546	1.6%	1.9%

The annual energy is projected to grow at an average rate of 1.0% over the next 5 years to 2009/10, and then 1.2% pa to 2014/15. Summer maximum demand forecasts are projected to grow faster than annual energy at an average growth rate of 2.5% pa over 2005/06 - 2009/10, and then 1.9% pa over the following 5 years to 2014/15 reflecting a slower penetration of cooling appliances and the impact of both the Federal and State greenhouse policies.



Network Adequacy

A review of the adequacy of the Victorian electricity transmission network to meet the actual and forecast 2004/05 summer peak demand conditions has been carried out. Highlights of the assessment include:

- The peak electricity demand experienced in Victoria in summer 2004/05 was 8,535 MW, on Tuesday 25 January 2005. The temperature conditions on this day were consistent with the 90% probability of exceedence level.
- The Victorian shared transmission network has been economically designed to securely supply an aggregate demand of 9,885 MW. Therefore, the network was operated well within its design capability during the year, with the actual peak demand being 1,350 MW below the maximum supportable demand.
- The intra / inter-regional transfer levels and Victorian prices during summer 2004/05 were only minimally impacted by planned outages associated with augmentation projects and forced network outages. No significant system incidents or bushfires occurred to cause price volatility during summer 2004/05.

Committed Augmentations

These are a number of transmission augmentations currently underway affecting the Victorian shared transmission network. Projects expected to be completed in the next 12 months include:

- 4th 500 kV Latrobe Valley to Melbourne Line;
- Murraylink Regulation Project;
- Basslink interconnector between Victoria and Tasmania;
- A number of 220 kV line upgrades in the south east metropolitan Melbourne area; and
- Installation of a number of wind monitoring schemes across Victoria.

Planned Augmentations

Options to relieve the constraints analysed in this Annual Planning Report have been categorised as follows, and are shown on the following page:

Large Network Augmentations

These are augmentations which have an estimated capital cost of greater than $10M, which require a separate and more detailed regulatory test application and consultation. Based on its initial assessment, VENCorp will undertake a detailed regulated test assessment in the coming months for the following projects:

- Installation of a second 500/220 kV Moorabool transformer by around 2008 to alleviate constraints on the Keilor 500/220 kV transformers and Keilor to Geelong 220 kV lines; and
- Installation of a fifth 500/220 kV Hazelwood transformer to alleviate constraints on the existing Hazelwood transformers, with a service date between 2008 and 2010.

A detailed regulatory test assessment has already been undertaken and consultation commenced for a second 500/220 kV Rowville transformer, with an expected service date of September 2007.

Small Network Augmentations

These are augmentations which have an estimated capital cost of between $1M and $10M for which the Annual Planning Report forms the basis of the formal consultation. There are no small network augmentations being consulted on this year.

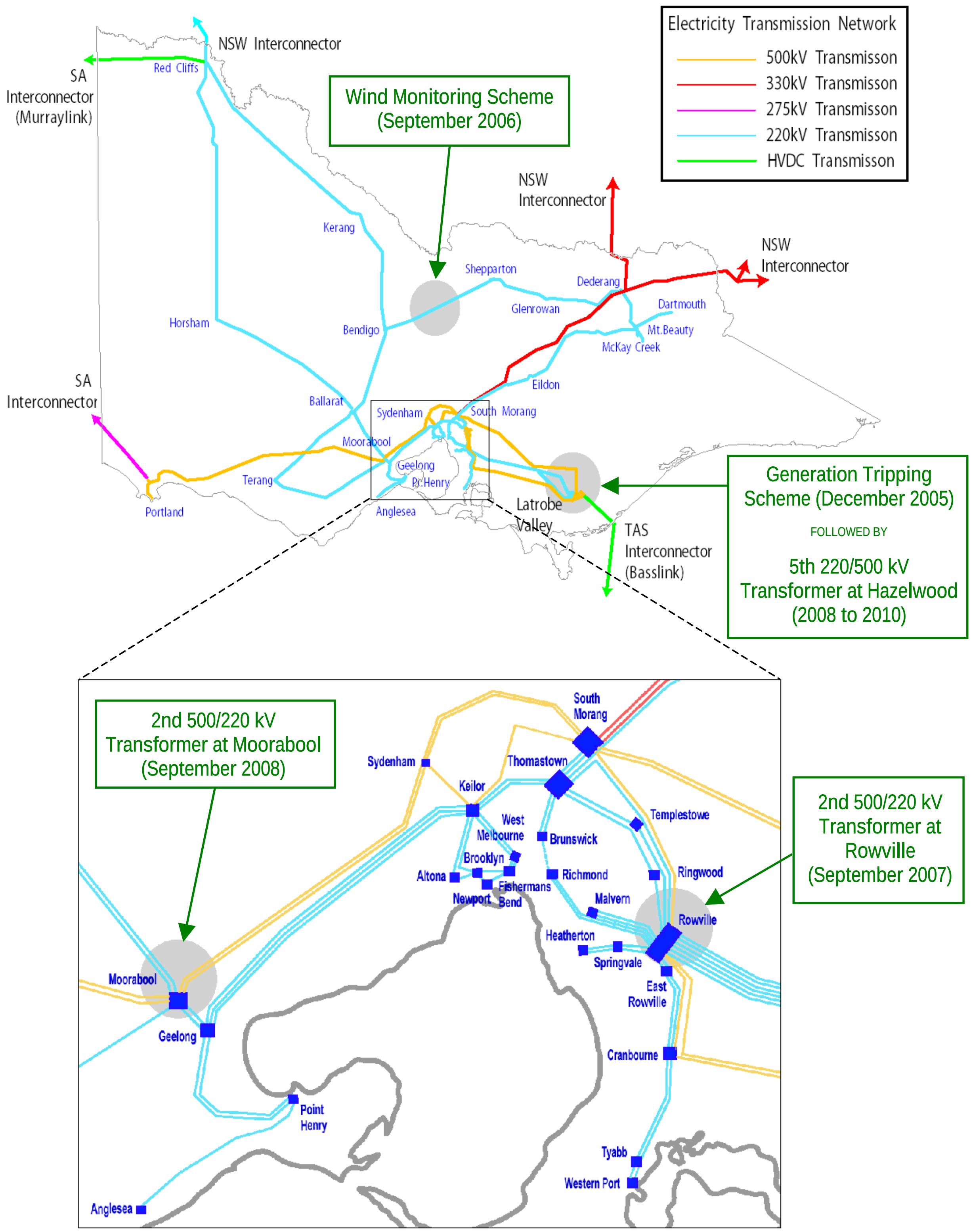
Minor Network Augmentations

These are augmentations which have an estimated capital cost of less than $1M, and as such do not require a formal consultation. The following projects, and the constraints being alleviated, are presented for participant information:

- Increase line capacity by the installation of a wind monitoring scheme on the Shepparton-Fosterville-Bendigo 220kV line by September 2006; and
- Installation of a control scheme, which would trip one or more generators in the event of loss of a Hazelwood transformer by December 2005. This is proposed to be an interim arrangement until new transformation is justified, and is subject to agreement with affected generators.

Emerging Constraints

Augmentation to mitigate the potential impacts of these constraints is not presently economically justified. These emerging constraints were identified in previous Annual Planning Reports, and will be reassessed in VENCorp's 2006 Electricity APR.


Electricity Transmission Network
500kV Transmisson
330kV Transmisson
275kV Transmisson
220kV Transmisson
HVDC Transmisson
NSW Interconnector
SA Interconnector (Murraylink)
Red Cliffs
Wind Monitoring Scheme (September 2006)
NSW Interconnector
NSW Interconnector
Kerang
Shepparton
Dederang
Glenrowan
Dartmouth
Mt.Beauty
McKay Creek
Horsham
Bendigo
SA Interconnector
Ballarat
Eildon
Sydenham
South Morang
Moorabool
Geelong
Pt.Henry
Terang
Portland
Anglesea
Latrobe Valley
TAS Interconnector (Basslink)
Generation Tripping Scheme (December 2005)
FOLLOWED BY
5th 220/500 kV Transformer at Hazelwood (2008 to 2010)
2nd 500/220 kV Transformer at Moorabool (September 2008)
South Morang
Sydenham
Thomastown
Keilor
West Melbourne
Brunswick
Templestowe
Brooklyn
Altona
Richmond
Ringwood
Fishermans Bend
Newport
Malvern
Rowville
Heatherton
Springvale
East Rowville
Moorabool
Geelong
Cranbourne
Point Henry
Tyabb
Western Port
Anglesea
2nd 500/220 kV Transformer at Rowville (September 2007)

Possible Network Developments

An indication of potential network constraints that may occur in the period up to 2014/15, together with transmission options to remove the constraints, assuming the full forecast Victorian demand is to be supported, is provided.

For this study the network has been modelled with a demand of 12,600 MW. To meet this demand and to allow for up to 300 MW export to South Australia, approximately 2,100 MW of additional new generation will need to be added by 2014/15, assuming 1900 MW and 600 MW is available from New South Wales and Tasmania respectively. As the location and size of generation will impact on the transmission needs, a range of supply scenarios, which load different parts of the transmission network, have been examined. These scenarios were selected as they give reasonable extremes for transmission network development.

The table below provides a summary of the five scenarios examined.

	Increased Latrobe Valley Generation (MW)	Increased Import from NSW/Snowy (MW)	Metro/State Grid Generation/DSM (MW)	Total Capital Cost ($M)
Scenario 1	1,800	0	300	497
Scenario 2	1,320	180	600	381
Scenario 3	720	180	1,200	373
Scenario 4	900	600	600	429
Scenario 5	200	1,600	300	629

A range of other scenarios are possible, and they are likely to result in different transmission requirements. In particular, for import levels from Snowy/NSW that require more than 1600MW, significant additional augmentation may be required, possibly in the form of HVDC links. However, the Latrobe Valley to Melbourne transfer capability designed for scenario 1 will accommodate at least an additional 1000MW of generation from the Latrobe Valley.

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APPENDICES

1. INTRODUCTION

VENCorp is the Transmission Network Service Provider for the shared transmission network[1] in Victoria under the National Electricity Code, and as such has entered into an access undertaking with the ACCC pursuant to the National Electricity Code regarding provision of access to the transmission network.

VENCorp's functions in relation to electricity are:

- to plan and direct the augmentation of the shared transmission network, to provide an economic level of transmission system capability consistent with market reliability requirements and expectations, and to advise and liaise with NEMMCO on network constraints, including interconnection transfer limits;
- to procure 'bulk' transmission network services from asset owners consistent with the above;
- to provide shared transmission network services to network users for a price in accordance with the National Electricity Code and ACCC requirements;
- to monitor and report on the technical compliance of connected parties to the shared transmission network in terms of quality of supply and control systems, and provide power system data and models to NEMMCO;
- to participate in market development activities in the areas that affect VENCorp's functions;
- to assist in managing an electricity emergency by liaising between the government and NEMMCO, communicating with the Victorian industry and community both before and during an emergency and entering into agreements with distributors and retailers regarding load shedding arrangements; and
- to provide information and support to the Victorian Government.

The National Electricity Code requires VENCorp, to undertake an annual planning review and publish an Annual Planning Report by 30 June each year, which must set out:

- The forecast loads submitted by Distribution Network Service Providers;
- Planning proposals for future connection points[2];
- A forecast of constraints and inability to meet network performance requirements; and
- Detailed analysis of all proposed augmentations to the network.

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[1] The term 'shared network' is defined in VENCorp's electricity transmission licence (www.esc.gov.au).

[2] The adequacy and reliability of the distribution networks, which are owned, operated, maintained and planned by the distribution businesses, have not been considered in this document. These issues are subject to oversight by the Essential Services Commission (ESC). Distribution businesses are also responsible for the planning of the transmission connection assets from which they take supply, and they publish a connection asset planning document (in accordance with obligations set out in their distribution licences) that is available on their specific websites.

The National Electricity Code requires NEMMCO to publish a Statement of Opportunities (SOO) and an Annual National Transmission Statement (ANTS) report each year, which examine the supply/demand balance within each region of the national market, and the capability of national transmission flow paths.

The Victorian Distribution Code requires the five Victorian electricity distribution businesses to publish a joint Transmission Connection Planning Report (TCPR), which examines of the adequacy of the facilities that connect their distribution systems to the shared transmission network.

Those documents, along with this Annual Planning Report, provide information to industry participants and potential participants on opportunities to invest in infrastructure, or to connect loads or generation.

Given VENCorp's functions and the planning responsibilities of the Victorian distribution businesses, and NEMMCO, the scope of VENCorp's Electricity Annual Planning Report is confined to assessing the adequacy of the Victorian shared transmission network to meet Victorian load growth over the next 10 years. The Annual Planning Report does not define a specific future development plan for the shared network. Rather, it is intended to be a key step in the provision of an economically optimum level of transmission system capacity.

This Annual Planing Report is structured as follows:

Chapter 2: A summary of relevant committed developments that will impact on the major national transmission flow paths.

Chapter 3: Intra-regional energy/demand projections of future Victorian load, which takes into account the variability of load with temperature, and different economic scenarios. Reconciles the recent performance of the load forecasts and provides commentary on the important characteristics of Victorian electricity demand.

Chapter 4: Review of the intra-regional network adequacy to meet the forecast demand.

Chapter 5: Information on committed intra-regional network augmentations.

Chapter 6: Information on proposed intra-regional network developments within 5 Years. Potential transmission constraints over the next five years are assessed and transmission augmentation options available to maintain the reliability of the network in the most economic manner are then considered.

Chapter 7: Information on possible intra-regional network developments within 10 Years. This provides a guide as to the developments that are likely to occur in the period beyond the detailed 5 year planning timeframe.

VENCorp would be pleased to provide any interested party with more detailed information on specific planning issues at any time. Interested parties should contact:

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Fax: 03 8664 6511
Email: vencorp@vencorp.vic.gov.au
Website: www.vencorp.com.au

In line with a continuous improvement focus, any interested parties wishing to comment on the format and content of this report, are encouraged to do so by emailing VENCorp at the above address.

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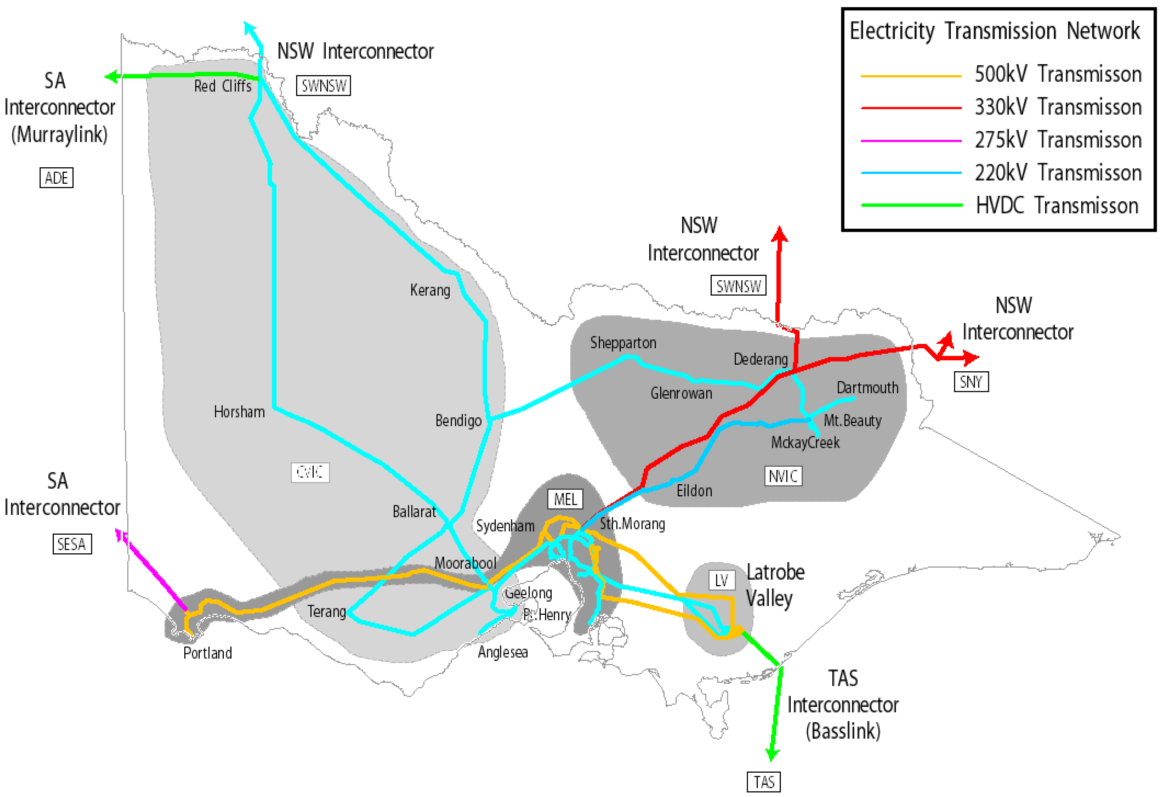
2. SUMMARY OF RELEVANT MAJOR NATIONAL TRANSMISSION FLOW PATH DEVELOPMENTS

2.1 Introduction

This chapter provides a summary of relevant major national transmission flow path developments, which are committed projects. The definition of a major national flow path development is as follows:

"Major national transmission flow path" means those elements of the transmission networks used to transport significant amounts of electricity between generation centres and major load centres.

The shaded areas in Figure 2.1 details the centres between which the major national flow paths in Victoria can be deduced:



MEL – Melbourne
LV – Latrobe Valley
NVIC – Northern Victoria
CVIC – Central Victoria
TAS – Tasmania
ADE – Adelaide
SESA – South East South Australia
SWNSW – South West New South Wales
SNY – Snowy

Figure 2.1 – Major Generation and Load Centres across Victoria

The committed projects, which have an impact on major flow paths within Victoria, are:

- 4th 500kV Latrobe Valley to Melbourne Line [LV – MEL]
- Murraylink Regulation Project [CVIC – ADE]
- Basslink, interconnector between Victoria and Tasmania [LV – TAS]

2.2 4th 500 kV Latrobe Valley to Melbourne Line

In 2002/03, VENCorp undertook a public consultation process on its assessment of the optimum capacity for the Latrobe Valley to Melbourne electricity transmission network. This was in accordance with the requirements of the ACCC Regulatory Test, and from this process it was identified that one of the Latrobe Valley to Melbourne transmission lines should be converted from operation at 220 kV to operation at 500 kV, and that a 500/220 kV 1,000 MVA transformer should be installed at a new station at Cranbourne for service by December 2004.

This project reduces the risk of load shedding as a result of 500 kV line outages, reduces transmission losses and will further improve the reliability and security of supply to the eastern metropolitan area. It will also compliment the distribution businesses' development of 220/66 kV transformation at Cranbourne.

Following a tender process commenced in April 2003, VENCorp contracted with SP AusNet for provision of the contestable network services which comprise the 500 kV switchyard and a 500/220 kV 1,000 MVA transformer at Cranbourne. The non-contestable works including conversion of the Hazelwood to Rowville No.3 line for operation at 500 kV, reconfiguration and circuit breaker replacement in the Latrobe Valley and reinstatement of the Hazelwood to Jeeralang No.2 220 kV line, are being carried out under contracts with the incumbent network owners, SP AusNet and Rowville Transmission Facility Pty Ltd.

The project has been delayed and is expected to be in service prior to summer 2005/06.

2.3 Murraylink Regulation Project

Murraylink is an electricity transmission asset operated by the Murraylink Transmission Company (MTC). It provides a connection between Red Cliffs Terminal Station in Victoria and Monash substation in South Australia and has a rated capacity of 220 MW. The connection was established as a privately funded transmission asset, operating as a market network service.

In October 2003, the ACCC approved MTC's application for conversion from a market network service to a prescribed service and set the maximum allowable revenue. As part of its decision, the ACCC approved augmentations to the Victorian shared transmission network which will allow for 220 MW transfer capacity across Murraylink from Victoria to South Australia during peak periods. The works involve seven new capacitor banks, modifications to five existing capacitor banks and schemes for very fast run-back of Murraylink for transmission outages.

The ACCC consulted on this project and was satisfied that the augmentation works meet the requirements of the regulatory test. Construction of the various augmentation works commenced in the second half of 2004, and the project is expected to be completed prior to summer 2005/06.

2.4 Basslink

Basslink is a planned monopolar DC link, with connection points at Loy Yang 500 kV bus in Victoria's Latrobe Valley and George Town 220 kV bus near Tasmania's north coast. The technology of the converter stations utilises solid-state thyristor switched converter bridges.

Its design capacity is 480 MW continuous import from Tasmania and up to 600 MW short term, and 500 MW export to Tasmania.

Preliminary assessment has been made to determine the effect Basslink has on Victorian export limits, based on transient stability, voltage control and thermal considerations. The assessment shows only a minor impact (less than 80 MW) on export capability to Snowy and South Australia with concurrent 500 MW export to Tasmania. Import capability from Snowy may be reduced by around 30 MW for the full 600 MW import from Tasmania. This reduction corresponds to the difference between Basslink capacity and the largest Victorian generator output, which is presently around 570 MW. For further information on Basslink see the NEMMCO website (www.nemmco.com.au) for the Interconnector Options Working Group (IOWG) technical assessment.

Basslink is a market network service and is planned for service in April 2006.

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3. INTRA-REGIONAL ENERGY/DEMAND PROJECTIONS

3.1 Introduction

This chapter presents Victorian electricity annual energy, and summer and winter Maximum Demand (MD) forecasts for the next 10 years to 2014/15. The load forecasts will be consistent[3] with those included in the 2005 Statement of Opportunities (SOO) prepared by NEMMCO. A review of 2004/05, including an assessment of the forecast variance based on last year's forecasts, is also discussed.

Details of the forecast methodologies, assumptions and other supporting load analysis are provided in Appendices A1 to A9. The Appendices are an integral part of the forecast chapter and contain detailed background information that will provide the basis for a good understanding of the load forecasts.

Energy refers to energy generated at Victorian generator terminals[4] scheduled under NEMMCO dispatches, less interstate net exports. Consistent with the above definition, demand is the demand averaged over each half-hourly trading interval. Daily MD is the highest half-hourly average demand for a given day. Summer (or winter) MD is the highest half-hourly average demand for a given summer (or winter).

Historical load data, available from SP AusNet, is used for load forecasting purposes. This data may not match exactly with that published by NEMMCO, due to different methods[5] of data calculations.

Daily average temperatures[6] are referred to throughout this chapter, and are a key input to the MD forecasts. Temperature data pertains to the Melbourne CBD weather station unless specified otherwise.

3.2 Review of Year 2004/05

This section presents the key highlights of the last 12 months to end of April 2005. A comparison of the projected annual energy and summer and winter maximum demands for 2004/05 with last year's forecasts is given in Sections 3.4.1, 3.5.1 and 3.6.1 respectively.

The weather in both winter (June to August) and summer (December to February) was mild. However, April 2005 was the hottest ever for Melbourne.

There was adequate generation to meet both winter and summer demands during the year and there were no supply incidents requiring load shedding.

Annual energy to end of April 2005 was 49,764 GWh, about 1.2% higher than the energy of 49,174 GWh for the same period a year ago.

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3 NEMMCO published sent-out energy which excludes generators' own-use

4 A list of scheduled generation in the National Electricity Market is available from the NEMMCO website (www.nemmco.com.au)

5 NEMMCO published demand is calculated based on demand data recorded at each 5 minute interval whereas SP AusNet records demand data at each 4 second interval

6 Average of daily maximum temperature from 9:00AM and overnight minimum temperature to 9:00AM of a given day

Table 3.1 shows the highest summer daily energy (and also the highest summer demand) was recorded on 25 January 2005, with 163.1 GWh and daily average temperature of 27.3°C. In comparison, the highest winter daily energy was 156.6 GWh on 23 July 2004 with 9.4°C, and was 4% lower than the maximum summer daily energy due to mild winter weather. Historically, the highest energy values used to be in winter.

Season	Date	Day of Week	Daily GWh	Daily Average Temp(°C)
Summer	25-Jan-05	Tue	163.1	27.3
Winter	23-Jul-04	Fri	156.6	9.4

Table 3.1 – Highest Summer and Winter Daily Energy

Table 3.2 shows the top 5 summer demand days in 2004/05. Peak summer half-hourly demand of 8,535 MW, occurred on 25 January 2005, the 5th warmest day of the year with an average temperature of 27.3°C. Historically, this mild summer temperature is exceeded, on average, not more than 9 in 10 years (corresponding to a 90% Probability of Exceedence (POE)). The POE of summer and winter MD average temperatures are explained in detail in Appendix A1. Australia Day, 26 January 2005, was the hottest day of the year but was not included in Table 3.2 because industrial load was much lower than for a normal weekday. The demand on 1 March and 28 January would have been higher if the cool changes did not arrive early, around 2:00pm on both days. Figure 3.1 shows a sharp fall in the half-hourly demand following the cool change, with temperature dropping by 7 to 8 degrees within half an hour.

Date	Day of Week	Demand (MW)	Time of Day (AEST)	Daily Average Temp(°C)	POE(%)[7]	Comment
25-Jan-05	Tue	8,535	4:30pm	27.3	90%	Educational Institutions still closed
01-Mar-05	Tue	8,424	2:00pm	28.8	61%	Cool Change
28-Jan-05	Fri	8,343	2:00pm	28.6	67%	Cool Change
23-Feb-05	Wed	7,950	4:00pm	26.5	93%	
11-Jan-05	Tue	7,928	4:00pm	29.5	50%	Public Holiday, Reduced industrial load

Table 3.2 – Top 5 Summer 2004/05 Maximum Demand

7 Refer to Appendix A1 for discussion on temperature standards for Summer and Winter MD

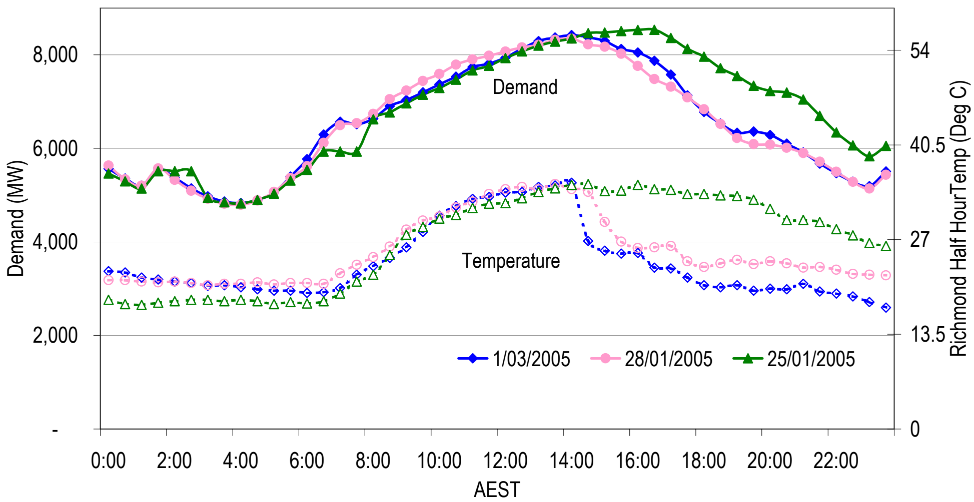

Figure 3.1 – Selected Summer 2004/05 High Demand Day Profiles

Table 3.3 shows the top 5 MD days in winter (Jun-Aug) 2004, all with similar demand between 7,415 MW and 7,435 MW. Daily average temperature on these days varied between 9.2°C and 11.5°C. Historically, these mild temperatures on winter peak demand days are exceeded, on average, not more than 9 in 10 years (90% POE). The POE of summer and winter MD average temperatures are explained in detail in Appendix A1.

Date	Day of Week	Demand (MW)	Time of Day (AEST)	Daily Average Temp(°C)	POE
23-Jun-04	Wed	7,435	6:00pm	11.4	>90%
28-Jul-04	Wed	7,434	6:30pm	10.7	>90%
22-Jul-04	Thu	7,426	6:30pm	9.2	>90%
17-Jun-04	Thu	7,417	6:00pm	9.5	>90%
26-Jul-04	Mon	7,415	6:30pm	11.5	>90%

Table 3.3 – Top 5 Winter 2004 Maximum Demand

Load duration curves (LDCs) depict the half-hourly demands for a given year, sorted from highest to lowest. Victorian demands peak in summer, and hence summer demands are placed in the top part of the LDCs. The shape of the top part of the LDCs is an indicator of how warm a given summer is. Figure 3.2 compares the shape of the top part of the LDC of an average summer in 2004/05 with those of a warm summer in 1996/7 and a cool summer in 2001/02.

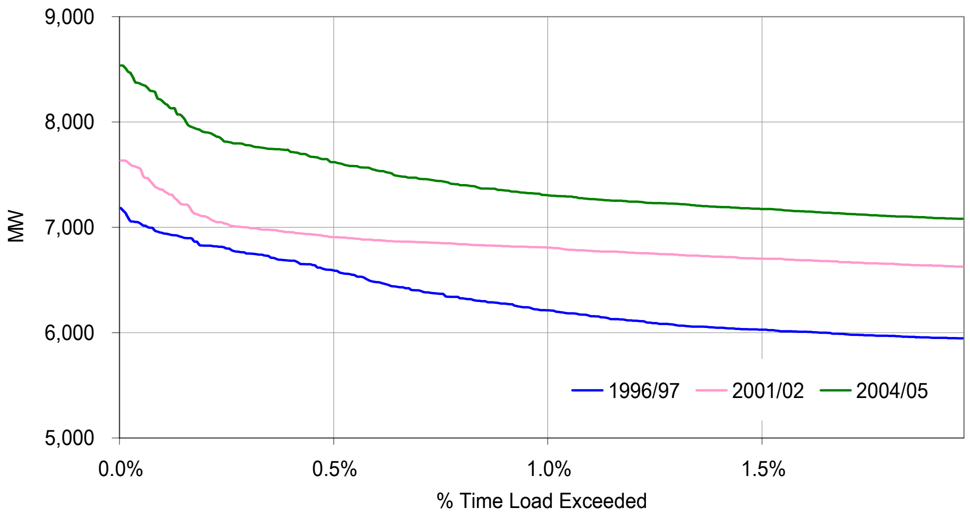

Figure 3.2 – Comparison of Load Duration Curves

3.3 Forecast Approach

VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to prepare Victorian long-term electricity energy and demand forecasts for Medium, High and Low economic growth scenarios.

NIEIR has developed an integrated multi-purpose model linking economic projections to energy forecasts. An overview of the forecast approach and key drivers of the load forecasts is presented in this section. Further details are included in Appendix A3.

3.3.1 Economic Projections

This section discusses Victorian Gross State Product (GSP) projections from 2004/05 to 2014/15. The basis of the projections and other key economic indicators are presented in Appendix A4.

The economic projections are based on Australian National Accounts and State Accounts[8] data to December 2004 such that the figures for 2004/05 are partly forecast, based on six months of actual data. The GSP projections were prepared in March-April 2005 prior to the announcements of the 2005/06 State and Commonwealth Budgets.

The Victorian GSP for 2004/05 is projected to grow at 1.8%, and is 0.4% lower than last year's Medium growth projection of 2.2%, due to lower than expected growth in private consumption, weak government investment and a slowdown in the residential housing sector.

The projected Victorian GSP growth is lower, compared with that in the Northern States and the national average, by 0.2% to 0.7% over the next 5 years. The Victorian GSP is expected to grow by an average of 2.3%, 3.2% and 1.6% pa over the next 5 years under the Medium, High and Low growth scenarios respectively. A sharp fall in the State GSP is projected for 2008/09 coinciding with a predicted economic slowdown in China following the Beijing Olympics. The economy is projected to grow stronger over the following 5 year period at 2.8%, 3.6% and 1.9% pa under the Medium,

8 ABS data was used for State projections

High and Low growth scenarios respectively. NIIEIR is of the view that the likelihood of the Low growth scenario has increased due to reduced export capacity and the growing current account deficit. The projected Victorian GSP scenarios are shown in Figure 3.3.

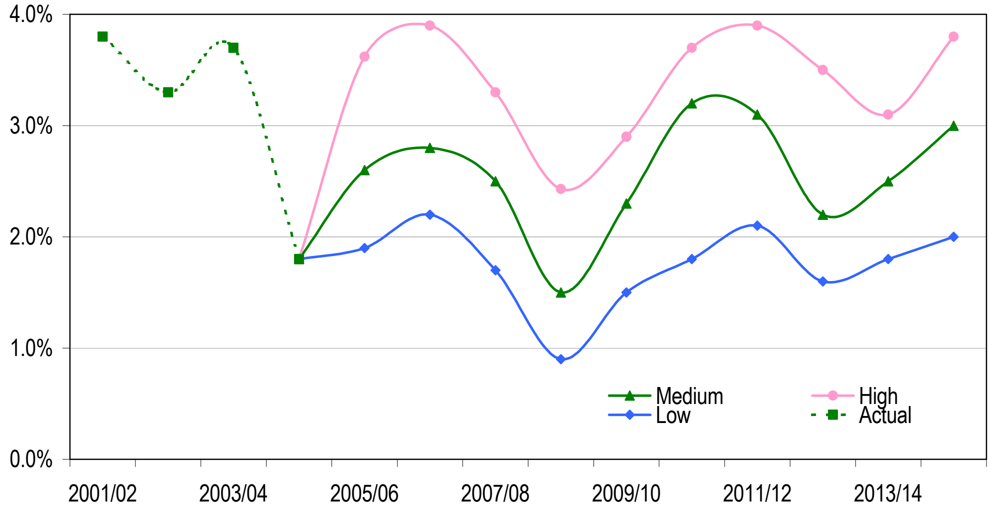

Figure 3.3 – Victorian GSP Projections

Figure 3.4 compares the Medium growth scenario in this year's forecasts with that included in the 2004 Electricity Annual Planning Report. The projected average GSP growth, over the next 5 years, is now 0.2% lower than last year's projections averaging 2.5% pa. The longer-term forecast average growth is identical in both forecasts, except a difference in the timing of the business cycle.

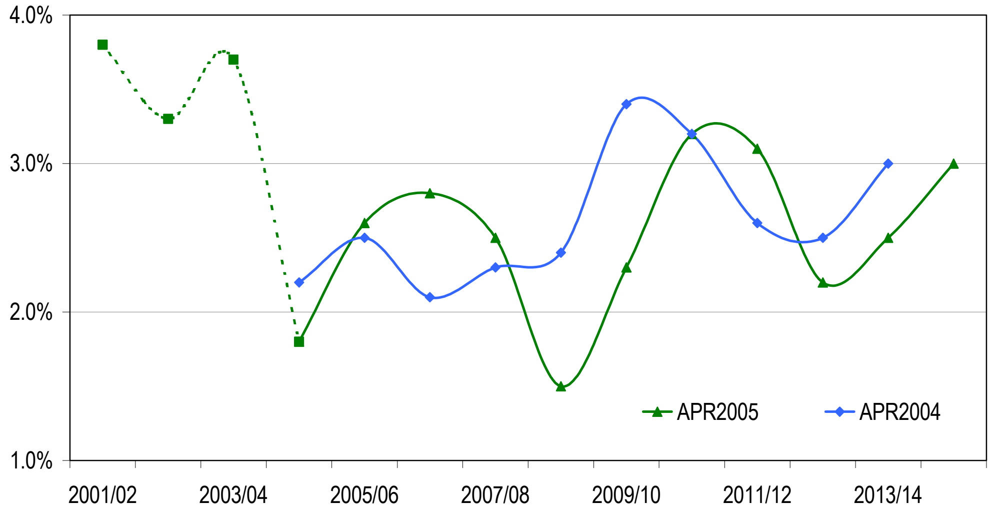

Figure 3.4 – Victorian GSP Projections Comparison

NIEIR's Medium GSP growth projections for the next 2 financial years are consistent with those prepared by Access Economics[9], but lower than the average growth of 3.3% pa in the 2005/06 State Budget. While NIEIR projects a significant slowdown in the State economic growth in 2008/09, Access Economics forecast a return to strong private consumption, dwelling investments and business investments with the GSP expected to grow more than 4% pa. Access Economics forecasts are for an annual average growth of 3.0% for the next 5 years to 2009/10.

3.3.2 Other Forecast Inputs

Other key drivers of electricity energy and demand forecasts include amongst others:

- Major projects;
- Future population growth impacting on housing demand;
- Household disposable income;
- Future energy prices;
- Application of innovative technologies to drive energy efficiency;
- State and Federal Government energy policies or proposals, explained in detail in Appendix A3.1;
- Forecast non-scheduled generation, detailed in Appendix A5; and
- Weather defined as per the temperature standards for energy and maximum demand forecasts discussed in Appendix A1 and A2

    Three temperature standards for summer and winter MD forecasts are defined, based on the probability distributions of the warmest summer and coldest winter weekday average temperatures of each year included in the analysis, such that:

    - *The 10% POE temperature is the weekday average temperature not exceeded, on average, more than 1 in every ten years*
    - *The 50% POE temperature is the weekday average temperature not exceeded, on average, more than 1 in every 2 years*
    - *The 90% POE temperature is the weekday average temperature not exceeded, on average, more than 9 in every ten years*

    Table 3.4 shows the temperature standards for summer and winter MD forecasts.

[9] Access Economics Business Outlook March 2005 and State and Territory Budget Monitor No 64

	Summer MD	Winter MD
10% POE Temperature	32.9°C	5.4°C
50%POE Temperature	29.4°C	7.1°C
90% POE Temperature	27.3°C	8.2°C

Table 3.4 – Summer and Winter MD Temperature Standards

3.4 Annual Energy Forecasts 2004/05 – 2014/15

This section begins with a comparison of the estimated actual (or projected) and previous year's forecast annual energy for 2004/05. The year 2004/05 is the base year for the next 10 year's energy projections to 2014/15.

3.4.1 Projected Annual Energy for 2004/05

The projected annual energy for 2004/05 is 50,064 GWh. The projection is based on actual consumption between 1 Jul 2004 to 30 April 2005 and estimated load for May and June 2005. After correcting for weather variations from standard average conditions, the projected annual energy is 50,254 GWh and 0.3% lower than the Medium growth forecast of 50,402 GWh in the 2004 Electricity Annual Planning Report. This represents 1.8% growth over the 2003/04 weather corrected annual energy of 49,384 GWh.

3.4.2 Annual Energy Forecasts

Three scenarios of energy forecasts are prepared for each year, based on Medium, High and Low economic growth projections. The forecasts do not account for potential Demand Side Participation (DSP), but take into account energy exported by non-scheduled generators. Non-scheduled generation, projected to grow faster in the future, plays an increasingly important role in the state supply and demand balance as this reduces the reliance on investments of large-scale generators to meet growing demand. Forecast non-scheduled generation is discussed in more detail in Appendix A5.

The forecasts assume average weather conditions with 426 Cooling-Degree-Days (CDD) and 1,080 Heating-Degree-Days (HDD) annually. CDD and HDD are temperature measures used to model and estimate annual temperature sensitive load. Temperature standards for annual energy forecasts are explained in Appendix A2. Temperature sensitive load is about 5% of annual energy, but is projected to grow in future due to increased penetration of air conditioners (AC). The increase in reverse cycle AC has driven up energy used for heating in recent years. Appendix A6 explains the trend in energy used for space cooling and heating.

The scenario forecasts for the next 10 years are shown in Figure 3.5 and Table 3.5. Annual energy for historical years has been corrected to annual temperature standards.

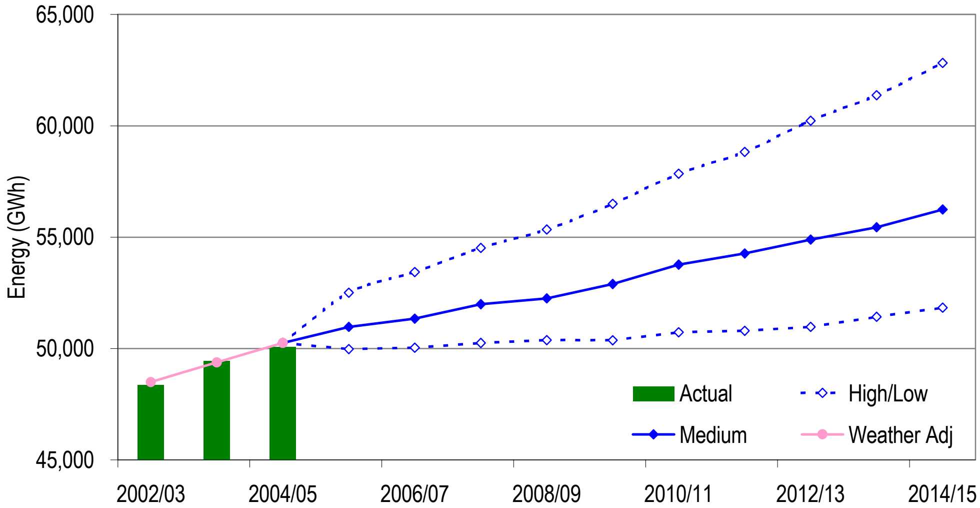

Figure 3.5 – Annual Energy Forecasts

Under the Medium growth scenario, annual energy is forecast to grow from 50,254 GWh (weather corrected) in 2004/05 to 56,247 GWh in 2014/15 at an average rate of 1.1% pa. The projected average growth for the first 5 years to 2009/10, is 1.0% pa compared with 1.9% for the previous 5 years to 2004/05. A stronger growth of 1.2% pa is projected for the following 5 years to 2014/15.

The projected growth in energy, under the High and Low growth scenarios, is consistent with the projected GSP growth. Under the High growth scenario, stronger growth of 2.4% pa and 2.1% pa is projected for the first 5 and the last 5 year periods, respectively. Under the Low growth scenario, weaker economic growth will reduce the projected energy growth to 0% and 0.6% pa respectively for each of the 5- year periods to 2014/15.

	Annual Energy (GWh)			Annual % Growth		
Year	Low	Medium	High	Low	Medium	High
2002/03	48,493*	48,493*	48,493*			
2003/04	49,384*	49,384*	49,384*	1.8%	1.8%	1.8%
2004/05	50,254*	50,254*	50,254*	1.8%	1.8%	1.8%
2005/06	49,976	50,976	52,510	-0.6%	1.4%	4.5%
2006/07	50,041	51,343	53,438	0.1%	0.7%	1.8%
2007/08	50,253	51,989	54,521	0.4%	1.3%	2.0%
2008/09	50,381	52,255	55,346	0.3%	0.5%	1.5%
2009/10	50,375	52,901	56,498	0.0%	1.2%	2.1%
2010/11	50,730	53,768	57,849	0.7%	1.6%	2.4%
2011/12	50,798	54,274	58,829	0.1%	0.9%	1.7%
2012/13	50,974	54,895	60,233	0.3%	1.1%	2.4%
2013/14	51,424	55,445	61,380	0.9%	1.0%	1.9%
2014/15	51,833	56,247	62,830	0.8%	1.4%	2.4%
2005-2010				0.0%	1.0%	2.4%
2010-2015				0.6%	1.2%	2.1%

Table 3.5 – Annual Energy Forecasts

The energy projections have been revised downwards quite significantly, compared to last year's forecasts. The revisions reflect a number of factors, which have had a more pronounced impact on this year's forecasts, including:

- slower economic growth;
- more accurate estimates of weather normalized energy;
- no further growth in smelter load;
- lower industrial sales forecasts which take into account the downside risks to the manufacturing sector in Victoria;
- The impact of Federal and Victorian government greenhouse and energy policies and initiatives including the Victorian government 5 star building standard and proposed changes to Appliance Minimum Energy Performance Standards (MEPS); and

* Weather adjusted

- Increased non-scheduled generation (wind farms)

Government energy initiatives and forecast non-scheduled generation are documented in Appendix A3 and A5 respectively.

Figure 3.6 compares the Medium growth scenario annual energy forecasts presented in the 2004 Electricity Annual Planning Report and those in the current forecasts. This year's forecasts are lower than last year's projections. The difference is about -350 GWh (-0.7%) in 2005/06, increasing to -2,400 GWh (-4.4%) in 2009/10 and over -4,000 GWh (-6.8%) in 2013/14.

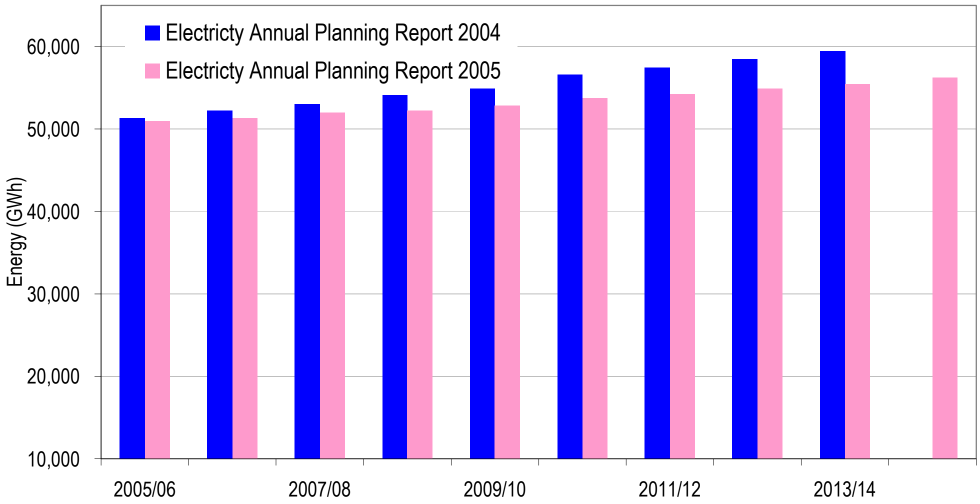

Figure 3.6 – Comparison of Annual Energy Forecasts (Medium Economic Growth)

3.5 Summer Maximum Demand Forecasts

This section includes an assessment of the 2004/05 summer MD forecast variance and the summer MD forecasts to 2014/15. The forecasts are based on defined temperature standards shown in Table 3.4 in Section 3.3.2, and explained in Appendix A1. These forecasts do not account for potential reductions in demand due to DSP. In this chapter, the 10% POE MD denotes the maximum demand corresponding to the 10% POE average temperature. This definition also applies to the 90% POE and 50% POE MD forecasts.

3.5.1 Summer Maximum Demand for 2004/05

Figure 3.7 compares 2004/05 actual summer[10] weekday demands with the weather corrected actual, and the forecast 90%, 50% and 10% POE MD forecasts. NIEIR estimates the weather corrected actual 90%, 50% and 10% POE MDs based on actual summer demands and actual cooling equipment sales, which is estimated to be 80 MW higher than what was predicted last year. Appendix A9 documents NIEIR's methodology for estimating the weather corrected 90%, 50% and 10% POE MDs for historical years from 1990/91.

10 Mondays – Thursdays between 1 November and 31 March, excluding Public Holidays, and 20 December to 20 January

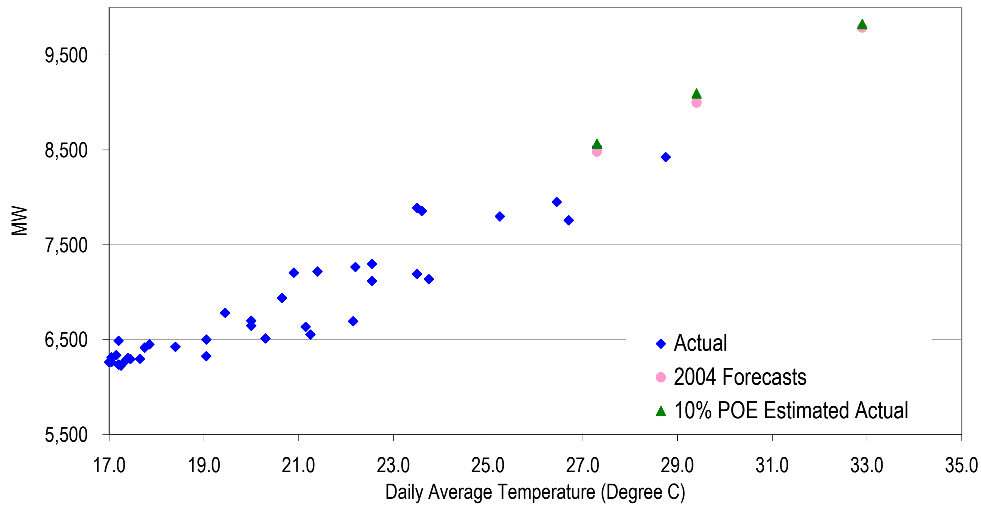

Figure 3.7 - Summer 2004/05 Maximum Demand Compared with Forecasts

Table 3.6 shows that the estimated actual 10% POE MD for 2004/05 is 9,826 MW, and is 39 MW (0.4%) above the forecast of 9,787 MW projected last year. This represents 3.0% growth over the estimated actual 2003/04 10% POE summer MD of 9,537 MW. The forecast 50% and 90% POE MD are about 1% below the estimated actual values.

			Forecast Variance	
	Forecast (MW)	Estimated Actual (MW)	MW	%
90% POE	8,482	8,564	82	1.0%
50% POE	8,997	9,093	96	1.1%
10% POE	9,787	9,826	39	0.4%

Table 3.6 – 2004/05 Summer MD Forecast Variance

3.5.2 Summer Maximum Demand Forecast

NIEIR provides, for each forecast year, a total of 27 forecast summer MDs, corresponding to 3 types of summer[11] (90% or cool, 50% or average, and 10% or warm), and 3 POE average temperatures (90%, 50% and 10% POE) and 3 economic growth scenarios. NIEIR's analysis demonstrates that the overall summer temperature in a given year impacts on sales of space cooling equipment (such as air conditioners). In addition, how hot a summer actually is, can have a significant effect on the utilisation of these equipments, and therefore the actual realised MDs. This impact can result in up to 120 MW difference in the forecast 10% POE MD in 2005/06. Forecast summer MDs corresponding to 50% (or average) summer and the Medium case economic scenario, are used for evaluating transmission planning options. The other scenario forecasts provide inputs to sensitivity analysis of planning options if required.

11 Defined based on overall summer average daily temperatures

Summer MDs consist of temperature sensitive (mainly cooling load) and temperature non-sensitive components. Detailed analysis of the impact of temperature on summer temperature sensitive demand is documented in Appendix A7. The forecasts also account for future growth in non-scheduled generation, treated as negative demands for forecasting purposes. Summer MD forecast methodology is documented in Appendix A3.2. Details of forecast non-scheduled generation are in Appendix A5.

Table 3.7 and Figure 3.8 present the MD forecasts, for the next 10 years, corresponding to 50% (or average) summer conditions and the Medium economic growth scenario. The 10% POE estimated actual MDs for 2002/03 to 2004/05 are also included for comparison. The forecasts for 50% (or average) summer and the High and Low economic growth scenarios are included in Appendix A8.

	Summer MD[12] (MW)			Annual % Growth		
Year	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2002/03	9,180*					
2003/04	9,537*			3.9%		
2004/05	9,826*			3.0%		
2005/06	10,119	9,260	8,700	3.0%	2.8%	2.6%
2006/07	10,367	9,471	8,886	2.5%	2.3%	2.1%
2007/08	10,635	9,701	9,092	2.6%	2.4%	2.3%
2008/09	10,850	9,876	9,241	2.0%	1.8%	1.6%
2009/10	11,097	10,088	9,431	2.3%	2.1%	2.0%
2010/11	11,356	10,316	9,637	2.3%	2.3%	2.2%
2011/12	11,573	10,499	9,799	1.9%	1.8%	1.7%
2012/13	11,793	10,687	9,966	1.9%	1.8%	1.7%
2013/14	12,001	10,864	10,122	1.8%	1.7%	1.6%
2014/15	12,218	11,056	10,299	1.8%	1.8%	1.7%
2005-2010				2.5%	2.3%	2.1%
2010-2015				1.9%	1.8%	1.8%

Table 3.7 – Summer Maximum Demand Forecasts
(Average Summer, Medium Economic Growth)

12 Generated at Victorian generator terminals scheduled under NEMMCO dispatches, less interstate net exports

* Estimated actual

The 10% POE summer MD forecasts are projected to grow from 9,826 MW in 2004/05 to 11,097 MW in 2009/10 and 12,218 MW in 2014/15. The projected average growth for the first 5 years to 2009/10, is 2.5% pa and 1.2% lower than the average growth over the previous 5 years to 2004/05. The projected average growth will slowdown to 1.9% pa for the following 5 years to 2014/15.

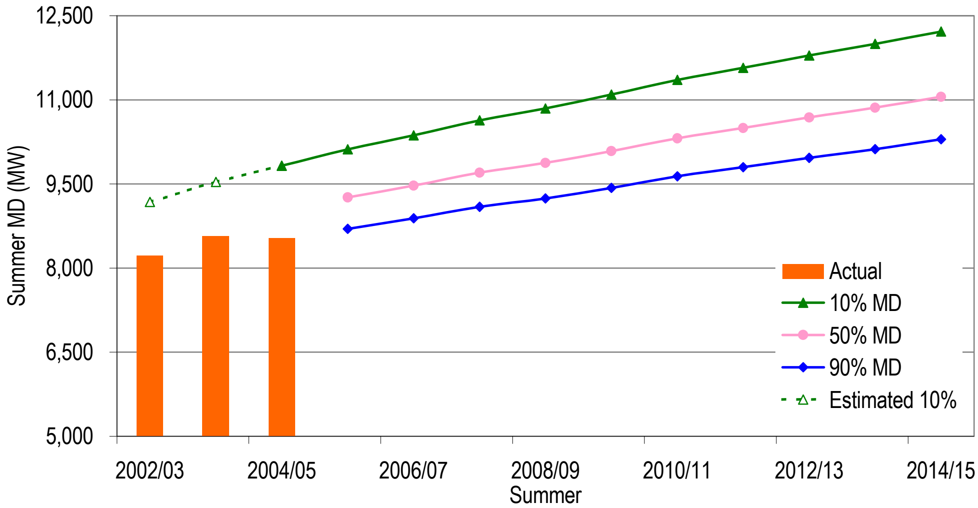

Figure 3.8 –Summer Maximum Demand Forecasts
(Average Summer, Medium Economic Growth)

Non-temperature sensitive demand (base load) is projected to grow at an average rate of 1.2% pa over the next 10 years, due to the downward revision to energy projections (described in Section 3.4.2 above).

Temperature sensitive demand is also projected to grow at a slower rate compared to the growth observed in recent years. This reflects expectations of a weaker housing market, a slower penetration of cooling appliances reaching saturation between 2009/10 and 2014/15, and potential but highly uncertain impact of future government energy policies and greenhouse initiatives. The forecast average growth rate for the first 5 years to 2009/10 is 4.4% pa, compared with average growth of over 7.0% pa in the previous 5 years to 2004/05. The growth rate is expected to slow down to an average of 2.9% pa over the 2010/11 to 2014/15 period. The 10% POE temperature sensitive demand is about 35% of summer MD in 2004/05, and increases to 39% and 41% in 2009/10 and 2014/15 respectively. The projected growth in the forecast 90% and 50% POE temperature sensitive demands, follows a similar trend.

Figure 3.9 compares the Medium growth scenario 10% POE summer MD forecasts in the 2004 and the 2005 Electricity Annual Planning Reports. The forecast MD for summer 2005/06 is 10,119 MW and is slightly higher than last year's forecast of 10,103 MW. NIEIR's MD forecast for summer 2005/06 is consistent, albeit slightly higher than the results of 2 independent studies by other consultants engaged by VENCorp. The objective of these studies is to provide comparative results to assess the accuracy and robustness of NIEIR's forecasts. Both top down and bottom up approaches, involving regression analysis and building shell simulation modelling respectively, generate forecasts between 9,800 MW and 10,021 MW.

The 10% POE summer MD forecasts for all other years post 2005/06 are lower than the previous forecasts. The difference, averaged over the forecast years, is –1.4% pa, and increases to -134 MW (or –0.2%) in 2009/10 and about -350 MW (-2.8%) in 2013/14.

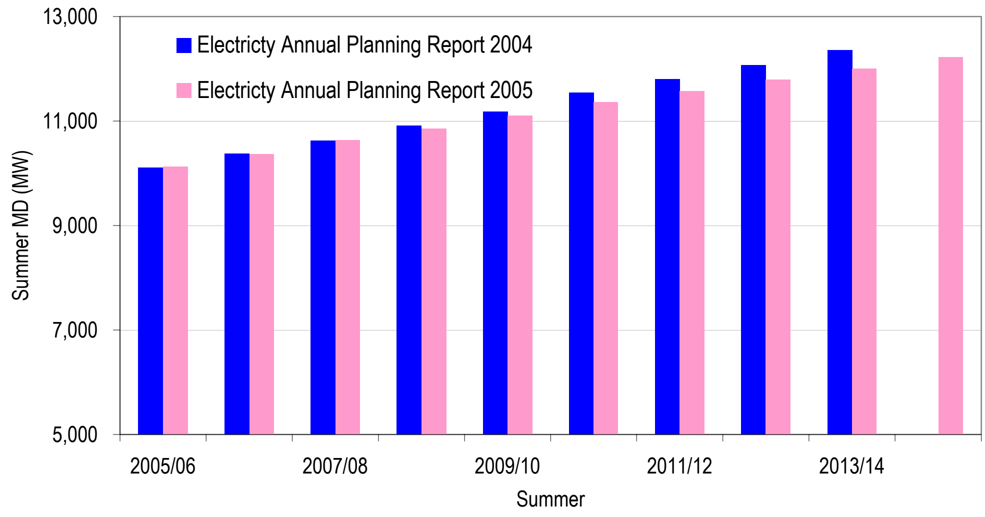

Figure 3.9 – Comparison of 10% POE Summer Maximum Demand Forecasts (Average Summer, Medium Economic Growth)

An adjunct to the MD forecasts in this chapter is the Terminal Station Demand Forecasts (TSDF) published by VENCorp on its website[13] in September each year. This document contains the aggregated demand forecasts prepared by the distributors, and reconciled with the long-term demand forecasts in the Electricity APR. A summary of the TSDF is included in Appendix B.

3.6 Winter Maximum Demand Forecasts

This section includes an assessment of the 2004 winter MD forecast variance and the forecasts to 2014/15. The forecasts are based on defined temperature standards shown in Table 3.4 in Section 3.3.2, and explained in Appendix A1. The forecasts do not account for potential DSP.

3.6.1 Winter Maximum Demand for 2004

Figure 3.10 compares 2004/ actual winter[14] weekday MDs with the weather-corrected actual and the forecast 90%, 50% and 10% POE MD forecasts. NIEIR estimates the weather corrected actual MDs based on actual winter demands and actual sales in reverse cycle air conditioners. Due to the mild weather in winter 2004, all the actual weekday MDs were lower than the 90% POE forecast MD.

13 www.vencorp.com.au under "Electricity Transmission Planning" section

14 Mondays – Thursdays between 15 May and 15 September, excluding Public Holidays

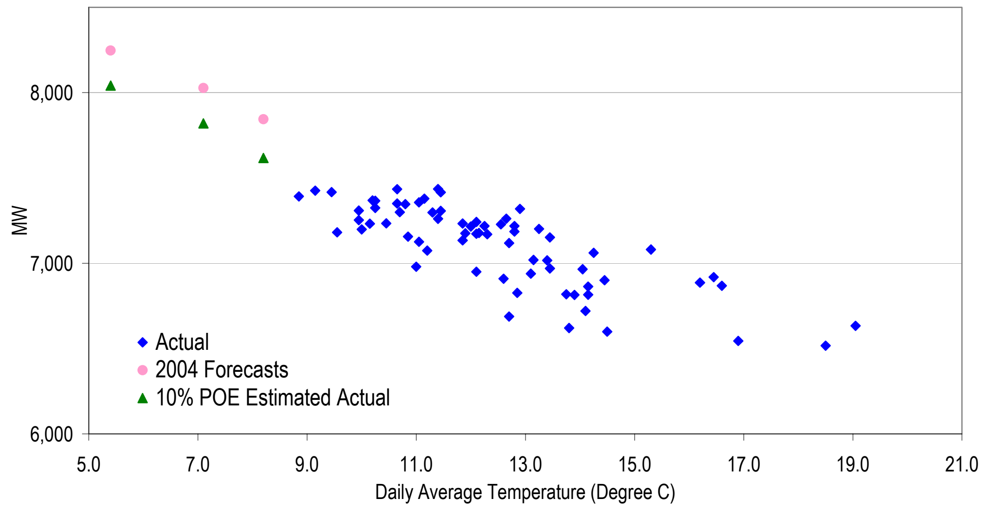

Figure 3.10 – Winter 2004 Maximum Demand Compared With Forecasts

Table 3.8 shows that the 2004 forecast of 10% POE winter MD was overstated by 206 MW or 2.6%, compared with the 10% estimated actual MD. The 90% and 50% POE winter MDs have been over-forecast by 2.7% to 3%.

			Forecast variance	
	Forecast (MW)	Estimated Actual (MW)	MW	%
90% POE	7,844	7,617	-227	-3.0%
50% POE	8,027	7,819	-208	-2.7%
10% POE	8,247	8,041	-206	-2.6%

Table 3.8 – Winter 2004 Maximum Demand Forecast Variance

3.6.2 Winter Maximum Demand Forecasts

NIEIR provides, for each forecast year, 9 forecast winter MDs, corresponding to 3 defined temperature standards (90%, 50% and 10% POE) and 3 economic growth scenarios. Winter MDs are made up of temperature sensitive (mainly heating load) and temperature non-sensitive components. The impact of temperature on winter temperature sensitive demand is discussed in Appendix A7. The forecasts also account for future growth in non-scheduled generation, treated as negative demands for forecasting purposes. Details of forecast non-scheduled generation are in Appendix A5.

Winter MD has risen steadily in recent times due to the penetration of reverse cycle AC in homes and in particular the apartment market. Table 3.9 and Figure 3.11 present the winter MD forecasts, compared with the estimated MD for winter 2004.

	Winter MD[15] (MW)			Annual % Growth		
Year	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2004	8,041*	7,819*	7,617*			
2005	8,111	7,877	7,671	0.9%	0.7%	0.7%
2006	8,228	7,983	7,762	1.4%	1.3%	1.2%
2007	8,400	8,142	7,904	2.1%	2.0%	1.8%
2008	8,529	8,259	8,006	1.5%	1.4%	1.3%
2009	8,687	8,407	8,140	1.9%	1.8%	1.7%
2010	8,881	8,589	8,307	2.2%	2.2%	2.0%
2011	9,037	8,732	8,436	1.8%	1.7%	1.6%
2012	9,212	8,896	8,586	1.9%	1.9%	1.8%
2013	9,368	9,042	8,720	1.7%	1.6%	1.6%
2014	9,546	9,209	8,875	1.9%	1.8%	1.8%
2005-2009				1.6%	1.5%	1.3%
2009-2014				1.9%	1.8%	1.7%

Table 3.9 – Winter Maximum Demand Forecasts

The 10% POE winter MD forecasts are projected to grow from 8,041 MW in 2004 to 8,687 MW in 2009 and 9,546 MW in 2014. The projected average growth rate for the first 5 years to 2009 is 1.6% pa. Stronger average growth of 1.9% pa is projected for the following 5 years to 2014, reflecting stronger economic growth and increased penetration of reverse cycle conditioners.

15 Generated at Victorian generator terminals scheduled under NEMMCO dispatches, less interstate net exports

* Estimated actual

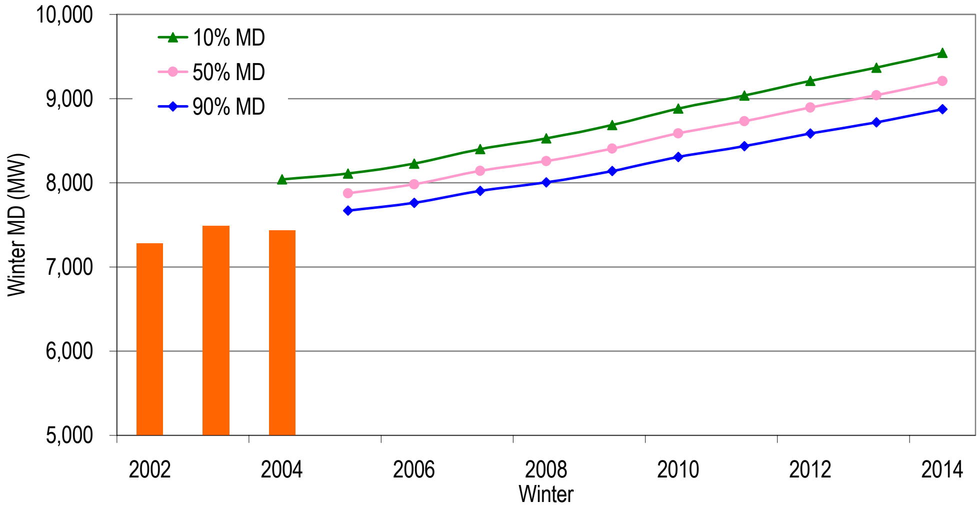

Figure 3.11 – Winter Maximum Demand Forecasts

Figure 3.12 compares winter MD forecasts presented in the 2004 Electricity Annual Planning Report and the current forecasts. This year's forecasts are lower than last year's projections, to reflect the downward revisions to energy projections (described in Section 3.4.2 above). The difference is -136 MW (-1.7%) in 2005, increasing to -274 MW (-3.1%) and -350 MW (-3.6%) in 2009 and 2013 respectively.

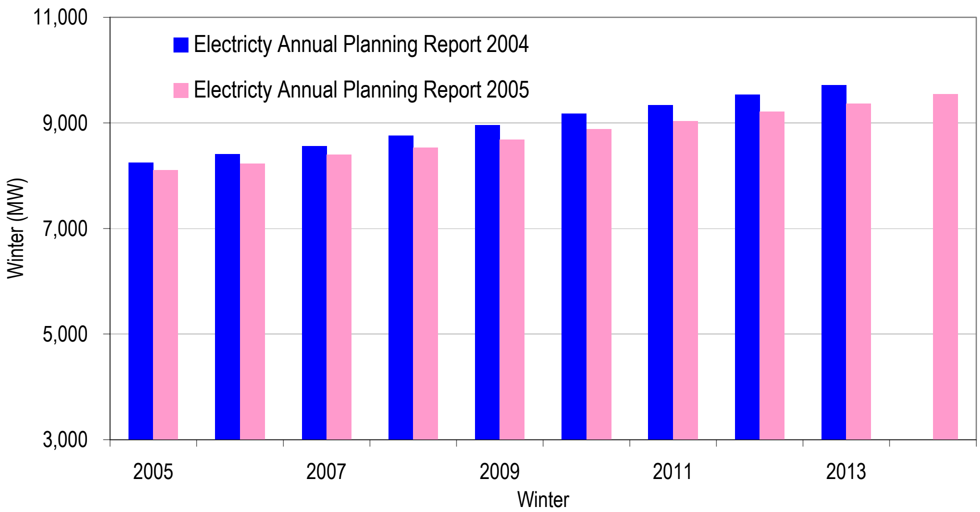

Figure 3.12 – Comparison of 10% POE Winter Maximum Demand Forecasts

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4. INTRA-REGIONAL NETWORK ADEQUACY

4.1 Introduction

This chapter describes the existing transmission network and its ability to meet the actual and forecast 2004/05 summer peak demand conditions. It includes:

- a review of the shared transmission network conditions during summer 2004/05;
- an overview of the active and reactive supply demand balance at the forecast peak demand; and
- a summary of fault levels and the available headroom on existing circuit breakers at Victorian terminal stations.

It aims to assist existing or potential network users in:

- understanding transmission network constraints;
- assessing future transmission augmentation requirements; and
- identifying locations with spare capacity for load growth or generation, or locations where demand management could defer the cost of network augmentation.

4.2 Existing Transmission Network

The Victorian transmission network consists of various transmission lines and transformers that link power stations to the distribution system. The transmission system operates at voltages of 500 kV, 330 kV, 275 kV, and 220 kV. The 500 kV transmission primarily transports bulk electricity from generators in the Latrobe Valley in Victoria's east, to the major load centre of Melbourne, and then on to the major smelter load and interconnection with South Australia in the west. Strongly meshed 220 kV transmission supplies the metropolitan area and major regional cities of Victoria, while the 330 kV transmission interconnects with the Snowy region and New South Wales. Transmission at 275 kV provides the interconnection with South Australia.

The electricity transmitted through the extra high voltage transmission is converted to lower voltages at terminal stations, where it then supplies the distribution system. The shared transmission network in Victoria consists of electrical equipment at almost 50 stations across the state, and the total circuit distance of transmission lines is approximately 6,000 kilometres. Figure 4.1 provides a map of the existing Victorian transmission network.

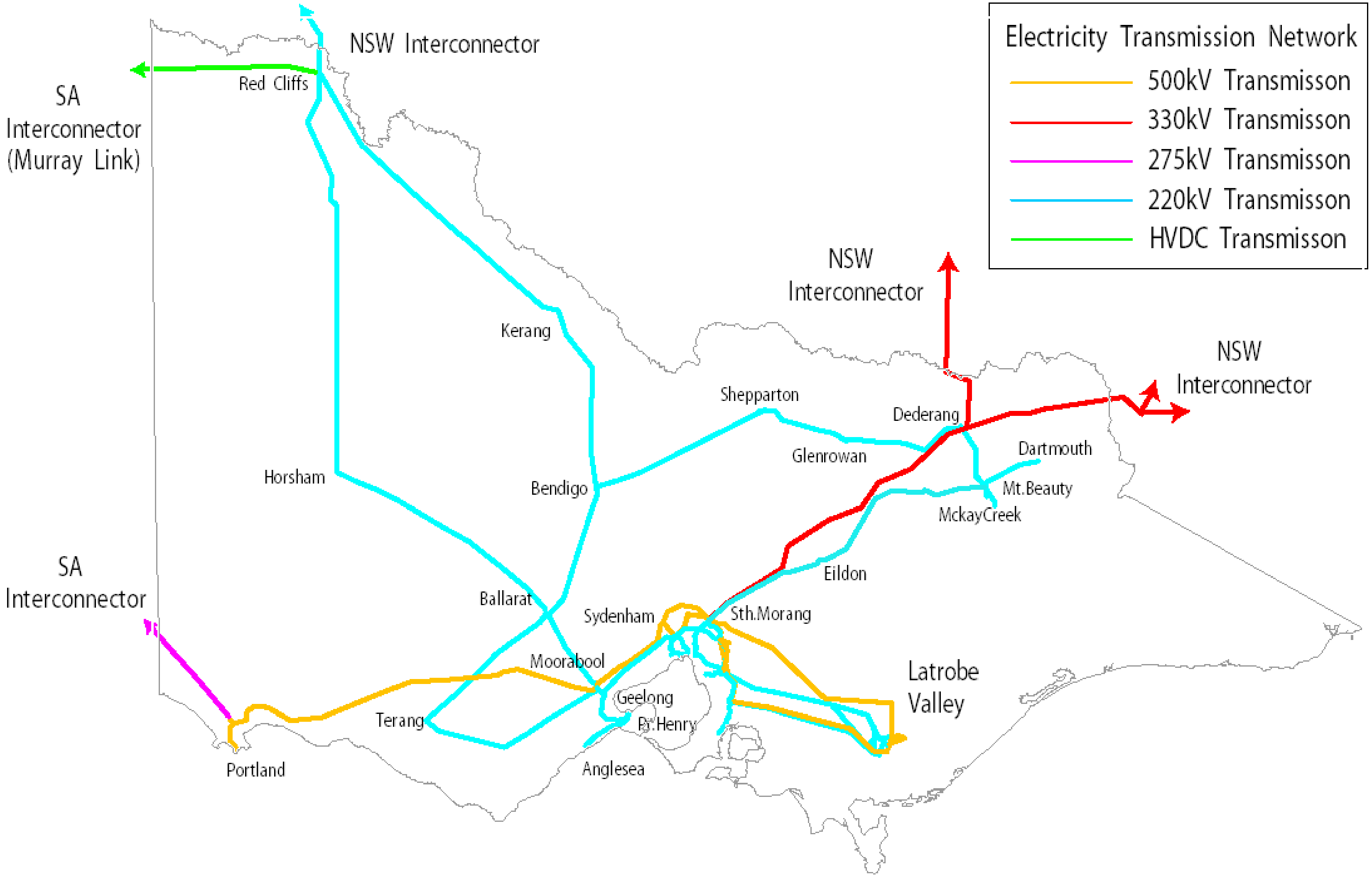

Figure 4.1 – Existing Victorian Transmission Network

4.3 Summer 2004/05 Conditions

As discussed in chapter 3, the peak electricity demand experienced in Victoria in summer 2004/05 was 8,535 MW, on Tuesday 25 January 2005. The maximum ambient temperature reached was relatively high at 36.2°C, and the average Melbourne temperature was 27.3°C. These temperature conditions on this day were consistent with a 90% Probability of Exceedence (POE).

The Victorian shared transmission network has been economically designed to meet a demand of 9,885 MW. Therefore, the shared transmission network was operated well within its design capability during the year, with the actual peak demand being 1,350 MW below the maximum supportable demand.

The intra / inter-regional transfer levels and Victorian prices during summer 2004/05 were only minimally impacted by planned network outages associated with augmentation projects and forced network outages. No significant system incidents or bushfires occurred to cause price volatility during summer 2004/05.

4.4 System Active and Reactive Power Supply Demand Balance

A detailed assessment of supply and demand is provided in NEMMCO's SOO, but the following summary is provided for information. Table 4.1 shows the combined Victorian and South Australian forecast reserve at peak demand conditions with all generation available was 361 MW, which is below the reserve requirement 530 MW. As such NEMMCO entered into reserve trader agreements for summer 2004/05, to meet this shortfall.

SUPPLY	Victorian Generation	8,156
	South Australian Generation	3,223
	Import Capability From Snowy/NSW	1,900
	Total Combined Region Supply	13,279
DEMAND	Victorian Forecast Demand (10% POE, Medium Economic Growth)	9,787
	South Australian Forecast Demand (10% POE, Medium Economic Growth)	3,294
	Expected Demand Side Participation	163
	Total Combined Region Demand	12,918
RESERVE	Reserve	361
	Combined Reserve Requirement	530
	Reserve Surplus	-169

Table 4.1 – Summer 2004/05 Supply Demand Balance for Victoria & South Australia (MW)

The supply demand balance presented in Table 4.1, reflects favourable conditions with the maximum import available from Snowy/NSW, and all Victorian generators available to produce their maximum outputs (as listed in Table 4.2) at the time of system peak.

Generation	Summer 2004/05 Capacity (MW)
Anglesea	154
Bairnsdale	70
Energy Brix Complex	139
Hazelwood	1,575
Hume (VIC)	58
Jeeralang A	200
Jeeralang B	216
Loy Yang A	2,020
Loy Yang B	1,000
Newport	475
Somerton GT	123
Southern Hydro	454
Valley Power	252
Yallourn W	1,420
Total	8,156

Table 4.2 - Summer Aggregate Generation Capacity for Victoria (Source: 2004 SOO)

The forecast demand level of 9,787 MW for summer 2004/05 is representative of conditions where:

- Transmission losses are approximately 400 MW (4.1%)
- Used in Station load is approximately 530 MW (5.4%)
- Major Industrial load is approximately 1,100 MW (11.2%)
- State Grid Regional load is approximately 1,590 MW (16.2%)[16]
- Western metropolitan area load is approximately 1,710 MW (17.5)[17]
- Eastern metropolitan area load is approximately 4,130 MW (42.2%)[18]
- Latrobe Valley area load is approximately 330 MW (3.4%)[19]

16 Defined as load supplied out of Geelong, Terang, Ballarat, Bendigo, Shepparton, Glenrowan, Mt Beauty, Wodonga, Kerang, Red Cliffs and Horsham Terminal Stations.

17 Defined as load supplied out of Keilor, West Melbourne, Fisherman's Bend, Brooklyn and Altona Terminal Stations.

18 Defined as load supplied out of Thomastown, Brunswick, Richmond, Malvern, Templestowe, Ringwood, Springvale, Heatherton, East Rowville, and Tyabb Terminal Stations.

19 Defined as load supplied out of Yallourn and Morwell.

The maximum supportable demand in Victoria is constrained by a voltage control limitation. At any time, the system must be operated to maintain an acceptable voltage profile and reactive reserve margin before and after a critical contingency. Economic analysis used to determine the pre-defined level of maximum supportable demand is conducted in accordance with VENCorp's application of the Regulatory Test. This reflects an optimal trade-off between the benefits of mitigating the risk of loss of load, and the cost of various network or non-network solutions. On a day-to-day basis, the actual system demand will be limited to below the maximum supportable demand to ensure acceptable post contingency voltages and reserve margins. For summer 2004/05, the maximum supportable demand under favourable conditions was 9,885 MW.

The reactive supply/demand balance for the summer 2004/05 system, with the forecast maximum demand of 9,787 MW, is given in Tables 4.3 and 4.4. Table 4.3 shows the system normal conditions with all generators and transmission elements in service. Table 4.4 shows the system reactive supply/demand balance following contingent outage of Newport Power Station (500 MW). For this condition, it was assumed that frequency control was being carried out utilising Snowy/NSW generators. As a result of the generator outage, import from NSW/Snowy increases from 1,900 MW to 2,400 MW, causing an increase in transmission active and reactive power losses. In addition, loss of the generator reduces the amount of reactive supply. The increased net reactive supply is met by the remaining generators, synchronous condensers, static var compensators and series capacitors.

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,269	Loads	3,746
SVC's and Synchronous Condensers	153	Line Reactors	218
Line Charging	2,586	Line Losses	5,829
Shunt Capacitors	4,884	Inter- regional Transfer	260
Series Capacitors	161		
Total	10,053	Total	10,053

Table 4.3 - Reactive Supply and Demand Balance at 9,787 MW (System Normal)

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,553	Loads	3,735
SVC's and Synchronous Condensers	438	Line Reactors	213
Line Charging	2,364	Line Losses	6,530
Shunt Capacitors	4,790	Inter- regional Transfer	-8
Series Capacitors	325		
Total	10,470	Total	10,470

Table 4.4 - Reactive Supply and Demand Balance at 9,787 MW (Following loss of Newport)

4.5 Shared Network Loading

This section compares the shared network loadings that were experienced during summer 2004/05, with the network loadings that would have occurred if the forecast summer load was achieved. This information is presented in Table 4.6, where loadings of shared transmission network lines and transformers, as a proportion of ratings, are shown for the following three conditions:

- Actual 2004/05 MD (8,535 MW);
- Forecast 2004/05 10% POE MD (9,787 MW); and
- Forecast 2004/05 MD with the worst single contingency outage, producing the highest loading for each network element.

Table 4.5 below summarises system conditions under actual MD and forecast MD conditions.

	Actual MD	Forecast MD
Victorian Demand	8,535	9,787
Victorian Generation	7,300	8,347
NSW/Snowy to Victoria transfer	1,775	1,900
Combined Victoria to SA transfer	540	460

Table 4.5 - Actual and Forecast 2004/05 MD System Loading Conditions

Allowing for hot summer conditions likely to produce a 10% POE forecast MD, continuous ratings used assume 40°C ambient temperature conditions. Line ratings are based on the standard 0.6 m/s wind speed, except in the case of Rowville to Springvale circuits, where wind monitoring is installed and ratings based on 1.2 m/s wind speed are typically applicable on hot days. Transformer continuous ratings are also used.

Some elements presented in Table 4.6 show a contingency loading greater than 100% of the continuous rating, however these overloads are within short term ratings. A range of post-contingent actions such as being able to reschedule generation, reconfigure the network, and/or shed load, using automatic controls or remote manual intervention, are available to ensure that after a critical contingency the transmission system remains in a satisfactory operating state. In some cases, action is needed within minutes of a critical contingency occurring, to remove the overload, and to ensure that loading is maintained within the elements' continuous ratings.

Table 4.6 also shows that the loading on a number of elements was higher for the actual MD conditions, compared with the forecast MD. This is due to the fact that actual generation patterns and levels of load at terminal stations differed from those assumed in the forecasts, resulting in different flows across elements, when these two conditions are compared.

TRANSMISSION LINK	ACTUAL	FORECAST	CRITICAL OUTAGE using FORECAST	APR REFERENCE
	(% of continuous rating)			
220 kV lines (East Metro Meshed)				
Brunswick-Richmond	43	75	108	Section 6.9
Brunswick-Thomastown	23	35	63	
East Rowville-Rowville	53	67	135	Section 2.2
East Rowville-Cranbourne	19	39	78	
Keilor-Thomastown	9	14	36	
Rowville-Richmond	39	40	90	
Rowville-Ringwood	35	40	72	
Rowville-Templestowe	29	31	50	
Rowville-Thomastown	17	26	77	
Ringwood-Thomastown	45	52	115	Section 5.2.6
Templestowe-Thomastown	18	20	115	Section 5.2.7
220 kV lines (East Metro Radial)				
Cranbourne-Tyabb	51	48	96	
Heatherton-Springvale	42	45	90	
Rowville-Malvern	34	42	86	
Rowville-Springvale	59	69	139	Section 5.3.1
Tyabb-JLA (BHP)	37	14	38	
220 kV lines (Latrobe Valley to Melbourne)				
Hazelwood PS-Jeeralang	28	23	83	
Hazelwood PS-Morwell	23	17	22	
Hazelwood PS-Rowville	69	74	96	
Hazelwood PS-Yallourn	71	78	96	
Hazelwood TS-Hazelwood PS	32	69	103	Section 6.13
Rowville-Yallourn (4 parallel circuits)	86	90	102	Section 5.2.1
220 kV lines (Regional)				
Ballarat-Bendigo	21	9	96	
Ballarat-Horsham	41	32	57	
Ballarat-Moorabool	45	41	105	Section 5.2.2
Ballarat-Terang	17	19	54	
Bendigo-Kerang	43	35	61	
Bendigo-Fosterville	79	73	98	
Dederang-Glenrowan	48	52	88	
Dederang-Mount Beauty	13	11	80	
Dederang-Shepparton	59	63	86	
Eildon-Mount Beauty	54	56	80	
Eildon-Thomastown	64	81	101	Section 6.20
Fosterville-Shepparton	79	76	98	
Geelong-Keilor	43	36	135	Section 5.2.3
Geelong-Moorabool	30	39	76	
Geelong-Point Henry/Anglesea	44	48	96	
Glenrowan-Shepparton	40	42	72	

TRANSMISSION LINK	ACTUAL	FORECAST	CRITICAL OUTAGE using FORECAST	APR REFERENCE
	(% of continuous rating)			
Horsham-Red Cliffs	16	10	24	
Kerang-Red Cliffs	31	17	51	
Moorabool-Terang	41	40	70	
220 kV lines (West Melbourne Loop)				
Altona-Brooklyn	7	19	29	
Altona-Keilor	15	19	34	
Brooklyn-Fishermans Bend	10	14	41	
Brooklyn-Keilor	14	23	40	
Brooklyn-Newport	47	45	80	
Fishermans Bend-Newport	25	32	62	
Fishermans Bend-West Melbourne	20	34	64	
Keilor-West Melbourne	34	36	64	
330 / 275 kV Lines				
Dederang-Murray (SNOWY)	73	77	156	Section 6.17
Dederang-South Morang	61	67	117	Section 6.18
Dederang-Wodonga	10	12	38	
Heywood-SESS (SA)	40	45	91	
Wodonga-Jindera (SNOWY)	13	23	47	
500 kV Lines				
APD-Heywood	25	22	39	
Hazelwood TS-Loy Yang PS	33	34	51	
Hazelwood TS-Rowville	54	63	94	
Hazelwood TS-South Morang	46	54	83	
Moorabool-Heywood/APD	30	31	64	
Moorabool-Sydenham	33	35	66	
Keilor-Sydenham	9	10	53	
South Morang-Keilor	45	52	53	
South Morang-Rowville	20	22	48	
South Morang-Sydenham	32	36	60	
Main Tie Transformers				
Dederang 330/220 kV	75	85	121	Section 6.19
Heywood 500/275 kV	59	65	100	
Keilor 500/220 kV	58	68	93	
Moorabool 500/220 kV	64	71	89	
South Morang 330/220 kV	53	81	104	Section 6.9
South Morang 500/330 kV	8	15	44	
Rowville 500/220 kV	66	83	110	Section 6.9
Hazelwood 500/220 kV	31	69	101	Section 6.13

Table 4.6 - Network Actual and Forecast 2004/05 MD Loadings

4.6 Transmission Connection Asset Loading

The responsibility for planning of distribution related transmission connection assets resides with the Distribution Businesses. The Distribution Businesses jointly publish an annual report on the performance and capability of connection assets entitled 'Transmission Connection Planning Report'. This report is available via the Distribution Businesses' respective websites.

4.7 Fault Levels

VENCorp has the responsibility to ensure fault levels in the Victorian shared transmission network are always maintained within plant capability. When calculating fault levels, a number of different assumptions are made about the development of generation, transmission, interconnection and system load levels.

For summer 2004/05, there were no locations within the Victorian transmission network where the interrupting capability of a circuit breaker was inadequate.

Fault levels in 2005 and the subsequent years will be influenced by the following committed or proposed projects:

- 4th 500 kV Line Project;
- A new 1000 MVA 500/220 kV Transformer at Rowville; and
- A new 1000 MVA 500/220 kV Transformer at Moorabool.

Major changes to generation and interconnection arrangements, that influence the fault levels over the next five years, include new generation at Laverton North connected at Altona Terminal Station, and the Basslink interconnector with Tasmania.

Analysis of the Victorian transmission network over the next five years has shown that fault levels at 275 kV, 330 kV and 500 kV voltage levels are well below switchgear ratings (in the range of 20-60% of the circuit breaker capability), and it is unlikely that fault levels will be a constraint on development at any of these voltage levels within the foreseeable future.

At 220 kV, 66 kV, and 22 kV buses, fault levels are approaching the rated fault capability of switchgear at a number of stations. Table 4.7 summarises the "headroom" available at these voltage levels at stations in the Victorian network, based on the summer 2004/05 fault level review undertaken by VENCorp.

Summer 2004/05 Maximum Prospective Short Circuit at the Busbars of the Victorian Power System in % of the Circuit Breaker Interrupting Capability			
TERMINAL STATION	< 80%	80 – 95 %	> 95%[20]
Altona	220kV & 66kV		
Ballarat	66kV		220kV
Bendigo	220kV, 66kV & 22kV		
Brooklyn			220kV, 66kV & 22kV
Brunswick		22kV	220kV
Cranbourne	220kV & 66kV		
Dederang	220kV		
East Rowville		220kV & 66kV	
Fishermans Bend			220kV & 66kV
Geelong	220kV	66kV	
Glenrowan	220kV & 66kV		
Hazelwood			220kV
Heatherton	220kV	66kV	
Horsham	220kV		
Jeeralang		220kV	
Keilor			220kV & 66kV
Kerang	220kV, 66kV & 22kV		
Loy Yang	66kV		
Malvern	220kV	66kV	22kV
Moorabool	220kV		
Morwell			66kV
Mount Beauty	66kV		220kV
Red Cliffs	220kV & 66kV	22kV	
Richmond		220kV	66kV & 22kV
Ringwood	220kV	66kV & 22kV	
Rowville			220kV
Shepparton	220kV & 66kV		
Springvale	220kV	66kV	
Templestowe	220kV	66kV	
Thomastown			220kV & 66kV
Terang	220kV & 66kV		
West Melbourne		22kV	220kV & 66kV
Wodonga	66kV		

Table 4.7 - Overview of Fault Levels at Victorian Terminal Stations for Summer 2004/2005

The maximum prospective short circuit currents shown in Table 4.7 are determined with all generation in service and for the most onerous feasible operating conditions

[20] For Summer 2004/05, the maximum prospective short circuit current seen by any single circuit breaker is below 100% of the circuit breaker interrupting capability.

The high number of locations where the maximum short circuit current is greater than 95% of the switchyard's minimum interrupting capability is an indication of the historical development of the transmission network in Victoria and the way in which new generation has been integrated into the system.

Consideration of fault levels over the last few years has pointed out the challenges involved in maintaining 220 kV fault levels at the following terminal stations:

- Brooklyn (BLTS),
- Hazelwood (HWPS),
- Keilor (KTS),
- Rowville (ROTS),
- Thomastown (TTS),
- West Melbourne (WMTS),

At these locations, the bus fault level is either forecast to exceed or already exceeds the rating of the lowest rated circuit breaker at the terminal station in the next five years. However, critical breakers are not exposed to the full bus current, and are therefore not a limiting factor at this stage.

Fault levels are continuing to rise as a result of increased load, new generation connections and network augmentations needed to support growth. In particular, new embedded generation connected close to critical stations, will have a significant impact on fault levels.

Options to mitigate problems associated with increasing fault levels include:

- Operational switching arrangements such as splitting buses or open-ending lines;
- Automatic control schemes to open and/or close appropriate circuit breakers;
- Replacement of the affected switchgear;
- Installation of fault current limiting reactors to lines and/or bus-ties; and
- Installation of neutral reactors on transformer tertiaries (where these are not already installed).

Factors that influence the selection of the most appropriate option include:

- the location of the station in the Victorian network;
- the magnitude of the problem; and
- the associated cost of the solution.

Operational switching arrangements have been implemented as the most effective and economic way to manage fault levels, and have facilitated the maintenance of fault levels at critical locations within plant ratings for many years. However, the application and increasing complexity of operational arrangements, and the inherent reduction in plant redundancy, means this approach may no longer always be a technically viable or economic solution.

Table 4.7 shows that the prospective short circuit currents at 10 of the 220 kV terminal stations were above 95 percent of the lowest rated breaker interrupting capability in summer 2004/05. This indicates that there is very little "headroom" for fault levels to increase at these ten terminal stations, and fault level mitigation is becoming an important driver of augmentation.

The ongoing issue of increasing fault levels raised the need for strategic consideration of this issue in distribution and transmission network planning. VENCorp, SP AusNet and the Distribution Businesses have formed a joint working group to review existing network investment plans, and to develop a strategy for fault level management. Two key considerations of the working group were asset replacement programs, and the need to mitigate fault level issues when network augmentations occur.

SP AusNet has scheduled much of the older 220 kV and 66 kV switchgear for replacement over the next 10 years as part of its asset replacement strategy. The standard design level for replacement 220 kV switchgear is 40 kA in the metropolitan stations, which replaces the older standard 26 kA plant. The co-ordination of SP AusNet's replacement program to ensure that increased fault level requirements are addressed, provides an opportunity to optimise total investment and minimise the additional costs. A consequence of higher fault levels at 220 kV is increased fault levels at the low voltage buses of terminal stations, and into the distribution systems. A case by case assessment is needed to determine the magnitude of this issue and how it should be addressed.

SP AusNet's refurbishment strategy over next 10 years indicates that the switchgear at the majority of stations with critical fault levels, namely HWPS, ROTS, BLTS, WMTS, TTS is planned to be upgraded during SP AusNet's next regulatory reset period (2009 to 2013).

VENCorp considers that some of the switchgear at these critical terminal stations may need to be replaced prior to the planned timing of station refurbishment under SP AusNet's refurbishment strategy. VENCorp will monitor the timeliness of station refurbishment programs, and where possible, refurbishment work will be coordinated to coincide with other transmission network augmentations, such as new generation connections, interconnection modifications, and transmission developments.

Any transmission network augmentations will be programmed to ensure that the extent of flow-through impacts and costs for the distribution system will be investigated, so that a coordinated and cost-effective approach to fault-level management can be identified and integrated with SP AusNet's asset replacement program.

5. COMMITTED INTRA-REGIONAL NETWORK AUGMENTATIONS

5.1 Introduction

This chapter provides a summary of committed intra-regional network augmentation projects. These projects will normally have appeared in VENCorp's previous APR documents as planned augmentations. The projects have been categorised as either:

- Minor Network Augmentations (cost <$1M);
- New Small Network Assets ($1M < cost < $10M); or
- Fully Funded projects.

VENCorp has not committed to any New Large Network Assets (cost > $10M) since the 2004 APR. However as discussed in Section 6.9, and in accordance with the NEC requirements for such projects, VENCorp is currently consulting on a proposed New Large Network Asset regarding additional 500/220kV transformation in the Melbourne metropolitan area.

The following seven projects are committed Minor Network Augmentations;

M1 – Latrobe Valley to Melbourne Wind Monitoring Scheme;

M2 – Moorabool to Ballarat Wind Monitoring Scheme;

M3 – Keilor to Geelong Wind Monitoring Scheme;

M4 – Moorabool 500/220 kV Transformer Connections Upgrade;

M5 – Modification to Dederang Bus Splitting Scheme;

M6 – Thomastown to Ringwood 220 kV Line Upgrade; and

M7 – Thomastown to Templestowe 220 kV Line Upgrade.

The following three projects are committed New Small Network Augmentations:

S1 – Rowville to Springvale 220 kV Line Upgrade;

S2 – Rowville to Richmond 220 kV Line Upgrade; and

S3 – Moorabool 500/220 kV Transformer Spare Phase.

The following project is a committed Fully Funded developments:

F1 – Brooklyn 220 kV Line Reactors associated with Laverton North Gas Station.

All of these projects are programmed for completion during summer 2005/06.

Figure 5.1 shows the geographical location of these committed projects.

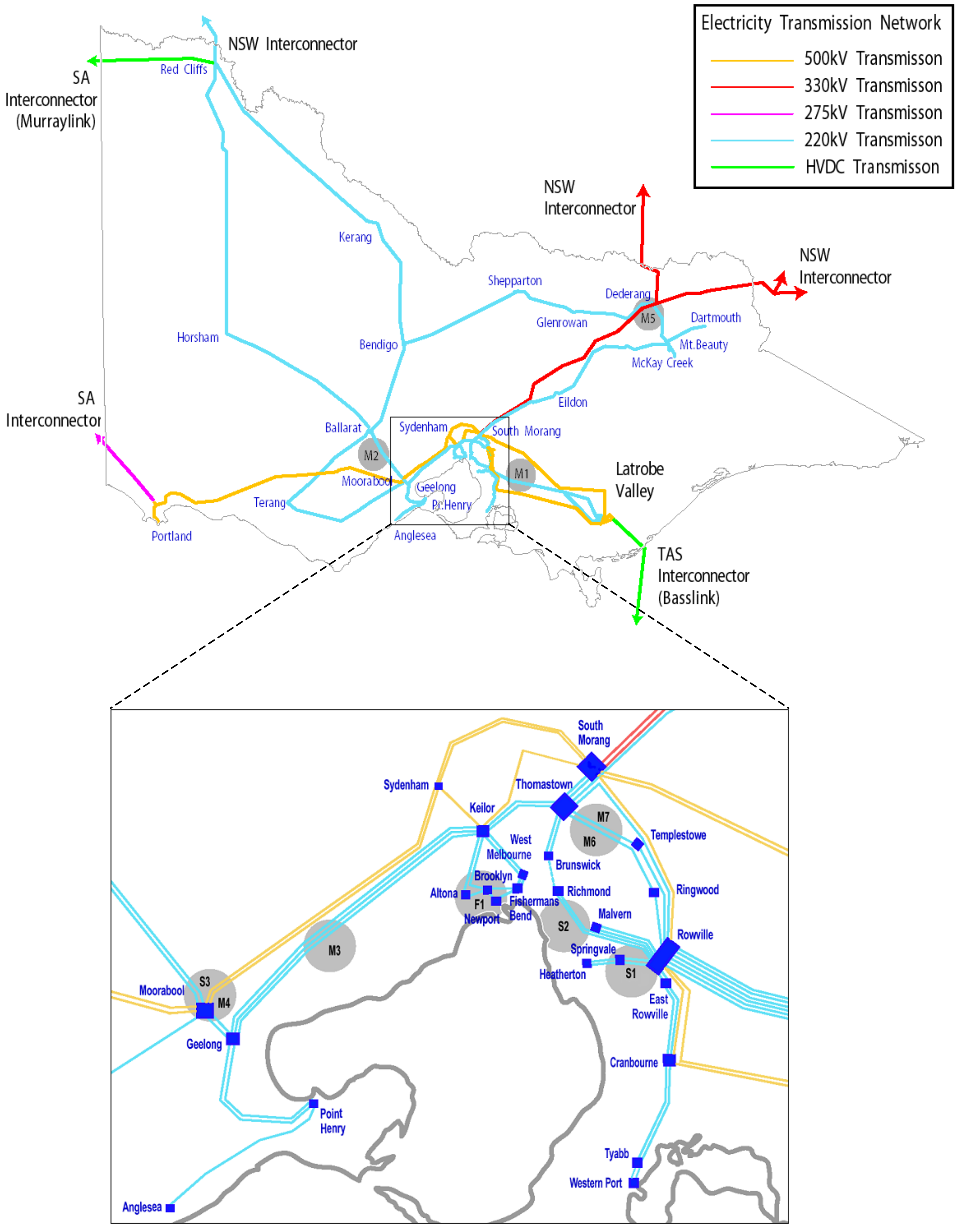

Figure 5.1 – Intra-Regional Committed Network Augmentations

5.2 Committed Minor Network Augmentations

5.2.1 M1 – Latrobe Valley to Melbourne Wind Monitoring Scheme

This project involves installation of a wind monitoring scheme for the six 220 kV lines from Yallourn and Hazelwood to Rowville. This scheme will allow the use of dynamic line ratings based on the real time measurement of wind speed. At an ambient temperature of 40°C and a transverse wind speed of 1.2m/s rather than the default level of 0.6m/s, this project will increase each of the six line ratings by around 18% each.

The project secures load in the both the Springvale and East Rowville areas for outage of either the Rowville or Cranbourne 500/220kV transformers.

5.2.2 M2 – Moorabool to Ballarat Wind Monitoring Scheme

There are two 220 kV lines between Moorabool and Ballarat Terminal Stations. The older, lower rated No.1 line can be overloaded following the loss of the parallel higher rated No.2 line at times of high State Grid load and high ambient temperature. To manage this condition, an automatic scheme is being installed to rapidly reduce flow on the Murraylink interconnector. However, during very high loading conditions this reduction in load may not be sufficient, therefore the existing System Overload Control Scheme is being extended to automatically shed load at Ballarat, Bendigo, Horsham and Terang Terminal Stations, as necessary.

In addition, real time wind monitoring equipment is being installed to further increase the rating of the No 1 220 kV line between Moorabool and Ballarat Terminal Stations. This will enable the No 1 line to be dynamically rated based on measured wind speeds to minimise constraints during critical loading periods following the loss of the No 2 Moorabool to Ballarat line.

5.2.3 M3 – Keilor to Geelong Wind Monitoring Scheme

The Geelong area load and the Point Henry smelter load are predominantly supplied from two sources. The first is a single 500/220 kV transformer at Moorabool Terminal Station and the second is three 220 kV lines from Keilor to Geelong.

At times of high load at Geelong and Point Henry, loss of the Moorabool 500/220 kV transformer results in overload of the three Keilor to Geelong 220 kV lines. If this occurs, it is necessary to shed load at Geelong or the Point Henry smelter to reduce loading on the Keilor to Geelong lines to within their continuous rating.

VENCorp has installed a scheme to monitor ambient temperature and wind speed, to allow dynamic ratings based on measured wind speed to be assigned to the Keilor to Geelong 220 kV lines. By allowing the use of dynamic line ratings based on the real time measurement of wind speed, studies indicate a sufficient increase in line ratings will prevent overload following the most critical single contingency.

5.2.4 M4 – Moorabool 500/220 kV Transformer Connections Upgrade

The Moorabool Terminal Station 500/220 kV transformer supports load at Geelong, Point Henry and the southwest Victorian load. The loading on this transformer is influenced by several factors. The most significant factors are the output of Anglesea Power Station, Geelong area load and Murray Link transfer to South Australia. The most critical contingencies which increase loading on the transformer are forced outage of the Keilor A2 or A4 transformer, loss of the Bendigo to Shepparton 220 kV line, or loss of 500 kV supply to Keilor. Following these contingencies it may be necessary to shed load in the Geelong area to reduce loading on the transformer.

This project involves the replacement of primary plant connections between the 220 kV terminals of the Moorabool Terminal Station 500/220 kV transformer and the Moorabool Terminal Station 220 kV switchyard. These connections presently limit the capability of the transformer, as they have a rating below both the continuous and short time overload ratings of the transformer.

5.2.5 M5 – Modification to Dederang Bus Splitting Scheme

An existing Dederang 330 kV bus splitting control scheme (DBUSS) is installed at Dederang Terminal Station to provide increased import capability following the loss of a Murray Switching Station 330 kV line or a Dederang Terminal Station 330/220 kV transformer. Bus splitting allows the Wodonga Terminal Station line to supply the Dederang Terminal Station 330/220 kV transformers exclusively. This has the following benefits, both of which increase Victorian import capability:

- Flow is reduced on the remaining Murray Switching Station line following loss of the parallel line; and
- Flow is reduced on the remaining Dederang Terminal Station 330/220 kV transformers following loss of a Dederang Terminal Station transformer.

Currently DBUSS operates for loss of a Dederang Terminal Station 330/220 kV transformer with all three transformers initially in service. DBUSS will be modified to also operate for contingent loss of a second Dederang Terminal Station transformer with a prior outage of one transformer. This project will allow higher import into Victoria during periods when one Dederang 330/220 kV transformer is out of service.

5.2.6 M6 – Thomastown to Ringwood 220 kV Line Upgrade

This project involves an upgrade of the Thomastown to Ringwood 220 kV line. The scope of works includes the replacement of three 220 kV towers and the conversion of another three from suspension to strain type. The project will increase the line rating by around 40%. The project secures load in the Ringwood area for outage of either the Rowville to Ringwood 220 kV line or the Rowville 500/220 kV transformer.

5.2.7 M7 – Thomastown to Templestowe 220 kV Line Upgrade

This project involves an upgrade of the Thomastown to Templestowe 220 kV line. The scope of works includes the replacement of one 220 kV tower. The project will increase the rating of the line by around 40%. The project secures load in the Templestowe area for outage of either the Rowville to Templestowe 220 kV line or the Rowville 500/220 kV transformer.

5.3 Committed New Small Network Assets

5.3.1 S1 – Rowville to Springvale 220kV Line Upgrade

The entire load at Springvale and Heatherton is supplied through the two radial Rowville to Springvale 220 kV lines. Following an outage of one of these lines, the loading on the remaining line may exceed the rating of the line terminating equipment at both Rowville and Springvale Terminal Stations. Also, following an outage of the No 4 220 kV bus at Rowville Terminal Station, the loading on the Rowville to Springvale No 1 220 kV line may exceed the rating of the line terminating equipment at both Rowville and Springvale Terminal Stations.

A project has been initiated to increase the rating of the Rowville and Springvale Terminal Stations 220 kV line terminating equipment. The increased termination ratings will also allow use of higher short time conductor overload ratings, and use of higher continuous line ratings based on measured wind speed.

5.3.2 S2 – Rowville to Richmond 220kV Line Upgrade

This project involves an upgrade of the Rowville to Richmond 220 kV line terminating equipment. The scope of works includes replacement of one 220 kV circuit breaker and four 220 kV isolators at Rowville. The project will increase the overall rating of the line by around 25%. The project secures load in the Richmond area for outage of either of the Rowville to Richmond 220 kV parallel lines.

5.3.3 S3 – Moorabool 500/220 kV Transformer Spare Phase

The Geelong area load and the Point Henry smelter load are predominantly supplied from two sources. The first is a single 500/220 kV transformer at Moorabool Terminal Station and the second is three 220 kV lines from Keilor to Geelong.

At times of high load at Geelong and Point Henry, loss of the Moorabool 500/220 kV transformer results in overload of the three Keilor to Geelong 220 kV lines. If this occurs it is necessary to shed load at Geelong or the Point Henry smelter to reduce loading on the Keilor to Geelong lines to within their continuous rating.

VENCorp is procuring a spare single-phase 500/220kV transformer that is compatible with the existing Moorabool transformer. It can be used to minimise the repair time should any of the existing units fail. By doing so, it minimises the exposure to load shedding for this event.

5.4 Committed Fully Funded Developments

5.4.1 F1 – Brooklyn 220 kV Line Reactors associated with Laverton North Gas Station

Snowy Hydro Limited is installing two 186 MVA gas turbine generators at Laverton North, connecting into the Altona Terminal Station at 220 kV. To manage increased fault levels associated with the new generators, two 220 kV series line reactors, and associated bypass equipment will be installed at the nearby Brooklyn Terminal Station.

The line reactors will each have an impedance of 3%, and will be installed in the Brooklyn to Fishermans Bend and the Brooklyn to Newport Power Station 220 kV lines, in time for commercial service of the Laverton North generators by December 2005.

6. PROPOSED INTRA-REGIONAL NETWORK DEVELOPMENTS WITHIN 5 YEARS

6.1 Introduction

This section discusses the options for removal of network constraints within Victoria, and presents the information required under the NEC for proposed augmentations.

As noted in Chapter 1, VENCorp is responsible for planning the Victorian shared electricity transmission network, and does so in an independent manner and on a not for profit basis. VENCorp undertakes this responsibility in accordance with its Licence obligations, the National Electricity Code and the Victorian Electricity System Code. VENCorp assesses the feasibility of transmission projects using the Regulatory Test as specified by the ACCC.

The analysis of constraints presented in this chapter is based of the energy and maximum demand forecasts presented in VENCorp's 2004 Electricity Annual Planning Report. Further, the committed projects listed in chapters 2 and 5 of this report are assumed to be in-service for this analysis.

6.2 Network Developments

The constraints analysed as part of this year's APR have been categorised as follow:

1) Large Network Augmentations – These have an estimated capital cost of greater than $10M which require a separate and more detailed regulatory test application and consultation, in accordance with Clause 5.6.6 of the NEC.

2) Small Network Augmentations – These have an estimated capital cost of between $1M and $10M for which the APR forms the basis of the formal consultation, in accordance with Clause 5.6.6A of the NEC. As a number of these were undertaken earlier this year outside the normal APR cycle (i.e. as part of the next metropolitan transformer project), there are no small network augmentations to be consulted on this year.

3) Minor Network Augmentations – These have an estimated capital cost of less than $1M, and as such do not require a formal consultation. The details of these augmentations, and the constraints being alleviated are provided for participant information.

4) Emerging Constraints – Augmentation to mitigate the potential impacts of these constraints is not presently economically justified. These emerging constraints were identified in previous Annual Planning Reports, and will be reassessed in VENCorp's 2006 Electricity APR.

Table 6.1 details the constraints that are presented in this Electricity Annual Planning Report.

Constraint Group	APR Section	Constraint	Augmentation Category	Timing	Estimated Cost
South East Metropolitan Radial Network	6.6	Loading of Rowville to Springvale and Heatherton 220 kV Lines	Emerging Constraint	The constraint remaining following upgrade of terminating equipment is small, and as such no economic solution has been identified.	
	6.7	Loading of Rowville to Malvern 220 kV Radial Lines	Emerging Constraint	Only after a proposed load transfer to this station becomes committed, could augmentation be justified.	
	6.8	Security of Double Circuit 220 kV Lines in South East Metropolitan Area	Emerging Constraint	Development of a feasible economic option to increase security would be the only way to justify an augmentation to remove this constraint. No such option has been identified at this time.	
South East Metropolitan Meshed Network	6.9	Loading on Metropolitan Tie Transformers and Associated 220 kV Links	Large Network Augmentation[21]	September 2007	$37.2M
Western Metropolitan	6.10	Loading of Keilor to Geelong 220 kV Lines and Keilor 500/220 kV Transformers	Large Network Augmentation	Around 2008	$17M
	6.11	Loading of Keilor to West Melbourne 220 kV Lines	Emerging Constraint	An emerging constraint, with no preferred economic solution yet identified.	
	6.12	Loading of Fishermans Bend to West Melbourne 220 kV Lines	Emerging Constraint	An emerging constraint, with no preferred economic solution yet identified. Further investigations may justify augmentation towards the end of this decade.	
Latrobe Valley	6.13	Loading of Hazelwood 220/500 kV Tie Transformers	Minor Network Augmentation	December 2005	$620k
			Large Network Augmentation	2008 to 2010	$22M
State Grid (High Export)	6.14	Loading of Moorabool to Ballarat 220 kV Lines	Emerging Constraint	The remaining constraint following installation of a Wind Monitoring Scheme is small, and as such no economic solution has yet been identified.	
	6.15	Loading of Ballarat to Bendigo 220 kV Lines	Emerging Constraint	An emerging constraint, with no economic solution yet identified. Further investigations may justify a Wind Monitoring Scheme towards the end of this decade.	

21 The application notice for this New Large Network Asset was published on 31st May 2005, and submissions close on 15th July 2005.

Constraint Group	APR Section	Constraint	Augmentation Category	Timing	Estimated Cost
State Grid (High Import)	6.16	Loading of Shepparton to Fosterville to Bendigo 220 kV Line	Minor Network Augmentation	September 2006	$600k
	6.17	Loading of Murray to Dederang 330 kV Lines	Emerging Constraint	No augmentation is economically justified at this time. This constraint would need to be reassessed as part of any Victoria to Snowy/NSW interconnector upgrade.	
	6.18	Loading of Dederang to South Morang 330 kV Lines	Emerging Constraint	No economic solution is justified. This constraint would need to be reassessed as part of any Victoria to Snowy/NSW interconnector upgrade.	
	6.19	Loading of 330/220 kV Dederang Tie Transformers	Emerging Constraint	A large network augmentation to alleviate this constraint is not justified in this five year period.	
	6.20	Loading of Eildon to Thomastown 220 kV Lines	Emerging Constraint	Minor works, including a Wind Monitoring scheme may be justified in a couple of years.	
Reactive Support	6.21	Additional Reactive Power Support	Emerging Constraint	There is no economic justification for additional reactive support to be installed for service before 2008.	

Table 6.1 – Summary of Network Constraints

6.3 Planning

In accordance with the requirements of the Regulatory Test, VENCorp considers the benefits associated with transmission investment are:

- a reduction in the amount of expected unserved energy;
- a reduction in the total fuel cost of generation in the NEM;
- a reduction in transmission losses;
- deferral of capital plant costs; and
- a reduction in ancillary service costs.

In its planning role, VENCorp does not adopt a planning standard or criteria based on N-1 redundancy. In Victoria, a value of customer reliability (VCR) has been adopted that represents the marginal cost to consumers of involuntary supply interruption, expressed in terms of $ per MWh. Application of the VCR allows expected unserved energy to be economically quantified, thereby providing a basis for assessing the net economic benefits of investment proposals. Importantly, the application of a net market benefit approach implies that under some conditions, shedding load following a credible contingency may represent the most economic option.

A probabilistic approach is applied in the assessment of expected unserved energy. This approach considers the likelihood of the coincident occurrence of a contingency event and onerous loading and ambient conditions. The probability of an outage is calculated using benchmark figures (as defined in the Victorian Electricity System Code) and the historical performance of the transmission element. VENCorp's approach to transmission investment analysis is detailed in the document *"Electricity Transmission Network Planning Criteria"*, which is available online at VENCorp's website (www.vencorp.com.au).

The principles applied by VENCorp for planning the transmission network are consistent with NEC requirements and NEMMCO's operational practices, and are as follows:

- Following a single contingency, the system must remain in a satisfactory state (i.e. no performance or plant limit breached).
- Following the forced outage of a single element, it must be possible to re-adjust (secure) the system within 30 minutes so that it is capable of tolerating a further forced outage and remain in a satisfactory state (i.e. no performance or plant limit breached).
- Following an outage at least 15 minutes must be available for manual action. If less than 15 minutes is available then, it is necessary to take pre-contingent action to provide the 15 minutes or have in place an automatic control scheme.
- Sufficient periods are available to allow maintenance of critical shared network elements without exposing the network to excessive risk in the event of a further unscheduled outage of a network element.
- Load shedding and re-dispatch of generation are considered as legitimate alternatives to network augmentation.

The expected unserved energy resulting from network constraints has been valued using a Value of Customer Reliability of $29,600/MWh. Expected rescheduled generation is valued on the basis of Short Run Marginal Cost (SRMC).

A flowchart describing these planning principles is included in Appendix C.

6.4 Market Modelling Basis

To implement its probabilistic planning approach, VENCorp simulates the National Electricity Market in order to determine the use of the shared network in such an environment. A Monte-Carlo based modelling of flows on the shared network is extrapolated from the NEM dispatch data. These forecast flow conditions are then compared with the capability of critical plant, allowing the exposure to unserved energy to be quantified over the analysis time frame.

The assumptions and specifications of VENCorp's NEM modelling for the 2005 Annual Planning Review include:

- Scenarios / Demand Traces – Only committed changes to the NEM interconnector capabilities and generation were considered for VENCorp's intra-regional transmission planning. Appropriate historical demand traces were scaled for all current NEM regions over the analysis period with 10 and 50 percentile peak demand scenarios being considered based on a medium economic (energy) growth outlook.

- Demand / Energy Forecasts – NEMMCO's 2004 Statement of Opportunity and VENCorp's 2004 APR were used as the source of regional energy and demand forecasts.
- Generation – The summer and winter capacities of all dispatched NEM generators were modelled from NEMMCO's 2004 Statement of Opportunity. Forced outage rates and mean repair times were based on aggregated data from NEMMCO. Planned outage programs were based on historical market behaviour and MT PASA forecasts.
- Generation Bidding – Short Run Marginal Costs were sourced from the 2003 ACIL Tasman report (SRMC and LRMC of Generators in the NEM).
- Inter-regional marginal loss factor equations and intra-regional loss factors were based on NEMMCO's 2004/05 loss factor publication.
- Hydro Generation – Forced Outage Rates were modelled for hydro units. Historical energy targets for Snowy and Southern Hydro Generation were enforced.
- New Entry Criteria – New Generators were entered into the market based on the principle of 'Reliability Driven Generation' to reflect an assumption that reserve margins would be maintained in all regions.

6.5 Distribution Business Planning

VENCorp performs network planning based on the load forecasts provided by Transmission Customers who have a supply point(s) of connection to the shared transmission network. In doing so VENCorp ensures that shared network augmentation plans take account of the distribution businesses' plans for development at existing stations and new connection points. Additionally, the impacts of the distribution business augmentation plans on the shared network planning have been individually addressed in VENCorp's assessment of each of the constraints.

The general impact of distribution load growth is addressed through modelling of growth at the connection stations. Table 6.2 shows the planned connection modifications presented in the distribution businesses' 2004 TCPR (Transmission Connection Planning Report), and VENCorp's consideration of these augmentations in respect of the shared network.

Terminal Station	Preferred Network Solution	VENCorp Consideration
Castlemaine	Establish new 220/66 kV terminal station to off-load Bendigo Terminal Station beyond 2010.	Establish a short length of 220 kV line to connect the new station, if it is not adjacent to an existing 220 kV line.
East Geelong	Establish new 220/66 kV terminal station to off-load Geelong Terminal Station some time around 2009.	The requirement to support supply into the Geelong area from Moorabool and Keilor will not be changed by this development. However, the relocation of load from Geelong to East Geelong will increase the loading on the Geelong to Point Henry 220 kV lines. There is spare capacity in these lines to support additional load. VENCorp will review the requirements with Powercor and advise affected parties
Malvern 66 kV and 22 kV	Redevelopment of Malvern Terminal Station and possible transfer of load from adjacent terminal stations by 2006. Possible transfer of 100 MW from Richmond Terminal Station around 2008/09.	The existing 220 kV circuits from Rowville are adequate to meet supply to Malvern. If the load at Malvern goes beyond 270 MVA the circuits could become a constraint at times of high demand. There is capability to uprate these circuits when economically justifiable- eg to cater for 100 MW transfer from Richmond Terminal Station.
Richmond 66 kV and 22 kV	Establish new terminal station, either by approximately 2010, or later if 100 MW is transferred to Malvern Terminal Station, possibly around 2008/09.	Transfer of 100 MW to Malvern Terminal Station would significantly reduce the loading on the Richmond to Brunswick circuit and the Rowville to Richmond circuits, reducing the risk of the constraints on these circuits. Establishing a new terminal station may further reduce these loadings and risks.
	Upgrade a Southbank area zone substation from 22 kV to 66 kV connection, permanently supplied from Fishermans Bend instead of Richmond Terminal Station, around 2007/08.	This would further reduce Richmond to Brunswick and Rowville to Richmond circuit loadings, while increasing Keilor-West Melbourne-Fishermans Bend loadings and constraint risks.
South Morang 66 kV	Establish new terminal station at South Morang to off-load Thomastown Terminal Station by 2007/08.	Providing a 220 kV bus connection at South Morang as Distribution Businesses propose may impact a large number of closely inter-related metropolitan area 220 kV shared network thermal and fault level constraints. Reliable termination of existing 330/220 kV transformation and 220 kV lines at South Morang will also need review.

Table 6.2 – Distribution Business Planning Impacts

6.6 Loading of Rowville to Springvale and Heatherton 220 kV Lines

6.6.1 Overview

The two Rowville to Springvale 220 kV lines form a radial supply to Springvale and Heatherton. A thermal constraint on these lines is forecast to arise after an outage of the either of these parallel lines. The constraint will only occur under conditions of high local demand. The effect of the constraint is load shedding at Springvale and Heatherton.

In VENCorp's 2004 Annual Planning Report, upgrading terminating equipment for each Rowville to Springvale line was identified as a technical and economic solution. This upgrade is now a committed New Small Network Augmentation (refer to section 5.3.1) and is expected to be completed during summer 2005/06.

This year's assessment has confirmed that the termination equipment upgrade has deferred the need for further augmentation and that the Rowville to Springvale constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be upgrading towers on each Rowville to Springvale line to increase the design rating from 460 MVA to 745 MVA, given an ambient temperature of 40°C. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.6.2 Introduction

(a) Location of Constraint

The Rowville to Springvale and Heatherton double circuit 220 kV lines supply electricity from Rowville Terminal Station to Springvale and Heatherton Terminal Stations, as shown in Figures 6.1 and 6.2.

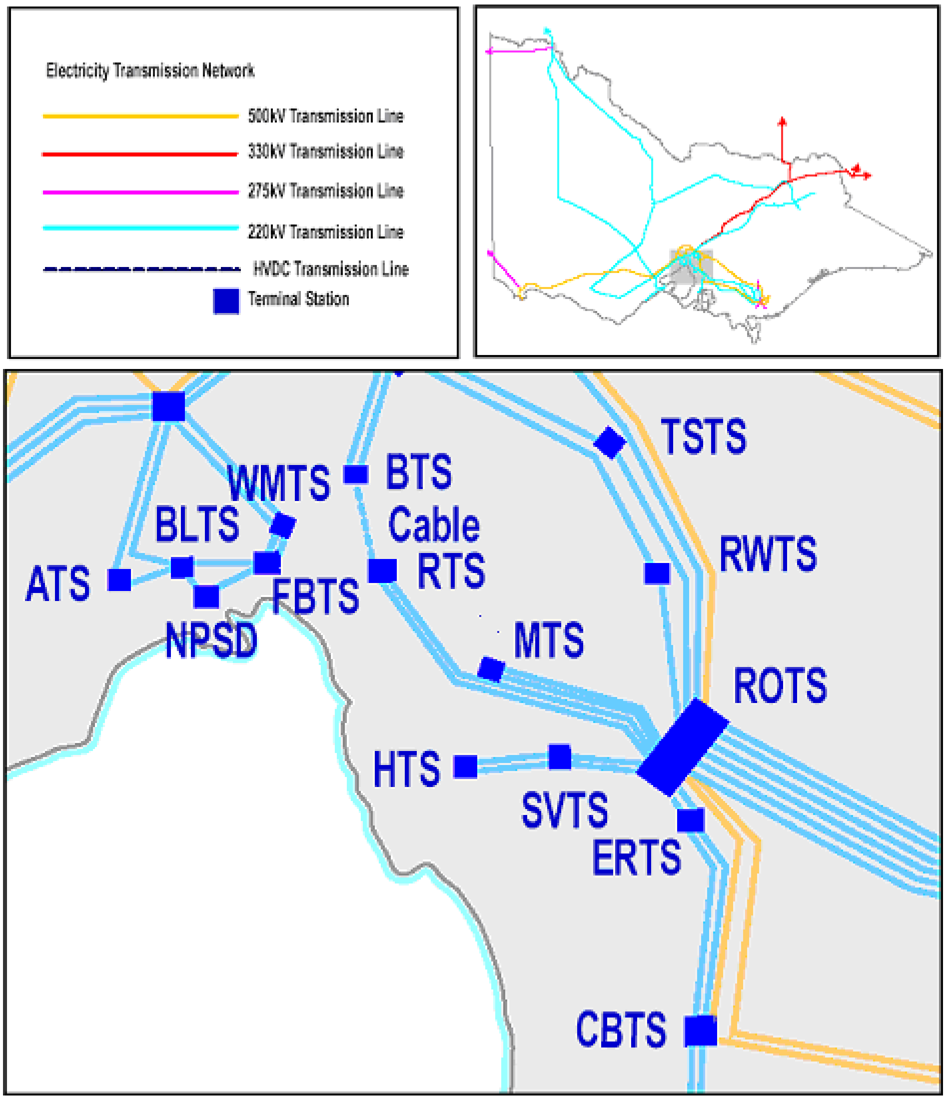

Figure 6.1 – Geographical Representation of the Rowville to Springvale and Heatherton 220kV Lines

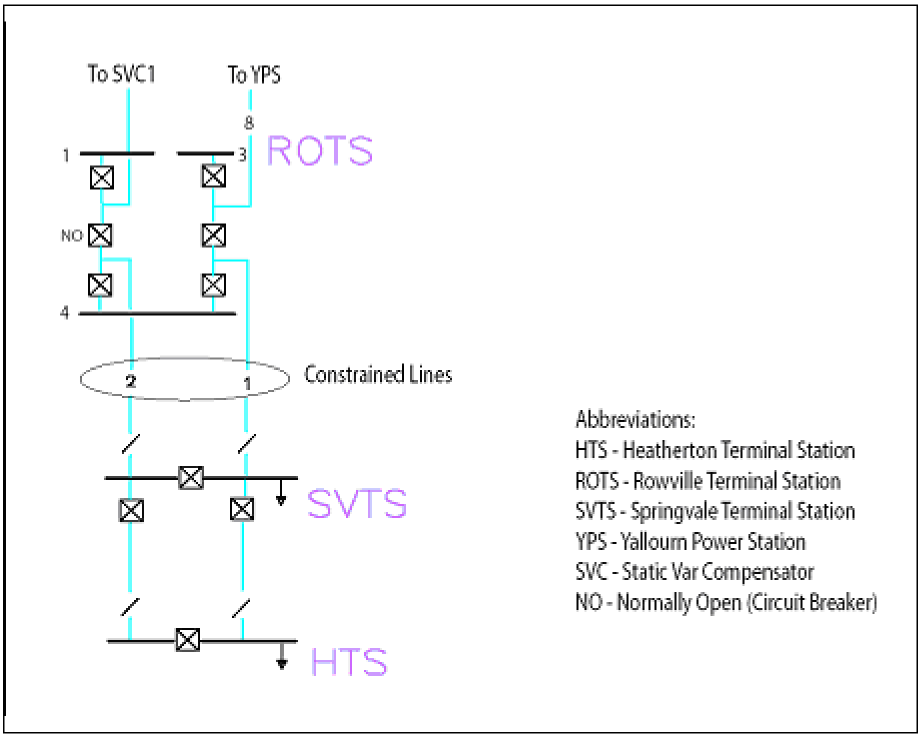

Figure 6.2 – Electrical Representation of the Rowville to Springvale and Heatherton 220kV Lines

(b) Reason for Constraint

Loading on the Rowville to Springvale and Heatherton circuits is forecast to increase due to Springvale and Heatherton area load growth. Table 6.3 summarises peak demand forecasts at Springvale and Heatherton up to summer 2009/10.

Year	Springvale Demand (MW)	Heatherton Demand (MW)	Total Demand (MW)
2005/06	474	342	816
2009/10	536	395	931

Table 6.3 – Forecast Maximum Demand at Springvale and Heatherton (10% POE, Medium Economic Growth)

(c) Conditions of Constraint

Normally the Rowville to Springvale circuits share the combined load at Springvale and Heatherton equally, and the Springvale to Heatherton circuits share the Heatherton load equally. Following outage of any of these circuits the loading of the parallel circuit doubles. Circuit rating decreases with increasing air temperature, and decreasing wind speed. Air temperature and wind speed are monitored adjacent the Rowville to Springvale circuits. Under very low probability conditions of high temperature, low wind speed, and unplanned outage of either circuit, the rating of the circuit remaining in service would constrain supply of Springvale/Heatherton load. Table 6.4 provides historical wind speeds during times of high ambient temperature.

Temperature (°C)	Wind speed (m/s)		
	0 - 0.6	0 - 1.2	0 - 1.8
42	0	0	0
40	0	0.5%	1.8%
35	0	4.6%	11.5%

Table 6.4 – Observed low wind speeds at high temperatures

Air temperature (but not wind speed) is monitored adjacent the Springvale to Heatherton circuits. Under low probability conditions of high temperature and unplanned outage of either circuit, the rating of the circuit remaining in service may constrain supply of Heatherton load.

A small network augmentation, presented in VENCorp's 2004 Electricity Annual Planning Report is in progress to upgrade terminating equipment at Rowville and Springvale terminal stations by next summer. Table 6.5 shows the continuous and short time ratings of the remaining constrained elements, following this augmentation.

Transmission Element	Wind speed (m/s)	Rating at 35°C (MVA)	
		Continuous	Short time
ROTS-SVTS Circuits	0.6	648	830
ROTS-SVTS Circuits	1.2	748	977
ROTS-SVTS Circuits	2.4	953	1,244
SVTS-HTS Circuits	0.6	400	475

Table 6.5 – Thermal Ratings of Constrained Elements

The "short time" ratings comprise the maximum permissible loading of the circuit remaining in service after outage of the other circuit until loading is reduced by control action or manually. The time to reduce loading is 10 minutes for Rowville-Springvale circuits, as their loading is reduced by automatic controls, and 15 minutes for the Springvale-Heatherton circuits, as their loading is reduced manually. Rating variations with wind speed across circuit conductors are also shown in Table 6.5.

The historically observed statistical distribution of wind speed adjacent the Rowville-Springvale line at higher temperatures has been included in the following assessments of energy at risk. Unserved energy levels assessments based on probabilistic wind speeds are significantly lower than those based on a fixed wind speed such as 0.6 m/s or 1.2 m/s because the probabilistic assessment reduces both peak and aggregate load curtailment.

Table 6.6 shows the probability of an outage on the Rowville to Springvale and Heatherton circuits, based on historical actual performance, and determined using the Victorian Electricity System Code benchmark, which is based on circuit length. Unserved energy assessments use the higher of these rates (i.e. the benchmark values).

Circuit	Length (km)	Probability of Outage	
		Actual	Benchmark
ROTS-SVTS	7.4	0.0190 %	0.02534 %
SVTS-HTS	8.1	0.0119 %	0.02774 %

Table 6.6 – Probability of Plant Outages

(d) Impacts of Constraint

Following the small network augmentation at Rowville and Springvale, there is little load at risk for outage of a Rowville-Springvale and Heatherton circuit for the next five years. Determining circuit ratings using probabilistic wind speed variation with ambient temperature reduces this load at risk significantly further. There is a small, but growing, amount of load at risk over the next 5 years due to these circuits. This risk is materially affected by a planning criterion constraining Rowville-Springvale circuit loadings under normal conditions to levels allowing 10 minutes to reduce load at Springvale and Heatherton, following unplanned outage of a Rowville-Springvale circuit. This relies on the wind monitoring and automatic load shedding control schemes in service.

Over the next 5 years the Springvale-Heatherton circuit ratings allow more than the 15 minutes needed to reduce Heatherton load manually if an unplanned outage of one circuit occurs, and therefore these circuit do not form a constraint under normal conditions in this period.

Due to the low unplanned outage rates of these circuits, in addition to the low probability of high ambient temperatures and low wind speeds causing lower circuit ratings, there is very little expected unserved energy for the next 5 years due to unplanned circuit outages.

(e) Impact on Constraint of Distribution Business Planning

Distribution plans published in the 2004 Transmission Connection Planning Report ("TCPR") ultimately cater for Springvale and Heatherton Terminal Station aggregate peak summer demands of 1,440 MVA under emergency conditions at other station/s, and between 1,080 MVA and 1,440 MVA under normal network conditions.

The Rowville to Springvale line can be uprated to enable this 1,440 MVA peak emergency summer demand to be carried under normal 220 kV network conditions (i.e. with both circuits in service), and extreme weather conditions (42 ^{o}C ambient temperature and light winds). However under these conditions, with unplanned outage of one circuit, the (uprated) circuit remaining in service could only supply:

- 62% of terminal station peak emergency demand; and
- 62-76% of the peak summer demand under normal terminal station conditions;

The additional loading of this easement also exacerbates the double circuit radial security issue considered in Section 6.8.

The probability per year is low that conditions will arise leading to these inabilities of the shared transmission network to supply distribution demand. Also, establishing a third 220 kV circuit to Heatherton or Springvale Terminal Station may be very expensive because underground cable (costing approximately $35 M, including station works) may be needed, as overhead circuit easements to these stations are fully utilised. Due to these joint conditions, establishing a third transmission circuit may not be economically justified, with exposure remaining indefinitely to a small risk each year that a single unplanned transmission circuit outage will require up to 550 MW of Springvale / Heatherton load to be shed.

6.6.3 Do Nothing – Expected Value of Constraint

Table 6.7 shows the assessed unserved energy for the next 5 years due to the Rowville to Springvale and Heatherton circuits. Approximately 99% of this unserved energy arises to control Rowville-Springvale circuit loading under system normal conditions. The remaining 1% of energy at risk is split approximately equally between load shedding to control loading of a Rowville-Springvale or a Springvale-Heatherton circuit, after unplanned outage of the parallel circuit.

The fractional average annual hours of constraint in Table 6.7 arise from the low probabilities involved and represent long run averages of at least one hour of constraint, occurring less frequently than once annually. For example 0.025 average annual hours of constraint in 2009/10 represents one hour of constraint occurring on average, over the long run, one year in 40 years.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0.001	0.003	0.005	0.012	0.025
Maximum single constraint	MW	81	104	125	152	183
Average constraint	MW	20	42	46	64	71
Expected unserved energy	MWh	0.03	0.07	0.18	0.43	0.99
Expected value of unserved energy	$k	1	2	5	13	29
EXPECTED VALUE OF CONSTRAINT	$k	1	2	5	13	29

Table 6.7 – Expected Value of Constraint

6.6.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

Possible network solutions to remove the constraint on 220 kV supply to Springvale and Heatherton are:

Option 1: Uprating the Rowville to Springvale circuits from 68°C to 82°C operation. This involves modification of at least 7 transmission towers. An indicative cost for this option is approximately $1M ± 25%, and at this point in time VENCorp considers this to be a non-contestable augmentation.

(b) Non-Network Options Considered

Demand management or new generation embedded in distribution networks local to Springvale or Heatherton, sufficient to keep demand below the continuous rating of termination equipment could reduce or remove load at risk.

6.6.5 Economic Evaluation

Table 6.8 presents a net market benefits assessment for this constraint.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-271	-1	-2	-5	-13	-29	-373
Option 1 (Thermal Uprate)	Market Benefits		1	2	5	13	29	373
	Costs		-83	-83	-83	-83	-83	-1,064
	Net Market Benefits		-82	-81	-78	-70	-54	-691

Table 6.8 – Net Market Benefits of Network Options

6.6.6 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Rowville to Springvale constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be upgrading towers on each Rowville to Springvale line to increase the design rating from 460 MVA to 745 MVA, given an ambient temperature of 40°C. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.7 Loading of Rowville to Malvern 220 kV Radial Lines

6.7.1 Overview

The two Rowville to Malvern 220 kV lines form a radial supply to Malvern. A thermal constraint on these lines is forecast to arise after an outage of the either of these parallel lines. The constraint will only occur under conditions of high local demand. The effect of the constraint is load shedding in Malvern.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Rowville to Malvern constraint can be managed until 2007/08. Beyond this time frame, VENCorp will continue to monitor the load growth at Malvern and plans by the Distribution Businesses to permanently transfer additional load to Malvern after it is redeveloped. VENCorp considers the next most likely network augmentation would be development of an automatic control scheme to control post contingent loading on the lines. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.7.2 Introduction

(a) Location of Constraint

Malvern Terminal Station is supplied at 220 kV by a radial double circuit line from Rowville Terminal Station. The supply arrangement is shown in Figures 6.3 and 6.4 below.

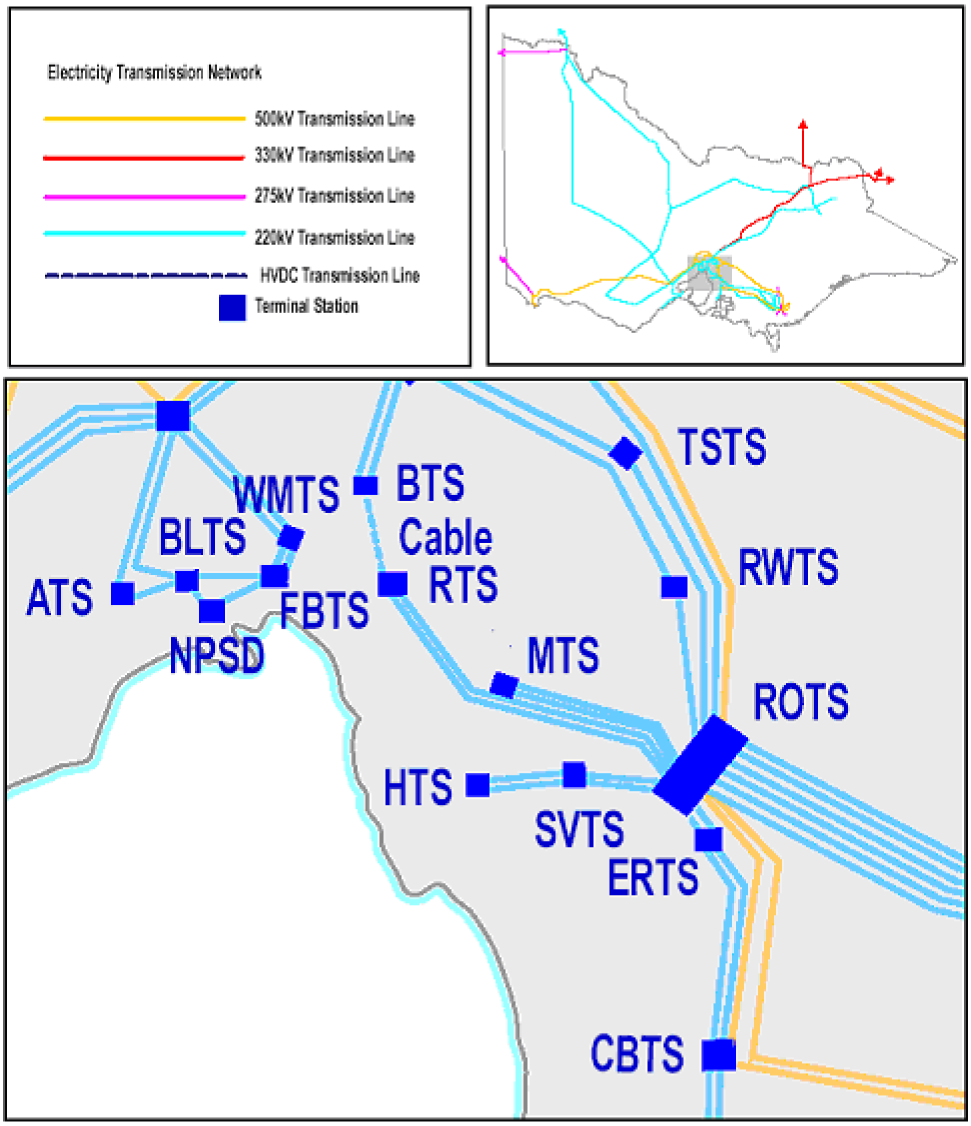

Figure 6.3 – Geographical Representation of the Rowville to Malvern 220 kV Radial Lines

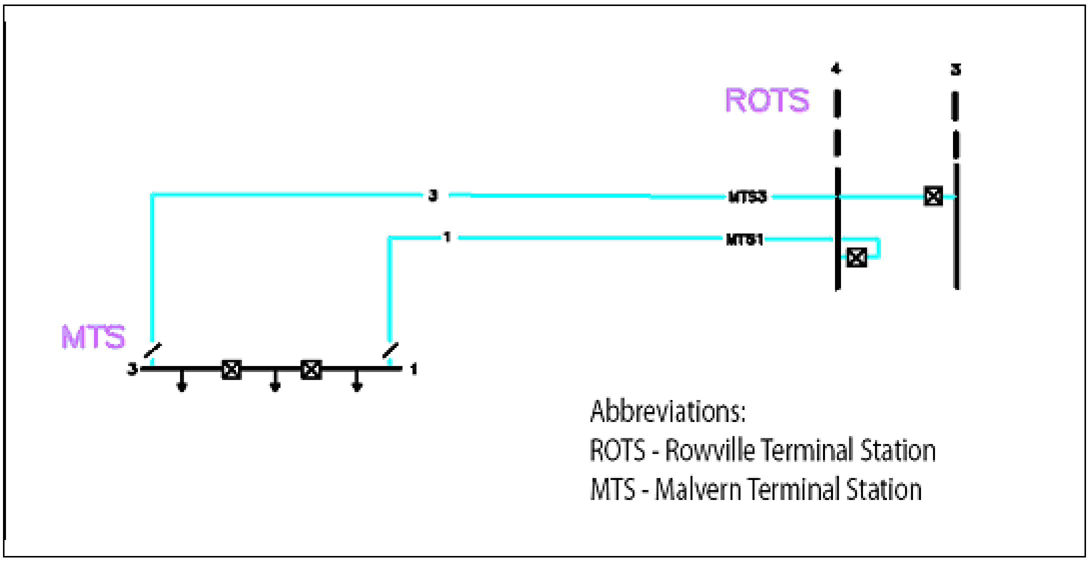

Figure 6.4 – Electrical Representation of the Rowville to Malvern 220 kV Radial Lines

(b) Reason for Constraint

Load growth at Malvern Terminal Station has led to this constraint. The second column of Table 6.9 provides peak load forecasts by Distribution Businesses for Malvern Terminal Station. These peak demands are 5-6% higher than forecast in 2004, representing almost 2 year's advance. The third column of Table 6.9 shows a possible additional permanent transfer of load from Richmond to Malvern that the Distribution Businesses have indicated may occur by approximately 2008.

Year	Maximum Total Demand at Malvern (MW)	Incremental Load Transfer (MW)
2005/06	200	0
2006/07	205	0
2007/08	212	0
2008/09	220	100
2009/10	228	100

Table 6.9 – Forecast Maximum Demand at Malvern Terminal Station (10% POE, Medium Economic Growth)

(c) Conditions of Constraint

Each of the Rowville to Malvern 220 kV circuits carries 50% of the total load of Malvern under normal conditions. Following outage of a Rowville to Malvern circuit, the remaining parallel circuit carries the total load of Malvern. Each circuit has a nominal continuous rating of 277 MVA at 35°C and 245 MVA at 40°C.

Potential loading of a Rowville to Malvern circuit may match its continuous rating following outage of the parallel circuit at times of peak demand and high ambient conditions by 2008/09. Peak loads forecast for subsequent summers would increasingly exceed this rating.

If an extra 100 MW is transferred from Richmond to Malvern in 2008 or later it would all be at risk for unplanned outage of either of these circuits on hot days.

(d) Impacts of Constraint

In summer 2009/10 approximately 7 MW of currently forecast peak demand is at risk for outage of the parallel circuit. Sufficient time is available for manual load transfer or shedding following an outage of the parallel circuit. There is a low probability per year that the circuit outage would occur coincident with high demand and temperature conditions.

If Distribution Businesses decide to transfer 100 MW of load to Malvern around 2008, the forecast peak demand in summer 2008/09 would be 320 MW, significantly impacting this constraint and justifying a minor network augmentation then.

(e) Impact on Constraint of Distribution Business Planning

As already noted, Distribution Businesses plan to increase the capacity of Malvern and are considering transferring about 100 MW of load from Richmond in 2008. The amount of load and its rate of growth will determine the timing for a future augmentation.

(f) Impact on Constraint of Asset Replacement Program

SP AusNet has planned to re-furbish the Malvern 220/66/22 kV Terminal Station in 2005/06. It is understood the new terminations of the Rowville to Malvern circuits at Malvern Terminal Station will match these circuits' ultimate ratings.

6.7.3 Options and Costs for Removal of Constraint

Network options to reduce constraints are:

- An automatic control scheme that would shed load to control Rowville-Malvern circuit loadings, at an estimated to cost $150k. This option is likely to be economically viable following transfer of 100 MW load from Richmond to Malvern;
- A wind monitoring scheme to take advantage of higher wind speeds, anticipated during hot summer days, to provide higher circuit ratings, at an estimated to cost $250k. The automatic control scheme mentioned above would also be needed to shed load, covering low probability weather conditions of high temperatures and light winds. This option is likely to be economically viable following transfer of 100 MW load from Richmond to Malvern;
- Uprate the Rowville to Malvern lines from 65°C to 82°C operation, providing 30% increase in capability from 277 MVA to 360 MVA at 35°C. This will require about 9 replacement towers and minor terminations work at Rowville.

At this point in time VENCorp considers these options to be non-contestable augmentations.

6.7.4 Economic Evaluation

If 100 MW load is transferred from Richmond to Malvern, both the automatic load shedding control and wind monitoring schemes would likely be economically justified. Lead time required for these schemes is not expected to exceed one year, so a firm commitment by Distribution Businesses to the 2008/09 date they are considering is not needed yet in relation to these schemes.

6.7.5 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Rowville to Malvern constraint can be managed until 2007/08.

VENCorp considers the next most likely network augmentation would be development of an automatic control scheme to control post contingent loading on the lines. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.8 Security of Double Circuit 220 kV Lines to South East Metropolitan Area

6.8.1 Overview

The Springvale, Heatherton, Malvern, Tyabb and Westernport (JLA) Terminal Stations are each supplied by radially configured double circuit 220 kV lines. Subject to the transfer of load away from these areas, failure of one or more of the towers on these radial lines could cause considerable loss of supply to any of these areas. The effect of the constraints is load shedding in the affected areas.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint at this time. However, there has been some review of failure rates for towers and load transfer capability.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint. The security of the double circuit 220 kV lines to the south east metropolitan area can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be the installation of an underground cable between Malvern and Heatherton. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.8.2 Introduction

(a) Location Of Constraint

The Springvale, Heatherton, Tyabb and Malvern Terminal Stations, and the facility at Western Port each relies on radial double circuit 220 kV line supply, as shown in Figure 6.5.

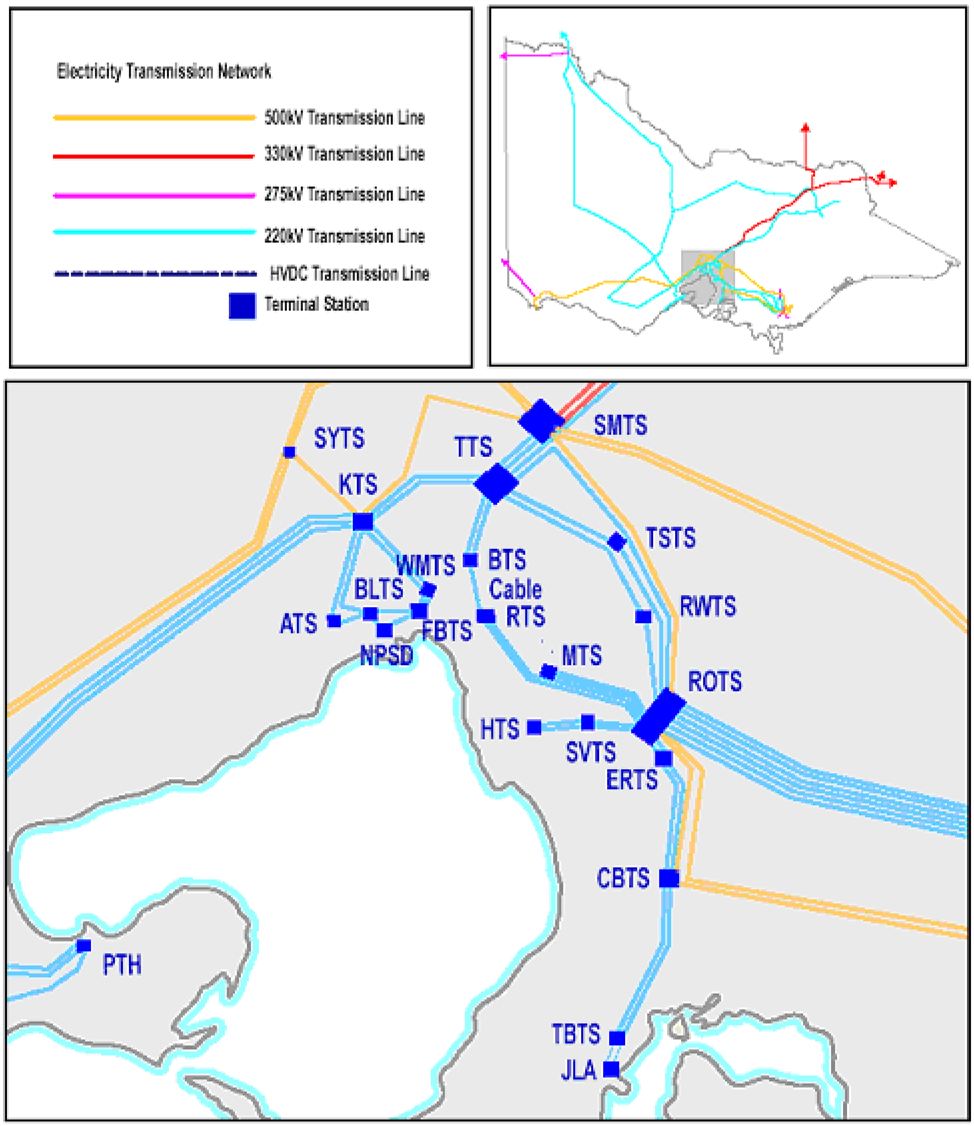

Figure 6.5 – Geographical Representation of the Double Circuit 220 kV Lines

(b) Reasons for Constraint

Failure of one or more double circuit towers, leading to an extended outage of both circuits on a tower line, and loss of most supply to a large area, is unlikely, but nonetheless possible. These events have very low probability per year of occurring, and so are expected to occur rarely, but are considered to be equally likely to occur in any one year.

(c) Impacts of Constraint

Table 6.10 identifies the forecast peak loading on each of the double circuit lines, including the effect of distribution transfers.

Double Circuit Line	Length (km)	Peak load at risk for double circuit line outage in summer 2005/06 (MW)	
		Prior to transfers	After transfers
Rowville to Springvale	7	816	596
Springvale to Heatherton	8	342	222
Cranbourne to Tyabb	23	301	181
Tyabb to Western Port	2	66	66
Rowville to Malvern	15	200	0

Table 6.10 – Load at Risk for Double Circuit 220 kV Line Outages

To minimise the consequences and restore supply after a double circuit failure the following emergency plans and works have been put in place by Alinta, SPI Networks, SP AusNet and VENCorp:

- emergency by-pass measures, utilising temporary structures and mobile cranes, developed by SP AusNet, allow for restoration of full supply within 12 hours in over half of the possible tower failure cases;
- emergency bridging measures developed by SP AusNet, in conjunction with VENCorp, will restore full supply to Malvern from the Rowville to Richmond double circuit line within 6 hours for a Rowville to Malvern double circuit outage; and
- emergency measures developed by Alinta and SPI Networks will progressively restore supply to some major blocks of load using transfer capacity available in their networks. Restoration time varies from 2 minutes (for remote control switching) up to about 6 hours (where some line construction work is needed).

Cranbourne 220/66 kV Terminal Station, commissioned during 2004/05, and Cranbourne 500/220 kV Terminal Station, due to be commissioned shortly, will together approximately halve the length of double circuit tower lines needed to supply Tyabb and Western Port. This approximately halves the related exposure of Tyabb and Western Port to an extended total supply loss. The new stations will also supply East Rowville independently of the short double circuit tower line from Rowville (although the short line will continue to supply East Rowville)[22].

22 The economic justification for these new stations is mainly the increased eastern metro supply capability under normal conditions, and following unplanned outage of a single transmission element. The reduced dependence on double circuit towers secures too little energy, assessed probabilistically, to contribute materially to their economic justification.

6.8.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

Possible network solutions to remove these constraints are:

Option 1: New 220 kV underground cable from Malvern to Heatherton (approximately 8 km), with a continuous rating of 400MVA and a 2 hour rating of 650MVA. An indicative cost for this option is approximately $35M.

Option 2: New 220 kV underground cable from Heatherton to Cranbourne (approximately 26 km), with a continuous rating of 400MVA and a 2 hour rating of 650MVA. An indicative cost for this option is approximately $98M.

VENCorp considers that these network options would be contestable augmentations.

(b) Non-Network Options Considered

Demand management or new generation embedded in distribution networks, sufficient to keep demand below the short time rating of these circuits could reduce or remove load at risk.

6.8.4 Economic Evaluation

Table 6.11 shows transmission options and their estimated capital costs, and compares these with indicative benefits associated with the augmentation.

	Market Benefits ($k)	Costs ($k)	Net Market Benefits ($k)
Option 1 (Malvern to Heatherton Cable)	25,000	-35,000	-10,000
Option 2 (Heatherton to Cranbourne Cable)	22,000	-98,000	-76,000

Table 6.11 – Net Market Benefits of Network Options

No economic and technically viable solution to completely remove these constraints has been identified.

Preliminary investigations did not identify an easement that could accommodate a technically viable overhead circuit from Malvern Terminal Station to Heatherton Terminal Station, although the cost of a conventional overhead circuit directly connecting these stations may be economically justified.

Possible availability of an easement to accommodate a viable overhead line, at least part way between Heatherton and another transmission easement, with some small amounts of underground cable, could be an option. This could include seeking options to establish a joint use overhead line, normally to be used for distribution purposes, but available for emergency use at 220 kV.

6.8.5 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The security of double circuit radial lines can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be the installation of an underground cable between Malvern and Heatherton. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.9 Loading of 500/220 kV Metropolitan Transformers and Associated 220 kV Links

6.9.1 Overview

Since the 2004 Annual Planning Report, VENCorp has undertaken detailed assessment of constraints in the metropolitan area associated with loading on the Rowville and Cranbourne 500/220 kV transformers and the constraints associated with the outage of these critical transformers. The effect of the constraints is load shedding in metropolitan Melbourne.

Following VENCorp's analysis, an Application Notice was published on 31 May 2005 in accordance with the NEC requirements for a proposed New Large Network Asset.

The Application Notice concludes a new 500/220 kV, 1000MVA transformer at Rowville Terminal Station satisfies Part 1(b) of the Regulatory Test. It does so on the basis it maximises the expected net present value of the market benefits compared with a number of alternative options and timings, in a majority of reasonable scenarios.

The capitalised cost estimate of the project is $37.2M ± 25% and the recommended completion date is September 2007.

The proposed New Large Network Asset delivers an expected net present value of the market benefit of between $161.5M to $80.5M[23], averaging over all of the sensitivity studies at around $117.6M.

This proposed New Large Network Asset has both contestable and non-contestable components as some of the works are integrated with, and associated with improving the capability of, the existing assets of both Rowville Transmission Facility Pty Ltd[24] and SP AusNet Pty Ltd.

VENCorp does not consider the preferred augmentation will have a material inter-regional impact.

For further information on these constraints, please refer to the full Application Notice, published under Consultations on the VENCorp website at www.vencorp.com.au.

23 Real dollars, referred to July 2005

24 Rowville Transmission Facility Pty Ltd owns the existing Rowville 500 kV switchyard and the Rowville A1 transformer.

6.10 Loading of Keilor 500/220 kV Transformers and Keilor to Geelong 220 kV Lines

6.10.1 Overview

Loading of the Keilor 500/220 kV tie transformers and the Keilor to Geelong 220 kV lines presents a thermal constraint that can arise with all plant in service and after various outages in the area, particularly outage of either a Moorabool or Keilor 500/220 kV transformer. The constraint will only occur at times of high demand and when there is limited generation available to supply this demand at the 220 kV voltage level in the west metropolitan area. The effect of the constraints is generation rescheduling and load shedding in metropolitan Melbourne and Geelong.

Since the 2004 Annual Planning Report, there have been a number of initiatives undertaken regarding this constraint. VENCorp has:

- procured a spare single phase 500/220 kV transformer compatible with the Moorabool unit (refer to section 5.3.3);
- installed a real time wind monitoring scheme adjacent to the Keilor to Geelong lines (refer to section 5.2.3); and
- upgraded the connections of the Moorabool transformer to allow higher transfer capability (refer to section 5.2.4).

Furthermore, the Laverton North generation plant is now a committed project targeted for service by December 2005.

This year's assessment has concluded that augmentation is required.

VENCorp considers that the installation of a second 500/220 kV transformer at Moorabool is likely to pass the Regulatory Test requirements. This network option would be a New Large Network Asset with a capitalised cost estimate of $17M ±25% providing a net present value of the market benefits of around $132M. The tentative timing for the project is September 2008.

In accordance with Clause 5.6.6A of the NEC, VENCorp will undertake a detailed assessment of these constraints and publish a separate Application Notice reporting on the outcomes.

6.10.2 Introduction

(a) Location of Constraint

The constraint is located on the Keilor 500/220 kV transformers in the western metropolitan area and the Keilor to Geelong 220 kV lines in southwest Victoria. Geographical and electrical representations of the constraint are given in Figure 6.6 and Figure 6.7.

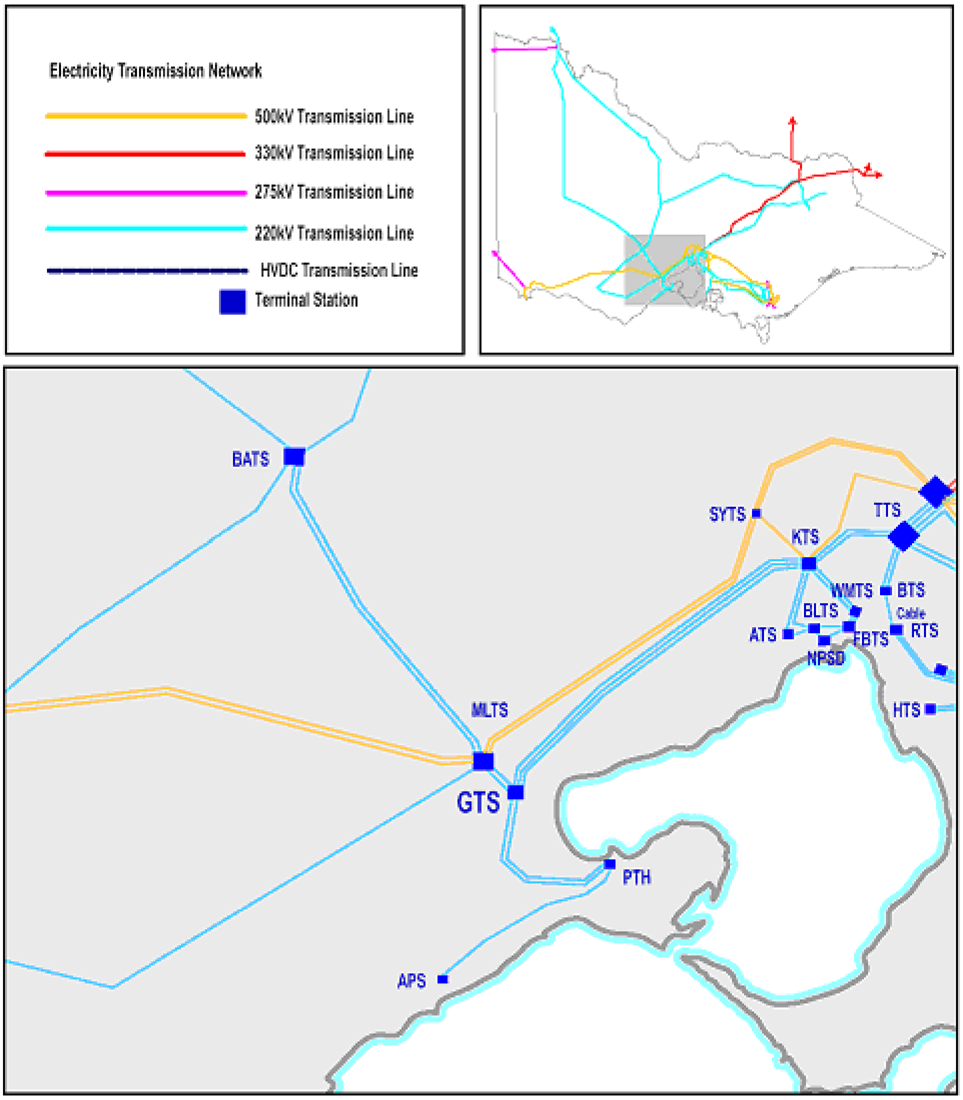

Figure 6.6 – Geographical Representation of the Keilor 500/220 kV Transformers and the Keilor to Geelong 220 kV Lines

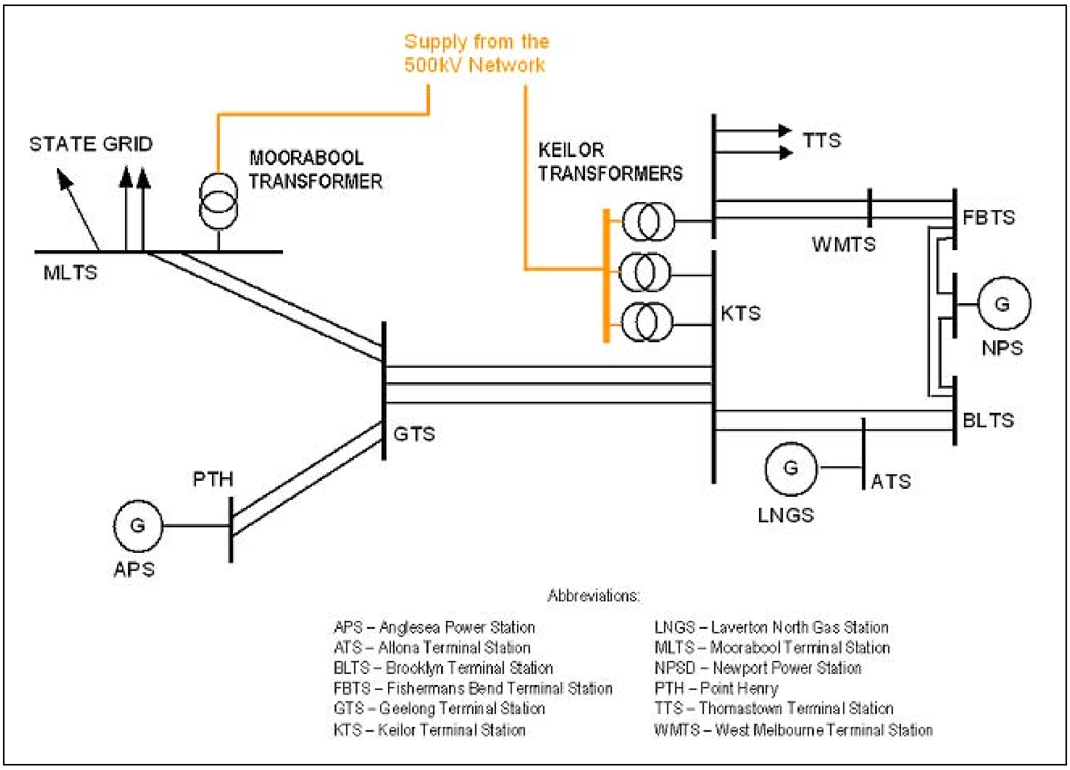

Figure 6.7 – Electrical Representation of the Keilor 500/220 kV Transformers and the Keilor to Geelong 220 kV Lines

(b) Reasons for Constraint

Western metropolitan Melbourne, Geelong and part of southern Victorian State Grid areas and Point Henry smelter load are supplied from a 500/220 kV transformer at Moorabool, three 500/220 kV transformers at Keilor, 220 kV lines from Thomastown and local generation in these areas.

The load in these areas is growing, such that outage of a Moorabool transformer can potentially overload Keilor transformers during high demand periods. In addition, the Keilor-Geelong lines potential load could exceed their continuous ratings during high ambient temperature coincident with low wind speed.

(c) Conditions of Constraint

The loading on Keilor 500/220 kV transformers and Keilor-Geelong 220 kV lines are limited by their thermal ratings, which are shown in Table 6.12.

Plant	Thermal rating (continuous)	Thermal rating (short term)
Keilor 500/220 kV transformer	750 MVA	810 MVA – 2 hours
Moorabool 500/220 kV transformer	1000 MVA	1290 MVA – 2 hours at 40 degC
Keilor to Geelong 220 kV lines	237 MVA at 40 degC (0.6 m/s wind speed)	Depends on ambient temperature, wind speed and pre-contingency loading

Table 6.12 – Thermal Ratings of Constrained Plants

Keilor 500/220 kV Transformers

The loading on the three Keilor 500/220 kV and Moorabool transformers depend on:

- Outage of a Keilor 500/220 kV or Moorabool 500/220 kV transformer, which causes an increase in remaining in-service transformers;
- Generation from Newport, Anglesea and Laverton North[25] generation levels, which causes an increase in transformer loading as generation is reduced;
- Increasing western metropolitan area, Geelong area and State Grid loads, which causes an increase in transformer loading, as these loads increase;
- Southern Hydro generation, which causes an increase in transformer loading as generation is reduced;
- The interchange between Victoria and NSW, which causes an increase in transformer loading as import decreases; and
- Murraylink transfer between Victoria and South Australia, which causes an increase in transformer loading as Murraylink export increases. The impact of Murraylink on post-contingent flow is removed by an automatic runback scheme. If the Moorabool transformer were to be tripped while Murraylink is exporting to South Australia, then the runback scheme would rapidly reduce Murraylink transfer to zero.

The most critical of these factors is the output levels of Newport generation, Laverton North gas power station, Anglesea power station and Geelong, Point Henry and western metropolitan area loads.

Keilor to Geelong 220 kV Lines

Following outage of the Moorabool transformer and during high demand period, the loading on Keilor-Geelong 220 kV lines would increase. The loading on these lines is most sensitive to Geelong, Terang and Ballarat loads and Anglesea power station output.

Since February 2005, a wind monitoring scheme for these lines has been in service. Wind speed in the vicinity of the lines is monitored and a dynamic rating is assigned to Keilor-Geelong 220 kV lines based on the actual wind speed. The occurrence of high wind speeds during high ambient temperature periods would increase the lines' thermal rating, allowing higher loading on these lines. However, it is possible for low wind speeds to occur during high ambient temperature (although the coincident occurrence of these conditions has a low probability) and hence the impact of wind speeds on the Keilor to Geelong 220 kV lines constraint is continuously monitored.

Table 6.13 provides the probability of plant outages, which have been used for the assessment of the expected unserved energy at risk.

25 Target service date 1 December 2005

Plant	Probability of outage
Moorabool 500/220 kV Transformer (A spare single phase unit is to be available at Moorabool by summer 2005/06)	Short term outage – 0.03% (based on historical data) Long term outage – 1 in 50 years, with a duration of 2 weeks
Keilor 500/220 kV Transformers (A spare single phase unit is available at Keilor)	Short term outage – 0.055% (based on historical data) Long term outage – 1 in 50 years, with a duration of 2 weeks
Keilor to Geelong 220 kV Lines	0.165% (based on historical data)

Table 6.13 – Probability of Plant Outages

(d) Impacts of Constraint

Keilor 500/220kV Transformers

Following an unplanned outage of the Moorabool transformer, the Keilor transformers would be expected to remain within their short-term rating for the demand forecast up to summer 2008/09. Beyond this time, the Keilor 500/220 kV transformer short-term ratings may be exceeded for this event. Impacts of this constraint can be managed as follows:

- Reschedule generation - increase Southern hydro generation, Newport and Laverton North generation and Snowy to Victoria import.
- If load shedding is required and if the time available is more than 15 minutes then coordinate load shedding at distribution/customer level.
- Arm the Keilor overload control scheme (a highly reliable and a highly secure control scheme) to cover the second contingency. The scheme will remove overload on Keilor transformers immediately following a second contingency by shedding load at western metro area.

Keilor to Geelong 220 kV Lines

Following installation of a wind monitoring scheme on Keilor-Geelong 220 kV lines, the exposure to overloading of these lines has been significantly reduced. However, if potential loading on these lines were to be exceeded at a time of low wind speed and high ambient temperature, one or more of following actions can be taken to reduce the loading:

- Reschedule generation - increase Southern hydro generation, Newport generation and Snowy to Victoria import.
- Manual or automatic load shedding at Geelong and Point Henry.

(e) Impacts on Constraint by Distribution Business Planning

There are no committed Distribution Business plans that affect these constraints.

(f) Impacts on Constraint by Asset Replacement Program

There are no committed asset replacement works that affect these constraints.

6.10.3 Do Nothing – Expected Value of Constraint

Market modelling studies have been undertaken to quantify exposure to Keilor 500/220 kV transformer and Keilor to Geelong 220 kV lines constraints.

Table 6.14 provides the rescheduled generation and unserved energy due to both constraints as a result of an unplanned outage of the Moorabool 500/220 kV transformer. Expected unserved energy and expected generation rescheduling energy are estimated based on the probabilities listed in Table 6.13.

		2005/06	2006/07	2007/08	2008/09	2009/10
System normal – to allow for Moorabool transformer contingent outage						
Annual hours of constraint	Hours	4	7	15	20	55
Maximum single constraint	MW	0	0	30	100	150
Expected rescheduled generation	MWh	690	1,056	1,226	5,106	12,063
Expected unserved energy	MWh	0	0	10	228	521
Following outage of Moorabool transformer – to allow for the next critical contingency						
Annual hours of constraint	Hours	113	183	288	364	562
Maximum single constraint	MW	180	300	350	350	400
Expected rescheduled generation	MWh	93	263	281	543	498
Expected unserved energy	MWh	0.6	2.0	2.4	3.6	4.6
Expected total constraint energy						
Expected value of rescheduled generation	$k	19	34	40	140	325
Expected value of unserved energy	$k	18	59	337	6,855	15,558
EXPECTED VALUE OF CONSTRAINT	$k	37	93	377	6,995	15,883

Table 6.14 – Expected Value of Constraint

6.10.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

A feasible network option to remove the constraint is installation of a 2nd 500/220 kV Transformer at Moorabool. The indicative capital cost for installation of a second transformer is $17M ± 25%, and VENCorp considers this would be a contestable augmentation.

(b) Non-Network Options

The following non-network solutions can partially or fully remove the network constraints:

- Demand side management in both Geelong and Keilor areas, and
- New generation in the Geelong/Moorabool and Western metropolitan areas.

6.10.5 Economic Evaluation

A net market benefit assessment has been carried out for a second Moorabool transformer with a 45-year life at a discount rate of 8%, to calculate the NPV. The assessment shows that the net market benefits will be maximised for installation of a second transformer from summer 2008/09. The results are summarised in Table 6.15.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-145,266	-37	-93	-377	-6,995	-15,883	-204,551
OPTION 1 (2nd Moorabool Transformer)	Market Benefits	144,853	0	0	0	6,995	15,883	204,551
	Costs	-13,381	0	0	0	-1,404	-1,404	-18,081
	Net Market Benefits	131,471	0	0	0	5,591	14,479	186,469

Table 6.15 – Net Market Benefits of Network Option

Additional generation of 300 MW around Geelong and/or southern State Grid areas could defer the 2nd Moorabool transformer by about 3 years, if this generation is available to be dispatched to remove the constraints. The most effective location is around Geelong area since this will have the potential to reduce the exposure of constraints on both Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformers.

6.10.6 Conclusions

This year's assessment has concluded that augmentation is required.

VENCorp considers that the installation of a second 500/220 kV transformer at Moorabool is likely to pass the Regulatory Test requirements. This network option would be a New Large Network Asset with a capitalised cost estimate of $17M ±25% providing a net present value of the market benefits of around $132M. The tentative timing for the project is September 2008.

In accordance with Clause 5.6.6A of the NEC, VENCorp will undertake a detailed assessment of these constraints and publish a separate Application Notice reporting on the outcomes.

6.11 Loading on Keilor to West Melbourne 220 kV Lines

6.11.1 Overview

The two Keilor to West Melbourne 220 kV lines supply load in the western area of the Melbourne central business district. A thermal constraint is forecast to arise after an outage of either of these parallel lines. The constraint will only occur at times of high demand and when there is limited generation available to supply this demand at the 220 kV voltage level in the west metropolitan area. The effect of the constraint is load shedding in metropolitan Melbourne.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint. However, the Laverton North generation plant is now a committed project targeted for service by December 2005.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Keilor to West Melbourne constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be upgrading the connections of each line to allow access to short term ratings, which will increase their overall transfer capacity. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.11.2 Introduction

(a) Location of Constraint

The network between Keilor and West Melbourne comprises two circuits on a single 220 kV tower line. This line forms part of the 220 kV loop emanating from Keilor Terminal Station and supplying terminal stations at Altona, Brooklyn, Fishermans Bend, Newport and West Melbourne. The stations in this loop provide power to commercial, industrial and domestic customers in the western metropolitan and the western Central Business District. The constraints are located at Keilor and West Melbourne terminal stations of the Keilor-West Melbourne 220 kV line. The location of these lines and stations is shown in Figure 6.8 and the electrical connections are shown in Figure 6.9, which also indicates the constrained elements.

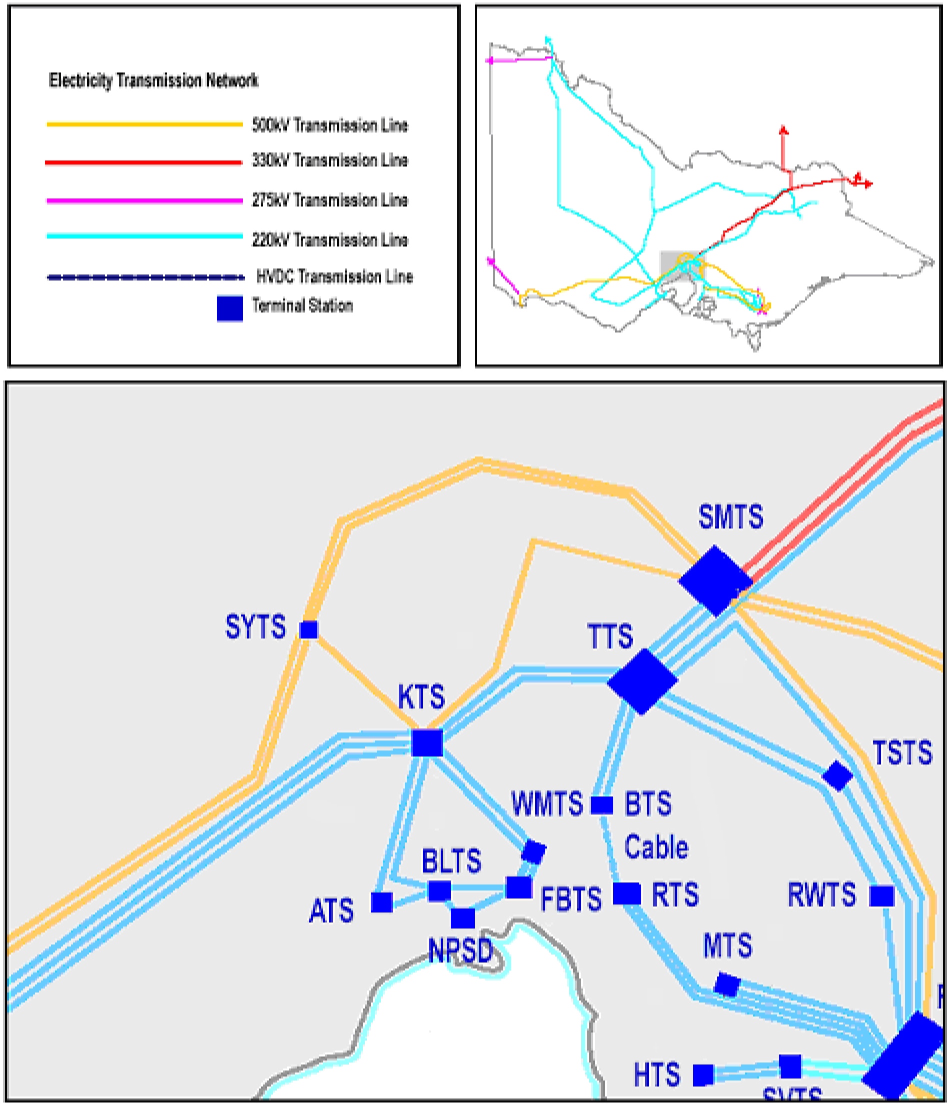

Figure 6.8 – Geographic Representation of the Keilor to West Melbourne 220 kV Lines

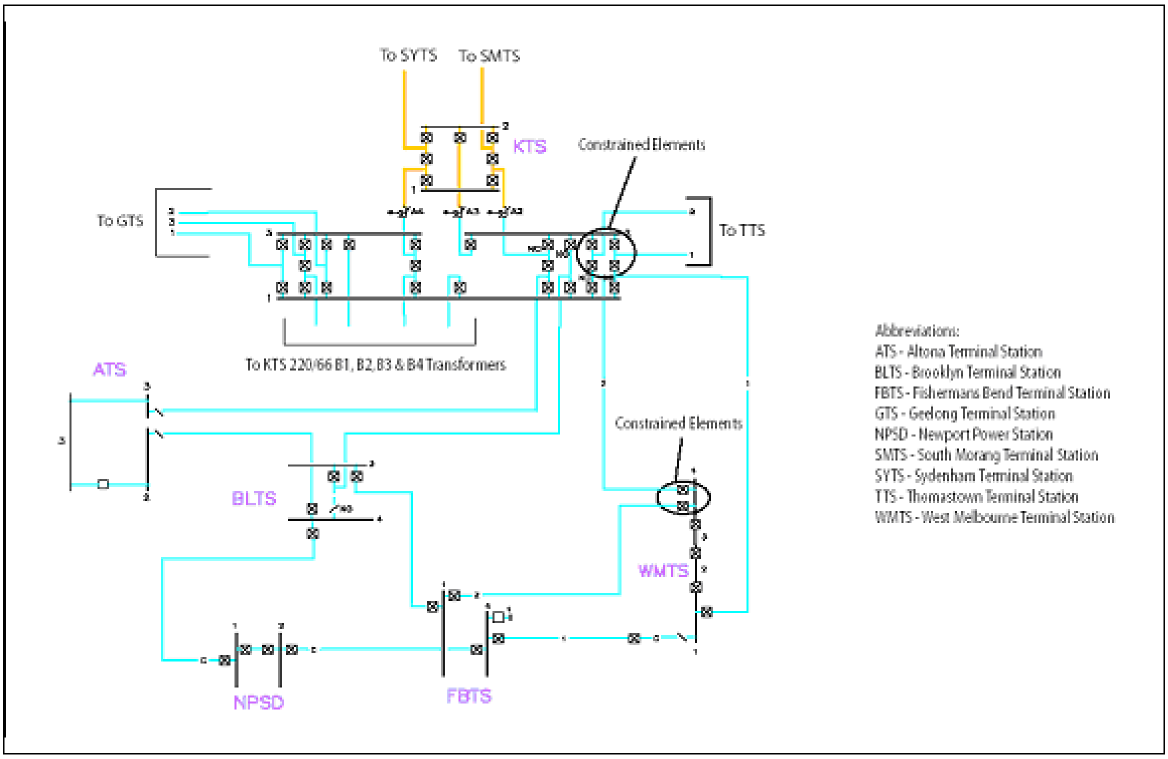

Figure 6.9 – Electrical Representation of the Keilor to West Melbourne 220 kV Lines

(b) Reason for Constraint

Following an outage of a Keilor-West Melbourne 220 kV circuit, loading on the remaining parallel circuit increases. The constrained elements are isolators, circuit breakers and terminations at Keilor, and terminations at West Melbourne of the Keilor-West Melbourne 220 kV circuits.

(c) Conditions of Constraint

One of the supply points to West Melbourne, Fishermans Bend, Brooklyn and Altona is via the Keilor-West Melbourne 220 kV circuits. The loading on these 220 kV circuits depends on:

- West Melbourne, Fishermans Bend, Brooklyn and Altona load, which causes an increase in line loading as they are increased;
- Newport and Laverton North[26] generation, which causes an increase in line loading as generation is reduced; and
- High ambient temperature, which causes reduction in thermal rating of constraint elements.

The thermal rating of the limiting plant is shown in Table 6.16. The transmission lines have short-term rating but interplant connections and isolators/circuit breakers do not, hence these become more critical.

26 Laverton North generation target service date 1 December 2005.

Critical Plant	Continuous Rating (40 degC)	15 Minute Short Time Rating (40 degC)
Keilor to West Melbourne 220 kV Lines	1,950 A	2,330 A
220 kV Connections at WMTS	2,035 A	2,035 A
220 kV Isolators and Connections at KTS	2,045 A	2,045 A

Table 6.16 – Thermal Ratings of Constrained Plants

Table 6.17 provides the probability of plant outages, which are used for the assessment of the expected value of constraint.

Critical Outage	Probability of Outage
Keilor to West Melbourne 220 kV circuit	0.154% (based on historical data)
Fishermans Bend to Newport/Brooklyn 220kV Double Circuit (Tower Outage)	0.0086% (based on historical data)

Table 6.17 – Probability of Plant Outages

(d) Impacts of Constraint

At times of peak demand on high ambient temperature days, following outage of the Newport generator, the loading on both Keilor-West Melbourne 220 kV circuits will increase but remain within the continuous rating. However, to ensure a secure operating state, action needs to be taken within 30 minutes to allow for next worst contingent event. The next worst credible contingent event is an outage of one of the Keilor-West Melbourne 220 kV circuits. Up to summer 2007/08, a secure state can be maintained (refer Table 6.18) without taking further action. Beyond this period, action need to taken to reduce the loading following the first contingency event. The first contingent event can be either Newport generator outage or a Keilor-West Melbourne 220 kV circuit outage.

A worst non-credible event is an outage of a tower on the Fishermans Bend-Brooklyn/Newport 220 kV circuits (since these are double circuits on a single tower construction). West Melbourne and Fishermans Bend loads would then be radially supplied from the Keilor-West Melbourne 220 kV circuits. Loading on these circuits would remain within their continuous rating, but not in secure operating state. Load at West Melbourne needs to be reduced, such that following outage of a Keilor-West Melbourne circuit, the loading on the remaining circuit will remain within its rating. This is a very low probability event, and is included (refer Table 6.19) in the assessment of unserved energy.

(e) Impacts on Constraint by Distribution Business Planning

The constraint will become more significant as load in West Melbourne, Fishermans Bend, Brooklyn and Altona increases. Currently Distribution Businesses have a proposal to transfer about 50 MW load from West Melbourne[27] to Brunswick Terminal Station. Distribution Businesses also have contingency plans to transfer some bulk load from West Melbourne to Richmond during an emergency. All these actions significantly reduce the constraint.

(f) Impact on Constraint by Asset Replacement Program

The constraining circuit breakers at Keilor are earmarked for replacement in SP AusNet's next regulatory period as part of their asset replacement strategy. This replacement plan has been taken into account in determining the costs for the option of circuit breaker and isolator replacements.

6.11.3 Do Nothing – Expected Value of Constraint

Market modelling has been used to assess the expected unserved energy based on constraints on the Keilor to West Melbourne 220 kV line over a range of demand and generation levels in each year with credible and non-credible events. Table 6.18 provides the unserved energy for a credible event with a Newport generator or Keilor-West Melbourne circuit outage. Table 6.19 provides the unexpected energy for the non-credible event with tower outage between Fishermans Bend-Brooklyn/Newport generator and West Melbourne and Fishermans Bend radially supplied from Keilor.

		2005/06 to 2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	2	4
Maximum single constraint (Outage of the Newport Generator or a Keilor to West Melbourne 220 kV Line)	MW	0	30	60
Expected rescheduled generation	MWh	0	0	0
Expected value of rescheduling	$k	0	0	0
Expected unserved energy	MWh	0	0.43	1.02
Expected value of unserved energy	$k	0	13	31
EXPECTED VALUE OF CONSTRAINT	$k	0	13	31

Table 6.18 – Expected Value of Constraint
(Credible contingent event without load transfer)

27 Joint TCPR published in December 2004.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	20	30	40	45	55
Maximum single constraint (Outage of Fishermans Bend to Brooklyn/Newport Double Circuit Tower)	MW	60	90	110	130	160
Expected rescheduled generation	MWh	0	0	0	0	0
Expected value of rescheduling	$k	0	0	0	0	0
Expected unserved energy	MWh	0.006	0.018	0.021	0.036	0.066
Expected value of unserved energy	$k	0.2	0.6	0.7	1.2	2.2
EXPECTED VALUE OF CONSTRAINT	$k	0.2	0.6	0.7	1.2	2.2

Table 6.19 – Expected Value of Constraint
(Non credible contingent event without load transfer)

6.11.4 Options and Costs for Removal of Constraint

(a) Network Options

Option 1: Uprate Keilor to West Melbourne Line Terminating Plant

Replace four 220 kV circuit breakers, eight isolators and any interplant connections at Keilor and uprate the interplant connections at West Melbourne terminal station to remove the constraint (due to these line terminating equipment). As SP AusNet has scheduled the circuit breakers for replacement by 2008/09 as part of its asset replacement strategy, earlier replacement would only incur advancement costs. Indicative capital cost for this option is $2.8M, with annual advancement cost of $61k[28].

Option 2: Automatic Control Scheme

This will involve in automatically reducing the demand from either at Fishermans Bend and/or West Melbourne terminal stations. VENCorp does not consider this as an acceptable long-term arrangement particularly due to increase in the exposure of potential overload risk due to future load growth.

At this point in time VENCorp considers these options to be non-contestable augmentations.

(b) Non Network Options

The following non-network solutions can partially or fully remove the network constraints:

- Load transfer from West Melbourne and Fishermans Bend areas;
- Demand side management in both the West Melbourne and Fishermans Bend areas; and

[28] The advancement of 4 years has been assumed as the worst case.

- New generation in the 220 kV loop from Keilor.

At the time of publication of this APR, there were no new committed generation developments in the 220 kV western metropolitan loop. The network augmentation options will be reviewed if a non-network option arises.

6.11.5 Economic Evaluation

A net market benefit assessment is summarised in Table 6.20.

		Present Value ($k)	Annualised Value ($k) 2005/06 to 2007/08	2008/09	2009/10	Residual Value ($k)
Do Nothing		-230	-0.9	-14.2	-33.2	-325
OPTION 1 (Keilor Terminations Upgrade)	Market Benefits		0	14.2	33.2	325
	Costs		0	-61	-61	-530
	Net Market Benefits		0	-46.8	-27.8	-205

Table 6.20 – Net Market Benefits of Network Option

The net market benefits assessment shows, network option cannot be justified based on a VCR of $29,600/MWh. Even with the sector specific VCR at West Melbourne[29] is used, option 1 cannot be justified before 2009-10.

6.11.6 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Keilor to West Melbourne constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be upgrading the connections of each line to allow access to short term ratings, which will increase their overall transfer capacity. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

29 $50,400/MWh @ WMTS from 2004 Joint TCPR

6.12 Loading on Fishermans Bend to West Melbourne 220 kV Lines

6.12.1 Overview

The two Fishermans Bend to West Melbourne 220 kV lines supply load in the western area of the metropolitan Melbourne area. A thermal constraint is forecast to arise after an outage of either of these parallel lines. The constraint will only occur at times of high demand and when there is limited generation available to supply this demand at the 220 kV voltage level in the west metropolitan area. The effect of the constraint is load shedding in metropolitan Melbourne.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint. However, the Laverton North generation plant is now a committed project targeted for service by December 2005.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Fishermans Bend to West Melbourne constraint can be managed until 2009/10. VENCorp considers the next most likely augmentation would be upgrading the connections of each line to allow access to short term ratings, which will increase their overall transfer capacity. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.12.2 Introduction

(a) Location of Constraint

West Melbourne terminal station is supplied from a double circuit line from Fishermans Bend and another double circuit line from Keilor. These lines form part of the 220 kV loop emanating from Keilor Terminal Station and supplying terminal stations at Altona, Brooklyn, Fishermans Bend and West Melbourne. The stations in this loop provide power to the commercial, industrial and domestic customers in the western metropolitan and the western Central Business District.

The constraint elements are located on the Fishermans Bend – West Melbourne 220 kV lines. The location of these lines and stations is shown in Figure 6.10 and the electrical connections are shown in Figure 6.11.

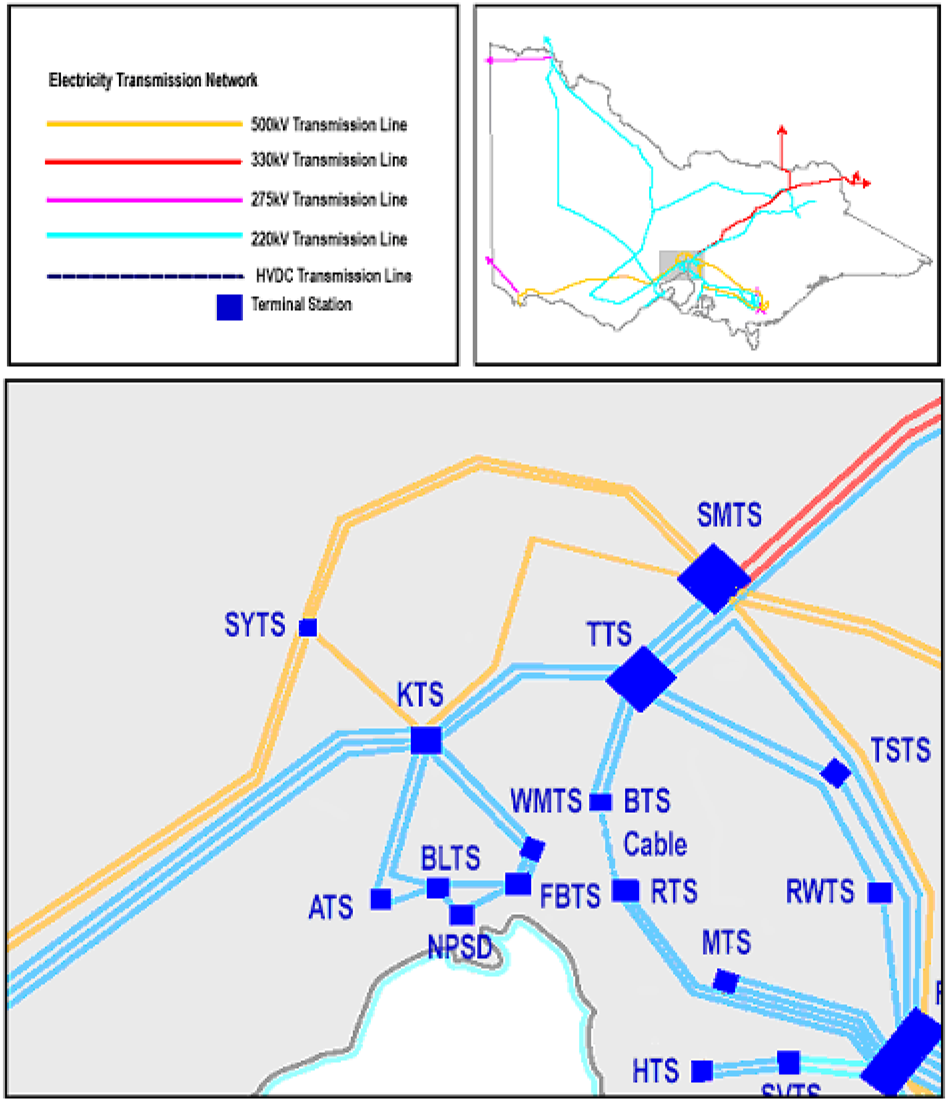

Figure 6.10 – Geographic Representation of the Fishermans Bend to West Melbourne 220 kV Lines

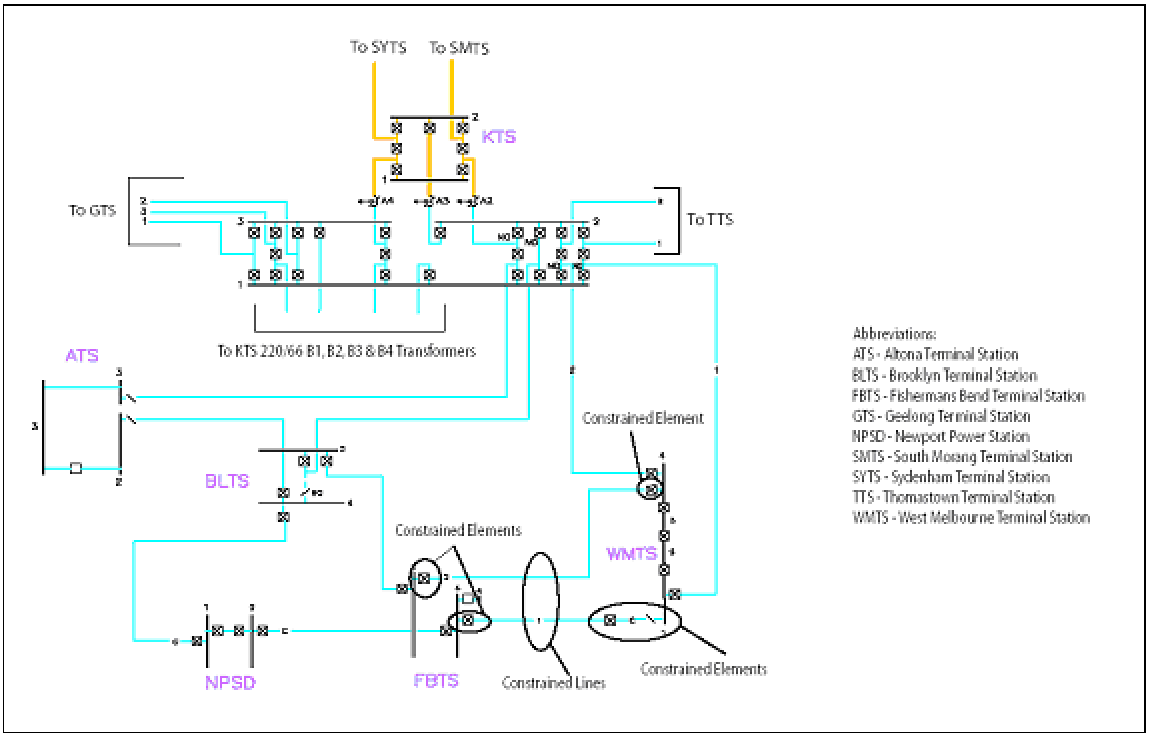

Figure 6.11 – Electrical Representation of the Fishermans Bend to West Melbourne 220 kV Lines

(b) Reason for Constraint

The constraint on the Fishermans Bend to West Melbourne 220 kV circuits has arisen due to gradual load growth at West Melbourne and limitation on the Fishermans Bend - West Melbourne line and connection element ratings.

(c) Conditions of Constraint

The Fishermans Bend – West Melbourne 220 kV line loading depends on:

- West Melbourne load, which causes an increase in line loading as it is increased;
- Newport and Laverton North[30] generation, which causes an increase in line loading as it is increased; and
- High ambient temperature, which causes reduction in thermal rating of constraint elements.

The flow on the Fishermans Bend to West Melbourne circuits is also increased for the condition where there is a 500/220 kV A3 transformer out of service at Keilor, which causes more power to be drawn into West Melbourne via Fishermans Bend.

30 Laverton North generation target service date 1 December 2005.

The rating of the limiting plant is shown in Table 6.21. The transmission lines have short-term rating but line terminations do not have short-term rating, as such the line terminations are critical.

Critical Plant	Continuous Rating (40 degC)	15 Minute Short Time Rating (40 degC)
Fishermans Bend West Melbourne 220 kV Lines	1,017 A	1,200 A
220 kV Connections at WMTS	1,070 A	1,070 A
220 kV Connections at FBTS	1,070 A	1,070 A

Table 6.21 – Thermal Ratings of Constrained Plants

Table 6.22 provides the probability of plant outages, which are used for the assessment of the expected value of constraint.

Critical Outage	Probability of Outage
Fishermans Bend to West Melbourne 220 kV circuit	0.032% (based on historical data)
Keilor to West Melbourne Double Circuit[31]	0.016% (based on historical data)
Keilor 500/220 kV Transformer (A spare single phase unit is available at Keilor to permit restoration within 14 days)	Short term outage – 0.055% (based on historical data) Long term outage – 1 in 50 years, with a duration of 2 weeks

Table 6.22 – Probability of Plant Outages

(d) Impacts of Constraint

The impact of the constraint depends on the amount of load, the ambient temperatures and the level of generation at Newport and Laverton North. The constraints have been analysed under different conditions:

- with Fishermans Bend to West Melbourne single circuit credible outage as a first event; and
- with Keilor to West Melbourne double circuit non-credible outage as a first event

At times of peak demand on high ambient temperature days, following outage of the Fishermans Bend to West Melbourne single circuit, both Fishermans Bend to West Melbourne 220 kV circuits will increase the loading but remains within the continuous rating. However, this is not a secure state, action need to be taken within 30 minutes to allow for next worst contingent event. The next worst credible contingent event is outage of the Keilor 500/220 kV A3 transformer. Up to summer

[31] Includes tower outage

2008/09, secure state can be maintained without taking further action. Beyond this period, action need to taken to reduce the loading following the first contingency event as shown in Table 6.23. The first contingent event can be either Keilor A3 transformer outage or a Fishermans Bend to West Melbourne 220 kV circuit outage.

The worst non-credible event is outage of Keilor to West Melbourne double circuit (since these are on the same tower construction). Then West Melbourne will be supplied radially from Fishermans Bend 220 kV circuits. Loading on both the Fishermans Bend-West Melbourne circuits remain within their continuous ratings, but could be in an insecure state during peak summer demand conditions. West Melbourne Terminal station load need to be reduced or transferred, such that following a Fishermans Bend-West Melbourne circuit outage, the constraint elements should at least remain within their short term ratings shown in Table 6.24. This is a very low probability event, and included in the assessment of unserved energy. Distribution Businesses have contingency plan to transfer the load away from West Melbourne to Richmond. It is expected around 30 to 50 MW load can be transferred to Richmond following a non-credible event of double circuit outage.

(e) Impacts on Constraint of Distribution Business Planning

The constraint will become more significant as West Melbourne and Fishermans Bend area load grows. There are no committed plans by the Distribution businesses to reduce load in West Melbourne and Fishermans Bend over the next ten-year period. However, there are proposals for permanent load transfer of 50 MW from West Melbourne[32] to Brunswick Terminal Station and also a feasible contingency plan to transfer some bulk load from West Melbourne to Richmond. All these proposals have an impact on the augmentation and timing to remove the constraint on Fishermans Bend to West Melbourne 220 kV circuits.

(f) Impact on Constraint of Asset Replacement Program

The circuit breakers at West Melbourne are earmarked for replacement during the next regulation-reset period as part of SP AusNet's asset replacement strategy. However, uprating of the Fishermans Bend – West Melbourne 220 kV transmission line not planned as part of asset replacement program.

6.12.3 Do Nothing – Expected Value of Constraint

Market modelling has been used to assess the expected unserved energy based on constraints on the Fishermans Bend to West Melbourne 220 kV line over a range of demand and generation levels in each year with a parallel Fishermans Bend to West Melbourne 220 kV line outage or the Keilor 500/220 kV A3 transformer outage.

The expected energy at risk takes account of the probability of the critical outages occurring at times of unfavourable loading and temperature conditions. Table 6.23 and 6.24 show the energy at risk for a single circuit outage (credible event) and for the tower line outage (non-credible event). The unserved energy in Table 6.23 and 6.24 has been valued at the state-wide "Value of Customer Reliability" of $29.6k.

32 Joint TCPR published in December 2004.

		2005/06 to 2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	3	5
Maximum single constraint	MW	0	100	150
Average constraint	MW	0	0.5	1
Expected rescheduled generation	MWh	0	0	0
Expected value of rescheduling	$k	0	0	0
Expected unserved energy	MWh	0	0.025	0.05
Expected value of unserved energy	$k	0	0.75	1.5
EXPECTED VALUE OF CONSTRAINT	$k	0	0.75	1.5

Table 6.23 – Expected Value of Constraint (Credible contingent event)

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	20	30	40	50	60
Maximum single constraint	MW	120	140	180	210	240
Average Constraint	MW	0.2	0.5	1	2	3
Expected rescheduled generation	MWh	0	0	0	0	0
Expected value of rescheduling	$k	0	0	0	0	0
Expected unserved energy	MWh	0.14	0.21	0.33	0.54	0.73
Expected value of unserved energy	$k	4.1	6.2	9.7	15.9	21.7
EXPECTED VALUE OF CONSTRAINT	$k	4.1	6.2	9.7	15.9	21.7

Table 6.24 – Expected Value of Constraint (Non credible contingent event)

There is no pre-contingent (system normal) load at risk for both the scenarios shown in Table 6.23 and Table 6.24 till 2009/10.

6.12.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network options are considered to remove or reduce the constraint:

Option 1: Uprate Fishermans Bend to West Melbourne Line Terminating Equipment

Uprate the limiting termination connections on both the Fishermans Bend-West Melbourne circuits. The capital cost is estimated around $160k ± 25%.

Option 2: Wind Monitoring with Automatic Control Scheme

Install wind-monitoring scheme with an automatic control scheme if feasible. Indicative cost around $400k ± 25%.

At this point in time VENCorp considers these options to be non-contestable augmentations.

(b) Other Options Considered

The following non-network options can partially or fully remove the network constraints:

- Demand side management in the West Melbourne and Fishermans Bend areas; and
- New generation developments around West Melbourne.

6.12.5 Economic Evaluation

A net market benefit assessment is carried out for all three options for 5 years. Unserved energy is valued at $29,600/MWh. Residual value for remaining 40 years is calculated assuming costs and benefits as calculated for 2009/10. Results are summarised in Table 6.25.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-220	-4.1	-6.2	-9.7	-16.7	-23.2	-299
OPTION 1 (Line terminations upgrade)	Market Benefits		2.0	3.1	5.0	8.0	11.1	143
	Costs		-13	-13	-13	-13	-13	-170
	Net Market Benefits		-11	-10	-8	-5	-2	-27
OPTION 2 (Wind monitoring scheme following option 1)	Market Benefits		2.1	3.1	4.7	8.7	12.1	112
	Costs		-41	-41	-41	-41	-41	-377
	Net Market Benefits		-39	-38	-36	-32	-29	-265

Table 6.25 – Net Market Benefits of Network Options

If a sector specific "Value of Customer Reliability" was used, such as those presented in the Distribution Businesses' TCPR ($50,400/MWh for WMTS and $42,400/MWh for FBTS), timing of line termination upgrade could be justified for summer 2008/09.

6.12.6 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Fishermans Bend to West Melbourne constraint can be managed until 2009/10.

VENCorp considers the next most likely augmentation would be upgrading the connections of each line to allow access to short term ratings, which will increase their overall transfer capacity. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.13 Loading of Hazelwood 220/500 kV Tie Transformers

6.13.1 Overview

Loading of the Hazelwood 220/500 kV tie transformers in the Latrobe Valley presents a thermal constraint that can arise with all plant in service. The constraint typically occurs at times of high demand when all generation connected at the 220 kV voltage level in the Latrobe Valley is dispatched. The effect of the constraint is on the 220 kV connected generation in the Latrobe Valley.

Since the 2004 Annual Planning Report, short term ratings for the critical transformers have been adopted. Furthermore, through discussions with the affected parties, a modified and preferred network arrangement has been identified following completion of the 500 kV Latrobe Valley to Melbourne line upgrade project (as discussed in Section 2.2).

This year's assessment has concluded that augmentation is required.

VENCorp considers that an interim arrangement, which involves the development of a protection system based control scheme that trips specific generation following a forced transformer outage, passes the Regulatory Test requirements. The control scheme would be a Minor Network Augmentation with a capitalised cost estimate of $620k providing a net present value of market benefit of around $760k. VENCorp will now advance this network option so that practical completion is achieved for December 2005, subject to agreement with the affected generators.

Furthermore, VENCorp will also undertake a detailed New Large Network Asset assessment in accordance with Clause 5.6.6A of the NEC to consider a permanent solution involving the establishment of additional transformation at Hazelwood, as per Option 1, which could be justified between 2008 and 2010.

6.13.2 *Introduction*

(a) Location of Constraint

This constraint occurs at Hazelwood Terminal Station, which is in the Latrobe Valley as shown in Figures 6.12 and 6.13. The configuration shown is realised after completion of the 4th Latrobe Valley to Melbourne 500 kV Line project.

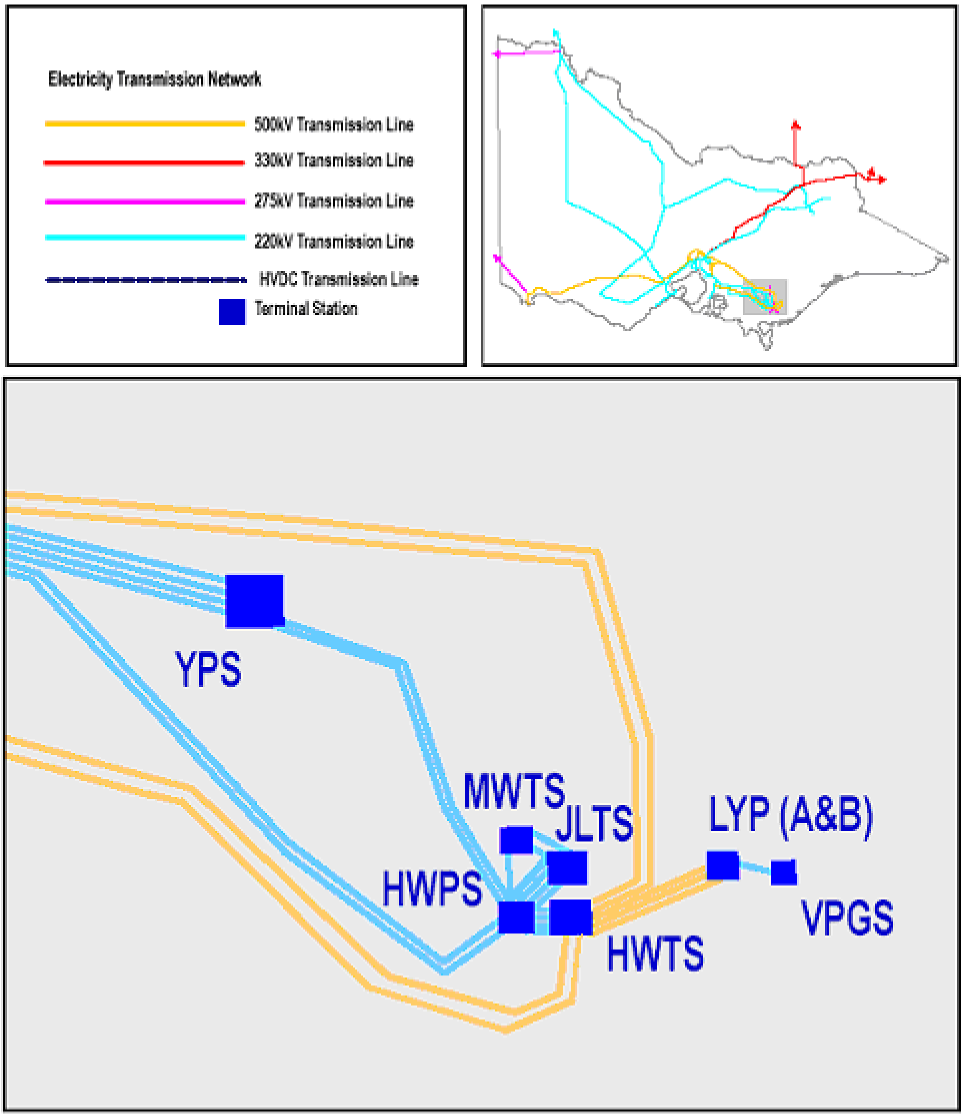

Figure 6.12 – Geographic Representation of the Hazelwood 220/500 kV Tie Transformers

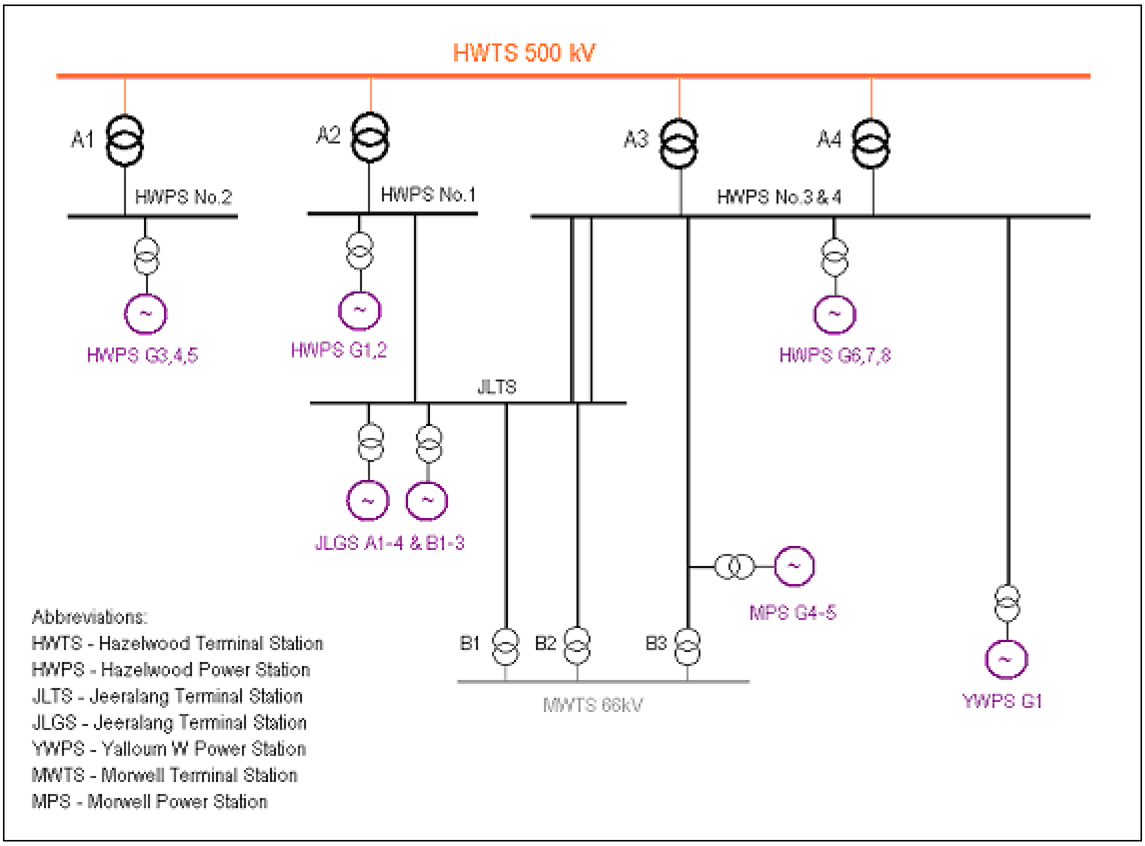

Figure 6.13 – Electrical Representation of the Hazelwood 220/500 kV Tie Transformers

(b) Reason for Constraint

This constraint is primarily associated with the transfer of power from generation connected at the 220 kV voltage level or below in the Latrobe Valley into the 500 kV network. Details of the maximum capability[33] of the generators affected by this constraint are identified in Table 6.26.

Plant	Maximum Summer Capability	Maximum Winter Capability
Hazelwood Power Station	1,585 MW	1,705 MW
Jeeralang Gas Station	416 MW	487 MW
Yallourn W Power Station (Unit 1)	350 MW	360 MW
Morwell Power Station	139 MW	143 MW
Bairnsdale Power Station	70 MW	90 MW
TOTAL	2,560 MW	2,785 MW

Table 6.26 – Generation Affected by the Hazelwood Transformer Constraint

33 Maximum capabilities are sourced from NEMMCO's 2004 SOO.

Unit 1 at Yallourn W Power Station has a flexible connection arrangement to the shared network, allowing it to be switched between the normally isolated 220 kV and 500 kV transmission systems. Under system normal conditions, the generator will be connected via the Yallourn to Hazelwood No.2 220 kV Line to the Hazelwood No.3-4 bus group and provide additional contribution to loading on the critical transformers connecting to the 500 kV network. However, if the constraint is forecast to occur when low reserve levels are expected within Victoria, the output of Yallourn W Unit 1 can be transferred to the 220 kV network via its alternative network connection.

(c) Conditions of Constraint

This constraint occurs as a result of the thermal limitations of the four Hazelwood Terminal Station 220/500 kV transformers, which have the following characteristics:

Critical Plant	Continuous Rating [MVA]	Short Term Rating [MVA]
Hazelwood A1	600	750 for 30 mins 638 for 1 hour
Hazelwood A2	600	638 for 1 hour
Hazelwood A3	600	638 for 1 hour
Hazelwood A4	600	638 for 1 hour

Table 6.27 – Plant Rating

As the new connection arrangement forms two separate transformer / generation groups, there are two completely separate mechanisms that define the loading on the HWTS transformers.

The HWTS A1 transformer radially connects Hazelwood Power Station's G3, G4 and G5 into the 500kV network. These generators have the capability of overloading the transformer under system normal operation, as the combined maximum output of these machines minus their in-house load, exceeds the continuous rating of the A1 transformer.

The other three HWTS transformers (A2-A4) connect the remaining Hazelwood Power Station machines, as well as generation at Jeeralang, Morwell, Bairnsdale, and Yallourn W Unit 1. The three transformers are not overloaded under system normal conditions, but the loading on these transformers must be limited such that loss of either the A2, A3 or A4 transformer, the remaining two transformer are not loaded above their short-term rating. Therefore at any given time the combined loading cannot exceed 1276 MVA.

Under planned transformer outage conditions or extended forced outages, operational arrangements are implemented to convert the network into a parallel mode. This has the effect of minimising the dependence on the Hazelwood transformers by utilising spare capacity in the 220 kV lines to Melbourne. However, this is not a suitable arrangement during system normal conditions as transmission losses are increased nor is it a suitable arrangement at times of high ambient temperature, because the capacity of 220 kV lines under such conditions is inadequate. Therefore this assessment does not cover the prior outage scenarios.

Any new generation connecting at a location that utilises the Hazelwood transformers (i.e. Hazelwood Power Station, Jeeralang, or even embedded at 66 kV at Morwell or its distribution network) would compete directly with the existing generation for dispatch into the National Electricity Market.

(d) Impacts of Constraint

As a consequence of this constraint, the generation connected at or below the 220 kV voltage level in the Latrobe Valley, may be constrained off during system normal conditions to ensure system security is maintained. Constraint equations have been developed and are simulated within the National Electricity Market Dispatch Engine to model this constraint.

These equations are presented to relate the acceptable levels of generation feeding the four transformers and local load, so they can be used to indicate when the HWTS transformer constraint may be binding. The generation terms on the left hand side of these equations are expressed as "at generator terminals", and the Morwell Terminal 66kV Demand is defined as that forecast at that terminal station and excludes scheduled embedded generation (i.e. if Bairnsdale Power Station or Morwell Power Station G1-3 are running, their dispatch has been added back into the demand).

The total generation of HWPS G3, G4 and G5, is limited by the continuous rating of the A1 transformer. Assuming that an in-house load of 14 MW is always present for each of these three generators, the limit equation which models this constraint has the following form:

HWTS A1 Transformer Limit Equation:

HWPS G 3-5 < 642.0

Acceptable levels of generation that utilise the HWTS A2-A4 transformers, is determined by the total generation connecting into the HWPS No.1, 3 and 4 220kV buses, minus the load (including any generation in-house load) supplied by these generators, not exceeding 1276 MVA. This is expressed by the following equation:

HWTS A2-4 Transformer Limit Equation:

HWPS G1-2, 6-8 + JLGS + MPS + BPS + YWPS G1 < 1341.3 + MWTS 66 kV Demand

Should this constraint arise when there is a supply demand imbalance, the indirect consequence may be additional load shedding. On this basis, Yallourn W Unit 1 is switched to its alternative network connection when low reserve conditions are forecast.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Any augmentation that increases the fault level at this location, will need to include a significant amount of circuit breaker replacement. The circuit breakers at Hazelwood Power Station are planned for replacement by 2010/11 as part of SP AusNet's asset replacement program. There may be an opportunity to advance some of these replacements, to occur at the same time as the network augmentation.

6.13.3 Do Nothing – Expected Value of Constraint

In order to quantify the value of this constraint, preliminary market modelling studies have been carried out which include generation forced outages rates, and assumes Yallourn W Unit 1 is switched into Hazelwood Power Station.

Given the specified market modelling conditions, it was identified that the Hazelwood A1 transformer constraint does not introduce a supply demand imbalance or result in any consequential load shedding. The impact of this constraint is therefore confined to rescheduling generation out of merit order, which has been valued at an incremental fuel cost depending on which generation was dispatched as a consequence of this constraint. It is assumed that Units 3, 4 and 5 at Hazelwood Power Station cannot all simultaneously output 220MW all of the time. As such, a probability weighting of 0.5 has been applied to calculate the expected value of this constraint. Table 6.28 presents the expected value of the A1 constraint.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	3318	3539	3519	3362	3318
Maximum single constraint	MW	18	18	18	18	18
Expected rescheduled generation	MWh	29859	31855	31673	30260	29859
Expected value of rescheduling	$k	448	507	517	521	549
Expected unserved energy	MWh	0	0	0	0	0
Expected value of unserved energy	$k	0	0	0	0	0
EXPECTED VALUE OF CONSTRAINT	$k	448	507	517	521	549

Table 6.28 – Expected Value of HWTS A1 Transformer Constraint

Assuming that Yallourn W Unit 1 is switched into Hazelwood Power Station for assessment of the Hazelwood A2-A4 transformer constraint, introduces a potential supply shortfall and creates a need for load shedding from 2006/07. It has been assumed in these preliminary studies that new generation required to meet increasing demand, alleviates this constraint rather than compounding it. Table 6.29 presents the expected value of the A2-A4 constraint.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	191	125	151	150	100
Maximum single constraint	MW	374	367	385	462	366
Expected rescheduled generation	MWh	5729	6163	7505	9693	6997
Expected value of rescheduling	$k	230	254	1192	1386	1235
Expected unserved energy	MWh	105	68	73	92	79
Expected value of unserved energy	$k	3108	2013	2161	2723	2338
EXPECTED VALUE OF CONSTRAINT	$k	3338	2267	3353	4109	3573

Table 6.29 – Expected Value of HWTS A2, A3, A4 Transformer Constraint

This assessment with Yallourn W Unit 1 unconditionally on the 500 kV network gives an indication of the upper bound of the constraint in each year. If Yallourn W Unit 1 was unconditionally on the 220kV network, the expected value of the A2-A4 constraint is zero over this five year planning period. The actual arrangements under which Yallourn W Unit 1 can be switched between the two connection points, will result in the expected value of this constraint lying somewhere between the upper and lower bounds. Assuming Yallourn W Unit 1 is only returned to its alternate connection on the 220kV network to prevent load shedding, the "expected value of rescheduling" presented in Table 6.29 gives a more appropriate expected value of the A2-A4 constraint.

Combining the expected value of both the A1 transformer constraint, and the A2-A4 transformer constraint, gives the total value of HWTS 220/550 kV tie transformers constraint, and is presented graphically in Figure 6.14.

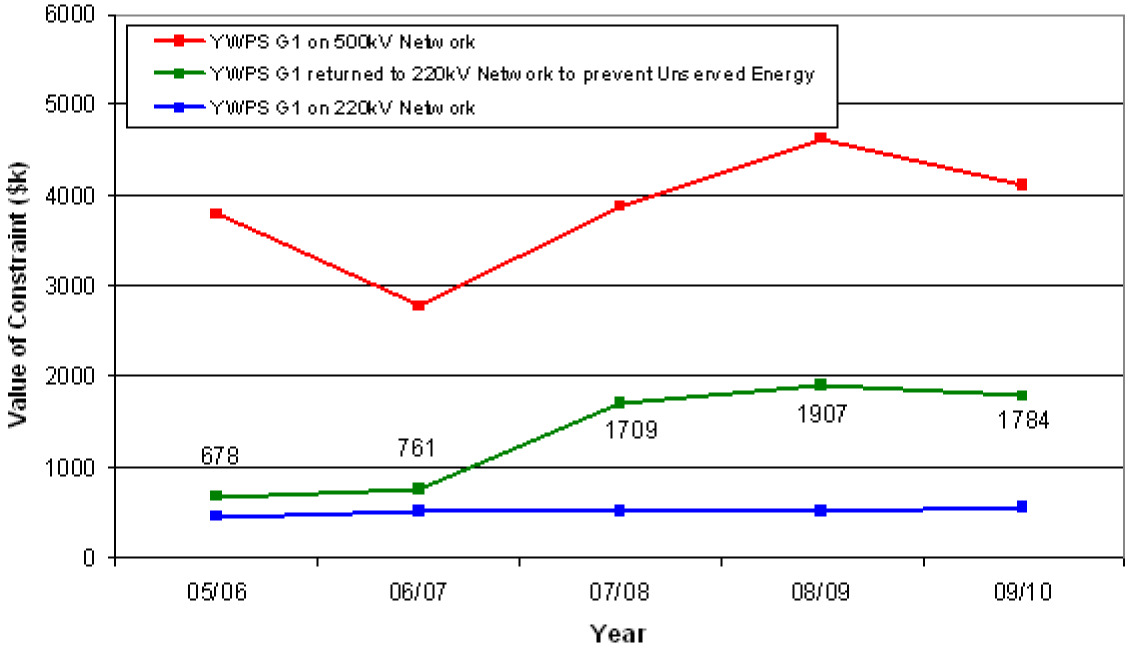

Figure 6.14 – Graph of the Expected Value of the Hazelwood Transformer Constraint

The reduction in the expected value of the constraint (when Yallourn W Unit 1 is on the 500 kV network) from 2005/06 to 2006/07 can be attributed to the introduction of Basslink[34] and its influence (reduction) on the dispatch of generation behind the A2-A4 constraint.

The small reduction in the expected value of this constraint in 2009/10 compared with 2008/09, is a result of the assumption made about new generation supplying the increasing load. When undertaking a full regulatory test, impacts of new generation will be examined in more detail.

34 Basslink is a monopolar DC link between Victoria and Tasmania, and is currently planned for service in April 2006.

6.13.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

1. Establish a control scheme that utilises protection time frame (seconds) short term ratings on the A2-A4 HWTS transformers, and trips excess generation post contingency to remove the transformer overload. This option would require one or more generator/s to agree to be tripped in the event of a transformer failure if the loading on the remaining three units exceeded their capability, and SP AusNet to agree to a protection time frame short term rating of 900MVA. This option eliminates the A2-A4 constraint, but does not affect the A1 constraint. An estimated cost for this option is \$620k ±25%, subject to feasibility and detailed assessment, and would likely form an interim arrangement until new transformation is justified. VENCorp considers this to be a non-contestable augmentation.

2. Install new 220/500 kV transformation and associated switching at Hazelwood Terminal Station 500kV and either Hazelwood Power Station or Jeeralang Terminal Station 220kV. This option would require a significant amount of fault level mitigation, and has an estimated capital cost of \$22M ±25%, subject to feasibility and detailed assessment, giving an approximate annualised cost of \$1.82M[35]. VENCorp considers this option would be a contestable augmentation.

(b) Other Options Considered

3. Investigate options for Yallourn W Unit 1 to remain connected to the 220 kV transmission network, which would eliminate the A2-A4 constraint.

(c) Material Inter-Network Impact of Constraint

None of the proposed solutions would have a material inter-regional impact.

6.13.5 Economic Evaluation

A net market benefit assessment is summarised in Table 6.30.

The assessment shows a generation tripping scheme is the preferred option for addressing the Hazelwood tie transformer constraint over the next three years. Optimal timing for installation is prior to summer 2005/06.

The net market benefits for installing a new transformer, become positive for summer 2008/09. As such, VENCorp will undertake a detailed regulatory test assessment and public consultation in the coming months, to determine when a new transformer at Hazelwood could be justified.

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35 Based on a term of 45 years and a discount rate of 8%.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-19,731	-678	-761	-1,709	-1,907	-1,784	-30,332
OPTION 1 (Generation Tripping Scheme)	Market Benefits	1,377	230	254	1192	0	0	0
	Costs	-620	-241	-241	-241	0	0	0
	Net Market Benefits	757	-11	13	951	0	0	0
OPTION 2 (5th HWTS Transformer following option 1)	Market Benefits		0	0	0	1,907	1,784	23,204
	Costs		0	0	0	-1,817	-1,817	-23,632
	Net Market Benefits		0	0	0	90	-33	-428

Table 6.30 – Net Market Benefits of Network Options

6.13.6 Conclusions

This year's assessment has concluded that augmentation is required.

VENCorp considers that an interim arrangement, which involves the development of a protection system based control scheme that trips specific generation following a forced transformer outage, passes the Regulatory Test requirements. The control scheme would be a Minor Network Augmentation with a capitalised cost estimate of $620k, providing a net present value of the market benefits of around $760k. The application of this control scheme is subject to agreement with the affected generators. VENCorp will now advance this network option so that practical completion is achieved for December 2005, subject to agreement with affected generators.

Furthermore, VENCorp will also undertake a detailed New Large Network Asset assessment in accordance with the Clause 5.6.6A of the NEC to consider a permanent solution involving the establishment of additional transformation at Hazelwood, as per Option 1, which could be justified between 2008 and 2010.

6.14 Loading of Moorabool to Ballarat 220 kV Lines

6.14.1 Overview

Loading of the two Moorabool to Ballarat 220 kV lines presents a thermal constraint that can arise with both lines still in service, or after an outage of one of these parallel lines. The constraint will only occur under high State Grid demand conditions coincident with high export to South Australia via Murraylink and high export to Snowy/NSW. The effect of the constraint is a reduction in the export level to South Australia via Murraylink and load shedding in the State Grid.

In VENCorp's 2004 Annual Planning Report, dynamic real time wind monitoring for the Moorabool to Ballarat No.1 line was identified as a technical and economic solution. This wind monitoring scheme is now a committed Minor Network Augmentation (refer to Section 5.2.2) and is expected to be completed during summer 2005/06.

This year's assessment has confirmed that the wind monitoring scheme has deferred the need for further augmentation and that the Moorabool to Ballarat constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be upgrading towers on the Moorabool to Ballarat No.1 line to increase the design rating from 235 MVA to 300 MVA, given an ambient temperature of 40°C. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.14.2 Introduction

(a) Location of Constraint

The constraint is located between Moorabool and Ballarat terminal stations in southwest Victoria. Geographical and electrical representations of the constraint are given in Figures 6.15 and 6.16, respectively.

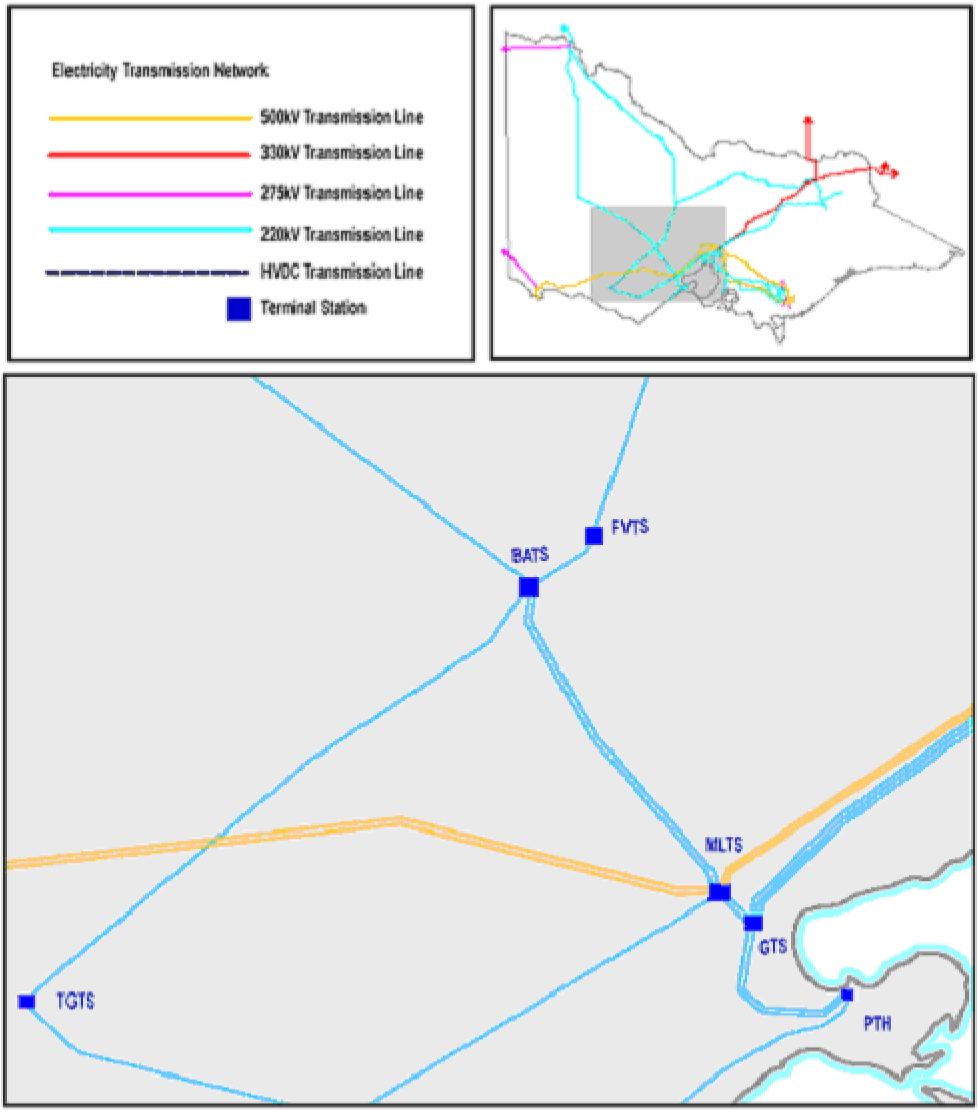

Figure 6.15 – Geographical Representation of the Moorabool to Ballarat 220 kV Lines

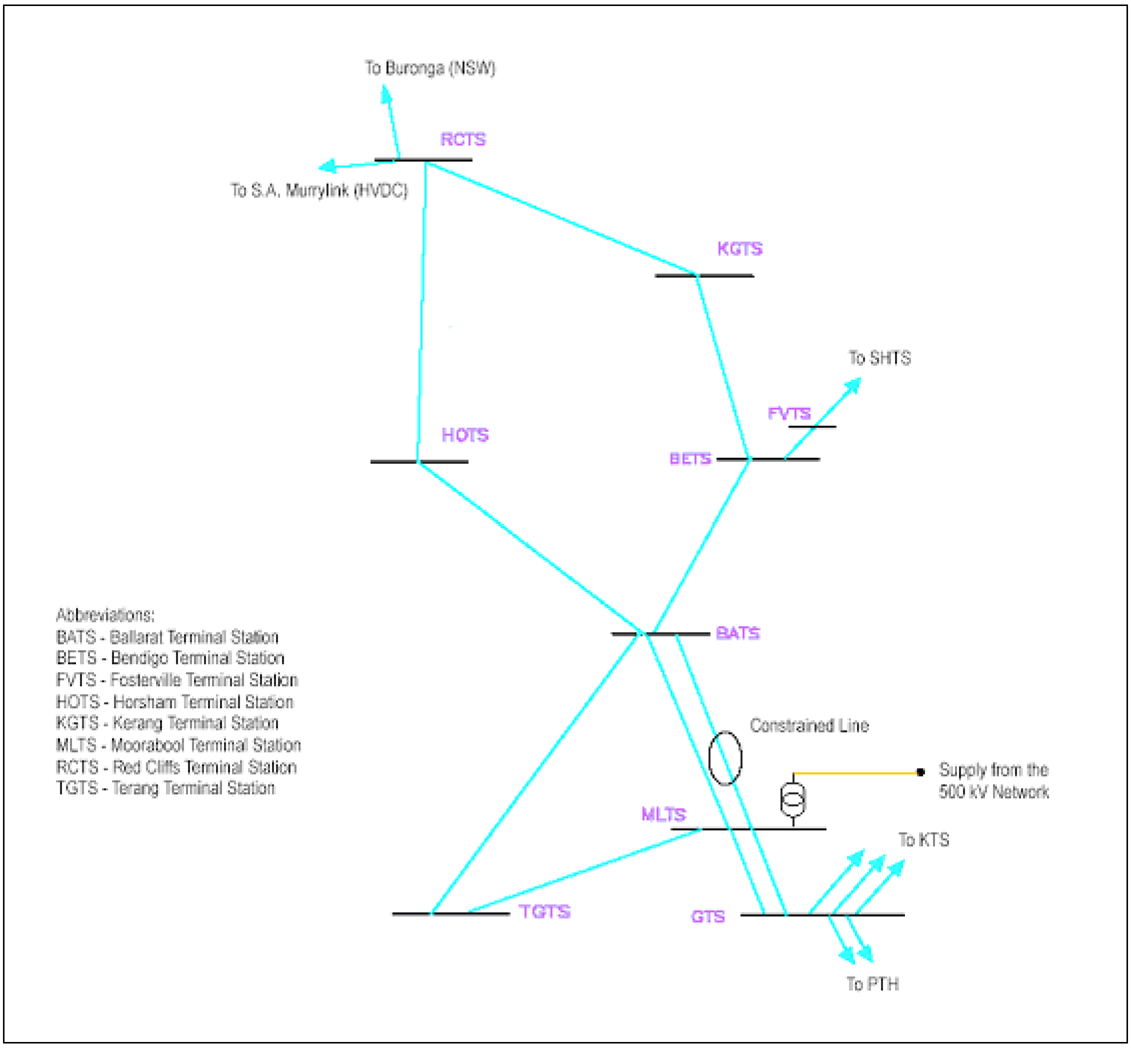

Figure 6.16 – Electrical Representation of the Moorabool to Ballarat 220 kV Lines

(b) Reason for Constraint

There are two Moorabool to Ballarat lines that form one of the main 220 kV supply points for the State Grid area in Northern and Western Victoria. The constraint can arise without any outages occurring but predominantly, the constraint is potential overloading on the No.1 circuit following an outage of the parallel No.2 circuit. The constraint has arisen as a result of progressive load growth in the Victorian State Grid.

(c) Conditions of Constraint

Power flow on the Moorabool to Ballarat lines is generally northwards from Moorabool, through Ballarat and further into the State Grid. The two circuits were built at different times on separate tower lines and they have different thermal ratings. The original No.1 line has a continuous rating of 270 MVA and the No.2 line is rated 450 MVA at 35°C ambient temperature, respectively. Due to the installation of wind monitoring for these lines, operational transmission ratings are a function of dynamic real time measurements of ambient temperature and wind speed.

A third 220 kV circuit passing from Moorabool through Terang to Ballarat primarily supports load at Terang, without significantly affecting loading on the two direct Moorabool to Ballarat connections.

The following system loading factors contribute to the Moorabool to Ballarat constraint:

- State grid load.
  Flow on the Moorabool to Ballarat lines increases with State Grid load.
  This is the most significant factor for loading on the Moorabool to Ballarat lines.
- Interconnection flow between Victoria and Snowy/NSW.
  Flow on the Moorabool to Ballarat lines increases with export from Victoria to Snowy/NSW.
  Flow reduces with increasing import.
- Kiewa area generation.
  Flow on the Moorabool to Ballarat lines reduces with increased Kiewa generation (at a reduced sensitivity compared with flow between Victoria and Snowy/NSW).
- Interconnection flow between Victoria and SA over Murraylink.
  Flow on the Moorabool to Ballarat lines increases with export from Victoria to SA.
  Flow reduces with increasing import from SA.
  The impact of Murraylink on post-contingent flow is removed by an automatic runback scheme. If the Moorabool to Ballarat No.2 line is tripped while Murraylink is exporting to SA, then the scheme will rapidly reduce Murraylink transfer to zero.

The constraint is critically dependent on the following plant characteristics:

- The thermal capability of the Moorabool to Ballarat No.1 line; and
- The probability of outage of the Moorabool to Ballarat No.2 line, which is (1.096×10^{-3}) based on long-term benchmark availability levels.

(d) Impacts of Constraint

The potential impacts of the constraint are the reduction in export to South Australia via Murraylink, and load shedding in the State Grid. These impacts can arise without any outage occurring or, more predominantly, after outage of the Moorabool to Ballarat No.2 line.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

Nil

6.14.3 Do Nothing – Expected Value of Constraint

Table 6.31 and Table 6.32 present the forecasts of generation rescheduling and State Grid load shedding over the next five years due to loading on the Moorabool to Ballarat lines.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	0	0	1	2
Maximum single constraint	MW	0	0	15	35	88
Expected rescheduled generation	MWh	0	0	2	6	9
Expected value of rescheduling	$k	0	0	0	0.01	0.02
Expected unserved energy	MWh	0	0	0	0	0
Expected value of unserved energy	$k	0	0	0.2	0.3	0.7
EXPECTED VALUE OF CONSTRAINT	$k	0	0	0.2	0.3	0.8

Table 6.31 – Expected Value of Constraint for System Normal Conditions

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	0	1	2	3
Maximum single constraint	MW	10	25	40	75	140
Expected rescheduled generation	MWh	0	0	0	0	0
Expected value of rescheduling	$k	0	0	0	0	0
Expected unserved energy	MWh	0	0	0	0	0
Expected value of unserved energy	$k	0	0	0	0.01	0.02
EXPECTED VALUE OF CONSTRAINT	$k	0	0	0	0.01	0.02

Table 6.32 – Expected Value of Constraint for Moorabool to Ballarat No.2 Line Outage

The constraints associated with loading on the Moorabool to Ballarat lines are relatively small over the five-year outlook. The application of dynamic real time wind monitoring in determining thermal line ratings provides considerable benefits.

6.14.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions have been identified to reduce or remove the forecast Moorabool to Ballarat constraints.

Options 1 - Increasing the Capacity of the Moorabool to Ballarat No.1 Circuit

The No.1 line is presently rated for operation at up to 65°C conductor temperature. A higher maximum conductor temperature and line rating could be obtained by re-tensioning the conductors and/or raising towers on critical spans. Uprating the circuit for 75°C operation would increase the circuit rating by around 25% to 300 MVA at 40°C ambient temperature at a cost of around $2.9 M.

Option 2 - Installation of a Third Moorabool to Ballarat 220 kV Circuit

The existing No.2 line is built on double circuit towers, with only one side of the towers presently strung. A third line could be strung on the vacant side of the tower. The estimated cost of this option and the associated 220 kV switching is around $7.9 M.

At this point in time VENCorp considers these options to be non-contestable augmentations.

(b) Non-Network Options Considered

Load transfers, demand management or generation within the State Grid, especially at Ballarat, would provide load relief on the Moorabool to Ballarat 220 kV circuits. Around 1.8 MW of load relief in the State Grid is required to reduce loading on the critical line by 1 MW.

VENCorp has not identified any technically or economically feasible non-network options to alleviate this constraint and therefore no non-network options have been considered in the economic analysis.

6.14.5 Economic Evaluation

All the network options identified eliminate the relatively small forecasts of expected energy at risk in the “do nothing” option. However, while they are technically feasible, they are not economically feasible as the expected value of constraint is low.

Table 6.33 identifies the value of expected energy at risk of the Moorabool to Ballarat constraint associated with Options 1 and 2. Expected energy at risk with the augmentations is calculated on the same basis as for the “do nothing” option. The benefit of each option is identified by comparing the value of expected energy at risk with the “do nothing” option.

		Present Value ($k)	Annualised Value ($k) 2005/06	2006/07	2007/08	2008/09	2009/10	Residual Value ($k)
Do Nothing		-7.4	0.0	0.0	-0.2	-0.3	-0.8	-10.3
OPTION 1 (Thermal upgrade to 75°C)	Market Benefits		0.0	0.0	0.2	0.3	0.8	10.3
	Costs		-240	-240	-240	-240	-240	-3,084
	Net Market Benefits		-240	-240	-240	-240	-239	-3,074
OPTION 2 (Third circuit)	Market Benefits		0.0	0.0	0.2	0.3	0.8	10.3
	Costs		-652	-652	-652	-652	-652	-8,402
	Net Market Benefits		-652	-652	-652	-652	-651	-8,392

Table 6.33 – Net Market Benefits of Network Options

6.14.6 Conclusion

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Moorabool to Ballarat constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be upgrading towers on the Moorabool to Ballarat No.1 line to increase the design rating from 235 MVA to 300 MVA, given an ambient temperature of 40°C. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.15 Loading of Ballarat to Bendigo 220 kV Line

6.15.1 Overview

Loading of the Ballarat to Bendigo 220 kV line presents a thermal constraint that is forecast to arise after an outage of the Bendigo-Fosterville-Shepparton line. The constraint will only occur under high State Grid demand conditions coincident with high export to South Australia via Murraylink and high export to Snowy/NSW. The effect of the constraint is a reduction in the export level to South Australia via Murraylink and load shedding in the State Grid.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint. However, the development of a new load connection point at Fosterville Terminal Station (between Bendigo and Shepparton) has slightly increased the system normal loading on the critical line.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Ballarat to Bendigo constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be the installation of a wind monitoring scheme on the Ballarat to Bendigo line. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.15.2 Introduction

(a) Location of Constraint

The constraint is located between Ballarat and Bendigo terminal stations in west Victoria. Geographical and electrical representations of the constraint are given in Figures 6.17 and 6.18, respectively.

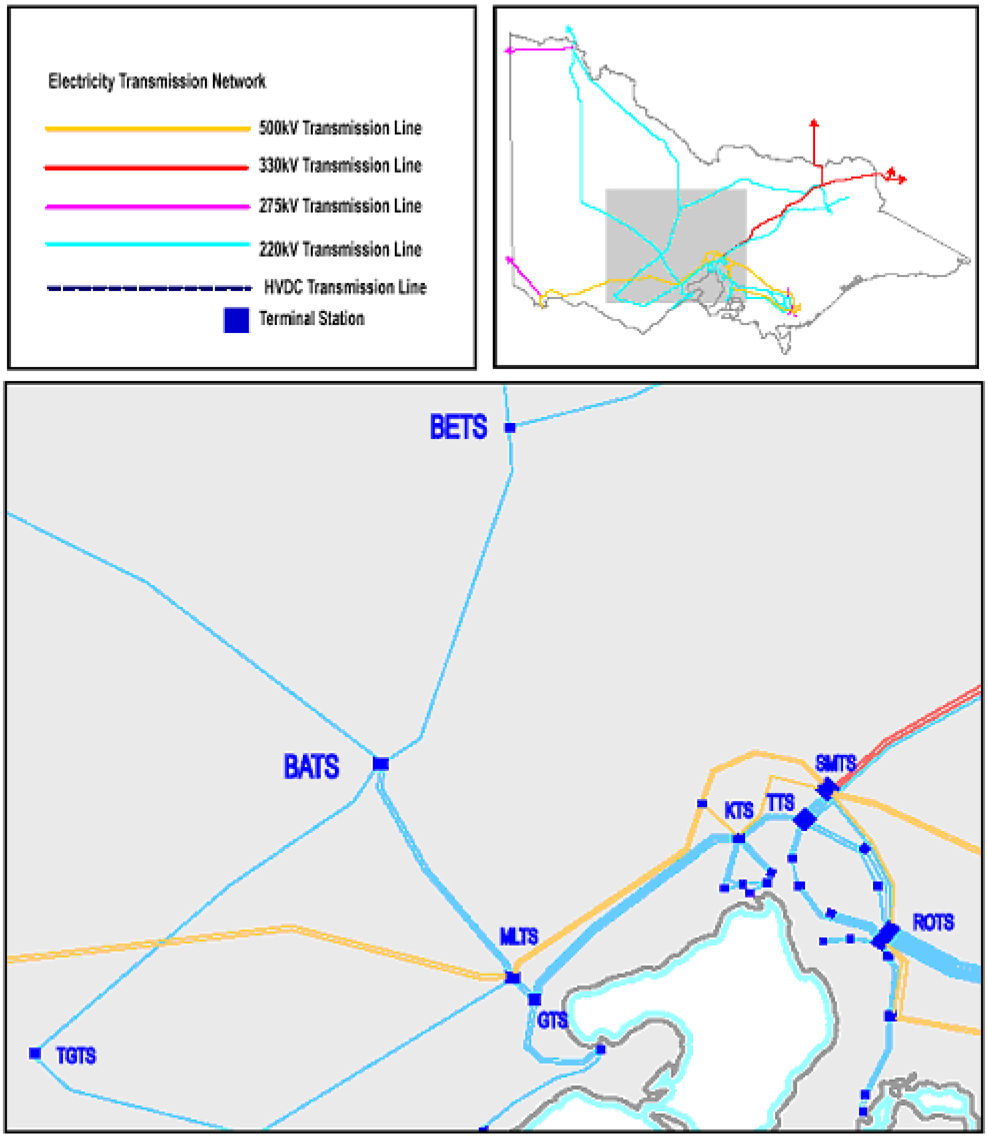

Figure 6.17 – Geographical Representation of the Ballarat to Bendigo 220 kV Line

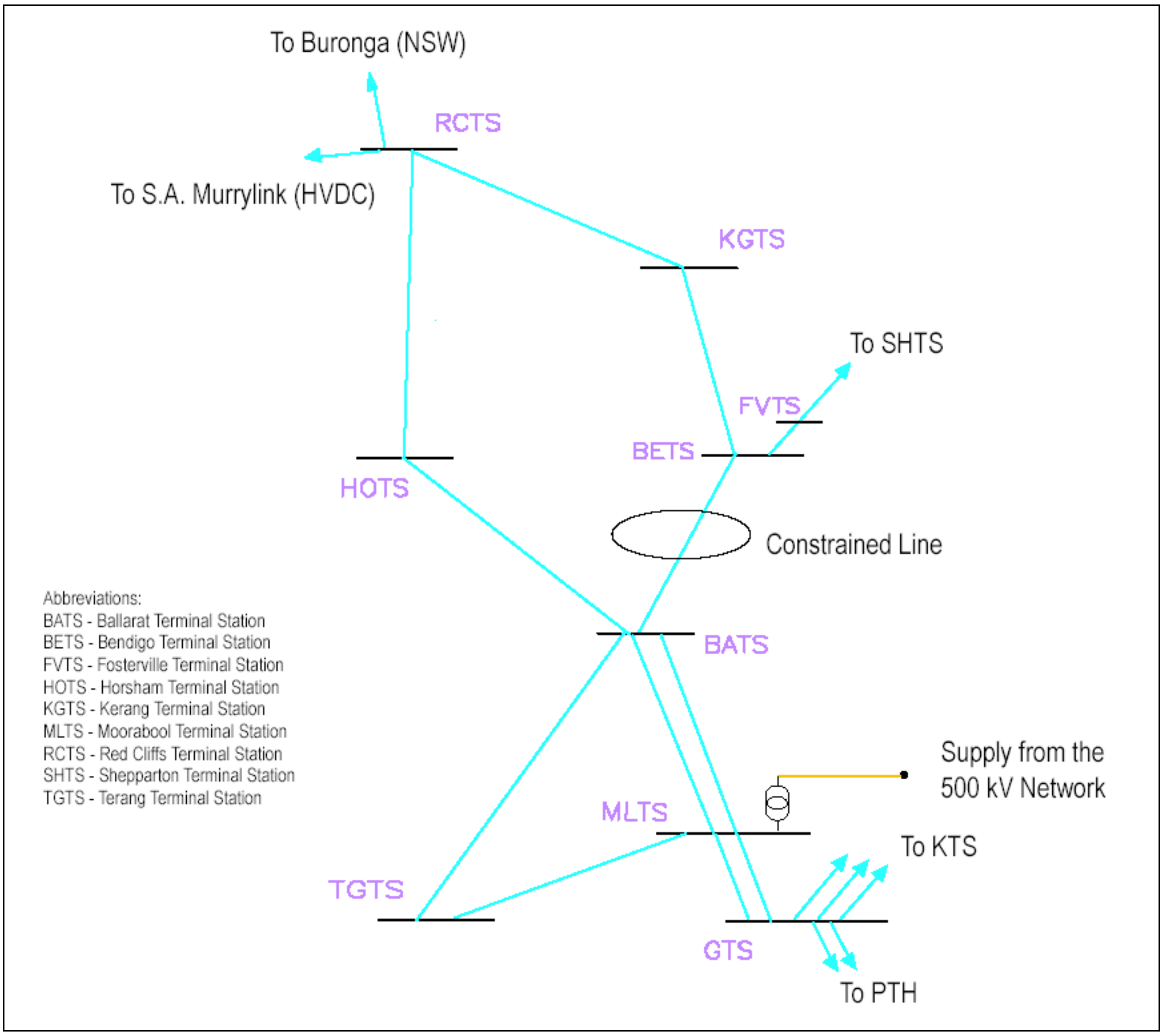

Figure 6.18 – Electrical Representation of the Ballarat to Bendigo 220 kV Line

(b) Reason For Constraint

The Ballarat to Bendigo circuit forms one of the main 220 kV supply points for the State Grid area in North Western Victoria. The other main 220 kV supply into North Western Victoria is the Shepparton to Fosterville to Bendigo line, so contingent loss of this line may overload the Ballarat to Bendigo line. The constraint has arisen as a result of progressive load growth at Bendigo, Kerang and Red Cliffs in North Western Victoria.

(c) Conditions of Constraint

Power flow on the Ballarat to Bendigo circuit is generally northwards from Ballarat, through Bendigo and further into the State Grid. The single circuit tower is rated 270 MVA at 35°C ambient temperature.

The following system loading factors contribute to the Ballarat to Bendigo constraint:

- North West Victoria Load.
  Flow on the Ballarat to Bendigo circuit increases with load at Bendigo, Kerang and Red Cliffs. This is the most significant factor for loading on the Ballarat to Bendigo circuit.
- Interconnection flow between Victoria and SA over Murraylink.
  Flow on the Ballarat to Bendigo circuit increases with export from Victoria to SA.
  The impact of Murraylink on line flows after a line outage is removed by an automatic runback scheme. If the Shepparton to Fosterville to Bendigo line is tripped while Murraylink is exporting to SA, then the scheme will rapidly reduce Murraylink transfer to zero.
- Interconnection flow between Victoria and Snowy/NSW.
  Flow on the Ballarat to Bendigo circuit increases with export from Victoria to Snowy/NSW.

The constraint is critically dependant on the following plant characteristics:

- The thermal capability of the Ballarat to Bendigo line; and
- The probability of outage of the Shepparton to Fosterville to Bendigo line, which is (2.002×10^{-3}) based on long-term benchmark availability levels.

(d) Impacts of Constraint

The potential impacts of the constraint the reduction in export to South Australia via Murraylink, and load shedding in the State Grid. These impacts will only arise after outage of the Shepparton to Fosterville to Bendigo line.

(e) Impact on Constraint of Distribution Business Planning

Nil.

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-network Impact of Constraint

Nil

6.15.3 Do Nothing – Expected Value of Constraint

Table 6.34 presents the forecasts of generation rescheduling and State Grid load shedding over the next five years due to loading on the Ballarat to Bendigo line.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	0	0	1	2
Maximum single constraint	MW	10	14	17	25	58
Expected rescheduled generation	MWh	0	1	0	0	2
Expected value of rescheduling	$k	0.05	0.03	0	0	0.2
Expected unserved energy	MWh	0	0	0	0	0
Expected value of unserved energy	$k	0.3	1.3	2	3	5
EXPECTED VALUE OF CONSTRAINT	$k	0.3	1.3	2	3	5

Table 6.34 – Expected Value of Constraint for Shepparton-Fosterville-Bendigo Line Outage

The constraints associated with loading on the Ballarat to Bendigo line are relatively small over the five-year outlook.

6.15.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network options have been identified to reduce or remove the forecast Ballarat to Bendigo constraints.

Option 1 – Wind Monitoring Scheme

The Ballarat to Bendigo line rating is determined for a fixed wind speed of 0.6 m/s. Dynamic real time wind speed could be used by installing wind monitoring stations adjacent the line, and a rapid demand reduction control scheme, at a cost of around $600k. The wind speed is typically higher than 0.6 m/s on hot days, when the higher temperature reduces line rating. A typical wind speed of 3m/s would provide a 25% increase in line capacity and significantly reduce the overall cost of the constraint. An investigation into wind speed between Ballarat and Bendigo needs to be carried out before implementing this scheme.

Option 2 – Increasing the Capacity of the Ballarat to Bendigo Circuit

The Ballarat to Bendigo line is presently rated for operation at up to 65°C conductor temperature. A higher maximum conductor temperature and line rating could be obtained by raising towers on critical spans. Uprating the circuit for 75°C operation would increase the circuit rating by around 25% at 40°C ambient temperature at a cost of around $3.4M.

At this point in time VENCorp considers these options to be non-contestable augmentations.

6.15.5 Economic Evaluation

All the network options identified eliminate the relatively small forecasts of expected energy at risk in the "do nothing" option. However, while they are technically feasible, they are not economically feasible as the expected value of constraint is low.

Table 6.35 identifies the value of expected energy at risk of the Ballarat to Bendigo constraint associated with Options 1 and 2. Expected energy at risk with the augmentations is calculated on the same basis as for the "do nothing" option. The benefit of each option is identified by comparing the value of expected energy at risk with the "do nothing" option.

		Present Value ($k)	Annualised Value ($k) 2005/06	2006/07	2007/08	2008/09	2009/10	Residual Value ($k)
Do Nothing		-37.7	-0.3	-1.3	-2.0	-3.0	-5.0	-46.2
OPTION 1 (Wind Monitoring Scheme)	Market Benefits		0.3	1.3	2.0	3.0	5.0	46.2
	Costs		-61	-61	-61	-61	-61	-565
	Net Market Benefits		-61	-60	-59	-58	-56	-519
OPTION 2 (Thermal upgrade to 75°C)	Market Benefits		0.3	1.3	2.0	3.0	5.0	64.4
	Costs		-281	-281	-281	-281	-281	-3,616
	Net Market Benefits		-280	-279	-279	-278	-276	-3,552

Table 6.35 – Net Market Benefits of Network Options

6.15.6 Conclusion

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Ballarat to Bendigo constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be the installation of a wind monitoring scheme on the Ballarat to Bendigo line. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.16 Loading of Shepparton to Fosterville to Bendigo 220 kV Line

6.16.1 Overview

Loading of the Shepparton – Fosterville – Bendigo 220 kV line presents a thermal constraint that can arise with all plant in service, or after various outages of transmission lines in the State Grid area. The constraint will only occur under high State Grid demand conditions coincident with high import from Snowy/NSW and high export to South Australia via Murraylink. The effect of the constraint is a reduction in the export level to South Australia via Murraylink, a reduction in the import level from Snowy/NSW and load shedding in the State Grid.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint. However, the development of a new load connection point at Fosterville Terminal Station (between Bendigo and Shepparton) has slightly increased the loading on the critical line.

This year's assessment has concluded that augmentation is required.

VENCorp considers that the development of wind monitoring scheme on the Shepparton-Fosterville-Bendigo line passes the Regulatory Test requirements. The wind monitoring scheme would be a Minor Network Augmentation with a capitalised cost estimate of $600k ±25% providing a net present value of market benefit of around $780k. VENCorp will now advance this network option so that practical completion is achieved for September 2006.

6.16.2 Introduction

(a) Location of Constraint

The Shepparton to Bendigo constraint is located between Shepparton and Bendigo terminal stations in northern Victoria. Geographical and electrical representations of the constraint are given in Figures 6.19 and 6.20 respectively.

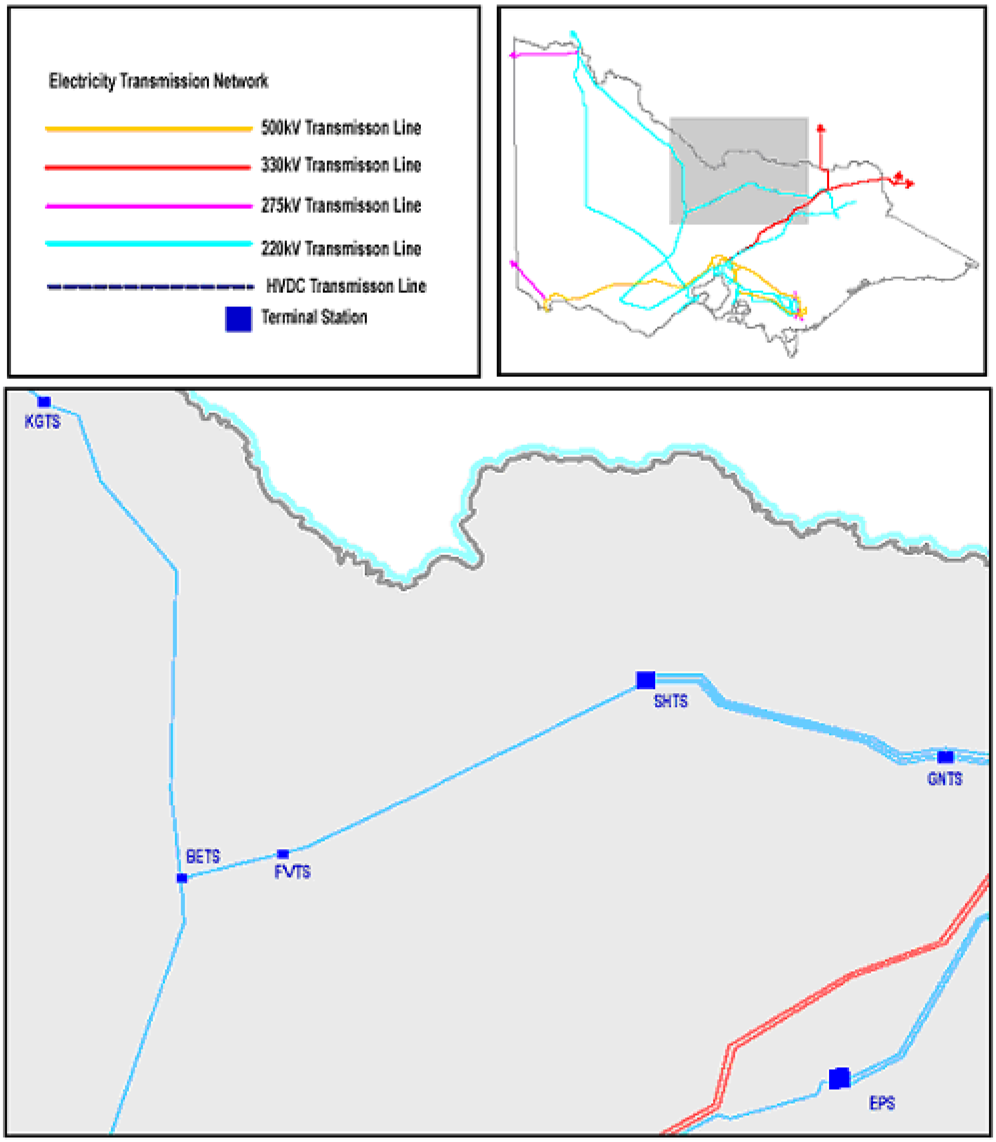

Figure 6.19 – Geographical Representation of the Shepparton to Fosterville to Bendigo 220 kV Line

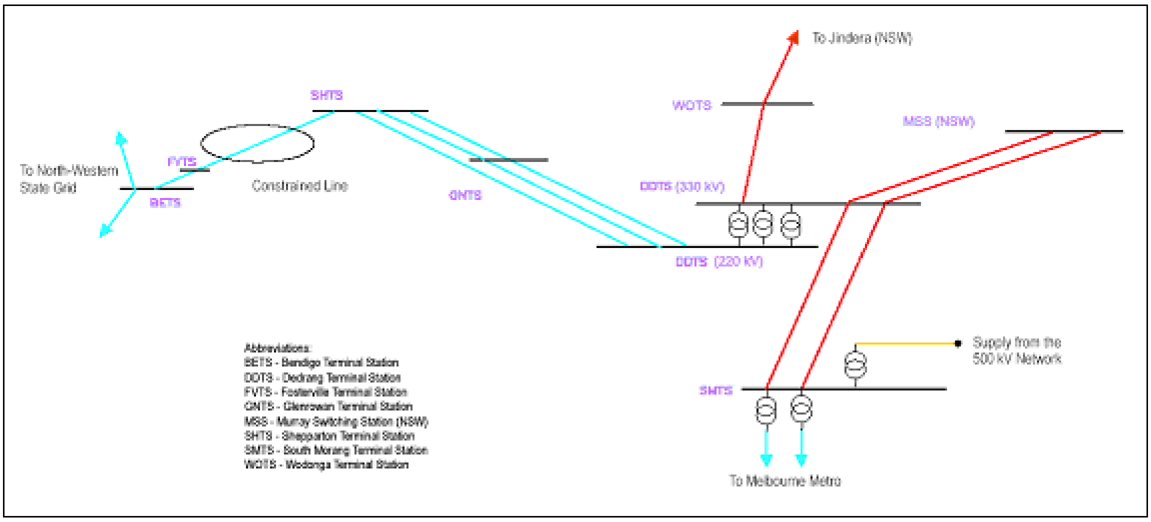

Figure 6.20 – Electrical Representation of the Shepparton to Fosterville to Bendigo 220 kV Line

(b) Reason For Constraint

The basis of the Shepparton to Bendigo constraint is potential loading of the Shepparton – Fosterville - Bendigo 220 kV line beyond its thermal rating. The constraint impacts on Victorian import from Snowy, Victorian export to South Australia via Murraylink and supply to the Victorian State Grid.

The constraint is emerging because of increasing load in the Victorian State Grid at times of high power transfer into Victoria and high ambient temperature. The constraint can apply under system normal conditions (i.e. all transmission plant in service prior to any contingency) or with prior outage of another transmission circuit.

Under system normal conditions, the critical contingency for the Shepparton to Bendigo constraint is loss of the Moorabool 500/220 kV transformer or loss of the Darlington Point – Balranald – Buronga 220 kV line in New South Wales. The worst case prior outage is of a South Morang to Dederang 330 kV line, and the critical contingency under this condition is loss of the remaining South Morang to Dederang line.

The following sections describe the conditions and impact of the system normal Shepparton to Bendigo constraint.

(c) Conditions of Constraint

Power flow on the Shepparton – Fosterville - Bendigo line can approach thermal capability in a southwest direction from Shepparton to Bendigo. The circuit has a continuous rating of 325 MVA at 40°C ambient temperature. The following factors contribute to increased loading on the Shepparton to Bendigo line:

- Victorian State Grid load west of Shepparton;
- Victorian import from Snowy; and

- Murraylink transfer to South Australia - the impact of Murraylink is limited by runback control schemes that automatically reduce Murraylink flow to zero following critical contingencies.

(d) Impacts of Constraint

Based on present system load forecasts, maximum potential loading on the Shepparton – Fosterville - Bendigo line for loss of the Moorabool 500/220 kV transformer will reach the continuous rating at 40°C ambient temperature in 2006/07 and rise to approximately 110% of rating by 2009/10. Maximum potential loading will occur under peak Victorian import from Snowy/New South Wales (1900 MW) and peak Murraylink transfer to South Australia (220 MW). The potential impacts of the constraint from summer 2006/07 are as follows:

- A reduction in Victorian export capability to South Australia via Murraylink;
- A reduction in Victorian import capability from Snowy/NSW or a reduction in supportable Kiewa area generation;
- A potential requirement to reduce demand in the Victorian State Grid following trip of the Moorabool 500/220 kV transformer or the Darlington Point – Balranald – Buronga 220 kV line.

The operational impacts of the constraint are related to how the constraint is managed. In the absence of any augmentation, the constraint could be managed as follows:

- Prior to the contingency, constrain Victorian transfer to South Australia or from Snowy/NSW so that post contingent loading on the Shepparton – Fosterville - Bendigo line would not exceed 15 minute rating. Where constraining transfer is not possible or insufficient, reduce demand in the Victorian State Grid area;
- Following the contingency, and where loading exceeds continuous rating, reschedule Kiewa area generation and/or transfer between Victoria and Snowy and/or Victoria and South Australia so that loading is reduced to continuous rating within 15 minutes; and
- Where residual overload exists after rescheduling, manually reduce load in the Victorian State Grid.

Under extreme conditions from summer 2006/07, it is expected that pre-contingent load shedding would be required to maintain post contingent loading on the Shepparton – Fosterville - Bendigo line within 15 minute rating. Approximately 4 MWh of load shedding would be required in 2006/07 rising to 5 MWh in 2007/08.

In order to minimise the need for precontingent load shedding, it is proposed that existing control facilities be reprogrammed prior to summer 2006/07 to reduce demand in the State Grid when imminent overloading is detected on the Shepparton – Fosterville - Bendigo line. These facilities would allow a 5 minute line rating to be utilised following a contingency. Use of rapid load shedding in conjunction with generation rescheduling would then be used to manage the constraint as follows:

- Prior to the contingency, constrain Victorian transfer to South Australia or from Snowy/NSW so that post contingent loading on the Shepparton – Fosterville - Bendigo line would not exceed 5 minute rating. Where constraining transfer is not possible or insufficient, reduce demand in the Victorian State Grid area;

- Following the contingency and where loading is between 5 and 15 minute rating, automatically shed load in the Victorian State Grid so that post contingent loading is reduced to continuous rating;

- Where post contingent loading is between the 15 minute and continuous rating, reschedule Kiewa generation and/or transfer between Victoria and Snowy and/or Victoria and South Australia so that post contingent loading is reduced to continuous rating within 15 minutes. Where residual overload exists after rescheduling, manually reduce load in the Victorian State Grid or utilise automatic load shedding. The constraint on Victorian import capability from Snowy is alleviated by approximately 6 MW for each 1 MW of load reduction in the Victorian State Grid.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

6.16.3 Do Nothing – Expected Value of Constraint

Market modelling studies have been undertaken to quantify exposure to the system normal Shepparton to Bendigo constraint assuming the constraint is managed as specified in section 6.16.2. The constraint is based on maintaining precontingent loading on the Shepparton – Fosterville – Bendigo line so that corresponding post contingent loading would not exceed the 5 minute circuit rating. Note that this "do nothing" option includes generation rescheduling and load shedding.

The expected value of the system normal Shepparton to Bendigo constraint arises from generation rescheduling and load shedding in the Victorian State Grid required prior to any contingency. Table 6.36 summarises the forecast impact of the constraint. Average and maximum values of the constraint refer to Victorian import from Snowy. Increasing demand in Victoria and South Australia causes the rise in expected value of constraint from 2005/06 to 2007/08. The decrease in 2008/09 and 2009/10 is associated with service of new generation in Victoria and South Australia, which has been assumed in the market simulations.

Where a constraint violation exists, generation is rescheduled so as to decrease Victorian import from Snowy / NSW and export to South Australia. Rescheduled generation is valued at an incremental fuel premium depending on which generators are redispatched as a consequence of the constraint. Where generation rescheduling is insufficient to relieve the potential overload, load is reduced in the Victorian State Grid.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	0	0.40	0.58	0.47	0.20
Maximum single constraint	MW	0	248	383	155	64
Average constraint	MW	0	126	139	73	45
Expected rescheduled generation	MWh	0	26	49	30	9
Expected value of rescheduling	$k	0	90	347	221	85
Expected unserved energy	MWh	0	4.2	5.3	0.78	0
Expected value of unserved energy	$k	0	123	158	23	0
EXPECTED VALUE OF CONSTRAINT	$k	0	213	505	244	85

Table 6.36 – Expected Value of Constraint

6.16.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions have been identified to reduce or remove the system normal Shepparton to Bendigo constraint.

Option 1 - Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used in the calculation by installing wind monitoring stations on the Shepparton - Fosterville - Bendigo line at an estimated cost of $600k ±25%. Recorded data from Bendigo and Shepparton shows that on high ambient temperature days the wind speed is typically greater than 1.2 m/s. A wind speed of 1.2 m/s would provide a 15~20% increase in line capacity at high ambient temperature and is assumed in the economic analysis of this option. Option 1 is assumed to have a 20 year life.

Option 2 - Increasing The Thermal Rating Of The Shepparton - Fosterville - Bendigo Circuit

The Shepparton - Fosterville - Bendigo line is presently rated for operation at 82°C conductor temperature. Re-tensioning the conductors and/or raising towers would provide a higher maximum conductor temperature and associated line rating. Uprating the circuit for 90°C operation is possible and would increase the circuit rating by around 10% at 40°C ambient temperature at an estimated cost of around $5M. Further uprating would require conductor and tower replacement and be significantly more expensive. Option 2 is assumed to have a 45 year life.

Continuous rating (in Amps) of the Shepparton - Fosterville – Bendigo circuit is shown in Figure 6.21 for the existing line and with augmentation Options 1 and 2. In all cases, overall circuit rating is limited by existing line protection to 990 A (377 MVA). The protection limit and other termination limits may be increased to address the Shepparton to Bendigo constraint associated with prior outage of a South Morang to Dederang 330 kV line or as part of an interconnection upgrade.

At this point in time VENCorp considers these options to be non-contestable augmentations.

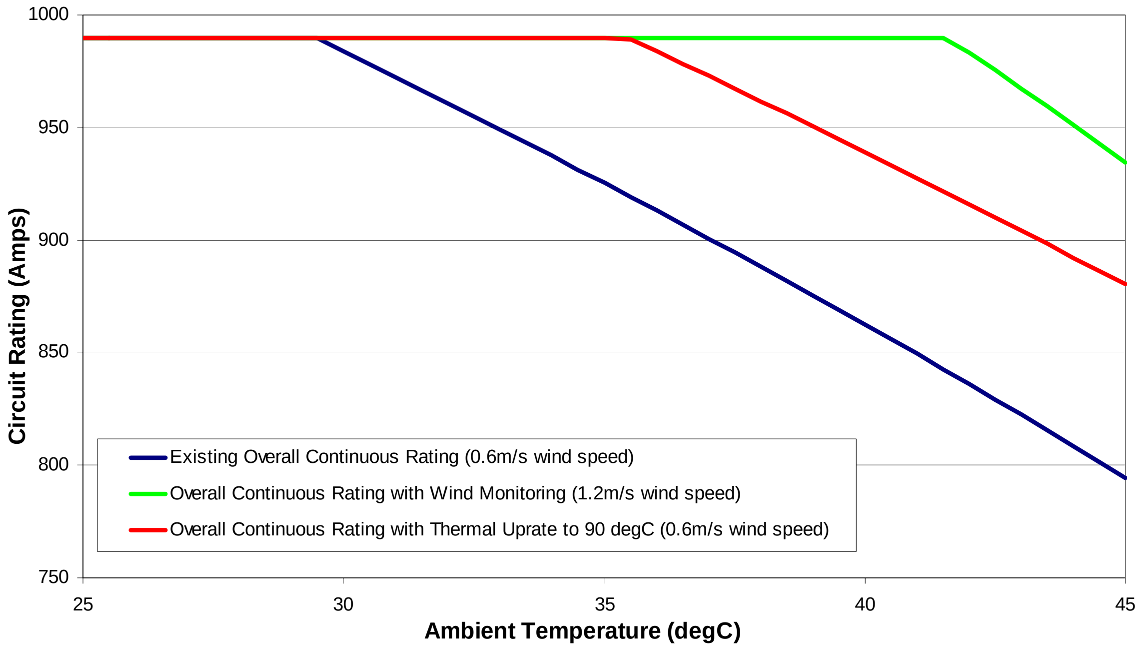

Figure 6.21 – Shepparton - Fosterville Bendigo Line Rating – Existing and With Augmentations

6.16.5 Economic Evaluation

This analysis identifies the most economic augmentation option to address the system normal Shepparton to Bendigo constraint prior to 2009/10.

(a) Benefits of Augmentation Options

Network options 1 and 2 each eliminate the expected unserved energy and need for generation rescheduling associated with the system normal Shepparton to Bendigo constraint over the period 2005/06 to 2009/10. The benefit of each option over the analysis period is therefore equal to the value of constraint shown in Table 6.36. The economic benefits of Options 1 and 2 are assessed against the "do nothing" option.

(b) Summary of Net Benefits and Present Values Going Forward

A net market benefit assessment is carried out for a five year period for network options 1 and 2 using a discount rate of 8% to calculate the present value. Residual value for the remaining life of each option is calculated assuming costs and benefits as calculated for 2009/10. Results are summarised in Table 6.37.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-1,333	0	-213	-505	-244	-85	-813
OPTION 1 (Wind Monitoring Scheme)	Market Benefits	1,333	0	213	505	244	85	813
	Costs	-556	0	-61	-61	-61	-61	-584
	Net Market Benefits	777	0	152	444	183	24	228
OPTION 2 (Thermal Uprate)	Market Benefits		0	213	505	244	85	1,095
	Costs		-413	-413	-413	-413	-413	-5,318
	Net Market Benefits		-413	-200	92	-169	-328	-4,223

Table 6.37 – Net Market Benefits of Network Options

(c) Timing of Options

Wind monitoring is the preferred option for addressing the Shepparton to Bendigo constraint over the next five years. Optimal timing for installation is prior to summer 2006/07.

Thermal uprating of the Shepparton – Fosterville - Bendigo 220kV line may be justifiable in the five year period after 2009/10 or as part of any proposal to increase the capacity of the Victoria to Snowy/New South Wales interconnection or Murraylink. These works would include termination and secondary equipment upgrades.

(d) Material Inter-Network Impact

The Shepparton to Bendigo constraint is emerging as a result of increasing load in the Victorian State Grid. The primary purpose of the proposed wind monitoring scheme is to address increasing Victorian load while maintaining existing inter-regional transfer capability on the Victoria to Snowy interconnection and Murraylink, which would otherwise reduce as Victorian load increases. The proposed works are therefore considered not to have a material inter-network impact.

Should the Victoria to Snowy/New South Wales or Murraylink interconnection require upgrading, then additional, more substantial works may be required to address the Shepparton to Bendigo constraint. These works, together with other components of the interconnection upgrade, would be considered to have a material inter-network impact on the basis of increased transfer capability.

6.16.6 Conclusions

This year's assessment has concluded that augmentation is required.

VENCorp considers that the development of wind monitoring scheme on the Shepparton-Fosterville-Bendigo line passes the Regulatory Test requirements. The wind monitoring scheme would be a Minor Network Augmentation with a capitalised cost estimate of \$600k ±25%, providing a net present value of the market benefits of around \$780k. VENCorp will now advance this network option so that practical completion is achieved for September 2006.

6.17 Loading of Murray to Dederang 330 kV Lines

6.17.1 Overview

Loading of the two Murray to Dederang 330 kV lines presents a thermal constraint that can arise with both lines in service, or after an outage of one of these parallel lines. The constraint will only occur during high import conditions from Snowy/NSW coincident with high demand in the southern NSW. The effect of the constraint is a reduction in the import level from Snowy/NSW and load shedding in Victoria.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Murray to Dederang constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be associated with increasing the overall capacity of the Victoria to NSW/Snowy inter-connection and supply side issues. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.17.2 *Introduction*

(a) Location of Constraint

The constraint is located between Murray switching station in southeast New South Wales and Dederang terminal station in northeast Victoria. Geographical and electrical representations of the constraint are given in Figures 6.22 and 6.23 respectively.

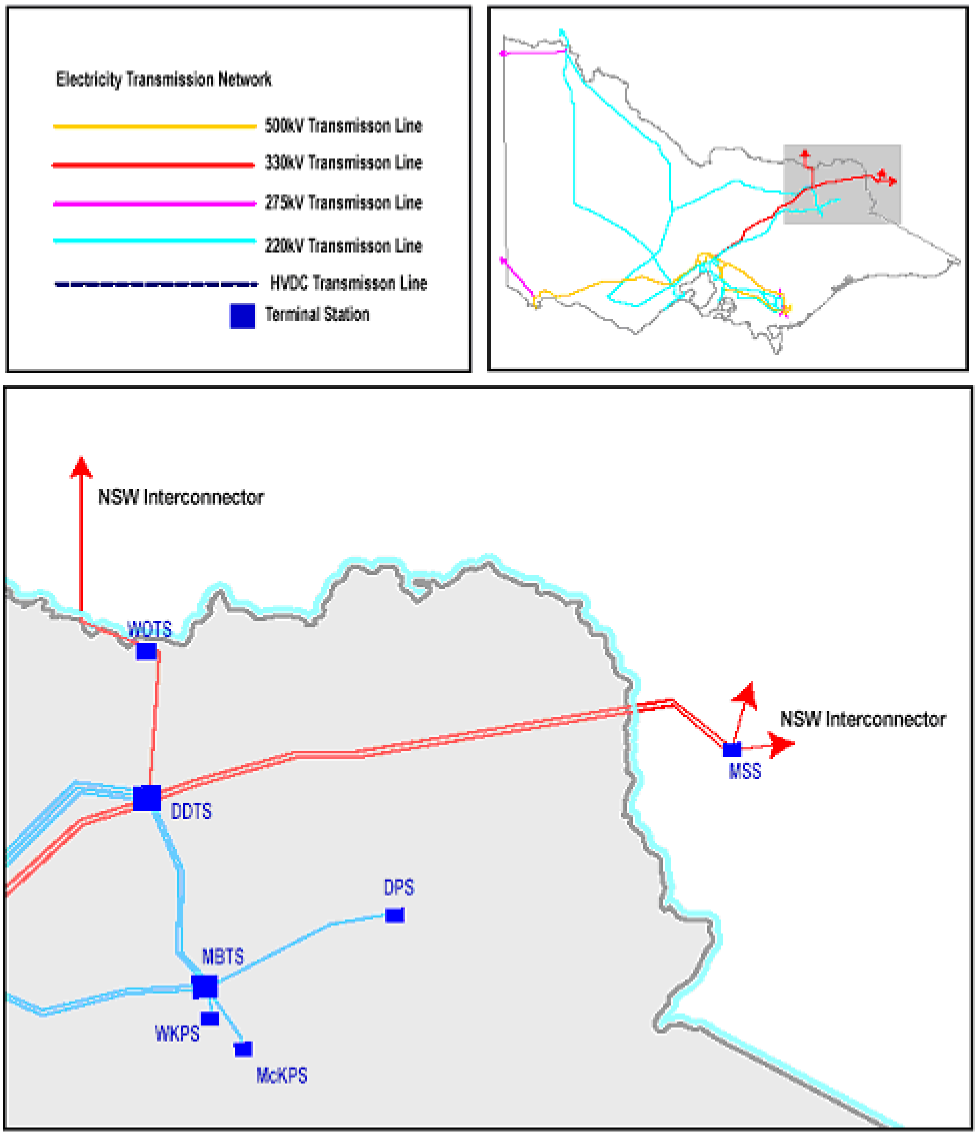

Figure 6.22 – Geographical Representation of the Murray to Dederang 330 kV Lines

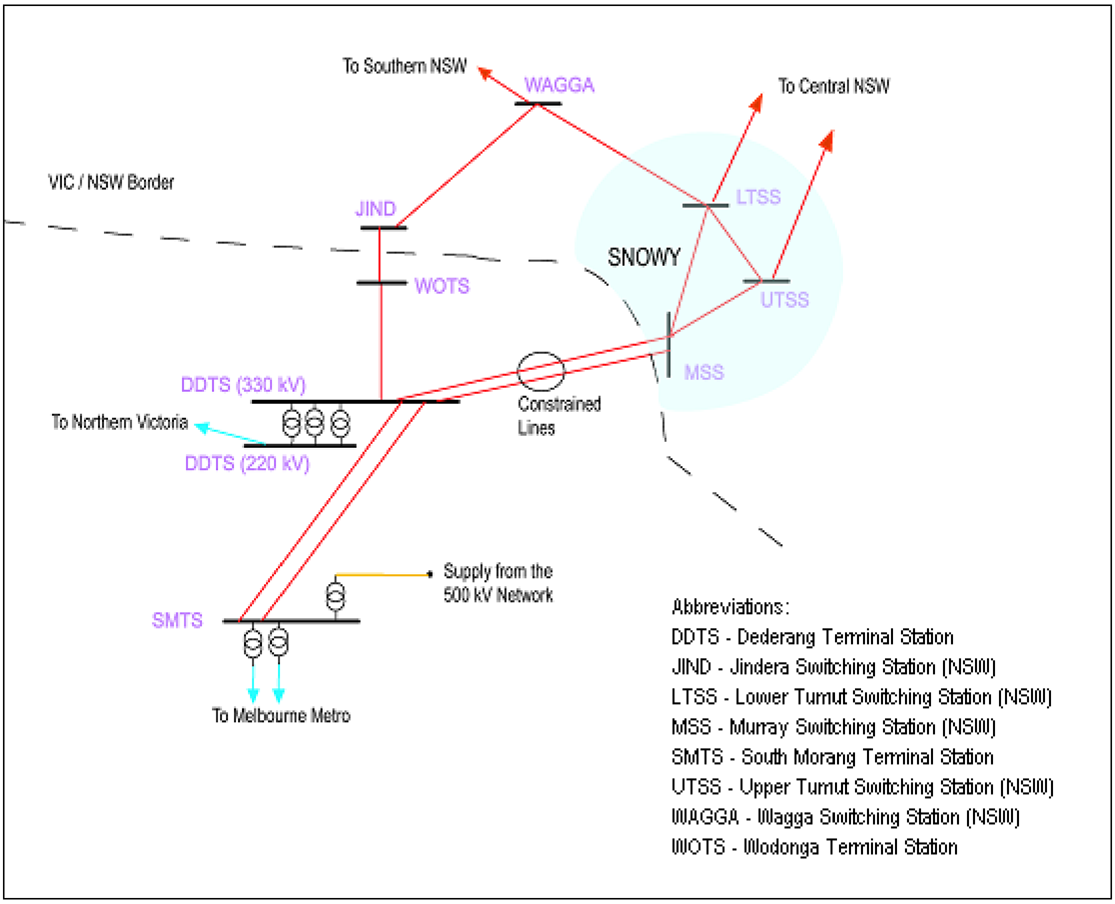

Figure 6.23 – Electrical Representation of the Murray to Dederang 330 kV Lines

(b) Reason for Constraint

All Transmission Plant In Service

Under system normal conditions (i.e. all transmission plant in service prior to any contingency) the constraint exists because of a requirement for high power transfer into Victoria coincident with high load in southern New South Wales and high ambient temperature. The basis of the constraint is potential loading of the Murray to Dederang 330 kV lines beyond their thermal capability under post contingent conditions. The system normal constraint affects only Victorian import capability.

The critical contingency under the majority of system conditions is loss of one Murray to Dederang 330 kV line. Under high loading conditions in southern New South Wales, the critical contingency can become loss of the Lower Tumut to Wagga 330 kV line, where loading on the two Murray to Dederang lines then defines the constraint.

Prior Outage Conditions

The Murray to Dederang constraint affects Victorian import and export capability under prior outage conditions. In both cases, the worst case prior outage is that of one Murray to Dederang line.

The basis of the constraint on Victorian import is potential loading on the Lower Tumut to Wagga 330 kV line in NSW following contingent loss of the remaining Murray to Dederang line.

The basis of the constraint on Victorian export is transient stability following contingent loss of either the remaining Murray to Dederang line or a Hazelwood to South Morang 500 kV line.

(c) Conditions of Constraint

All Transmission Plant In Service

Power flow on the Murray to Dederang lines can approach thermal capability for power flow into Victoria from Murray to Dederang. The two circuits are on separate tower lines and are each continuously rated at 995 MVA at 40°C. A third 330 kV circuit passes from Lower Tumut to Dederang via Wagga, Jindera and Wodonga. This circuit is significantly longer and does not share loading evenly with the Murray to Dederang lines. A control scheme is installed at Dederang to increase utilisation of this circuit following contingent loss of a Murray to Dederang line.

The following system loading factors influence the Murray to Dederang constraint on Victorian import:

- Victorian northern State Grid load and Murraylink transfer to South Australia

  Increasing northern State Grid load and Murraylink transfer to South Australia alleviate the constraint by increasing utilisation of the Lower Tumut to Dederang circuits following loss of a Murray to Dederang line and operation of the Dederang control scheme. This results in a higher Victorian import limit as defined by Murray to Dederang line loading for loss of the parallel line.

- Kiewa area and Eildon generation

  Increasing Kiewa and Eildon generation exacerbates the Murray to Dederang constraint by reducing utilisation of the Lower Tumut to Dederang circuits following loss of a Murray to Dederang line and operation of the Dederang control scheme. This results in a lower Victorian import limit as defined by Murray to Dederang line loading for loss of the parallel line.

- Southwest New South Wales Load

  Increasing southwest New South Wales load exacerbates the Murray to Dederang constraint by diverting power flow on the Lower Tumut to Dederang circuits away from Dederang. This results in a lower Victorian import limit as defined by Murray to Dederang line loading for loss of a Murray to Dederang line or the Lower Tumut to Wagga line.

A Network Control Ancillary Service (NCAS) can be invoked to alleviate the Murray to Dederang constraint under high temperature / high demand conditions where maximum Victorian import is required from Snowy/New South Wales. With NCAS invoked, preselected load is automatically shed in Victoria following detection of an overload above continuous rating on the Murray to Dederang lines.

Prior Outage Of A Murray to Dederang Line

With prior outage of a Murray to Dederang line, power flow on the remaining Murray to Dederang and Lower Tumut to Wagga lines can approach thermal capability under high Victorian import. Sensitivity of the prior outage Victorian import constraint to southwest New South Wales load is increased compared with the system normal constraint. Increasing southwest New South Wales load exacerbates the prior outage constraint by increasing loading on the Lower Tumut to Wagga line. This results in a lower Victorian import limit as defined by Lower Tumut to Wagga line loading for loss of a Murray to Dederang line. The prior outage constraint is insensitive to loading and generation levels in Victoria. The control scheme installed at Dederang is ineffective and cannot be used with the prior outage.

The Victorian export limit with prior outage of a Murray to Dederang line is sensitive to machine inertia and demand levels. Overall sensitivity to Victorian demand is reduced as compared with the system normal transient export limit.

The Murray to Dederang lines are each 113.5 km in length. The probability of forced outage of either line derived from benchmark data is 1.943×10^{-3}. The combined probability of an outage occurring on either line is therefore 3.882×10^{-3}. Economic assessment of the prior outage constraint is based on this probability figure.

(d) Impacts of Constraint

All Transmission Plant in Service

The two Murray to Dederang 330 kV lines are major elements of the Victoria to Snowy/New South Wales interconnection. The constraint is a major factor in limiting overall power transfer from Snowy/New South Wales to Victoria. The constraint results in a thermal Victorian import limit from Snowy/New South Wales ranging from approximately 1600 MW without the NCAS invoked to 1900 MW with full NCAS (maximum available load selected for post contingent shedding). These import limits apply with all transmission plant in service prior to the contingency.

Prior Outage Conditions

Victorian import capability from Snowy/New South Wales with prior outage of a Murray to Dederang line is between 600 MW and 900 MW depending on load in southern New South Wales. A lower import limit may apply with Snowy generation below around 800 MW.

Victorian export capability is reduced by around 100 MW to 150 MW from system normal levels with outage of a Murray to Dederang line.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact of Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

The Murray to Dederang constraint is a major limitation on Victorian transfer from Snowy/New South Wales. Any works to alleviate this constraint are therefore considered to have a material inter-network impact. Analysis of this constraint and development of options for its alleviation or removal will be performed in consultation with the Inter-regional Planning Committee.

6.17.3 Do Nothing – Expected Value of Constraint

All transmission Plant In Service

Economic analysis of the system normal Murray to Dederang constraint was conducted in late 2003 as part of an interconnection upgrade assessment. The analysis demonstrated that upgrade of the Victorian to NSW interconnection based on system normal capability was not economically justified in the short to medium term. Further economic analysis of the Murray to Dederang constraint under system normal conditions is therefore not intended as part of this review. This analysis considers impact of prior outage of a Murray to Dederang line and contingency on the remaining line.

Prior Outage Of A Murray to Dederang Line

Table 6.38 summarises the forecast impact of the constraint on Victorian import with prior outage of a Murray to Dederang line. The expected value of the constraint is shown graphically in Figure 6.24. The constraint is based on thermal loading of the Lower Tumut to Wagga line for contingent loss of the remaining Murray to Dederang line.

Where a constraint violation exists, generation is rescheduled so as to decrease Victorian import from Snowy / NSW. Rescheduled generation is valued at an incremental fuel premium depending on which generators are redispatched as a consequence of the constraint. Unserved energy exists where there is a residual violation of the constraint after all possible rescheduling is represented. The expected value of the constraint is weighted by the combined probability of prior outage of either Murray to Dederang line (3.882×10^{-3}).

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	2702	3129	3388	3861	4085
Maximum single constraint	MW	1238	1289	1301	1272	1285
Average constraint	MW	477	521	545	565	579
Expected rescheduled generation	MWh	4998	6316	7158	8462	9172
Expected value of rescheduling	$k	122	153	221	258	253
Expected unserved energy	MWh	3	10	9	8	9
Expected value of unserved energy	$k	99	282	266	241	258
EXPECTED VALUE OF CONSTRAINT	$k	221	434	488	499	512

Table 6.38 – Expected Value of Constraint for Prior Outage of a Murray to Dederang Line

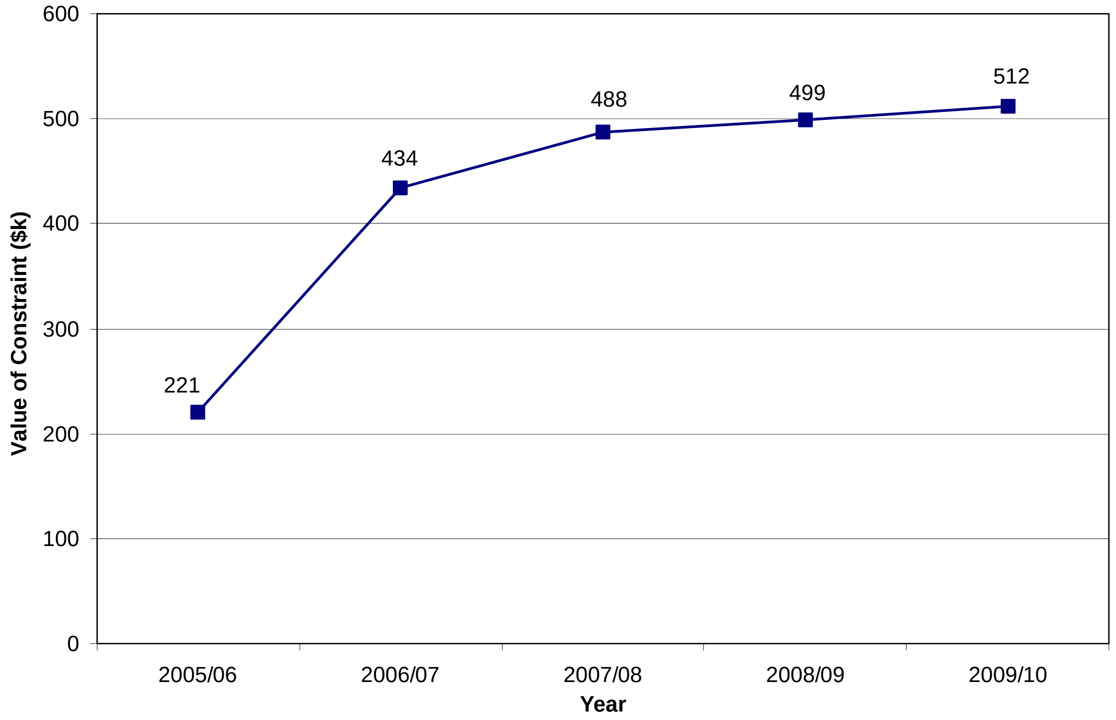

Figure 6.24 – Expected Value of Constraint for Prior Outage of a Murray to Dederang Line

The expected value of the constraint on Victorian export with prior outage of a Murray to Dederang line does not contribute significantly to the overall expected value of constraints for the prior outage.

6.17.4 Options and Costs for Removal of Constraint

Options for alleviation or removal of the Murray to Dederang constraint include the following:

- Uprating of the Lower Tumut to Wagga and Wagga to Jindera lines and installation of dynamic reactive support at Dederang at a total estimated cost of $27M. This option would provide approximately $150k of annual benefit from 2006/07.
- Installation of a 3rd Murray to Dederang line at an estimated cost of $64M. This option would eliminate the prior outage constraint. However, it is subject to confirmation of feasibility as no easement for a 3rd Murray to Dederang line presently exists.

Neither of the above options would be justified within 5 years based on the expected value of constraint at the present stage of system development.

VENCorp considers that these network options would be contestable augmentations.

6.17.5 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Murray to Dederang constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be associated increasing the overall capacity of the Victoria to NSW/Snowy inter-connection and supply side issues. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.18 Loading of Dederang to South Morang 330 kV Lines

6.18.1 Overview

Loading of the two Dederang to South Morang 330 kV lines presents a thermal constraint that can arise with both lines in service, or after an outage of one of these parallel lines. The constraint will only occur during high import or high export conditions from Snowy/NSW coincident with high State Grid loading in Victoria. The effect of the constraint is a reduction in the import level from Snowy/NSW and load shedding in Victoria.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Dederang to South Morang constraint can be managed until 2010/11, or beyond. VENCorp considers the next most likely augmentation would be associated with increasing the overall capacity of the Victoria to NSW/Snowy inter-connection and supply side issues. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.18.2 Introduction

(a) Location of Constraint

The constraint is located between Dederang and South Morang terminal stations. Geographical and electrical representations of the constraint are given in Figures 6.25 and 6.26 respectively.

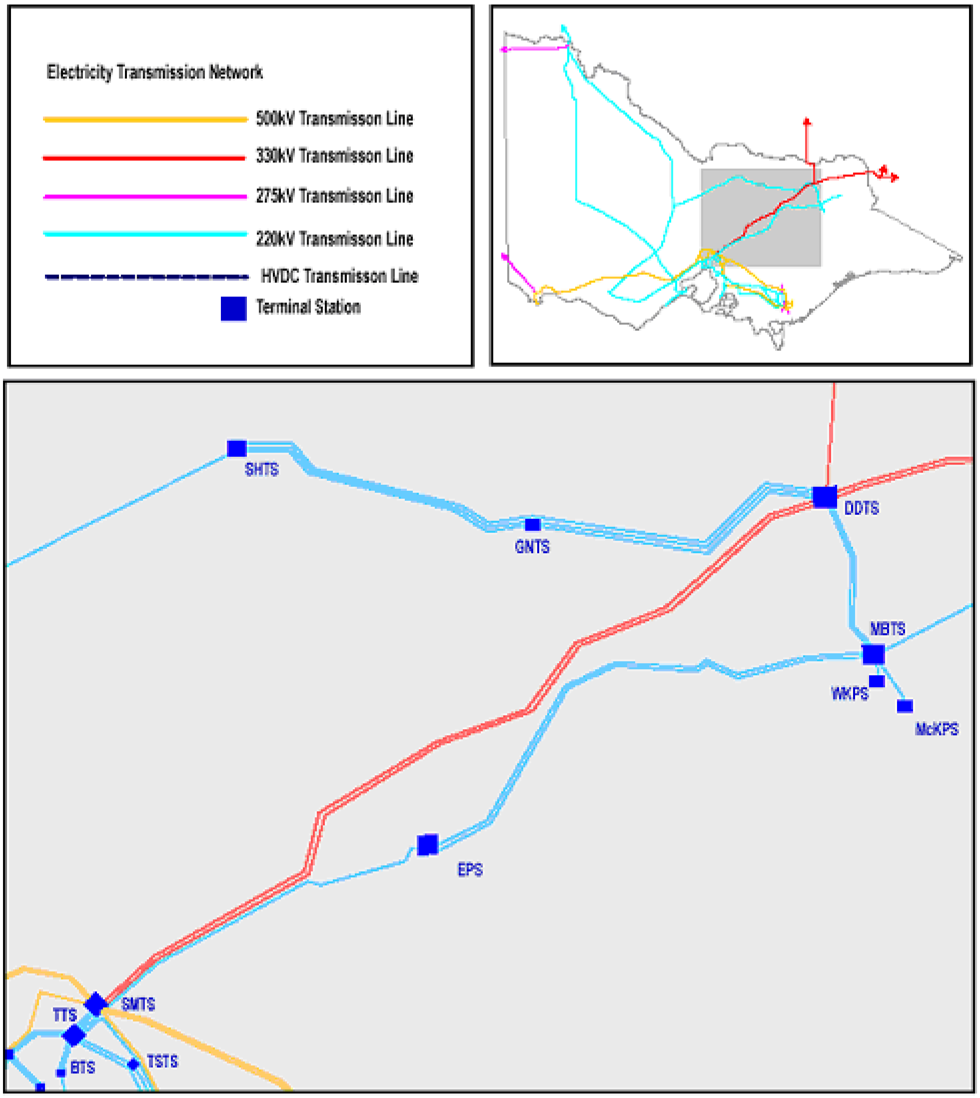

Figure 6.25 – Geographical Representation of the Dederang to South Morang 330 kV Lines

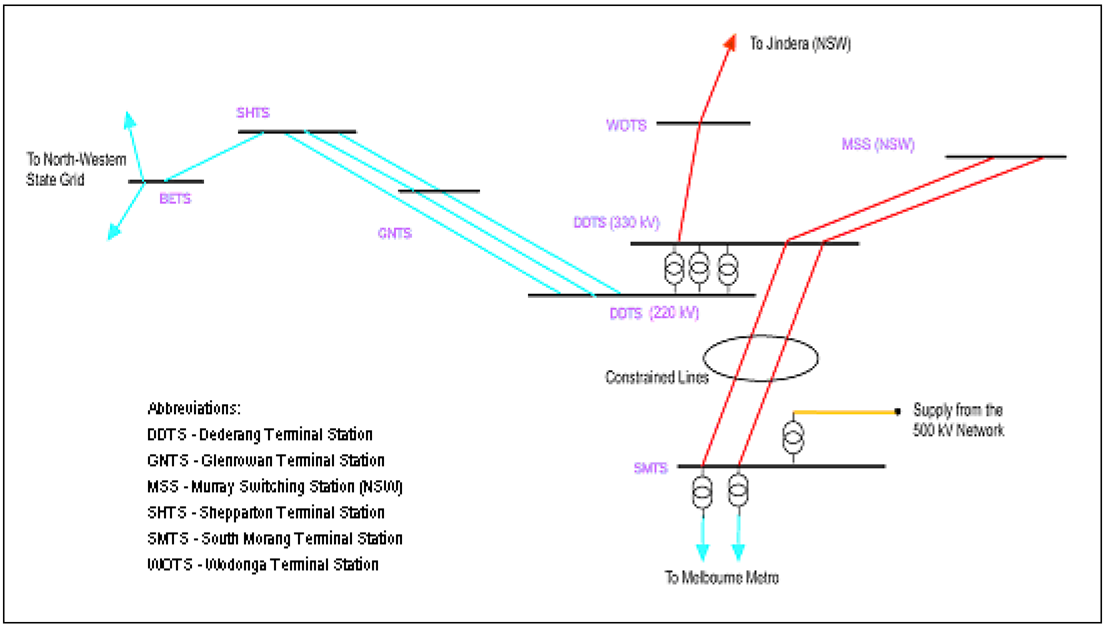

Figure 6.26 – Electrical Representation of the Dederang to South Morang 330 kV Lines

(b) Reason For Constraint

The constraint exists because the Dederang to South Morang lines carry a substantial proportion of power flow over the Victoria to Snowy/New South Wales interconnection. Under Victorian export conditions, these lines also support load in the northern Victorian State Grid.

The basis of the constraint is potential loading on the Dederang to South Morang lines beyond their thermal capability. The constraint can occur under Victorian import or export conditions over the Victoria to Snowy interconnection. The constraint is defined by loading on one Dederang to South Morang 330 kV line following forced outage of the parallel 330 kV line.

(c) Conditions of Constraint

The two Dederang to South Morang circuits are on separate tower lines. A series capacitor bank is installed on each line at South Morang, which provides 50% compensation of the line impedance. The continuous MVA rating of each overall circuit at 40°C is defined by the minimum of the line conductor (806 MVA) and series capacitor rating (743 MVA). Higher short term ratings are available depending on the timing and extent of action to reduce post contingent loading. An overall short term rating of up to 1,000 MVA is presently available. Following contingent loss of a Dederang to South Morang line, power flow on the remaining Dederang to South Morang line can approach thermal capability in either direction.

Under Victorian import conditions, power flow is from Dederang to South Morang. Principal system loading factors influencing the constraint are as follows:

- Victorian State Grid load and Murraylink transfer to South Australia.

  Increasing northern State Grid load and Murraylink transfer to South Australia alleviate the constraint by diverting power flow from the 330 kV busbar at Dederang to the northern State Grid 220 kV network. This results in a higher Victorian import limit as defined by Dederang to South Morang 330 kV line loading for loss of the parallel line.

- Kiewa area and Eildon generation.

  Increasing Kiewa and Eildon generation exacerbates the constraint by reducing flow from the 330 kV to 220 kV busbars at Dederang. This results in a lower Victorian import limit as defined by Dederang to South Morang 330 kV line loading for loss of the parallel line.

Under Victorian export to Snowy/New South Wales, power flow is from South Morang to Dederang. The impact of the above system loading factors is reversed as compared to the import case.

A Network Control Ancillary Service (NCAS) is presently available to alleviate the Dederang to South Morang constraint under high temperature / high demand conditions where maximum Victorian import is required from Snowy/New South Wales. With NCAS invoked, preselected load is automatically shed in Victoria following detection of an overload above continuous rating on the Dederang to South Morang lines.

(d) Impacts of Constraint

The two Dederang to South Morang 330 kV lines are major elements of the Victoria to Snowy/New South Wales interconnection. The constraint can limit power flow in either direction, as summarised below.

Under high temperature / high demand conditions, Victorian import capability is defined by thermal limitations on the Murray to Dederang lines. Under reduced ambient temperature and southern New South Wales load conditions, the Victorian import limit as defined by the Murray to Dederang limit increases above 1,900 MW. Import capability can then be limited to around 2,000 MW by the Dederang to South Morang constraint.

Under the majority of system conditions, Victorian export to Snowy/New South Wales is limited below 1,000 MW by transient stability for a 500 kV line fault between Latrobe Valley and Melbourne. Under certain conditions including Victorian demand below 4,500 MW together with reduced transfer or import from South Australia, Victorian export may be limited between 1,000 MW and 1,150 MW by a Dederang to South Morang transient stability limit.

At the present stage of system development, the Dederang to South Morang constraint is not the principal system normal constraint for transfer in either direction over the Victoria to Snowy/New South Wales interconnection and its market impacts are relatively minor. However, the constraint would need to be addressed as part of any significant interconnection upgrade.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-network Impact of Constraint

Works to alleviate the Dederang to South Morang constraint are expected to form part of a future interconnection upgrade. These works are likely to be justified on the basis of increased transfer capability and so are expected to have a material inter-network impact.

6.18.3 Do Nothing – Expected Value of Constraint

The Dederang to South Morang constraint would be analysed as part of any future proposal to increase capacity of the Victorian to Snowy/New South Wales interconnection.

6.18.4 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Dederang to South Morang constraint can be managed until 2010/11, or beyond.

VENCorp considers the next most likely augmentation would be associated with increasing the overall capacity of the Victoria to Snowy/NSW inter-connection and supply side issues. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.19 Loading of Dederang 330/220 kV Tie Transformers

6.19.1 Overview

Loading of the three Dederang 330/220 kV tie transformers in the north east of Victoria presents a thermal constraint that can arise with all plant in service, or after outage of either of these parallel transformers. The constraint typically occurs at times of high import from Snowy/NSW and when generation in the State Grid is relatively low. The effect of the constraint is a reduction in the import level from Snowy/NSW and load shedding in the State Grid.

In VENCorp's 2004 Annual Planning Report, a modification to the Dederang Bus Splitting Scheme (DBUSS) was identified as a technical and economic solution. This upgrade is now a committed Minor Network Augmentation (refer to section 5.2.5) and is expected to be completed during summer 2005/06.

This year's assessment has confirmed that the modification to DBUSS has deferred the need for further augmentation and that the Dederang 330/220 kV tie transformer constraint can be managed until 2009/10. VENCorp considers the next most likely augmentation would be installation of a fourth 330/220 kV transformer at Dederang. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.19.2 Introduction

(a) Location of Constraint

There are three 330/220 kV transformers in service at Dederang Terminal Station. The constraint is located across these transformers between the 330 kV and 220 kV Dederang busbars. Geographical and electrical representations of the constraint are provided in Figures 6.27 and 6.28.

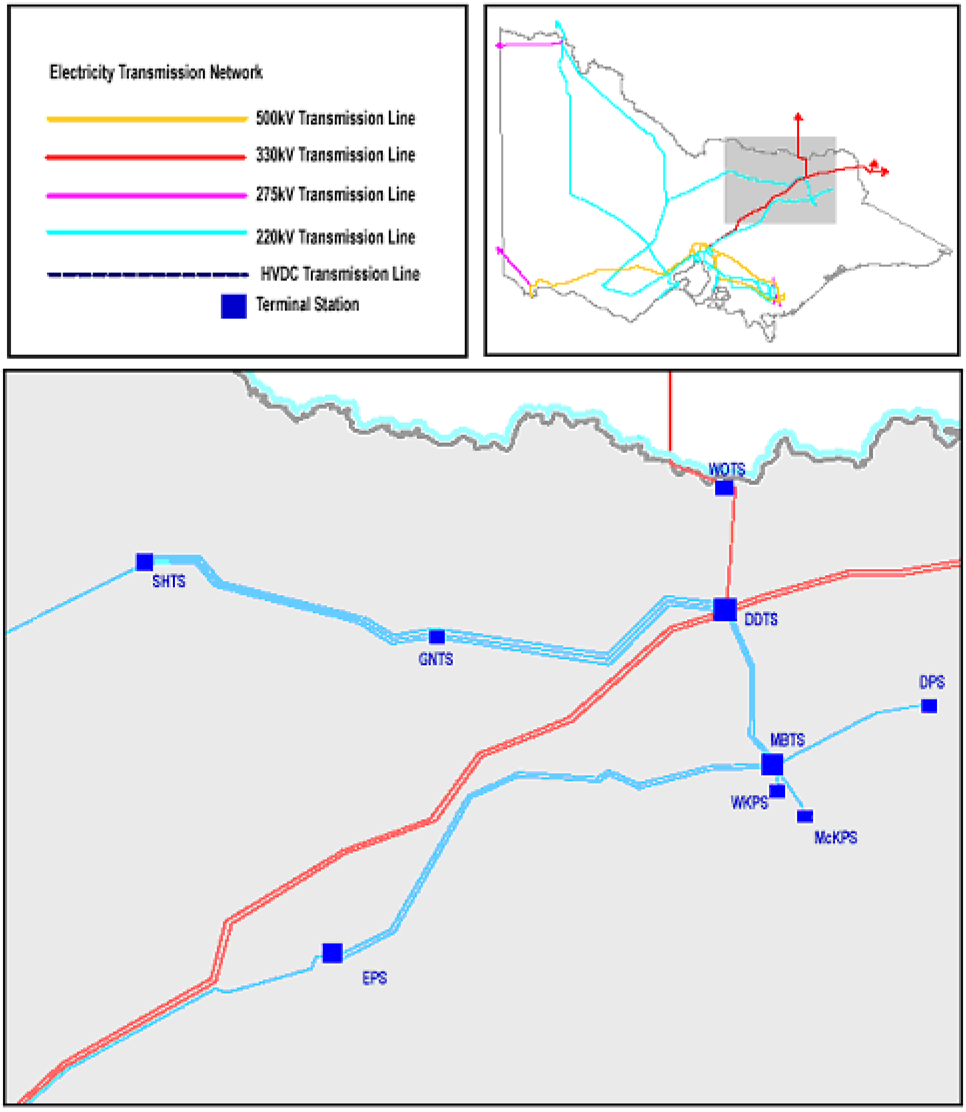

Figure 6.27 – Geographical Representation of the Dederang 330/220 kV Tie Transformers

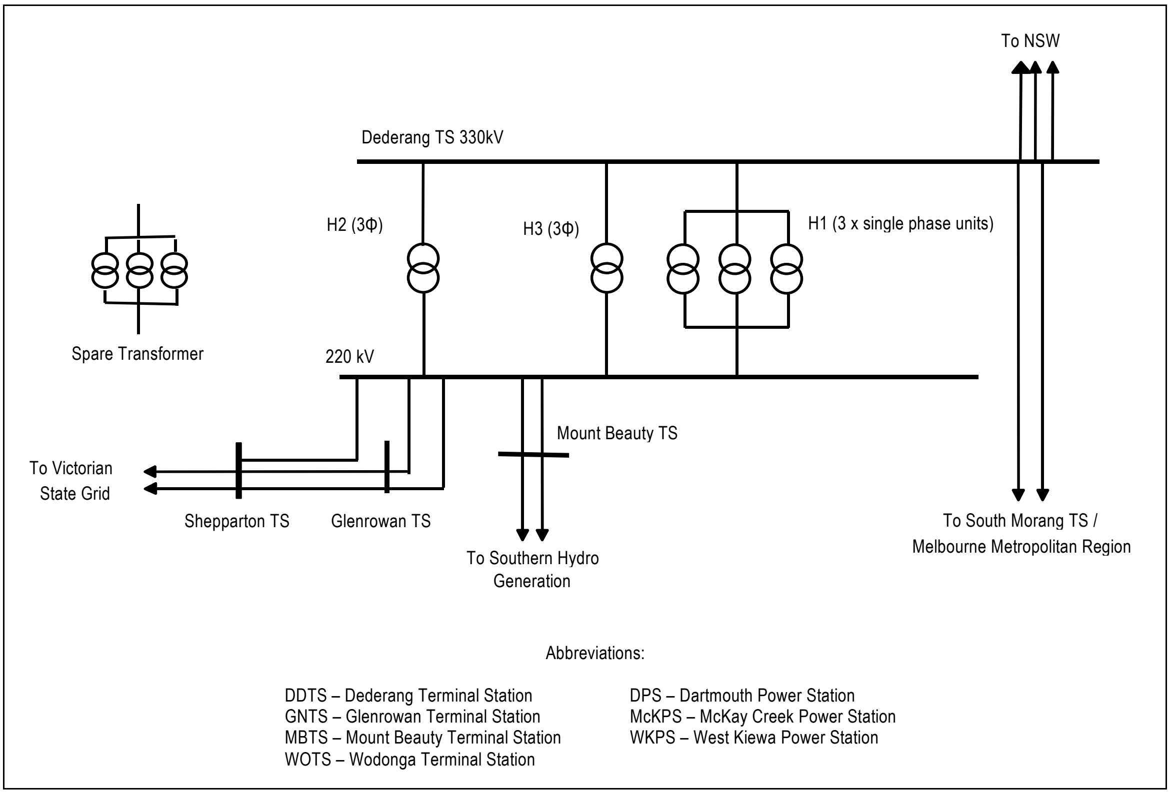

Figure 6.28 – Electrical Representation of the Dederang 330/220 kV Tie Transformers

(b) Reason for Constraint

The constraint is determined by the thermal capability of the Dederang transformers and is defined as a constraint on Victorian import into Victoria via the Snowy to Victoria interconnection. Dederang transformer loading increases with import into Victoria from Snowy and with load in the northern State Grid[36]. Southern Hydro Generation[37] reduces Dederang transformer loading. The Dederang transformer constraint can apply under system normal conditions (all transmission plant in service) or with prior outage of a Dederang transformer or Dederang to South Morang 330 kV line.

(c) Conditions of Constraint

Under system normal conditions (all Dederang transformers in service), thermal loading on the Dederang transformers can limit Victorian import with low Southern Hydro Generation. With prior outage of one of the transformers, the Dederang transformer thermal constraint can limit Victorian import under a much wider range of generation and system loading conditions.

This analysis covers the impact of the Dederang transformer thermal constraint in the absence of any upgrade to the Snowy to Victoria interconnection. Both system normal conditions and prior outage of a Dederang transformer are considered.

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36 Northern state grid load refers to Mount Beauty, Glenrowan, Shepparton and Bendigo load.

37 Southern Hydro Generation refers to Dartmouth, West Kiewa, McKay Creek, and Eildon generation.

Should there be any upgrade to the Snowy to Victoria interconnection, the system normal Dederang constraint would become more significant and most likely require a network solution as part of the interconnection upgrade works.

Table 6.39 lists thermal ratings and other relevant data of the constraining plant at Dederang.

Plant	Type / Age (years)	Continuous Rating (MVA)	Short Time Rating (MVA)
Dederang H1 330/220kV	3 x 1 phase / 45	225	315 for 20min
Dederang H2 330/220kV	1 x 3 phase / 3	340	400 for 20min
Dederang H3 330/220kV	1 x 3 phase / 28	240	400 for 20min
Spare	3 x 1 phase / 45	225	315 for 20min

Table 6.39 – Thermal ratings of Dederang transformers

The spare transformer can be used to reduce the duration of long term forced outages of any of the three in service units. However, because of its age and condition there is no intention to use this set of transformers as a permanent bank.

The long term forced outage rate for the Dederang H1 transformer is 0.077% and for each of the H2 and H3 transformers it is 0.0513%. This is on the basis that each of the three single phase transformers and two three phase transformers have failure rates of 1/150 years. The spare transformer enables long term forced outages to be kept to 2 weeks for H1 and 4 weeks for H2 or H3 transformers. Without the spare transformer, the expected long term forced outage duration would be 18 months allowing for manufacture and installation of a new replacement unit.

(d) Impacts of Constraint

All Transformers In Service

The Dederang transformer system normal constraint is defined as a constraint on Victorian import from Snowy to maintain the flow on all three Dederang transformers within continuous rating with all transformers in service[38]. Under conditions where no Southern Hydro Generation is available Victoria's import capability can at present be reduced to around 1300 MW under high demand conditions. With more than about 60% of Southern Hydro Generation dispatched, the import limit would be increased to above 1900 MW. Under these conditions, Victorian import capability is limited to around 1900 MW by other constraints not related to the Dederang transformers.

[38] The system normal and prior outage Dederang transformer constraints are based on operation of the DBUSS-transformer overload control scheme. The DBUSS scheme relieves transformer overloading by separating the Dederang 330 kV busbars when transformer overloading is detected.

Prior Transformers Outages

The Dederang transformer prior outage constraint is defined as a constraint on Victorian import from Snowy to maintain flow on the remaining two in-service transformers within continuous rating prior to any further outage. Under conditions where no Southern Hydro Generation is available Victorian import capability can be reduced to around 200 MW if one of the Dederang transformers is unavailable. With more than about 60% of Southern Hydro Generation dispatched, the import limit would be increased to around 1400 MW.

Prior Outage of a Dederang to South Morang 330kV line

With prior outage of a Dederang to South Morang 330 kV line, Victorian import from Snowy is limited to around 1200 MW in order to maintain flow on the Dederang transformers within short term rating following contingent loss of the remaining Dederang to South Morang 330 kV line. The Dederang transformer constraint is one of a number of combined constraints associated with prior outage of a South Morang to Dederang 330 kV line.

(e) Impacts on Constraint of Distribution Business Planning

Nil.

(f) Impacts on Constraint of Asset Replacement Program

The Dederang transformer constraint does not impact on works currently included in the asset replacement program.

6.19.3 Do Nothing – Expected Value of Constraint

In this analysis, the expected value of constraint is the combined cost of generation rescheduling and unserved energy associated with operating the system within the Dederang transformer constraints on Victorian import. The expected value of constraint for prior transformer outages is weighted by the probability of the prior outage, which is derived from Dederang transformer forced outage rates. It is assumed that the outage duration for each transformer is limited by use of the spare transformer. A weighting factor of one applies to system normal constraints.

Where a constraint violation exists, generation is rescheduled so as to decrease Victorian import from Snowy. For both the system normal and prior outage constraints, rescheduled generation is valued at an incremental fuel premium depending on which generators are redispatched as a consequence of the constraint. Unserved energy is equal to any residual constraint violation on Victorian import after all possible generation rescheduling.

Table 6.40 summarises the forecast impact of the Dederang transformer system normal constraint on Victorian import. The rise in expected value of constraint from 2005/06 to 2007/08 is caused by increasing demand in the Victorian State Grid. The decrease in 2008/09 is associated with service of new generation in Victoria and South Australia.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	83	87	108	112	149
Maximum single constraint	MW	623	700	772	802	714
Average constraint	MW	157	162	171	173	172
Expected rescheduled generation	MWh	4070	4078	5502	5890	7656
Expected value of rescheduling	$k	98	100	175	141	250
Expected unserved energy	MWh	0	0	2	0	0
Expected value of unserved energy	$k	0	0	59	0	0
EXPECTED VALUE OF CONSTRAINT	$k	98	100	234	141	250

Table 6.40 – Expected Value of Constraint for System Normal Conditions

Combined results for prior outage of the Dederang H2 or H3 transformer are shown in Table 6.41. Outage of the H2 or H3 transformer is the most severe as loading on the lower rated H1 transformer defines the constraint. The weighting factor for the expected quantities is equal to the combined H2 and H3 transformer forced outage rate of 0.103%.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	2062	2526	2817	3291	3605
Maximum single constraint	MW	1647	1673	1707	1712	1723
Average constraint	MW	435	452	478	489	508
Expected rescheduled generation	MWh	303	400	462	554	645
Expected value of rescheduling	$k	8	11	17	21	24
Expected unserved energy	MWh	0.1	0.5	0.6	0.6	1.1
Expected value of unserved energy	$k	2	15	18	19	31
EXPECTED VALUE OF CONSTRAINT	$k	10	26	35	39	55

Table 6.41 – Expected Value of Constraint for Dederang H2 or H3 Transformer Outage

Results for prior outage of the Dederang H1 transformer are shown in Table 6.42. The weighting factor for the expected quantities is equal to the H1 transformer forced outage rate or 0.077%.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	1571	1969	2260	2663	2947
Maximum single constraint	MW	1479	1505	1539	1544	1555
Average constraint	MW	376	388	407	417	434
Expected rescheduled generation	MWh	145	193	227	273	320
Expected value of rescheduling	$k	4	5	8	10	13
Expected unserved energy	MWh	0.0	0.2	0.3	0.3	0.5
Expected value of unserved energy	$k	1	6	8	8	15
EXPECTED VALUE OF CONSTRAINT	$k	4	11	17	19	28

Table 6.42 – Expected Value of Constraint for Dederang H1 Transformer Outage

Summated expected value of the Dederang transformer constraints associated with system normal and Dederang transformer prior outage conditions are shown in Table 6.43.

		2005/06	2006/07	2007/08	2008/09	2009/10
EXPECTED VALUE OF CONSTRAINT	$k	113	137	285	199	333

Table 6.43 – Summated Expected Value of Constraints

6.19.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solution exists to reduce or remove the constraint through the Dederang transformers:

- Installation of a fourth 330/220 kV Dederang transformer, while maintaining the existing spare, and associated fault level mitigation. Estimated capital cost: $11M, and VENCorp considers this to be a contestable augmentation.

(b) Non-Network Options Considered

Generation or DSM or in the northern State Grid area would alleviate the Dederang transformer constraint on Victorian import by around 3 MW for every 1 MW of generation or DSM. No new generation is presently committed for installation in this area.

6.19.5 Economic Evaluation

(a) Benefit of Network Option

Installation of a fourth 330/220 kV Dederang transformer would eliminate the system normal constraint in the medium term. A new prior outage constraint would emerge corresponding to the present system normal constraint. The expected value of this constraint would be negligible in the medium term when weighted by the combined transformer forced outage rate. The benefit of this option in relation to the system normal and prior Dederang transformer outage constraints is therefore equal to the summated expected value of constraint shown in Table 6.43.

An additional benefit of a fourth 330/220 kV Dederang transformer would be a reduction in the value of combined constraints associated with prior outage of a South Morang to Dederang 330 kV line. Total benefits of this option are shown in Table 6.44.

	2005/06	2006/07	2007/08	2008/09	2009/10
Expected Value of System Normal and Dederang Transformer Prior Outage Constraints	113	137	285	199	333
Reduction in Expected Value of South Morang to Dederang Prior Outage Constraint	36	38	47	49	48
TOTAL BENEFITS OF THE 4TH DEDERANG TRANSFORMER	149	175	333	248	381

Table 6.44 – Total Benefits of 4th Dederang Transformer ($k)

The economic benefit of a fourth 330/220 kV Dederang transformer is assessed against the "do nothing" option.

(b) Summary of Net Benefits and Present Values Going Forward

A net market benefit assessment is carried out for a five year period for installation of a fourth 330/220 kV Dederang transformer using a discount rate of 8%. Residual value for a further 40 years is calculated assuming costs and benefits as calculated for 2009/10. Results are summarised in Figure 6.45.

		Present Value ($k)	Annualised Value ($k) 2005/06	2006/07	2007/08	2008/09	2009/10	Residual Value ($k)
Do Nothing		-4,083	-149	-175	-333	-248	-381	-4,903
OPTION 1 (4th 330/220kV Transformer at Dederang)	Market Benefits		149	175	333	248	381	4,903
	Costs		-908	-908	-908	-908	-908	-11,700
	Net Market Benefits		-759	-733	-575	-660	-527	-6,797

Table 6.45 – Net Market Benefits of Network Options

(c) Timing of Option

Analysis indicates that a fourth 330/220 kV Dederang transformer would yield negative benefits if installed within the next 5 years and would therefore not be justified until after 2009/10. Based on forecast load growth, the transformer may be justified soon after 2009/10. However, optimal timing is dependent on a number of factors including:

- Availability of Victorian hydro generation.
- Load levels in northern Victoria.
- Extent of the requirement for import into Victoria over the Snowy to Victoria interconnection.

Variation in any of the above listed factors could influence the level of unserved energy and bring forward the need for a fourth transformer.

(d) Material Inter-Network Impact

Installation of a fourth 330/220 kV transformer at Dederang would significantly increase power transfer capability over the Snowy to Victoria interconnection under conditions of low Victorian hydro generation. This increase in power transfer capability would form a major part of the justification for the augmentation passing the regulatory test. Installation of a fourth Dederang transformer is considered to have a material inter-network impact on the basis of increased transfer capability.

6.19.6 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Dederang 330/220 kV tie transformer constraint can be managed until 2009/10.

VENCorp considers the next most likely augmentation would be installation of a fourth 330/220 kV transformer at Dederang. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.20 Loading of Eildon to Thomastown 220 kV Line

6.20.1 Overview

Loading of the Eildon to Thomastown 220 kV line presents a thermal constraint that can arise after an outage of either of the Dederang to South Morang 330 kV lines. The constraint will typically only occur during high import conditions from Snowy/NSW coincident with high Kiewa area and Eildon generation. The effect of the constraint is a reduction in the import level from Snowy/NSW and load shedding in metropolitan Melbourne.

Since the 2004 Annual Planning Report, there have been no material changes regarding the evaluation of this constraint.

This year's assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The Eildon to Thomastown constraint can be managed until 2008/09. VENCorp considers the next most likely augmentation would be the installation of a wind monitoring scheme on the Eildon to Thomastown line. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.20.2 Introduction

(a) Location of Constraint

The constraint is located between Eildon and Thomastown terminal stations. Geographical and electrical representations of the constraint are given in Figures 6.29 and 6.30 respectively.

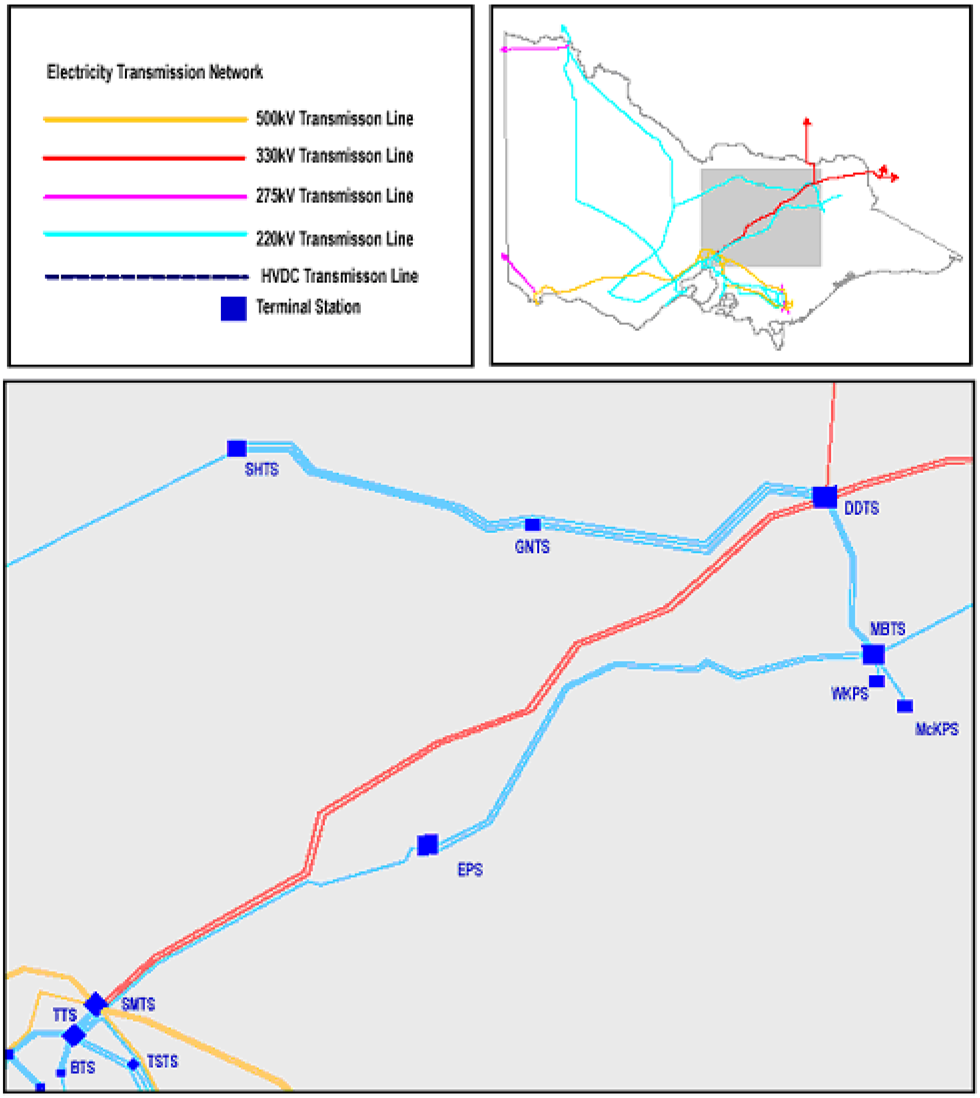

Figure 6.29 – Geographical Representation of the Eildon to Thomastown 220 kV Line

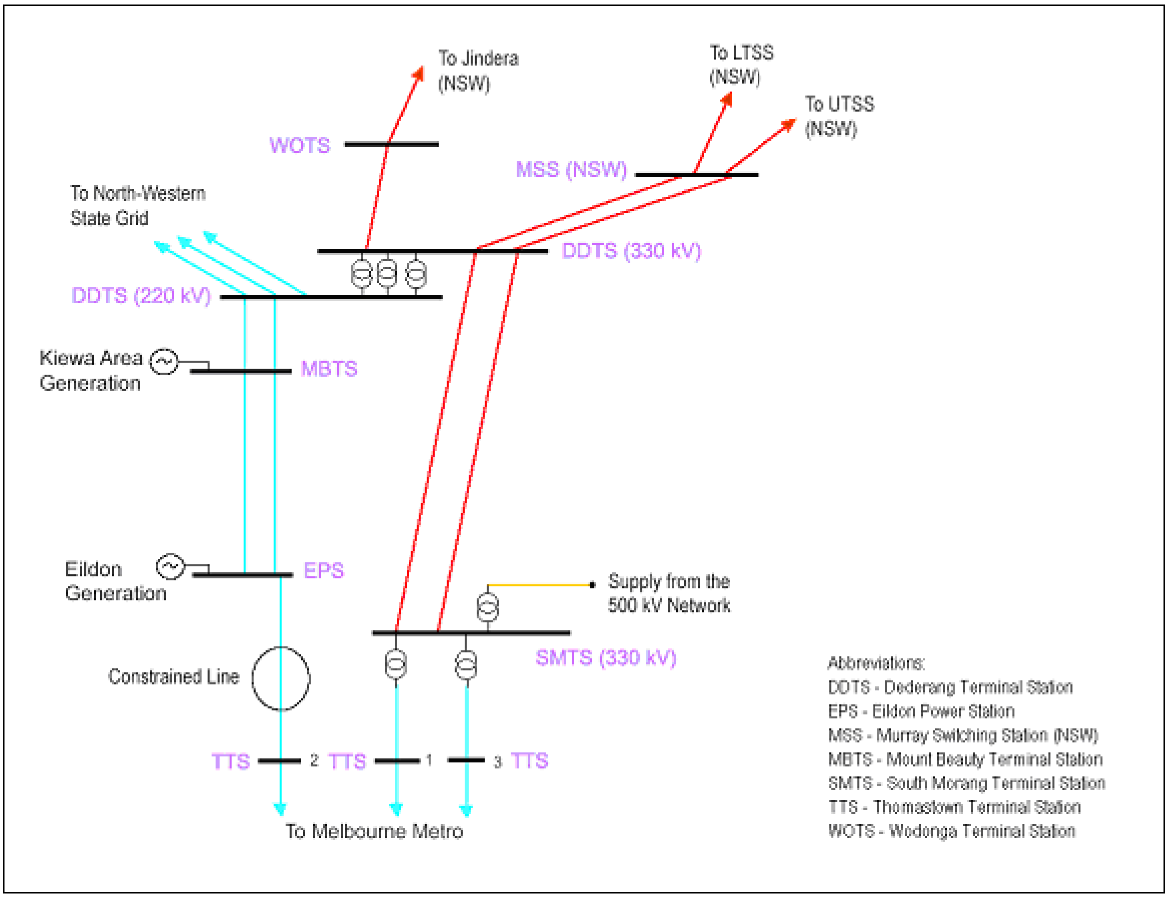

Figure 6.30 – Electrical Representation of the Eildon to Thomastown 220 kV Line

(b) Reason for Constraint

The constraint exists because the Eildon to Thomastown line forms part of the Victoria to Snowy interconnection as well as connecting Eildon and Kiewa area generation to Melbourne load. The basis of the constraint is potential loading on the Eildon to Thomastown line beyond its thermal capability. The constraint impacts on flow in both directions over the Victoria to Snowy interconnection. The constraint applies with prior outage of a Dederang to South Morang line and is based on securing the system for forced outage (i.e. contingent loss) of the remaining South Morang to Dederang line.

The Eildon to Thomastown constraint is one of several overlapping constraints with prior outage of a Dederang to South Morang line. The following considerations define the additional overlapping constraints on Victorian import:

- Thermal loading on the Shepparton – Fosterville – Bendigo 220 kV line
- Thermal loading on the DDTS 330/220 kV transformers
- Thermal loading on the Mount Beauty – Eildon 220 kV lines
- Voltage collapse in the Victorian State Grid
- Transient stability

The following considerations define additional overlapping constraints on Victorian export:

- Transient stability
- Thermal loading on the Ballarat – Bendigo 220 kV line

Under high Victorian demand conditions, the critical contingency for Victorian export can become loss of a Hazelwood to South Morang 500 kV line. Transient stability considerations then define the Victorian export limit.

(c) Conditions of Constraint

The continuous thermal rating of the Eildon to Thomastown line at 40^{o}C ambient temperature is 459 MVA. Higher short term ratings are available depending on the timing and extent of action to reduce post contingent loading. Post contingent power flow on the Eildon to Thomastown line can approach thermal capability from Eildon to Thomastown with high import over Snowy/New South Wales at high ambient temperature. Principal system loading factors influencing the constraint are as follows:

- Victorian State Grid load and Murraylink transfer to South Australia.

  Increasing northern State Grid load and Murraylink transfer to South Australia alleviates the constraint by diverts power into the Victorian State Grid via Glenrowan and Shepparton and away from the Eildon to Thomastown line. This results in a higher Victorian import limit as defined by Eildon to Thomastown line loading.

- Kiewa area and Eildon generation.

  Increasing Kiewa and Eildon generation exacerbates the constraint by increasing southward flow on the Eildon to Thomastown line. This results in a lower Victorian import limit as defined by Eildon to Thomastown line loading.

Under Victorian export to Snowy/New South Wales, power flow is from Thomastown to Eildon. The impact of the above system loading factors is reversed as compared to the import case.

(d) Impacts of Constraint

With prior outage of a South Morang to Dederang line, the Eildon to Thomastown constraint restricts Victorian import from Snowy to around 1,200 MW in combination with the other constraints described above.

At the present stage of system development, the Eildon to Thomastown constraint has no impact under system normal conditions (i.e. all transmission plant in service prior to any contingency). However, the Eildon to Thomastown constraint would need to be addressed as part of any Victoria to Snowy interconnection upgrade to beyond around 2080 MW Victorian import capability.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

Works to alleviate the Eildon to Thomastown constraint with prior outage of a South Morang to Dederang line are expected to have only an incremental impact on transfer capability. Such works are therefore unlikely to have a material inter-network impact.

Works to alleviate the system normal Eildon to Thomastown constraint are expected to form part of a future interconnection upgrade. These works are likely to be justified on the basis of increased transfer capability and so are expected to have a material inter-network impact.

6.20.3 Do Nothing – Expected Value of Constraint

All Transmission Plant In Service

The system normal Eildon to Thomastown constraint would be analysed as part of any future proposal to increase capacity of the Victorian to Snowy/New South Wales interconnection.

Prior Outage of a Dederang to South Morang 330kV Line

The expected value of the Eildon to Thomastown constraint is determined in combination with the other constraints described in section 6.20.2(b) above. Table 6.46 summarises the forecast impact of the combined prior outage constraint on Victorian import with no augmentation works (i.e. “do nothing” scenario). The rise in the expected value of constraint from 2005/06 to 2007/08 is caused by increasing Victorian and South Australian demand. The decrease from 2008/09 is associated with service of new generation in Victoria and South Australia. Note that the “do nothing” scenario does include wind monitoring on the Shepparton – Fosterville – Bendigo 220kV from 2006/07 (refer Section 6.16).

Where a constraint violation exists, generation is rescheduled so as to decrease Victorian import from Snowy. Rescheduled generation is valued at an incremental fuel premium depending on which generators are redispatched as a consequence of the constraint. Unserved energy is equal to any residual constraint violation on Victorian import after all possible generation rescheduling.

		2005/06	2006/07	2007/08	2008/09	2009/10
Average annual hours of constraint	Hours	1228	1571	1800	2129	2244
Maximum single constraint	MW	804	969	1002	947	940
Average constraint	MW	330	348	353	354	364
Expected rescheduled generation	MWh	3129	4213	4898	5811	6305
Expected value of rescheduling	$k	81	105	189	220	208
Expected unserved energy	MWh	2.5	11.0	9.3	7.9	7.9
Expected value of unserved energy	$k	74	326	276	235	232
EXPECTED VALUE OF CONSTRAINT	$k	155	432	464	455	441

Table 6.46 – Expected Value of Combined Constraints on Victorian Import for Prior Outage of a Dederang to South Morang Line

Table 6.47 summarises the forecast impact of the combined prior outage constraint on Victorian export with no augmentation works (i.e. “do nothing” scenario).

		2005/06	2006/07	2007/08	2008/09	2009/10
EXPECTED VALUE OF CONSTRAINT	$k	153	137	132	108	100

Table 6.47 – Expected Value of Constraint on Victorian Import for Prior Outage of a Dederang to South Morang Line

The reduction in the expected value of constraint from 2005/06 to 2009/10 is caused by increasing Victorian and South Australian demand.

6.20.4 Options and Costs for Removal of Constraint

(a) Network Options Considered

Two network solutions have been identified to alleviate the Eildon to Thomastown constraint. Each provides a potential increase in line rating of approximately 18% at 40°C ambient temperature. With prior outage of a South Morang to Dederang line, this would alleviate the Eildon to Thomastown constraint on Victorian import by up to 140 MW. However, this benefit is subject to alleviation of the other overlapping constraints listed in section 6.20.2(b). These options would also increase the system normal Eildon to Thomastown constraint and could form part of an augmentation of the Victoria to Snowy/New South Wales interconnection of up to 600 MW.

Option 1 - Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used by installing wind monitoring facilities on the Eildon to Thomastown line. On high ambient temperature days the wind speed is typically higher than 0.6 m/s. A typical wind speed of 1.2 m/s would provide an increase in line capacity of approximately 80 MVA at 40°C ambient temperature. Overall Eildon to Thomastown circuit rating is presently limited to 1500 A by secondary systems at Thomastown. Works would include uprating of secondary systems at Thomastown to 1800 A to provide additional capacity below 40°C. Total estimated cost of Option 1 is $430k.

Prior to implementing this scheme, a wind survey along the Eildon to Thomastown line easement needs to be carried out to enable full assessment of probable wind speed.

Option 2 - Increasing the Capacity of the Eildon to Thomastown Line

The Eildon to Thomastown line is presently rated for operation at up to 65°C conductor temperature. Re-tensioning the conductors and/or raising towers would provide a higher maximum conductor temperature and associated line rating. Uprating the line to 73°C operation would increase capacity by approximately 80 MVA at 40°C ambient temperature at a cost of around $2.4M.

At this point in time VENCorp considers these options to be non-contestable augmentations.

6.20.5 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

The Eildon to Thomastown constraint can be managed until 2008/09.

VENCorp considers the next most likely augmentation would be the installation of a wind monitoring scheme on the Eildon to Thomastown line. However, the timing of this and other feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.21 Additional Reactive Power Support

6.21.1 Overview

There are a number of outages that significantly increase the reactive transmission losses in Victoria. Most critical are outages of large generators in Victoria or the loss of critical 500 kV and 330 kV lines.

In order to maintain an acceptable voltage profile and sufficient voltage stability after a critical outage, a system normal constraint is applied to the total Victorian demand.

The constraint typically only occurs during very high demand conditions in Victoria coincident with high import from Snowy/NSW. The effect of the constraint is load shedding in Victoria.

Since the 2004 Annual Planning Report, there have been a number of projects that influence the as the maximum Victorian supportable demand, as constrained by voltage stability. They are:

- the shunt capacitor banks installed in the State Grid area for the conversion of Murraylink to regulated status;
- the 500 kV Latrobe Valley to Melbourne upgrade project; and
- the Laverton North generation plant;

which are all targeted for service by summer 2005/06.

This year's assessment has identified that the maximum Victorian supportable demand, as constrained by voltage stability, exceeds the forecast demand in 2008/09. However, during summer 2009/10 and beyond there may be constraints. There are no network options that technically and economically alleviate the forecast constraint at this time. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

6.21.2 Introduction

(a) Location Of Constraint

With increased load growth, adequate reactive power support at appropriate locations in the Victorian transmission network is required to maintain an acceptable voltage profile and voltage stability. Reactive power constraint locations that can impact on Victorian transmission adequacy are the Melbourne metropolitan area, Victorian State Grid and Southern NSW. Figure 6.31 shows the map of the Victorian Transmission Network.

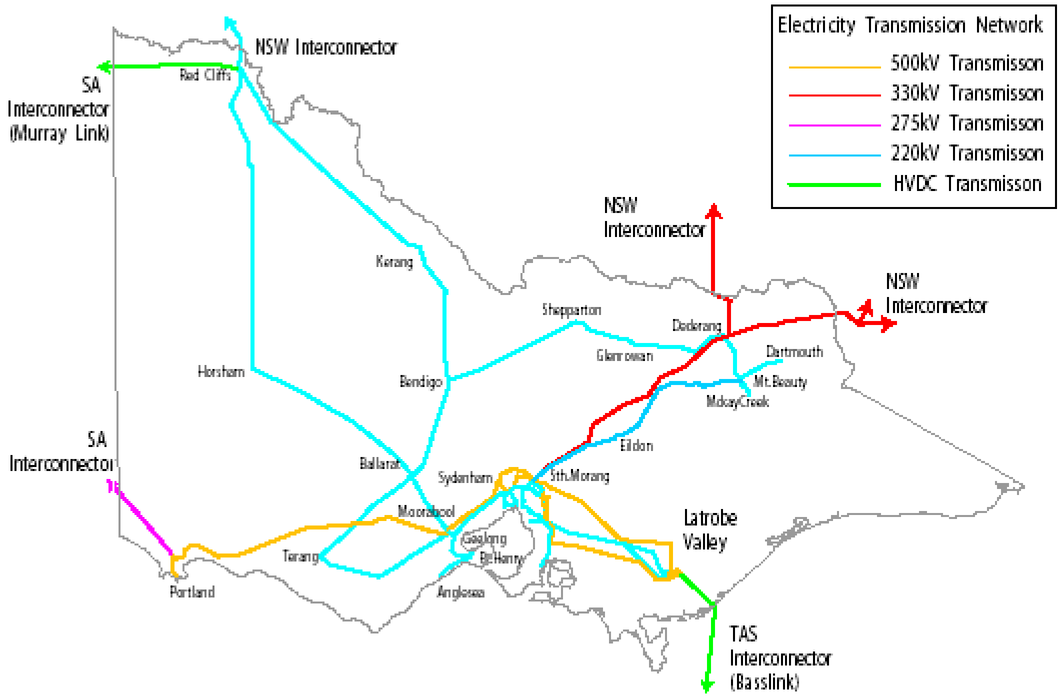

Figure 6.31 – Map of the Victorian Transmission Network

(b) Reason for Constraint

The reactive demand on the transmission network generally increases each year due to increasing load growth, and increased network reactive losses from transferring increased power from generators to load centres. The increased reactive load growth during high ambient temperature summer days is mainly due to an increased proportion of air conditioning load.

Schedule 5.1 of National Electricity Code requires that for a given demand level, voltage magnitudes at all energised busbars of the power system should be within the acceptable levels, and the voltage stability of the power system must be maintained following the most severe credible contingency. This range of conditions can only be achieved by providing sufficient reactive power at appropriate locations. The consequence of not maintaining voltage stability is a potential partial or total system wide voltage collapse resulting in loss of load.

(c) Conditions of Constraint

The critical contingences, which increase the reactive demand significantly, are outages of:

- the 500 MW generator at Newport;
- a Loy Yang generator;
- Basslink, while importing 500-600 MW from Tasmania;
- a 500 kV line from Latrobe Valley to Melbourne;
- a Murray to Dederang 330 kV line;
- a Dederang to South Morang 330 kV line;
- the Moorabool transformer; or
- a 220 kV line in northwest Victoria.

It is assumed that the minimum reactive output of all existing generators meets the capability requirements specified in the National Electricity Code unless otherwise agreed with relevant generating companies. The reactive output of all generators and the system voltage profile are optimised (within the technical constraints) to maximise the overall capability of the network.

A significant factor impacting on import of power from NSW to Victoria is the availability of reactive support in Southern NSW region. It is likely southern NSW can also experience high summer load during high summer demand periods in Victoria. Under such conditions, high import levels from NSW would increase the reactive power requirement in southern NSW. The following conditions would increase the reactive power losses in southern NSW and northern Victoria:

- Outage of a generator in Victoria – (after which, it is likely that additional power is transferred from NSW/Snowy to Victoria, prior to action taken to operate the system in a secure operating state); or
- Outage of a transmission line in Southern NSW.

In order to maintain 1900 MW import from NSW at times of high summer demand periods in Victoria and Southern NSW, adequate capacitor banks have been installed in the Victorian State Grid, however additional reactive support may be needed in southern NSW.

(d) Impacts of Constraint

If adequate reactive support to the network is not provided, critical contingencies at times of summer peak demand period can result in loss of partial or in the extreme case, full system load through voltage collapse.

To allow for the worst credible contingency to occur and to maintain system security, action needs to be taken prior to a contingency. To achieve this, one or more of the following actions can be taken to reduce the impacts of constraint:

- Rescheduling of generation (this may involve in reduction of import from NSW/Snowy and/or reduction in export to South Australia); or
- Load shedding in Victoria (other than in Latrobe Valley area).

(e) Impact on Constraint of Distribution Business Planning

The power factor assumed in the analysis at the point of connection is based on the data provided by Distribution Businesses and customers directly connected with the transmission system. Power factor at transmission points of connection can be improved by Distribution Businesses by:

- installation of capacitor banks at distribution level; and/or
- installation of additional transformers at connection points.

These actions would increase network reactive capability and reduce the amount of additional reactive support at transmission level.

(f) Impact on Asset Replacement Program

Nil.

6.21.3 Do Nothing – Expected Value of Constraint

The forecast maximum supportable demand with all Victorian plant in service, 1900 MW import from NSW, 600 MW import from Basslink and 300 MW export to South Australia is 10,580 MW. This is based on the existing transmission network configuration, existing and committed generation levels and with no additional capacitor banks.

Market modelling studies have been undertaken to quantify the exposure of constraint energy. Where a constraint violation exists, generation is rescheduled prior to assessment of the load at risk in Victoria. Table 6.48 summarises the value of expected constrained energy and energy at risk. This assessment does not include the benefits of the proposed 2nd 500/220 kV transformer at Rowville.

In the market model, 10% probability of exceedence forecast demand is reduced by demand side participation and/or new additional generation in order to maintain the supply/demand balance from 2007/08 onwards. Reactive capability assessment is based on these new generators located in Latrobe Valley. This is the worst case. If some or all of these new generators were to be installed in the Melbourne metropolitan and/or Vic State Grid area, the constraint shown for 2009/10 would be reduced significantly.

		2005/06	2006/07	2007/08	2008/09	2009/10
System normal – to allow for a worst credible contingency						
Annual hours of constraint	Hours	0	0	0	0	2
Maximum single constraint	MW	0	0	0	0	137
Expected rescheduled generation	MWh	0	0	0	0	162
Expected unserved energy	MWh	0	0	0	0	9.7
Prior outage of a critical plant – to allow for a worst credible contingency						
Annual hours of constraint	Hours	0	0.5	3	3	10
Maximum single constraint	MW	0	25	125	135	535
Expected rescheduled generation	MWh	0	0	19	3	95
Expected unserved energy	MWh	0	0	0.2	1.6	42
Expected total constraint energy						
Expected value of rescheduled generation	$k	0	0	0.95	0.15	12.8
Expected value of unserved energy	$k	0	0	6.3	47.7	1,524
EXPECTED VALUE OF CONSTRAINT	$k	0	0	7.3	48	1,537

Table 6.48 – Expected Value of Constraint

6.21.4 Options and Costs for Removal of Constraint

The following network solutions can increase the network reactive capability:

- Improvement of power factor

  Installation of shunt and/or series capacitors at transmission level. Indicative cost for a 200 MVAr 220 kV shunt capacitor bank is $3M, with an equivalent annual cost of $270k.

  Space availability in existing terminal stations is becoming an issue when considering the placement of new shunt capacitor banks. This has the potential to increase the cost of capacitors at high voltage levels.

  Furthermore, shunt capacitors produce a harmonic resonance, the frequency of which must be controlled by designing an appropriate series reactor with each capacitor bank. Harmonic interaction between adjacent capacitor banks also becoming and increasing planning issue. The issue of harmonic resonance is also tending to increase the reactive augmentation costs, as larger series reactors are needed.

- Reduction in reactive losses

  Additional new transmission lines and/or new transformers would reduce reactive losses. Each of the 500/220 kV transformer at Rowville and at Moorabool as planned for 07/08 and 08/09 would decrease the reactive power losses by about 150-200 MVAr

- Under-voltage load shedding scheme – this can reduce the network reactive requirement before a contingency but will not avoid load shedding following a contingency. In addition, feasibility to maintain the voltage stability following non-credible events requires investigation.

Additional reactive support may be required, if additional new generation is added in the Latrobe Valley and/or import level is increased from NSW. The required level of reactive support and location needs to be assessed as part of these generation capacity increase works. At this point in time VENCorp considers provision of reactive support to be a contestable augmentation.

The following non-network solutions can also increase the networks reactive capability.

- New generators in the Metropolitan and/or State Grid areas – reduces the reactive losses & provides reactive support; and
- Demand side management – reduces the system demand, hence less requirement for additional reactive support.

6.21.5 Economic Evaluation

Economic analysis is carried out for installation of a 220 kV 200 MVAr shunt capacitor bank at a Melbourne metropolitan terminal station and results are presented in Table 6.49. Based on these results, no additional reactive support that can be economically justified until the end of summer 2008/09.

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2005/06	2006/07	2007/08	2008/09	2009/10	
Do Nothing		-12,253	0	0	-7	-48	-1,537	-17,720
OPTION 1 (200 MVAr 200 kV Shunt Capacitor)	Market Benefits		0	0	7	48	519	5,983
	Costs		-266	-266	-266	-266	-266	-3,072
	Net Market Benefits		-266	-266	-259	-218	253	2,911

Table 6.49 – Net Market Benefits of Additional Reactive Support

6.21.6 Conclusions

This assessment has identified no network options that technically and economically alleviate the forecast constraint at this time.

This year's assessment has identified that the maximum Victorian supportable demand, as constrained by voltage stability, exceeds the forecast demand in 2008/09. However, during summer 2009/10 and beyond there may be constraints.

VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2006 Annual Planning Report.

7. POSSIBLE INTRA-REGIONAL NETWORK DEVELOPMENTS WITHIN 10 YEARS

7.1 Introduction

This chapter provides an indication of potential network constraints that may occur in the ten year period up to 2014/15, together with transmission options to remove the constraints, assuming the full forecast Victorian demand is to be supported.

For this study the transmission network has been modelled with a demand of 12,600[39] MW. To meet this demand and to allow for up to 300 MW export to South Australia, approximately 2,100 MW of additional new generation will be required in Victoria by 2014/15. Table 7.1 provides the supply-demand balance used for the ten year plan, which sets out the level of existing and committed generation, import & export levels, Victorian demand and the reserve levels used to determine the requirement for additional new generation.

Demand	Victorian maximum demand (10% POE)	12,600
	Export to South Australia	300
	Victorian Reserve level	265
	Total demand plus reserve level	13,165
Supply[40]	Anglesea	158
	Bairnsdale	70
	Energy Brix Complex	139
	Hazelwood	1,650
	Hume (Vic)	58
	Jeeralang	416
	Laverton North GT	312
	Loy Yang A	2,050
	Loy Yang B	1,000
	Newport	475
	Somerton GT	123
	Southern Hydro	483
	Valley Power	252
	Yallourn	1420
	Import from NSW	1,900[41]
	Import from Tasmania	600
	Total Supply	11,106
Amount of additional new generation needed		2059 (~2100)

Table 7.1 – Supply and Demand Balance for 2014/15

39 This demand is based on the forecasts presented in the Electricity Annual Planning Review 2004.

40 Generation capacities for the year 2013/14, are based on NEMMCO's 2004 SOO.

41 The availability of this level of import is subject to works being undertaken in Southern NSW.

As the location and size of generation will impact on the augmentations required on the transmission network, a range of supply scenarios, which load different parts of the transmission network, have been examined. These are as shown in Table 7.2.

	Increased Latrobe Valley Generation (MW)	Increased Import from Snowy/NSW (MW)	Metro/State Grid Generation/DSM (MW)	Total Additional Supply (MW)
Scenario 1	1,800	0	300	2,100
Scenario 2	1,320	180	600	2,100
Scenario 3	720	180	1,200	2,100
Scenario 4	900	600	600	2,100
Scenario 5	200	1,600	300	2,100

Table 7.2 – Supply Scenarios for the Ten Year Plan

These scenarios were selected because together they provide a good representation of the many plausible scenarios for the development of the transmission network. However, a range of other scenarios are possible, and they are likely to result in different transmission requirements. In particular, for import levels from Snowy/NSW beyond 3,500[42] MW, significant additional augmentation may be required, possibly in the form of HVDC links. The Latrobe Valley to Melbourne transfer capability designed for scenario 1 will accommodate at least an additional 1000 MW of generation from the Latrobe Valley.

In considering this ten year period, the network constraints and solutions outlined for the 5 year period up to 2009/10, as described in Chapter 6, are included. For the constraints in the second half of the ten year period, a probabilistic analysis of the amount of energy at risk due to these network constraints has not been undertaken so the timing of any possible augmentation works is only indicative and would be confirmed by full economic assessment at an appropriate time in the future.

7.2 Increased Latrobe Valley Generation

Latrobe Valley generation increases by 200 MW to 1800 MW depending on the scenario, in addition to the 600 MW from Basslink. If Basslink is not available, it is assumed that 600 MW of alternative generation is available from the Latrobe Valley. It is also assumed that all additional Latrobe Valley generation is connected to the 500kV transmission network and transmitted to Melbourne via the 500 kV transmission lines. However, if this was not the case and some generation is connected at 220kV, additional 500/220 kV transformation capacity would be required in the Latrobe Valley.

7.3 Metropolitan/State Grid Generation and/or Demand Side Management

The effect of generation or significant demand side management within the metropolitan and State Grid areas is modelled by including new generation on the 220 kV network at Moorabool, Keilor, and

[42] Scenario 5 has a total import capability of 3,500 MW from Snowy/NSW (i.e. 1,900 MW existing plus 1,600 MW additional)

Rowville areas. The actual timing and location of any new embedded generation or large scale demand side management may have a significant impact on the timing and nature of any transmission augmentations. The locations selected are representative of possible locations, and should provide an indication of the effects of this new generation. The scenarios include a range of options from 300 MW to 1,200 MW.

7.4 Increased Import from Snowy/NSW

The import level considered is in addition to the current import level of 1,900 MW from Snowy/NSW. Joint planning between VENCorp and TransGrid has identified an initial outline of works required to increase the import capability into the Victorian/SA region to 2,080 MW, 2,500 MW and 3,500 MW, and these works form the basis of the 180 MW, 600 MW and 1,600 MW increases in import limits applied in the scenario studies.

7.5 Summary of Results

A summary of the impact of the different supply scenarios and of the major projects arising from transmission constraints over the next ten years is given below:

a) In scenarios with high levels of new generation added in the Latrobe Valley, the existing 500 kV lines (after completion of the 4th 500 kV Latrobe Valley to Melbourne line – described in section 2.2) may not provide sufficient power transfer capability into the metropolitan area. The existing limitations of the terminating plant at the Hazelwood terminal station need to be upgraded when the amount of new generation in the Latrobe Valley connected at 500 kV exceeds about 500 MW. With increased generation in the Latrobe Valley, the upgraded capacity may not be sufficient towards the end of the ten year period.

b) If significant additional generation is connected at Loy Yang 500 kV switchyard, the existing capacity between Loy Yang and Hazelwood would become a constraint, and an additional 500 kV circuit between Loy Yang and Hazelwood may be required. The existing easements for this line do not have space to accommodate another circuit, hence widening of the existing easement or a new easement would be required.

c) The capacity of the existing 500/220 kV and 330/220 kV transformation in the Melbourne metropolitan area will become a constraint on delivery of increased power from the Latrobe Valley into the metropolitan 220 kV network. An additional metropolitan 1,000 MVA 500/220 kV transformer is planned for 2007/08 and a second transformer would be required towards the end of the ten-year period. The location of any new 500/220 kV transformation would be sited to maximise the benefits and minimise the costs, having regard to the impact on fault levels, thermal loading of existing assets and the reliability of supply.

d) In the scenarios where additional capacity is obtained from Snowy/NSW, enhancement of the existing interconnection would be required. All the scenarios considered here assume either no increase at all in the Snowy to Victoria interconnection capability beyond the existing committed level of 1,900 MW, or an upgrade, which would provide 180 MW, 600 MW and 1,600 MW of additional interconnection capability. The 1,600 MW upgrade would require significant capital works, including augmentation of the transformation tying the 330 kV lines from Snowy/NSW with the Victorian 500 kV and 220 kV networks, additional 330 kV lines between Dederang and South Morang, and Dederang and Wagga, series compensation of several existing lines, additional shunt reactive plant, and some line upgrading works in New South Wales. Any works required in NSW have not been costed or included in the summary of works.

e) New generation developments and transmission network augmentations will generally result in higher fault levels across the transmission system. Management of fault levels is already a critical issue at a number of locations within the Melbourne metropolitan area, and a combination of circuit breaker replacement (to permit operation at higher fault levels), installation of series reactor and operational measures such as segregation of the transmission network to limit fault current in feed, are likely to continue over the next ten years. The appropriate balance between containing the fault level and allowing the fault level to increase will require ongoing investigation, and this work will consider SP AusNet's plans for circuit breaker replacement. The issue of fault levels will be particularly impacted by higher levels of generation connected at 220 kV and lower voltage levels, and a higher cost is assigned for the higher embedded generation scenarios. To address the long term fault level issues, a strategic fault level review is underway, details of which are summarised in Section 4.7.

f) Some uprating and/or re-configuration of the 220 kV transmission circuits within the Melbourne metropolitan area is likely to be required, particularly affecting lines between and around Thomastown and Rowville, both to provide for increased power transfer capacity across the metropolitan area, and to manage the loading of critical radial systems such as Springvale and Heatherton.

g) Augmentation of the 500/220 kV transformation at Moorabool is currently related more to local issues around Moorabool and Keilor following loss of this transformer, than to system wide 220 kV supply issues. However, over time, augmentation of the transformation at Moorabool also becomes more important from a system wide perspective.

h) Some reinforcement of the supply to the State Grid will be required. Augmentation of the transformation at Moorabool and Dederang, and the 220 kV lines supplying, and forming part of, the State Grid is shown to be necessary during this period. The location of any new generation is particularly important here, as significant levels of generation at or near Moorabool or Geelong can defer or remove the need for transformer augmentation at Moorabool. Scenarios involving a substantial increase in import capability are likely to advance augmentation of Dederang transformation.

i) The increased reactive support required in all scenarios is due to load growth, to compensate for increased reactive losses and to maintain system voltage stability.

j) In scenarios 4 and 5, which assume increase in interconnector capability, the supply into the 220 kV network is augmented with 330/220 kV transformation. Scenario 5 also requires the construction of new 330 kV transmission lines in Victoria and NSW, and associated series compensation. This accounts for a large portion of the increased costs associated with these options, compared to scenarios where a large portion of the supply comes from the Latrobe Valley.

k) The different balance between embedded generation, Latrobe Valley generation and increased import from NSW/Snowy under the different scenarios would have a significant impact on the level of energy at risk if the augmentation were not to proceed, and hence the timing for many of these projects would be different between the scenarios.

Table 7.4, provides a summary of the works required to remove transmission constraints emerging over the next ten year period for each of the five supply scenarios. Table 7.5 indicates the estimated capital cost for network solutions over the 1-5 year and 6-10 year periods. The capital cost in the first 5 years is similar because there is little difference in the augmentation requirements across the 5 scenarios in this time period. This is because there is more certainty on the generation scenarios in this period.

The capital cost for network solutions in the 6-10 year period varies more significantly across the scenarios. The scenarios that rely on transporting the bulk of the additional generation from a specific location such as the Latrobe Valley (scenario 1) or NSW (scenario 5) require more investment in transmission capacity and therefore involve higher capital costs. Those scenarios that have a high level of embedded generation (scenario 3) or rely on moderate increases in generation from the Latrobe Valley and NSW reduce the amount of new transmission needed and therefore have a lower capital cost.

Constraint	Network Solution	Project Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Latrobe Valley to Melbourne 500 kV transmission for outage of a 500 kV line.	4th 500 kV Latrobe Valley to Melbourne line upgrade project and associated work for installation of the 500/220 kV 1000 MVA transformer at Cranbourne	75	Summer 2005/06					Project in progress
Murraylink regulation project – Voltage collapse and thermal limits in the State Grid area during peak periods	7 new shunt capacitor banks (290 MVAr) in the State Grid area, modify existing 5 shunt capacitor banks and a control scheme to provide very fast runback on Murraylink for transmission outages		Summer 2005/06					Project in progress
Rowville-Springvale circuit overload for outage of parallel circuit.	Replace circuit breakers, isolators and line terminations at Rowville and Springvale		Summer 2005/06					Project in progress
Ballarat to Moorabool circuit overload for outage of parallel Ballarat to Moorabool circuit at high load.	Wind monitoring scheme on the Ballarat to Moorabool 220 kV lines		Summer 2005/06					Project in progress
Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformers overload for outage of Moorabool transformer	Spare Moorabool 500/220 kV single phase transformer		Summer 2005/06					Project in progress The spare also serve as a spare for the Rowville and Cranbourne 500/220 kV single-phase transformer banks
Outage of Keilor transformer overload 220 kV terminations of the Moorabool transformer	Uprating of 220 kV terminations of the Moorabool transformer		Summer 2005/06					Project in progress
Dederang 330/220 kV transformer overload for prior outage of a parallel transformer	Modification to the existing Dederang 330 kV bus-splitting scheme		Summer 2005/06					Project in progress
Rowville to Richmond circuit overload for outage of parallel circuit	Circuit breaker replacement at Richmond		Summer 2005/06					Project in progress

Constraint	Network Solution	Project Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Templestowe to Thomastown circuit overload for outage of Cranbourne 500/220 kV transformer at high summer load	Templestowe to Thomastown 220 kV line upgrade		Summer 2005/06					Project in progress
Ringwood to Thomastown circuit overload for outage of Rowville to Ringwood circuit or Rowville 500/220 kV transformer at high summer load	Ringwood to Thomastown 220 kV line upgrade		Summer 2005/06					Project in progress
Rowville to Yallourn/Hazelwood 220 kV lines overload for outage of a parallel circuit	Wind monitoring scheme on all Rowville to Yallourn/Hazelwood 220 kV lines		Summer 2005/06					Project in progress
Increase in fault levels at Western metro terminal stations due to addition of new generation at Laverton North	Fault level control – Installation of series reactors on each of the Brooklyn-Newport 220 kV line and the Brooklyn-Fishermans Bend 220 kV line		Summer 2005/06					Project in progress

Table 7.3 – Summary of Committed Projects

Constraint	Network Solution	Estimated Capital Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Inadequate thermal capacity on LV to Melbourne 500 kV lines	Upgrade terminations and circuit breaker thermal ratings at Hazelwood	6	At the time of about 500 MW new generation at LV 500 kV	At the time of about 500 MW new generation at LV 500 kV	At the time of about 500 MW new generation at LV 500 kV	At the time of about 500 MW new generation at LV 500 kV		Economic timing depends on generation development behind the constraint
	Fifth 500 kV line from LV to Melbourne	125	Around 2014					
Inadequate thermal capacity of Loy Yang to Hazelwood 500 kV lines	4th 500 kV line from Loy Yang to Hazelwood	15	At the time of about 500 MW new generation connected Loy Yang	At the time of about 500 MW new generation connected Loy Yang	At the time of about 500 MW new generation connected Loy Yang	At the time of about 500 MW new generation connected Loy Yang		Economic timing depends on generation development behind the constraint
Dederang transformers for outage of a Dederang transformer. 4th transformer causes fault levels to increase at Mount Beauty.	4th Dederang 330/220 kV transformer and Mount Beauty 220 kV switchgear replacement	11	Around 2011	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade or earlier date subjected to economic timing
South Morang – Thomastown 220 kV circuit for outage of a parallel circuit	Formation of a South Morang 220 kV bus & cutting of existing Rowville to Thomastown 220 kV circuit into South Morang 220 kV bus to form 3rd South Morang to Thomastown 220kV circuit	15	Around 2012	Around 2012	Around 2012	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	About 2012 or with increased import from NSW
	Cutting of existing Eildon to Thomastown 220 kV circuit onto South Morang 220 V bus to form 4th South Morang to Thomastown 220 kV circuit	4					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW

Constraint	Network Solution	Estimated Capital Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Reactive support at Wodonga and Dederang	Installation of a 150 MVAr capacitor bank at Wodonga and control & communications	4		At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	Timing with increased import from NSW
Murray to Dederang line overload for outage of a parallel circuit	60~65% series compensation on Wodonga to Dederang 330 kV lines & 150 MVAr shunt cap at Wodonga/Dederang	12				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
	2nd Jindera-Dederang 330 kV line (bypass at Wodonga)	35					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
South Morang to Dederang 330 kV line and series capacitors overload for outage of parallel circuit	Uprate of South Morang to Dederang 330 kV lines to 82°C & increase in rating of South Morang to Dederang series compensation to match line uprate	4.5				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
Eildon-Thomastown line for outage of South Morang to Dederang line	Wind monitoring scheme on the Eildon-Thomastown line	0.5	Sep 2007	Sep 2007	Sep 2007	Sep 2007	Sep 2007	
	Upgrade of Eildon – Thomastown 220 kV line to 70°C operation & 25% series compensation on the Eildon to Thomastown 220 kV line	8				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
South Morang 330/220 kV transformer for outage of a parallel transformer	3rd 700 MVA 330/220 South Morang transformer	20				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
	4th 700 MVA 330/220 kV transformer at South Morang	20					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW

Constraint	Network Solution	Estimated Capital Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
South Morang 500/330 kV transformer overload with increased import from NSW/Snowy	2nd 1000 MVA 500/330 kV transformer at South Morang	40					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
South Morang to Dederang line overload for outage of a parallel circuit	3rd South Morang to Dederang 330 kV circuit and series compensation	120					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
Voltage collapse at Dederang and South Morang	Controlled series compensation of South Morang to Dederang lines	15					At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
Bendigo-Fosterville-Shepparton circuit overload for outage of a Ballarat to Bendigo circuit	Wind monitoring scheme on the Bendigo-Fosterville-Shepparton circuit	0.6	Sep 2006	Sep 2006	Sep 2006	Sep 2006	Sep 2006	
	Bendigo-Fosterville-Shepparton 220 kV line upgrade to 90°C	5				At time of Interconnection Upgrade by 600MW	At time of Interconnection Upgrade to 600 MW	
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	One 500/220 kV 1,000 MVA transformer at Rowville and fault level mitigation	37.2	Sep 2007	Sep 2007	Sep 2007	Sep 2007	Sep 2007	Regulatory test and tendering processes in progress
Outage of the Moorabool transformer overloads Keilor 500/220 kV transformers and Keilor-Geelong 220 kV lines	Second 500/220 kV transformer at Moorabool	17	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	Economic timing subjected to generation development in Keilor/Moorabool areas

Constraint	Network Solution	Estimated Capital Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Hazelwood transformers constraint for system normal	Hazelwood transformer overload control scheme	0.6	Dec 2005	Dec 2005	Dec 2005	Dec 2005	Dec 2005	
	Additional 220/500 kV transformation at Hazelwood and fault level mitigation	22	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	Economic timing depends on generation development behind the constraint and the reliance of Victorian demand on the generation
Rowville-Springvale circuit overload for outage of parallel circuit.	Uprate Rowville-Springvale line to 82°C	1	Around 2012	Around 2012	Around 2012	Around 2012	Around 2012	
Rowville to Malvern circuit overload for outage of a parallel circuit	Wind monitoring scheme on Rowville to Malvern circuits and a control scheme for load shedding	0.3	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	CitiPower plans to transfer about 100 MW load from Rowville to Malvern, following refurbishment of Malvern by SP AusNet
	Rowville to Malvern 220 kV line upgrade	3	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	
Security of supply to radially connected Springvale, Heatherton and Malvern terminal stations	Malvern-Heatherton 220 kV underground cable (or a overhead line - if feasible at a lower cost)	35	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	Economic timing subjected to alternative contingency arrangement by Distribution businesses and feasibility of network options
Ringwood to Thomastown circuit overload for outage of Rowville to Ringwood circuit or Rowville 500/220 kV transformer at high summer load	Wind monitoring scheme on the Ringwood-Thomastown 220 kV line	0.4	Around 2012	Around 2012	Around 2012	Around 2012	Around 2012	
Rowville to Richmond circuit overload for outage of parallel circuit	Wind monitoring scheme on the Rowville-Richmond 220 kV lines	0.4	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	
Keilor to West Melbourne-circuit overload for outage of a parallel circuit	Replacement of four circuit breakers and terminations at West Melbourne of the Keilor to West Melbourne 220 kV lines	-	Around 2009	Around 2009	Around 2009	Around 2009	Around 2009	SP AusNet scheduled to replace the limiting plants by 2008/09 as part of asset refurbishment program

Constraint	Network Solution	Estimated Capital Cost ($M)	Estimated Timing					Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	
Fishermans Bend to West Melbourne circuit overload for outage of a parallel circuit	Terminations at Fishermans Bend and West Melbourne upgrade	0.2	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	
	Wind monitoring scheme on the Fishermans Bend-West Melbourne line	0.4	Around 2012	Around 2012	Around 2012	Around 2012	Around 2012	
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	One 1,000 MVA 500/220 kV transformer in Eastern metro	40	Around 2012	Around 2012	Around 2012	Around 2012	Around 2012	Timing and location subjected to further assessment
Ballarat to Moorabool circuit overload for outage of parallel Ballarat to Moorabool circuit at high load.	Uprate the Ballarat to Moorabool No.1 circuit to 75°C conductor temperature	3	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	
Dederang to Glenrowan circuit overload for outage of a parallel Dederang to Glenrowan circuit.	Switch Dederang to Shepparton 220 kV line at Glenrowan	3	Around 2011	Around 2011	Around 2011	Around 2011	Around 2011	
Ballarat to Bendigo circuit overload for outage of the Bendigo to Shepparton line	Wind monitoring scheme on the Ballarat to Bendigo circuit	0.2	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	
	Ballarat to Bendigo 220 kV line upgrade to 75°C conductor temperature	3.2	Around 2013	Around 2013	Around 2013	Around 2013	Around 2013	
Limitation on maximum supportable demand due to system voltage collapse following a single credible contingency	1,500 MVAr to 2,100 MVAr Reactive Support	18-32	On-going 2,100 MVAr from 2008	On going 2,100 MVAr from 2008	On going 1,200 MVAr from 2008	On going 2,000 MW from 2008	On going 1,500 MW from 2008	Location of capacitor banks depend on sequence of upgrade works
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the metropolitan area	20-30	On-going as required	On-going as required	On going as required	On-going as required	On going as required	$30 M for Scenario 3
Line terminations, secondary equipment and dynamic system and supply of quality monitoring equipment.	Miscellaneous Works	30	On-going	On-going	On-going	On-going	On-going	On-going

Table 7.4 – Summary of Network Constraints over the Next 10 Years

Scenario	Estimated Total Capital Cost ($M)		
	Years 1 –5	Years 6-10	Total
1	186	311	497
2	197	184	381
3	194	179	373
4	197	232	429
5	195	434	629

Table 7.5 – Estimated Total Capital Cost for Network Solutions

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ELECTRICITY ANNUAL PLANNING REPORT

2005

APPENDICES

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A FORECAST METHODOLOGIES AND ASSUMPTIONS

A1 TEMPERATURE STANDARDS FOR SUMMER AND WINTER MAXIMUM DEMAND FORECASTS

Daily demand is highly dependent on ambient temperature. Summer and winter MD forecasts are based on temperature standards developed, and last reviewed, by NIEIR in 2004. Three temperature standards are defined, based on the probability distributions of the warmest summer and coldest winter weekday average temperatures of each year included in the analysis, such that:

- The 10% POE temperature is the weekday average temperature not exceeded, on average, more than 1 in every ten years
- The 50% POE temperature is the weekday average temperature not exceeded, on average, more than 1 in every 2 years
- The 90% POE temperature is the weekday average temperature not exceeded, on average, more than 9 in every ten years

Figure A1.1 and A1.2 show the probability distributions of the warmest summer and coldest winter weekday[43] average temperatures, used to derive the summer and winter forecast MD temperature standards. Summer temperature standards are based on weekday data December – February between 1954/55 and 2003/04 and excluding 20 December-20 January. Winter temperature standards are based on weekdays June – August each year between 1970 and 2003.

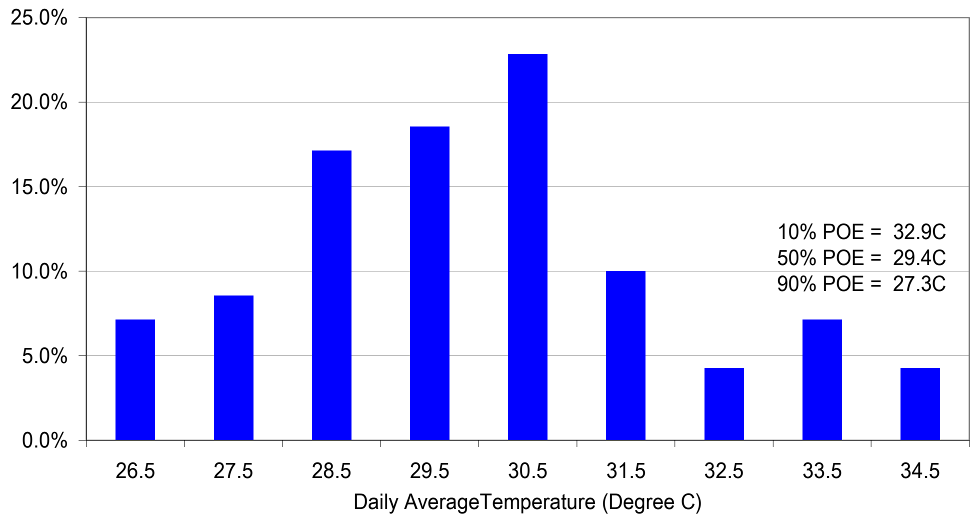


Figure A1.1 –Warmest Summer Weekday Day Daily Average Temperature Distribution

43 Some selected hot and cold weekends were also included

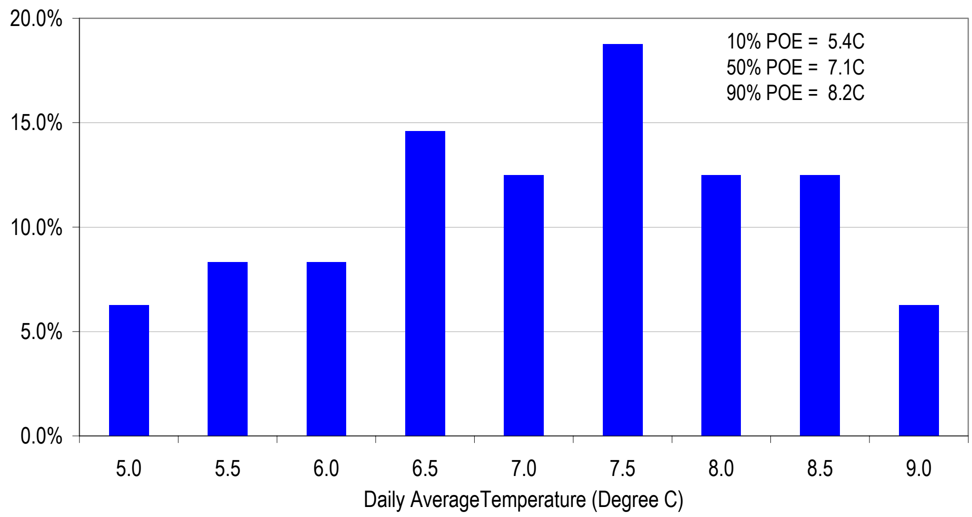


Figure A1.2 – Winter Coldest Day Daily Average Temperature Distribution

A2 TEMPERATURE STANDARDS FOR ANNUAL ENERGY FORECASTS (COOLING AND HEATING-DEGREE-DAYS)

Daily energy has shown increased variations compared to the past, due to increased heating and cooling load. It is therefore important to estimate the effect of weather on the temperature sensitive component of energy so that the underlying growth in energy can be assessed more accurately. Weather standards, defined by Heating-Degree-Day (HDD) and Cooling-Degree-Day (CDD), are used in energy forecasts.

HDD and CDD are used by energy utilities to measure the coldness (or hotness) in outdoor ambient temperatures affecting energy usage for space heating and cooling. It has been shown that space heating occurs when daily average temperature is below a certain threshold. Similarly, cooling appliances are switched on when daily average temperature is above the defined threshold. VENCorp uses a threshold temperature of 18°C (65°F), which is most commonly used in the energy industry. The definitions of CDD and HDD are given below.

HDD = 18°C – Daily Average Temperature

And

CDD = Daily Average Temperature - 18°C

Daily average temperature is the average of the daily maximum temperature (from 9:00AM) and the overnight minimum daily temperature (to 9:00AM) of the day in consideration. For forecasting purposes daily maximum and minimum temperatures at the Melbourne CBD weather station are used.

The colder the winter the greater is the annual HDD, similarly the hotter the summer, the greater the CDD. HDD is normally 0 in summer months and similarly CDD is 0 in winter months. However, Melbourne weather is known to be highly variable such that very warm days can end with a drastic cool change lasting for a couple of days, as shown in Figure A2.1 for summer 2004/05.

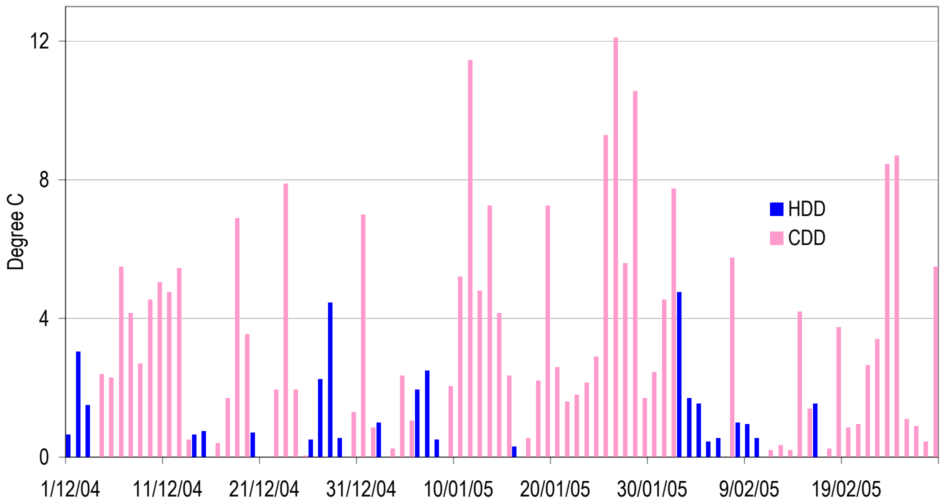


Figure A2.1 – Summer 2004/05 Daily CDD and HDD

Normally, shoulder months, March – April and October – November, have a mixture of warm and cold days. Figure A2.2 shows that, for the last 12 months to end of March 2005, the coldest month was July with over 200 HDD[44], whereas the warmest month was December with over 100 CDD. February used to be the warmest month of the year. However, there were a number of cool days last February.

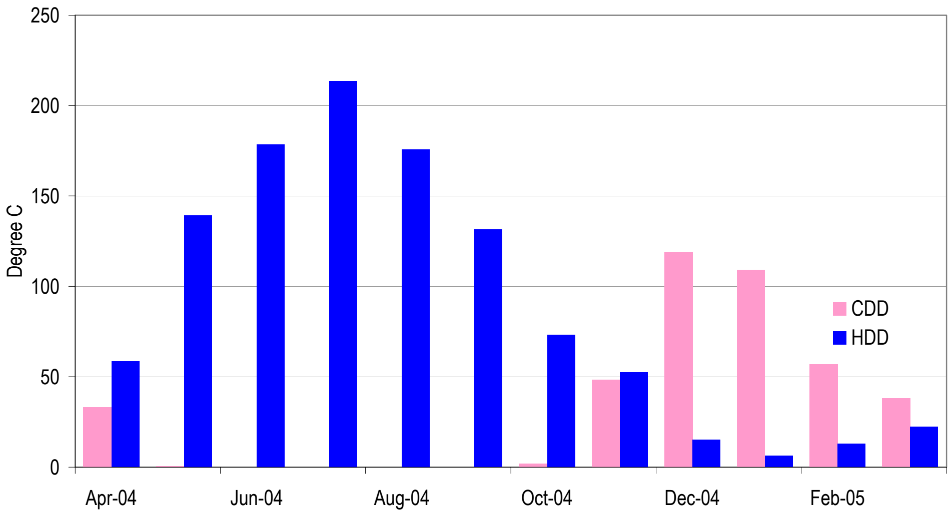


Figure A2.2 – 2004/05 Monthly CDD and HDD

44 This is the sum of daily HDD values

Figure A2.3 displays the annual[45] HDD and CDD for the last 55 years, and depicts a warming trend in Melbourne CBD temperatures since 1949. The warming trend is stronger in annual HDD than in annual CDD. Melbourne annual CDD has increased by about 2.5°C pa while annual HDD has fallen by about 7°C pa. The annual temperature standards for annual energy forecasts are 426 CDD and 1,080 HDD respectively, being the projected warming trend to year 2007/08. The annual standards will be reviewed periodically, possibly every five years, or as required.

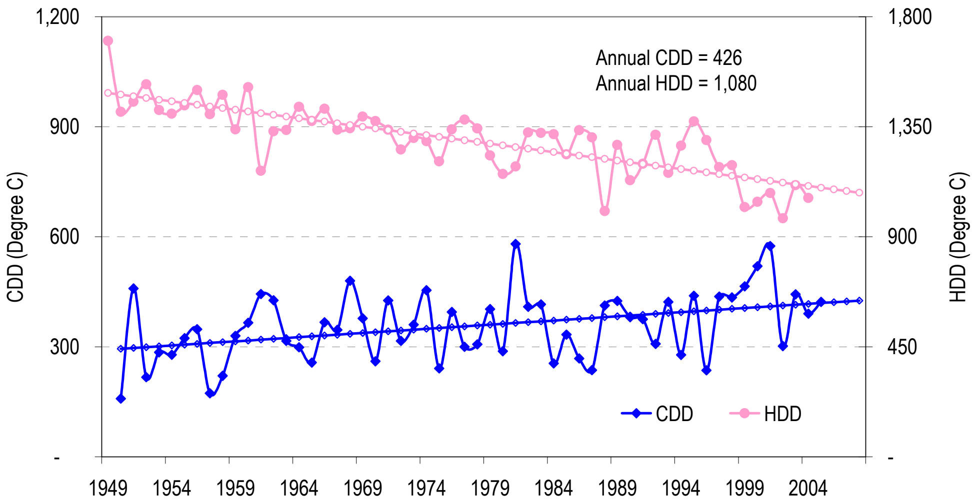


Figure A2.3 – Annual HDD and CDD Warming Trend

A3 FORECAST METHODOLOGY AND ASSUMPTIONS

VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to produce independent long-term Victorian electricity energy and demand forecasts for Medium (most likely), High (optimistic) and Low (pessimistic) economic scenarios. The State economic projections are documented in Appendix A4.

Electricity energy refers to the energy generated at the Victorian scheduled generators, plus interstate net imports. Electricity demand is the total Victorian generated demand averaged over each half-hourly trading interval. Historical demand and energy data is as per historical data published by SP AusNet.

A3.1 Energy Forecast Methodology

NIEIR has developed an integrated multi-purpose econometric model linking the economic forecast module with the energy forecast module. Energy forecasts are prepared by industrial, commercial and residential sectors[46]. Large industrial load, namely the smelter load, is forecast separately. The aggregated end-use forecasts, adjusted up for transmission and distribution losses, and less non-

[45] HDD and CDD are calculated on a calendar and fiscal year basis respectively

[46] NIEIR collated historical sales data from individual retailers/distributors

scheduled generators net outputs, are reconciled with the forecast scheduled generators' sent-out energy[47]. Non-scheduled generators are generally small plants non-scheduled in the distribution networks or not scheduled such as wind farms. Non-scheduled generation has played an increasingly important role in the electricity supply and demand balance in recent times. Forecast non-scheduled generation is discussed in more detail in Appendix A5.

Key economic inputs to the econometric model include:

- Victorian Gross State Product (GSP);
- State industry output projections; and
- Forecasts of State population, dwelling stocks, Real Household Disposable Income, electricity and gas prices.

The forecasts also take into account impact on load growth of the following factors:

- Major private and government projects;
- Development of new energy efficiency technologies and their applications in industrial and residential sectors;
- Energy conservation measures;
- Impact of state and federal energy policies;
- Penetration of appliances, in particular air conditioner units; and
- Temperature standards already discussed in Appendix A2

Government Energy Policies and Initiatives

A number of energy initiatives, at both the national and state level, have been proposed or implemented in recent times.

The development of national energy policies is being overseen by the Ministerial Council on Energy (MCE). A key task of the MCE is to identify policies and programs to deliver significant improvements in energy efficiency through coordinated action by Federal, State and Territory government agencies.

In November 2003, the MCE endorsed a proposal for the development of a National Framework for Energy Efficiency (NFEE) to define future directions for energy efficiency policy and programs in Australia.

The MCE, at its meeting on 27 August 2004, committed to implement over 3 years a package of policy measures as Stage 1 of the NFEE. This consists of 9 integrated and inter-linked packages including the following key proposals:

47 This is equal to energy generated at the scheduled generators less their own-use

- More stringent residential building energy efficiency regulation;
- Introducing commercial building energy efficiency regulation;
- Extending labelling and standards (Minimum Energy Efficiency Standards “MEPS”) for electrical appliances and applying the same approach to gas appliances
- Consumer awareness programs including the mandatory audit of large energy consumers

The proposed measures were reviewed by the Productivity Commission’s inquiry into energy efficiency. The draft report was published in April 2005 for public consultation. The Commission recommended to defer the NFEE stage 1 measures until independent evaluations of existing energy efficiency programs have been undertaken.

In addition, the Commonwealth government has also endorsed ‘Solar Cities’ demonstration projects to trial innovative energy technologies and techniques such as solar heaters, photovoltaics, smart meter technologies, energy efficiency improvements and load management, and effective energy pricing.

The Victorian government requires all new homes to have 5 star rated building shell from July 2004[48] followed with mandatory installation of a rain water tank or a solar hot water service from July 2005.

The impacts of the above programs/Government initiatives on future growth of Victorian electricity energy and demand are highly uncertain. It is expected that a clearer picture and more market information will be available in the next few months to assist in more accurately assessing the effects of these Government policies.

A3.2 Forecast Methodology For Summer and Winter Maximum Demands

Victorian summer MD usually occurs around 4:00pm (AEST) on a weekday in late January or February. NIEIR’s forecast MDs are adjusted to reflect the peak demand for a weekday at 4:00pm in mid February.

Summer MDs consist of 3 components which are forecast separately:

- Large industrial (smelters) demand which is not sensitive to weather
- Non-smelter non-temperature sensitive load; and
- Non-smelter temperature sensitive load

The smelter load forecasts are provided to VENCorp by VicPower Trading and incorporated into NIEIR’s aggregate forecasts.

Forecast growth in non-smelter non-temperature sensitive demand is consistent with forecast annual energy growth.

48 Other choices are 4 star building shells plus rainwater tank or solar hot water system over a transition period of 12 months from July 2004.

Forecasting summer MD temperature sensitive load requires detailed analysis of historical temperature sensitive demand. The latter is directly linked to AC sales. The process involves the following steps:

- Estimate temperature sensitive load for each historical year, based on historical stock and sales of space cooling equipment from ABS import data and electrical load data. The estimated temperature sensitive load also includes an estimate of the stock of refrigerators and fans. These estimates are then reconciled with the actual temperature sensitive load at 4:00pm (AEST) from 2 or 3 years with close to 10% POE MDs;

- Estimate the actual temperature sensitive demand for different temperature ranges from a "switching" regression model using historical summer MD data. Average temperatures of the MD day and the previous day are included in the analysis. The modelled temperature sensitive demand, when compared with the maximum temperature sensitive load derived in the above step, determines the space cooling utilisation rates for different defined temperature ranges and different summer weather conditions;

- Generate forecast growth in temperature sensitive load from an econometric model including such drivers as projected building activities, real household income, assumed space cooling replacement rates and summer weather conditions. The projections of temperature sensitive load take into account energy savings from new technologies and government greenhouse initiatives (for example the MEPS);

- Apply the relevant space cooling utilisation rates from the switching regression model to the forecast temperature sensitive load to generate the 90%, 50% and 10% POE summer MD cooling demand.

The final summer MD forecasts take into account forecast available non-scheduled generation capacity on hot summer days. Forecast non-scheduled generation is presented in Appendix A5.

Forecasting winter daily MD follows a similar process. NIEIR prepares 3 sets of winter MDs for each economic scenario based on 90%, 50% and 10% POE temperatures. The forecast methodology uses a combination of regression methods and estimated reverse cycle AC stocks and sales to derive the winter MD temperature sensitive load.

A4 VICTORIAN ECONOMIC PROJECTIONS

NIEIR provides 3 economic scenario forecasts based on Medium, High and Low growth assumptions. Figure A4.1 depicts the projected growth in Victorian GSP over the next 10 years to 2014/15. The State economic outlook is discussed below, focussing on the Medium growth scenario over the medium term to 2009/10.

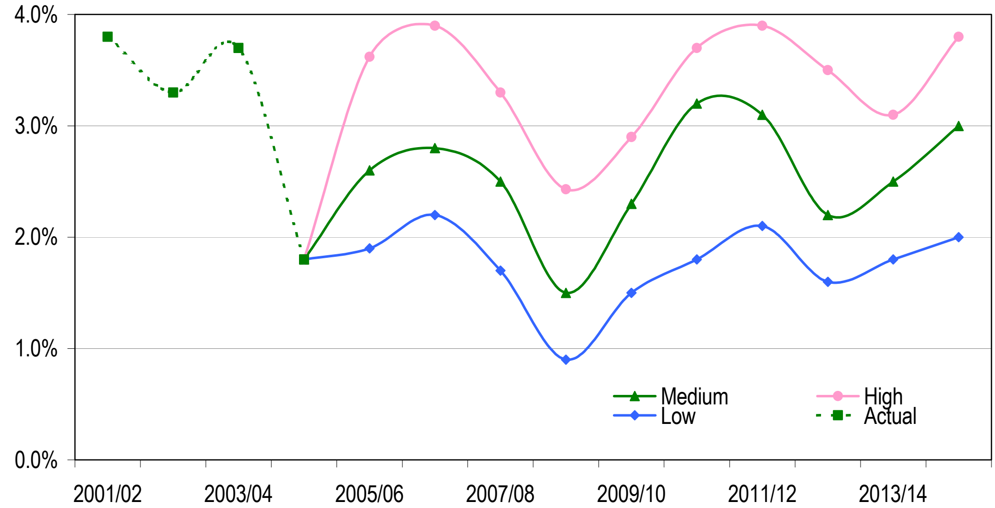


Figure A4.1 – Victorian GSP Projections

A4.1 Medium Growth Scenario

After 3 years of strong growth above 3%, the Victorian economic growth for 2004/05 is projected to slow down to 1.8%[49], which is 0.4% below the forecast of 2.2% predicted last year. Reduced household consumption and a slowdown in residential building activities are behind the observed economic downturn. However, stronger private business and government investments are projected to support the state economy growing at above 2.5% pa until 2007/08. The projected sluggish economic growth in China in 2008/09, coincided with a decline in business investment in Victoria, will reduce the Victorian GSP to 1.5%. The economy will rebound thereafter.

The projected growth over the medium term to 2009/10 is 2.3% pa, compared with 2.5% forecast last year. Stronger growth of 2.8% is forecast for the following 5 year period to 2014/15. Table A4.1 and Figure A4.1 summarise the Victorian GSP scenario forecasts.

Victoria has experienced a recovery in population growth over recent years driven by higher net international migration gains and a turnaround in net interstate migration. This has partly driven up the housing sector in Victoria. Nevertheless, population growth is projected to slowdown over the medium term due to a net loss of population to other states. The population is projected to grow at an average of 1.0% per year.

49 Based on actual to December 2004

Year	Medium	High	Low
2001/02	3.8%	3.8%	3.8%
2002/03	3.3%	3.3%	3.3%
2003/04	3.7%	3.7%	3.7%
2004/05	1.8%	1.8%	1.8%
2005/06	2.6%	3.6%	1.9%
2006/07	2.8%	3.9%	2.2%
2007/08	2.5%	3.3%	1.7%
2008/09	1.5%	2.4%	0.9%
2009/10	2.3%	2.9%	1.5%
2010/11	3.2%	3.7%	1.8%
2011/12	3.1%	3.9%	2.1%
2012/13	2.2%	3.5%	1.6%
2013/14	2.5%	3.1%	1.8%
2014/15	3.0%	3.8%	2.0%
2005-2010	2.3%	3.2%	1.6%
2010-2015	2.8%	3.6%	1.9%

Table A4.1 – Victorian GSP Projections

A4.2 High and Low Growth Scenarios

The high economic growth scenario is based on assumptions of stronger growth globally across Asia, USA and Europe. International terrorism will be settled. The Australian economy is projected to grow stronger, driven by new major resource projects. Under this scenario, the GSP is projected to grow at an average rate of 3.2% and 3.6% pa, over the medium and longer term respectively.

The Low economic scenario is for a US economy struggling to recover, rising oil prices affecting consumer and investor confidence and global economic growth. Under this scenario, the average Victorian GSP growth rate is 1.6% and 1.9% pa over the medium (5 year) and longer term (10 year) respectively.

NIEIR is of the view that the likelihood of the Low growth scenario has increased due to reduced export capacity and the growing current accounts deficit.

A5 FORECAST NON-SCHEDULED GENERATION

Non-scheduled generation refers to smaller generators, either exempted from NEM registration or registered with NEMMCO as non-scheduled. Most of these generators are non-scheduled within the distribution networks, however some are connected to the transmission grid such as the wind farms. Non-scheduled generation, projected to grow faster in future, plays an increasingly important role in the state supply and demand balance as this has the effect of reducing the reliance on investments of large-scale generators to meet growing demand.

Non-scheduled generators can be classified under Cogeneration and Non-Cogeneration, further grouped into Renewable and Non-Renewable. Renewable non-scheduled generation includes foremost, hydro and wind, and others such as biomass (for example sawdust, bagasse or animal waste). The information presented here excludes remote area and non-grid connected generators, emergency or standby generation.

Future growth in this sector depends on, amongst other factors, future electricity price and government energy policies. Of particular relevance to Victoria are the following key policy drivers:

- The Mandated Renewable Energy Target (MRET) which was first set under the Renewable Energy (Electricity) Act 2000, requiring the purchase of additional renewable energy by Australian electricity retailers from 2001 to 2020, of up to 9,500 GWh pa in 2010, and beyond. The MRET is implemented via the creation of tradeable Renewable Energy Certificates (RECs) which are earned for each MWh of renewable energy created by generators or through installation of solar hot water units. The Victorian 5 star building regulations, operating since July 2004, and expected to be fully operational from July 2005, will see an increase in solar hot water units installed in new homes in the future.

  A review of MRET in 2004, conducted by an independent panel, recommended that the MRET be increased from 9,500 MW by 2010 to 20,000 MW by 2020. However, the Federal government has rejected to increase the MRET above the previously set target of 9,500 MW.

  NIEIR believes that the level of the MRET is unlikely to change, at least, until 2008. Post 2012, NIEIR assumes additional policies will be in place that will lead to small increases in renewable generation.

- The Greenhouse Gas Abatement Program (GGAP), a government initiative to sponsor projects capable of delivering reduction in greenhouse gas of 250,000 tonnes of carbon dioxide or more pa.

- Green Power products offered by retailers to customers

NIEIR's projections of non-scheduled generation, including capacity and annual outputs (broken down by Buyback[50] and Own-use), are given in Table A5.1 and Figure A5.1. The projections are for the Medium economic growth scenario and are broken down by type of generation. The projections include existing and planned generators, and are based on market information collected by NIEIR, and cross-checked against the survey results of non-scheduled generation, organised by NEMMCO for all NEM states with the assistance of electricity retailers and distributors.

[50] This is the volume exported to the grid

It should also be noted that the projections are based on assumptions that normal weather will prevail throughout the projection period (droughts and floods are not predictable) and do not take into account new technological innovation.

	Capacity (MW)				Annual Output (GWh)					
Year	Cogen	Wind	Other Non-Cogen	Total	Cogen	Wind	Other Non-Cogen	Total	Buyback	Own Use
2002/03	269	91	135	495	1,484	215	318	2,016	795	1,221
2003/04	267	91	135	493	1,479	221	318	2,018	797	1,222
2004/05	279	91	144	515	1,551	221	347	2,120	843	1,277
2005/06	287	121	148	556	1,607	300	358	2,266	974	1,292
2006/07	294	226	151	672	1,651	576	369	2,596	1,262	1,334
2007/08	300	286	155	741	1,688	734	380	2,802	1,434	1,368
2008/09	330	286	158	775	1,859	734	391	2,983	1,482	1,501
2009/10	340	286	162	788	1,920	734	402	3,056	1,511	1,544
2010/11	340	286	162	788	1,920	734	402	3,056	1,511	1,544
2011/12	355	286	165	807	2,012	734	412	3,158	1,531	1,627
2012/13	355	286	165	807	2,012	734	412	3,158	1,531	1,627
2013/14	366	286	169	822	2,085	734	423	3,242	1,572	1,670
2014/15	384	286	169	839	2,194	734	423	3,352	1,614	1,738

Table A5.1 – Non-scheduled Generation Forecasts – Medium Growth Scenario

Table A5.1 shows that total installed non-scheduled generation is 515 MW in 2004/05, with 279 MW (54%) classified as cogeneration and 91 MW of wind capacity. Total installed capacity is projected to grow to 788 MW in 2009/10 and 839 MW in 2014/15. The fastest growing components are cogeneration and wind generation, driven by greenhouse initiatives. The projections assume that the Portland wind farm project of 195 MW of capacity will be completed between 2005/06 and 2007/08. No new wind generation is assumed beyond 2007/08. Cogeneration and wind generation account for 72% of total non-scheduled generation in 2004/05 but increases to 80% in 2014/15.

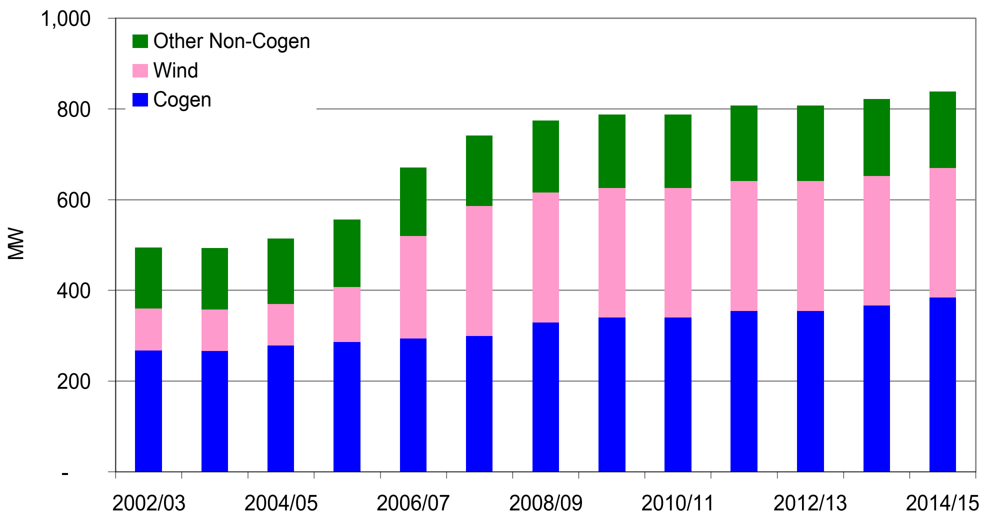


Figure A5.1 – Non-scheduled Generation Forecasts

The following assumptions are used in forecasting non-scheduled generation capacity available at peak demand times. However the unpredictable nature of wind generation means that forecast wind generation is more uncertain.

Non-scheduled Cogeneration	20%
Biomass and Biogas	60%
Wind	8%
Mini Hydro	30%
Other Non-Renewable	50%

Total estimated energy produced by non-scheduled generators was 2,120 GWh in 2004/05, increasing to 3,056 GWh in 2009/10 and 3,352 GWh in 2014/15. About 40% of the energy output was exported to the grid in 2003/04, increasing to 48% over the next 10 years.

A6 CORRELATION BETWEEN DAILY AVERAGE TEMPERATURE AND DAILY ENERGY

Victorian daily energy peaks in summer and winter due to increased cooling and heating load as shown in Figure A6.1. Maximum daily energy used to occur in winter. However, over the last 12 months to 8 April, the highest energy of 163 GWh, occurred on 25 January 2005, compared with a slightly lower maximum winter usage of 157 GWh on 23 July 2004. Given similar daily average temperatures, weekday (Mondays to Fridays[51]) daily energy is relatively stable. Given similar daily average temperatures, Saturday and Sunday loads are lower, by about 10% and 15% respectively, than weekday loads. Daily electricity load is lower on Public Holidays and lowest on Christmas and Boxing days with load close to 105 GWh.

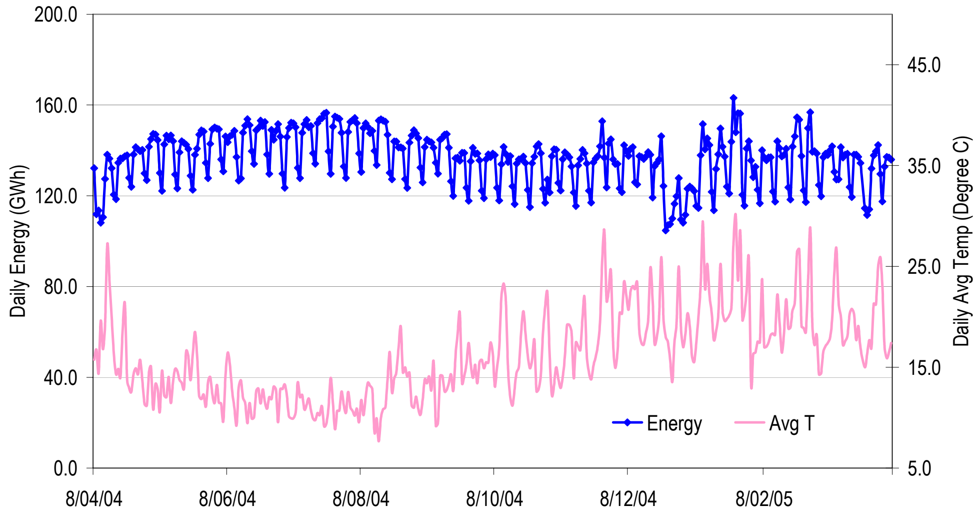


Figure A6.1 – Daily Energy and Daily Average Temperature

[51] Friday load can be lower sometimes

Another graphical method to summarise the characteristics of Victorian daily electricity load is to plot the load by day type against daily average temperatures as shown in Figure A6.2 below.

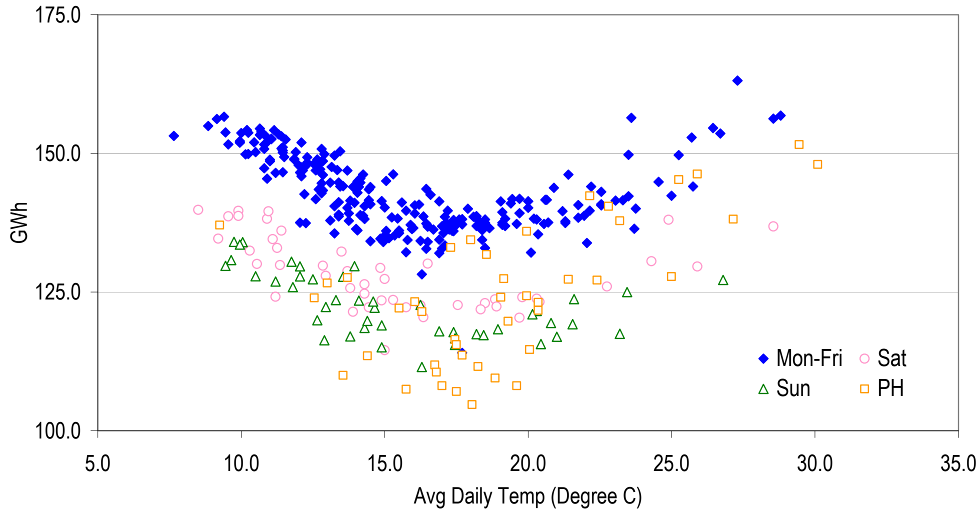


Figure A6.2 – Daily Energy and Daily Average Temperature

Analysis of the impact of weather (temperature) on daily electricity load has not received the same level of attention, in the past, as that for electricity demand. This was because energy used for space cooling and heating has been an insignificant proportion of daily energy. However, increased penetration of residential cooling appliances in recent years and, in particular reverse cycle AC, has driven the temperature sensitive components of daily electricity load higher.

VENCorp has recently conducted a study to estimate the cooling and heating sensitivities of daily energy. The results are to be used to correct historical monthly and annual energy for temperature variations so that the underlying growth in energy, not related to weather (for example, economic growth), can be assessed more accurately. A simple regression model, which links daily energy with key predictors (average daily temperatures measured in CDD and HDD[52] and monthly dummy variables), is used. Public holidays, Saturdays and Sundays are excluded from the analysis. It is recognised that, a more complicated model, possibly non-linear in daily average temperature, may fit the energy data better. However, this approach is more complicated to implement and not cost effective considering the incremental gain in accuracy. The analysis covers historical years from 1990/91 to 2004/05. Results of the analysis are explained below.

Rolling 12-month regression analysis of daily energy is undertaken such that new temperature sensitivities are generated each time a new set of data is analysed. The derived rolling cooling sensitivities are shown in Figure A6.3, together with the corresponding 12 month annual CDD. Two key results have emerged. Energy cooling sensitivities have increased rapidly from early 1995, and vary depending on how warm or cool the summer in question is. In general, a 1% increase in temperatures (measured in annual CDD), relative to an average summer, will incur 0.6% increase in energy cooling sensitivities. Conversely, a 1% decrease in temperatures (measured in annual CDD) will incur 0.4% decrease in energy cooling sensitivities.

52 See Appendix A2

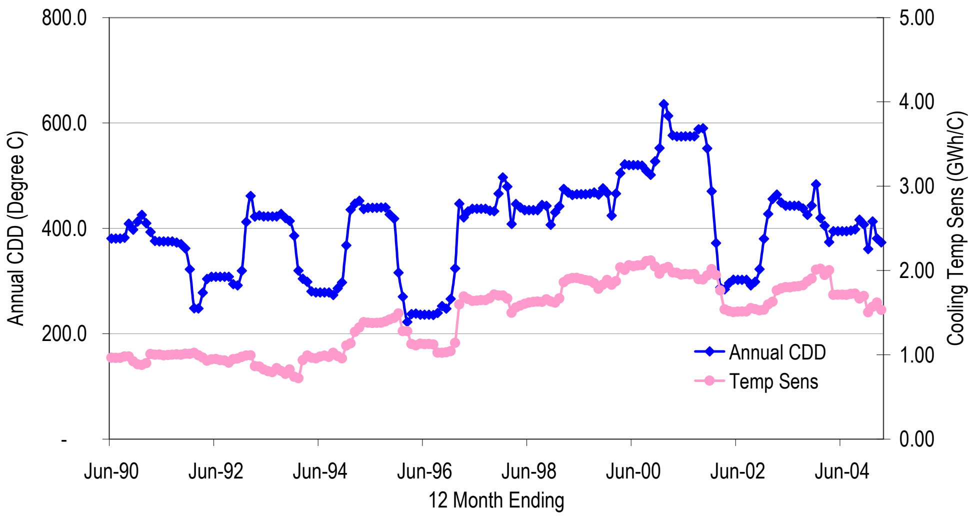


Figure A6.3 – Cooling Temperature Sensitivities and Annual CDD

Figure A6.4 displays the energy cooling sensitivities for 1990/91 to 2004/05, corrected for the effect of the overall summer temperatures. The corrected cooling temperature sensitivities increase from below 1 GWh/°C to about 1.8 GWh/°C over the last 15 years. More moderate growth is observed in recent years following a rapid rise in the early 1990s.

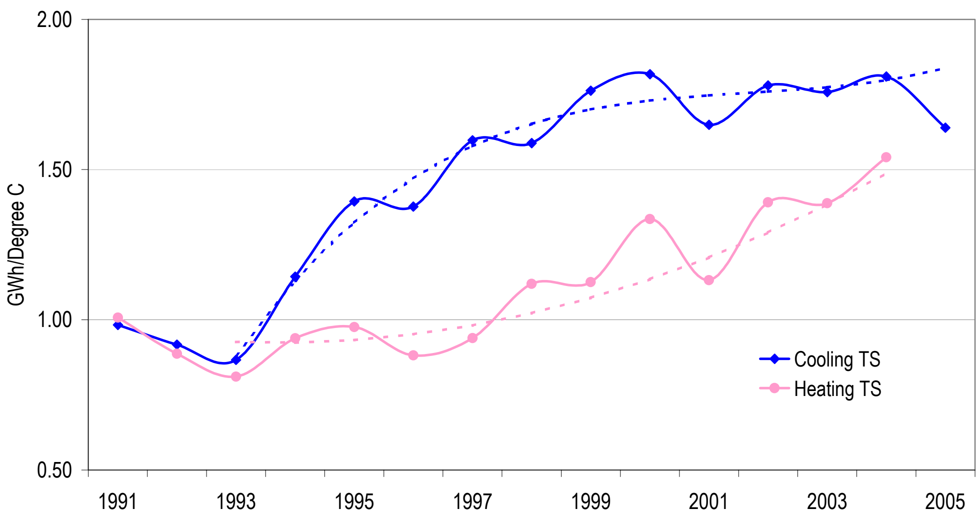


Figure A6.4 – Trend in Daily Energy Cooling and Heating Sensitivities

The regression analysis does not reveal a strong link between energy heating sensitivities and annual HDD. As shown in Figure A6.4, Victorian energy heating sensitivities were small, below 1 GWh/°C in the early years to 1997, due to the dominance of cheaper gas heating in Victoria. Recent years have seen a 50% increase in energy heating sensitivities to above 1.5 GWh/°C due to increased penetration of reverse cycle AC in households.

Total annual temperature sensitive load has increased to about 5% in recent years with 1.5% - 1.6% cooling and 3.1% to 3.4% heating load respectively.

A7 CORRELATION BETWEEN DAILY SUMMER AND WINTER MAXIMUM DEMAND AND DAILY AVERAGE TEMPERATURE

A7.1 Correlation between Summer Daily Maximum Demand and Daily Average Temperature

Victorian summer daily demand normally peaks around 4:00pm (AEST) on most summer weekdays. However, an early cool change in temperature on a warm day will see the demand falling and sometimes plummeting by over 100 MW, within a short space of time. This happened on the second and third highest demand days last summer when demand fell after 2:00pm following the cool change (see Figure 3.1).

Research into what drives Victorian summer MD is an ongoing project for VENCorp and NIEIR. Although daily average temperature has been identified as the key driver of summer MD, other influential factors include:

- Day type. Given similar weather conditions, daily MD for weekdays, Mondays-Thursdays, are similar. Friday demand can be lower, by some 3% than weekday demand, due to businesses winding down early for weekends. Saturday and Sunday demands can be 15%-20% lower than normal weekdays. Demand for Public Holidays (PH) and days prior to the PH are also lower. For the purpose of analysing summer MD, the period 20 December to 20 January of each year, has been treated as extended Christmas – New Year holiday when industries operate below their maximum capacity. Figure A7.1 displays summer 2004/05 daily MD by day type.

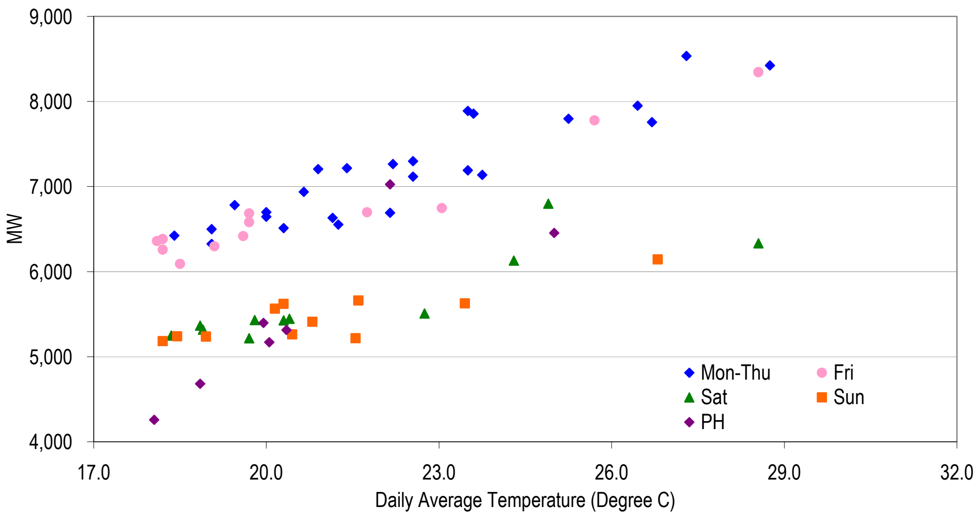


Figure A7.1 – 2004/05 Summer MD by Day Type

- Temperatures of previous days
- Maximum temperature of the day, when the maximum temperature of the day occurs and how long it lasts. As discussed earlier, a cool change in temperature in the early part of the day will see a lower demand than normally expected
- The overall summer weather conditions
- Time of season (this impacts on cooling appliance sales)

- Outputs from non-scheduled generators

It is not unusual to find 2 days with similar temperature profiles ending with maximum demand differing by 200 MW or more.

Figure A7.2 compares the demand profiles for 3 selected days in summer 2004/05. Tuesday 10 March 2005 was a day with an average temperature of 18°C. The demand profile of the day is representative of a summer day with little cooling or heating load. The demand was stable at about 6,410 MW between 10:00am and 4:00pm. Monday 28 February started with a similar temperature profile as 10 March. However temperature rose rapidly after 9:00 am, driving up demand to a maximum of just below 7,900 MW. Although the maximum temperatures for both days on 25 January 2005 and 28 February were similar, the maximum demand on 25 January was higher by more than 600 MW due to warmer overnight temperature and slightly warmer temperatures leading to the peak demand.

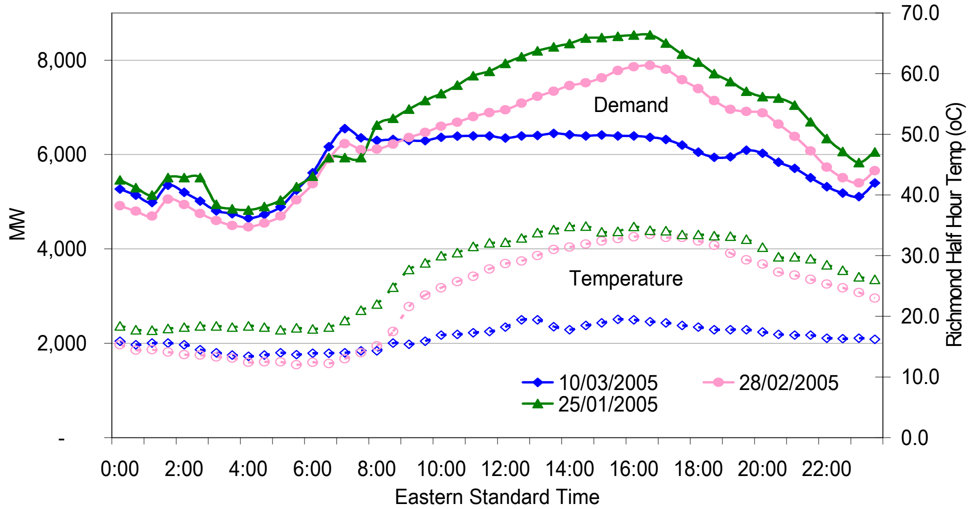


Figure A7.2 – Selected Summer MD and Temperature Profiles

A significant amount of work has been devoted to investigate how demands respond to temperatures, in particular very warm temperatures at the 10% POE temperature. The issue is whether summer MD increases linearly with temperature increases or non-linearly in an "S" shape. Conceptually, it is expected that the demand curves will reach saturation when all available AC capacity is utilised. Historically, there were very few warm days, as shown in Table A7.1, which can be used in this analysis. Most of these days either fell on public holidays (including the extended Christmas-New Year period between 20 December and 20 January), or weekends, or when load shedding was effected.

Year	Date	Day of Week	Avg Temperature (°C)	Comments
1992/93	3-Feb-93	Wed	33.3	Load Shedding
1993/94	26-Jan-94	Wed3	30.5	Australia Day, reduced load
1994/95	6-Dec-94	Tue	30.7	
1995/96	14-Jan-96	Sun	27.3	Xmas-NY holiday, reduced load
1996/97	21-Jan-97	Tue	34.3	Load peaked at 12:30pm
1997/98	26-Feb-98	Thu	30.3	
1998/99	12-Dec-98	Sat	33.8	Saturday, reduced load
1999/00	3-Feb-00	Thu	33.4	Load shedding
2000/01	11-Jan-01	Thu	32.0	Xmas-NY holiday, reduced load
2001/02	15-Feb-02	Fri	29.3	Friday, reduced load
2002/03	25-Jan-03	Sat	35.5	Saturday, reduced load
2003/04	30-Dec-03	Tue	32.0	Xmas-NY holiday, reduced load
2003/05	26-Jan-05	Wed	30.1	Australia Day, reduced load

Table A7.1 – Warmest Day Average Temperatures By Year

There were other warm days in recent years not shown in the above table. Most of them were in summer 1996/97 representative of a 10% summer in recent history. It was a summer with a total of 9 days with daily average temperatures above 30°C, and these warm days happened in sequences of 2 or 3. However, the amount of useful data is reduced to 1 or 2 days due to the same reasons discussed above or due to the arrival of an early cool change during the day.

The 1996/97 summer weekday maximum demands[53] are plotted in Figure A7.3, together with the demands of summer 2000/01, an equally warm summer. The shapes of the demand curves for both years are quite different. Both curves show summer daily MDs increasing slowly when daily average temperatures were between 18°C and 20°C. Demands increased rapidly, when daily average temperatures rose above 20°C, and more so in 1996/97 for daily average temperatures between 20°C and 25°C. While the summer MDs in 2000/01 continued rising almost linearly beyond 25°C, the 1996/97 summer MDs appeared to have reached saturation close to 30°C.

53 Excluding Public Holidays and exceptional days ending with a cool change in temperature

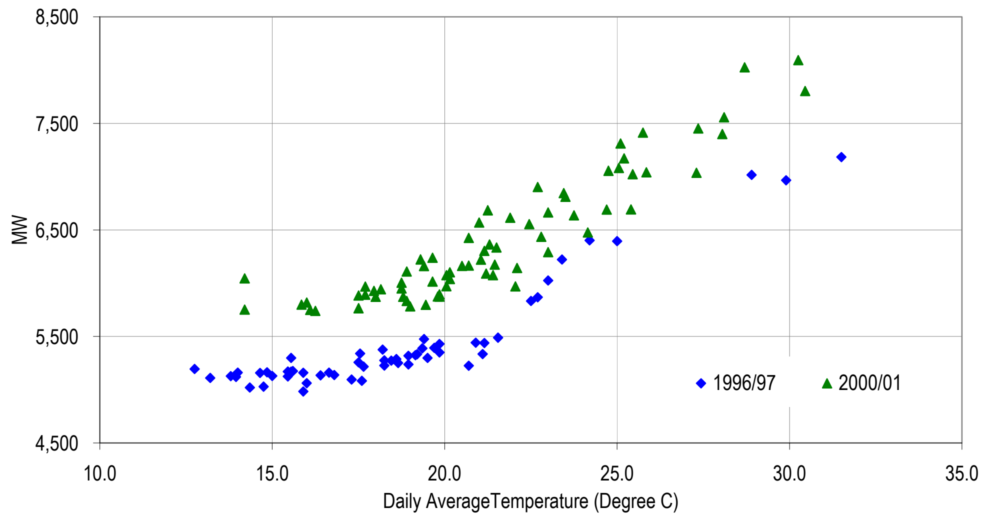


Figure A7.3 – Comparison of 1996/7 and 2000/01 Summer MD

Figure A7.4 compares the shape of the demand curves for 3 types of summer, a 10% (warm) summer represented by summer 1996/97, a 50% (average) summer represented by summer 2004/05 and a 90% (cool) summer represented by summer 2001/02. The shape of 2001/02 demand curve is comparatively flatter.

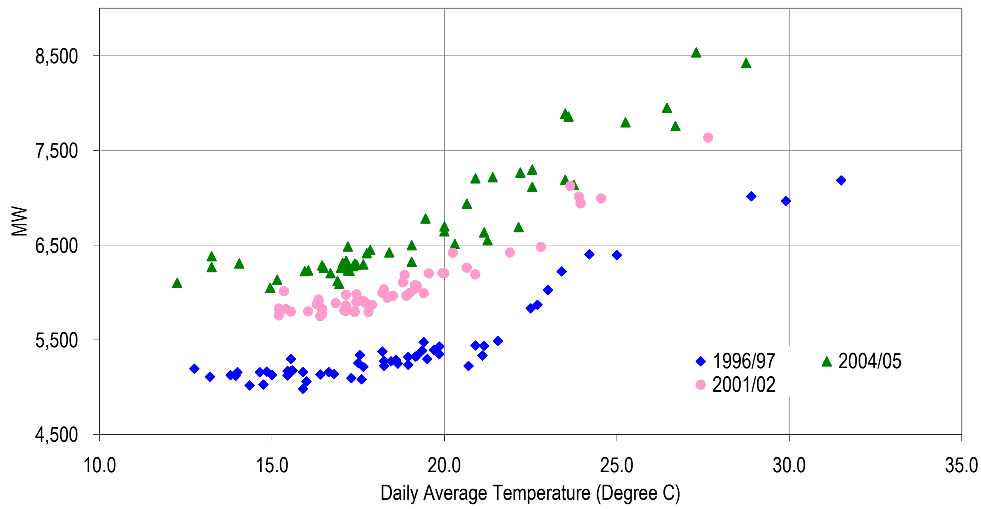


Figure A7.4 – Comparison of 1996/7 Summer MD and Other Years

Figure A7.5 shows that summer weekday temperature sensitive demand, below the 10% POE level, has increased steadily, by 25% since 1996/97, from below 180 MW/°C in 1996/97 to about 225 MW/°C in 2004/05.

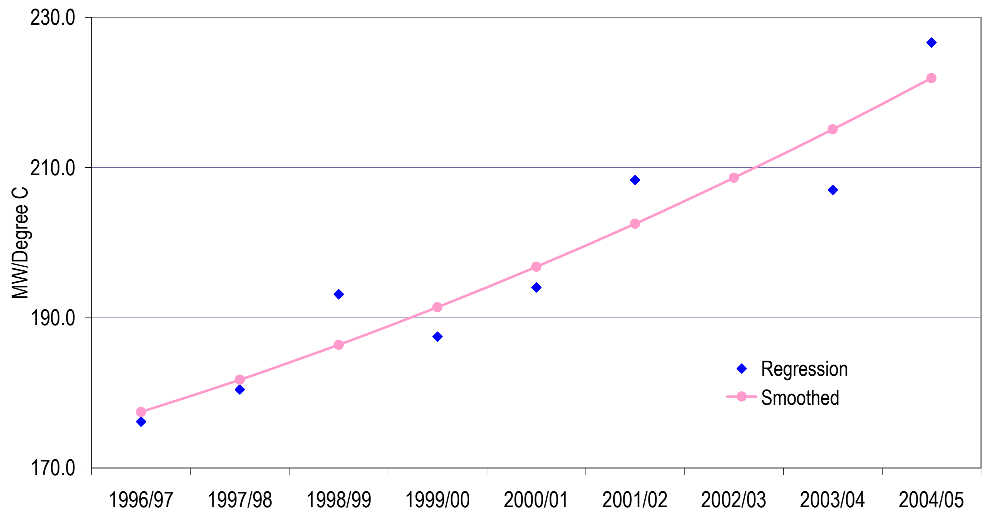


Figure A7.5 – Summer MD Temperature Sensitivities

Given limited amount of useful data for analysing the 10% POE summer demand and temperature relationship, NIEIR has applied the results from analysing South Australian summer MDs to the Victoria summer MD forecasts as the weather in SA is warmer and more stable. This means that the 10% POE forecast MDs are more uncertain.

A7.2 Correlation between Winter Daily Maximum Demand and Daily Average Temperature

Winter weekday MDs peak between 6:00pm and 6:30pm (AEST) as shown in Figure A7.6. The link between winter MD and temperature is not as strong as summer MD due to a smaller temperature sensitive component.

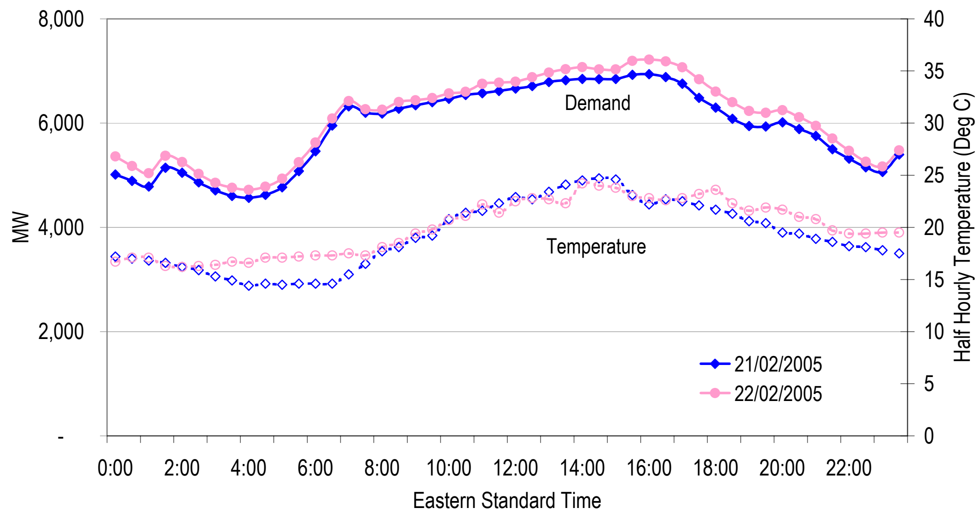


Figure A7.6 – Selected Winter MD and Temperature Profiles

Winter 2005 daily MD[54], excluding PH, is shown by day type in Figure A7.7. There is a greater diversity in winter demands, not explained by weather. Given similar weather conditions, Friday demands are about 3% lower than weekday demands whereas Saturday and Sunday demands are some 11% - 12% lower.

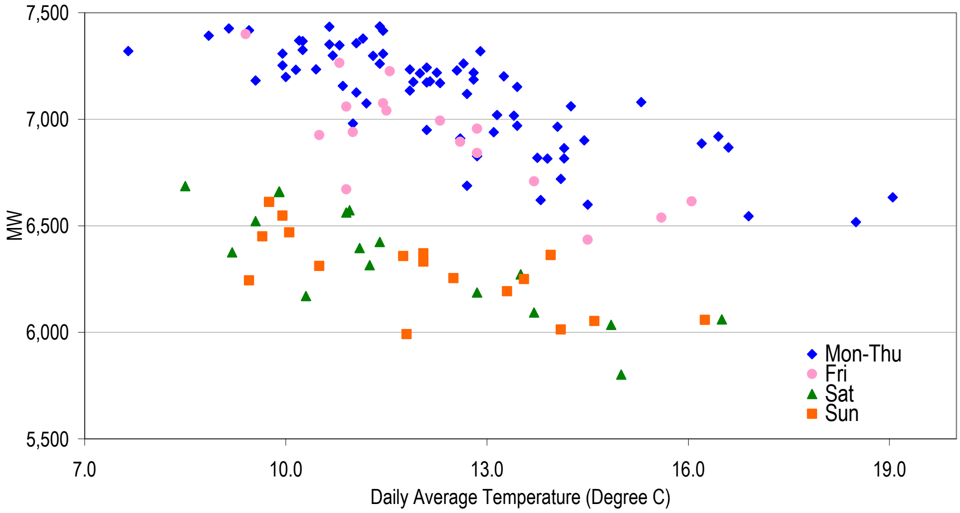


Figure A7.7 – Winter 2004 Maximum Demand by Day Type

A8 FORECAST SUMMER AND WINTER MAXIMUM DEMAND FOR HIGH AND LOW ECONOMIC GROWTH SCENARIOS

Table A8.1 shows that, under the High growth scenario, forecast 10% summer MDs are projected to grow at an average rate of 3.2% pa for the first 5 year period to 2009/10, and at a slower rate of 2.8% pa for the next 5 years. Under the Low growth scenario, slower growth of 1.7% pa and 1.4% pa is projected for each 5 year period to 2009/10 and 2014/15 respectively.

54 Between 15 May 2005 and 15 September 2005

	Year	Summer MD (MW) 10% POE	50% POE	90% POE	Annual % Growth 10% POE	50% POE	90% POE
High	2005/06	10,169	9,304	8,740	3.5%	3.3%	3.2%
	2006/07	10,505	9,599	9,008	3.3%	3.2%	3.1%
	2007/08	10,837	9,889	9,271	3.2%	3.0%	2.9%
Economic	2008/09	11,140	10,148	9,501	2.8%	2.6%	2.5%
	2009/10	11,474	10,441	9,767	3.0%	2.9%	2.8%
	2010/11	11,823	10,750	10,050	3.0%	3.0%	2.9%
Growth	2011/12	12,121	11,006	10,280	2.5%	2.4%	2.3%
	2012/13	12,491	11,334	10,580	3.1%	3.0%	2.9%
	2013/14	12,822	11,622	10,840	2.7%	2.5%	2.5%
	2014/15	13,176	11,937	11,130	2.8%	2.7%	2.7%
	2005-2010				3.2%	3.0%	2.9%
	2010-2015				2.8%	2.7%	2.6%
Low	2005/06	10,039	9,188	8,633	2.2%	2.0%	1.9%
	2006/07	10,239	9,355	8,778	2.0%	1.8%	1.7%
	2007/08	10,408	9,492	8,894	1.7%	1.5%	1.3%
Economic	2008/09	10,578	9,629	9,010	1.6%	1.4%	1.3%
	2009/10	10,691	9,713	9,075	1.1%	0.9%	0.7%
	2010/11	10,865	9,860	9,204	1.6%	1.5%	1.4%
Growth	2011/12	10,985	9,954	9,281	1.1%	1.0%	0.8%
	2012/13	11,119	10,063	9,374	1.2%	1.1%	1.0%
	2013/14	11,295	10,215	9,510	1.6%	1.5%	1.5%
	2014/15	11,437	10,338	9,621	1.3%	1.2%	1.2%
	2005-2010				1.7%	1.5%	1.4%
	2010-2015				1.4%	1.3%	1.2%

Table A8.1 – Summer Maximum Demand Forecasts
(Average Summer, High and Low Economic Growth)

Forecast winter MDs for High and Low growth scenarios are shown in Table A8.2. Under the High growth scenario, forecast 10% winter MDs are projected to grow at an average rate of 3.0% pa for the first 5 year period to 2009/10, and at a slower rate of 2.8% pa for the next 5 years. The projected growth is reduced to 0.5% pa and 1.2% pa under the Low growth scenario.

	Year	Winter MD (MW) 10% POE	50% POE	90% POE	Annual % Growth 10% POE	50% POE	90% POE
High	2005	8,368	8,128	7,916	4.1%	4.0%	3.9%
	2006	8,579	8,325	8,094	2.5%	2.4%	2.3%
	2007	8,827	8,557	8,306	2.9%	2.8%	2.6%
Economic	2008	9,050	8,764	8,495	2.5%	2.4%	2.3%
	2009	9,299	8,999	8,712	2.8%	2.7%	2.6%
	2010	9,584	9,267	8,961	3.1%	3.0%	2.9%
Growth	2011	9,829	9,496	9,169	2.6%	2.5%	2.3%
	2012	10,133	9,783	9,436	3.1%	3.0%	2.9%
	2013	10,402	10,036	9,670	2.7%	2.6%	2.5%
	2014	10,701	10,318	9,931	2.9%	2.8%	2.7%
	2005-2009				3.0%	2.9%	2.7%
	2009-2014				2.8%	2.8%	2.7%
Low	2005	7,909	7,680	7,480	-1.6%	-1.8%	-1.8%
	2006	7,972	7,735	7,522	0.8%	0.7%	0.6%
	2007	8,072	7,825	7,600	1.3%	1.2%	1.0%
Economic	2008	8,167	7,910	7,672	1.2%	1.1%	1.0%
	2009	8,221	7,958	7,711	0.7%	0.6%	0.5%
	2010	8,333	8,061	7,803	1.4%	1.3%	1.2%
Growth	2011	8,407	8,127	7,858	0.9%	0.8%	0.7%
	2012	8,496	8,208	7,930	1.1%	1.0%	0.9%
	2013	8,619	8,324	8,036	1.4%	1.4%	1.3%
	2014	8,728	8,426	8,130	1.3%	1.2%	1.2%
	2005-2009				0.5%	0.4%	0.3%
	2009-2014				1.2%	1.1%	1.1%

Table A8.2 – Winter Maximum Demand Forecasts (High and Low Economic Growth)

A9 BACKCASTING OF HISTORICAL SUMMER MAXIMUM DEMANDS

NIEIR has undertaken a preliminary back-casting exercise of historical summer MDs from 1989/90 to 2004/05. The objective of the exercise is to validate the current method of forecasting summer MDs explained in detail in Section A3.2. Details of the analysis are explained below.

For each year, 9 estimated % POE MDs are calculated (corresponding to three % POE summers and three % POE temperature standards). These estimated MDs form the % POE bands as shown in Figure A9.1 below. The estimated % POE MDs are derived from temperature sensitive load and cooling appliance utilisation rates. Temperature sensitive load is estimated from cooling appliance stock. Cooling appliance utilisation rates are estimated from the switching regression model. Table A9.1 shows that cooling appliance utilisation rates at the 10% POE temperature vary within a narrow band between 91% and 95%. This demonstrates that, most of the cooling capacity is utilised on hot summer days. However, the utilisation rates at the 50% and 90% POE temperatures display a greater degree of diversity.

	10% POE MD	50% POE MD	90% POE MD
10% POE Summer	95%	78%	65%
50% POE Summer	92%	74%	61%
90% POE Summer	91%	71%	55%

Table A9.1 – Cooling Appliance Utilisation Rates

The actual MDs are adjusted so that historical data is consistent with the summer MD forecasts, which assume summer MDs occur in mid February and on a weekday around 4:00pm (AEST). Table A9.2 displays the actual and adjusted actual summer MDs, and the POE temperatures for each year from 1989/90. The adjustments include:

- a correction for time of season which applies to summer MDs occurring before late January when demand is lower due to school closures;
- a correction for time of MD which applies to cases where a cool change in mid-afternoon leads to a sharp fall in load. The actual peak in these cases typically falls between 1:00pm and 2:30pm such as in 1989/90 and 2000/01
- a correction for cooling appliance sales. This applies to cases where actual MDs occur in early December (for eg 2003/04) when not all of the cooling appliances are installed

It should be noted that the effects of the State economic activities and other factors (previous day's temperature) have not been taken account in these corrections. For comparison purposes and for simplicity, the MDs are separated into 3 groups, according to the MD % POE temperatures. These groups are as shown below:

- Group 1 includes adjusted actual MDs (in 1991/92, 1995/96, 2001/02 and 2004/05 summers) with average temperatures closest to the 90% POE (this group is shaded in green in the table)

- Group 2 includes 8 adjusted actual MDs (in 1989/90, 1990/91, 1993/94, 1997/98, 1998/99, 1999/00, 2002/03 and 2003/04) with average temperatures closest to the 50% POE (this group is shaded in pink in the table)
- Group 3 includes adjusted actual MDs (in 1992/93, 1994/95, 1996/97, 2000/01) with average temperatures closest to the 10% POE (this group is shaded in blue in the table)

Year	Date	Time (AEST)	Actual (MW)	Adjusted Actual (MW)	Avg Temp	% POE Temperature	Group
1989/90	24-Jan-1990	1.30pm	5,754	5,999	28.6	67%	2
1990/91	25-Feb-1991	5.00pm	6,019	6,014	28.4	73%	2
1991/92	17-Feb-1992	5.00pm	5,775	5,775	26.0	94%	1
1992/93	3-Feb-1993	4.00pm	6,489	6,489	33.3	4%	3
1993/94	25-Jan-1994	5.00pm	6,134	6,234	28.2	74%	2
1994/95	6-Dec-1994	4.30 pm	6,509	6,554	30.7	23%	3
1995/96	26-Feb-1996	3.00pm	5,922	5,954	25.1	99%	1
1996/97	19-Feb-1997	4.00pm	7,115	7,115	31.5	15%	3
1997/98	26-Feb-1998	4.00pm	7,213	7,201	30.3	35%	2
1998/99	4-Feb-1999	3.30pm	7,576	7,626	29.7	45%	2
1999/00	2-Mar-2000	4.00pm	7,815	7,815	29.7	45%	2
2000/01	8-Feb-2001	1.30pm	8,179	8,479	30.3	35%	3
2001/02	14-Feb-2002	4.30pm	7,621	7,621	27.7	82%	1
2002/03	24-Feb-2003	4.30pm	8,203	8,183	30.1	41%	2
2003/04	17-Dec-2003	4.00pm	8,574	8,684	30.1	41%	2
2004/05	25-Jan-2004	4.30pm	8,535	8,645	27.3	90%	1

Table A9.2 – Historical Summer MDs and % POE Temperatures

Figure A9.1 compares the adjusted actual MDs, identified by the assigned grouping, with the estimated 90%, 50% and 10% POE MD bands. The upper and the lower bounds of each band correspond to the estimated MDs for 10%[55] and the 90% summers respectively.

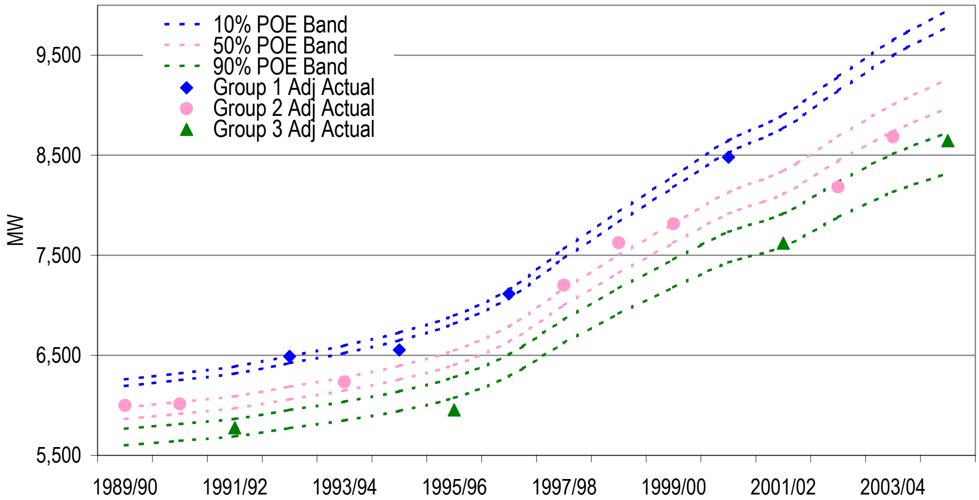


Figure A9.1 – Adjusted Actual Summer MDs and the %POE Bands

All of the adjusted actual MDs are within or outside the % POE bands, as expected, except 2002/03. The average temperature for the 2002/03 actual MD was 30.1°C, which places this MD close to the 50% POE level. However, the load on the day was significantly lower and falls within the 90% POE band. Table A9.3 summarises the back-casting results.

In conclusion, NIEIR has proved the robustness of the summer MD forecast system through the back-casting exercise. There is a greater uncertainty surrounding the 10% POE band, as there is little historical data to support the analysis. As this is the first back-casting exercise undertaken by NIEIR, some refinements to this work are expected in the future.

55 The 50% POE MDs are not shown in the chart

Year	Date	% POE Temperature	Group	Comments
1989/90	24-Jan-1990	67%	2	Adjusted actual MD within the 50% POE band
1990/91	25-Feb-1991	73%	2	Adjusted actual MD within the 50% POE band
1991/92	17-Feb-1992	94%	1	Adjusted actual MD within the 90% POE band
1992/93	3-Feb-1993	4%	3	Adjusted actual MD within the 10% POE band
1993/94	25-Jan-1994	74%	2	Adjusted actual MD within the 50% POE band
1994/95	6-Dec-1994	23%	3	Adjusted actual MD below the 10% POE band as expected as it was a 23% POE day
1995/96	26-Feb-1996	99%	1	Adjusted actual MD below the 90% POE band as expected as it was a 99% POE day
1996/97	19-Feb-1997	15%	3	Adjusted actual MD within the 10% POE band
1997/98	26-Feb-1998	35%	2	Adjusted actual MD slightly above the 50% POE band as it was a 35% POE day
1998/99	4-Feb-1999	45%	2	Adjusted actual MD slightly above the 50% POE band as it was a 45% POE day
1999/00	2-Mar-2000	45%	2	Adjusted actual MD slightly above the 50% POE band as it was a 45% POE day
2000/01	8-Feb-2001	35%	3	Adjusted actual MD slightly above the 10% POE band as it was a 35% POE day
2001/02	14-Feb-2002	82%	1	Adjusted actual MD within the 90% POE band
2002/03	24-Feb-2003	41%	2	Adjusted actual MD outside the 50% POE band
2003/04	17-Dec-2003	41%	2	Adjusted actual MD slightly below the 50% POE band
2004/05	25-Jan-2004	90%	1	Adjusted actual MD within the 90% POE band

Table A9.3 – Summary of Backcasting Results

B TERMINAL STATION DEMAND FORECASTS (2004/05 – 2013/14)

VENCorp has prepared and makes available load forecasts for points of connection within the shared electricity transmission network in Victoria, as required by the Victorian Electricity System Code (section 6.260.1.3) and the National Electricity Code (clause 5.6.2a section b.1).

The forecasts for each terminal station in Victoria are provided in the following tables, and the detailed report *"Terminal Station Demand Forecasts 2004/05 - 2013/14"*, is available online on VENCorp's website (www.vencorp.com.au).

Alinta Summer Peak Forecasts by Terminal Station

Terminal Station	POE	2005 MW	2005 MVAr	2006 MW	2006 MVAr	2007 MW	2007 MVAr	2008 MW	2008 MVAr	2009 MW	2009 MVAr	2010 MW	2010 MVAr	2011 MW	2011 MVAr	2012 MW	2012 MVAr	2013 MW	2013 MVAr	2014 MW	2014 MVAr
Heatherton 66 kV [56]	10	329.5	86.3	340.2	89.1	349.6	91.5	358.7	93.9	368.3	96.5	379.5	99.4	390.3	102.24	399.9	104.7	409.7	107.3	419.7	109.9
	50	321.7	84.3	332.0	86.9	341.1	89.4	349.9	91.6	359.2	94.1	370.0	96.9	380.5	99.7	389.7	102.1	399.2	104.6	408.9	107.1
Malvern 22 kV	10	73.0	25.5	64.0	22.4	65.6	22.9	66.9	23.4	68.4	23.9	70.0	24.5	71.5	25.0	72.9	25.5	74.3	26.0	75.7	26.5
	50	71.9	25.1	63.3	22.1	64.9	22.7	66.2	23.1	67.6	23.6	69.2	24.2	70.7	24.7	72.0	25.3	73.4	25.7	74.8	26.1
Malvern 66 kV	10	116.9	26.8	131.7	30.2	135.5	31.1	139.2	32.0	143.0	32.8	147.4	33.8	151.6	34.8	155.6	35.7	159.6	36.6	163.8	37.6
	50	114.0	26.2	128.2	29.4	131.8	30.3	135.4	31.1	139.0	31.9	143.2	32.9	147.3	33.8	151.1	34.7	155.0	35.6	159.0	36.5
Tyabb 66 kV	10	220.1	58.8	229.1	61.2	237.8	63.6	246.0	65.7	253.9	67.9	263.1	70.3	272.2	72.8	280.4	75.0	288.8	77.2	297.4	79.5
	50	213.6	57.1	222.2	59.4	230.6	61.6	238.4	63.7	246.0	65.8	254.9	68.1	263.7	70.5	271.6	72.6	279.6	74.8	287.9	77.0

Alinta Winter Peak Forecasts by Terminal Station

Terminal Station	POE	2005 MW	2005 MVAr	2006 MW	2006 MVAr	2007 MW	2007 MVAr	2008 MW	2008 MVAr	2009 MW	2009 MVAr	2010 MW	2010 MVAr	2011 MW	2011 MVAr	2012 MW	2012 MVAr	2013 MW	2013 MVAr	2014 MW	2014 MVAr
Heatherton 66 kV [56]	10	294.9	53.1	255.5	46.0	259.2	46.7	262.2	47.2	267.7	48.2	273.1	49.2	280.8	50.6	288.1	51.9	295.0	53.2	302.1	54.4
	50	289.9	52.2	251.2	45.3	254.6	45.9	257.4	46.4	262.7	47.3	267.8	48.3	275.3	49.6	282.3	50.9	288.9	52.1	295.7	53.3
Malvern 22 kV	10	70.1	22.4	63.2	20.2	55.0	17.6	55.9	17.9	57.4	18.4	58.3	18.7	59.5	19.0	60.7	19.4	62.0	19.8	63.4	20.3
	50	69.0	22.1	62.5	20.0	54.7	17.5	55.6	17.8	57.0	18.3	58.0	18.5	59.1	18.9	60.2	19.3	61.5	19.7	62.9	20.1
Malvern 66 kV	10	80.1	12.1	91.0	13.8	101.3	15.4	103.3	15.7	106.3	16.1	108.7	16.5	111.3	16.9	114.3	17.3	117.3	17.8	120.3	18.2
	50	78.8	11.9	89.1	13.5	98.8	15.0	100.7	15.3	103.6	15.7	105.8	16.0	108.4	16.4	111.2	16.8	114.0	17.3	117.0	17.7
Tyabb 66 kV	10	195.8	37.0	201.8	38.2	206.0	39.0	210.4	39.8	217.6	41.2	223.7	42.3	230.1	43.5	236.4	44.7	243.4	46.0	250.6	47.4
	50	191.3	36.2	197.0	37.3	201.0	38.0	205.2	38.8	212.1	40.1	218.0	41.2	224.1	42.4	230.2	43.5	236.9	44.8	243.8	46.1

[56] Forecast assumed load transfer to the new CBTS after next summer season.

Citipower Summer Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	95.6	46.4	105.3	52.8	108.7	55.1	111.0	56.7	113.3	58.3	115.7	60.0	118.0	61.6	120.4	63.2	122.7	64.9	125.1	66.6
	50	88.5	41.8	97.5	47.8	100.6	49.9	102.8	51.4	104.9	52.9	107.1	54.4	109.3	55.9	111.5	57.4	113.7	58.9	115.9	60.5
West Melbourne 22 kV	10	94.8	60.5	102.8	68.0	108.8	73.6	113.6	78.1	116.7	81.0	119.8	84.0	122.9	87.0	126.1	90.1	129.3	93.2	132.5	96.3
	50	89.4	56.2	97.0	63.2	102.6	68.5	107.2	72.7	110.1	75.5	113.0	78.3	116.0	81.2	119.0	84.0	122.0	87.0	125.0	89.9
West Melbourne 66 kV	10	416.3	204.7	437.2	226.0	451.4	239.2	479.1	254.1	489.6	263.9	500.4	274.0	511.4	284.2	522.5	294.6	533.7	305.3	545.0	316.1
	50	392.6	187.1	412.2	207.2	425.7	219.7	451.7	233.7	461.6	243.0	471.8	252.4	482.2	262.1	492.6	271.9	503.2	282.0	513.9	292.2

Citipower Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	74.9	30.6	82.5	35.4	89.0	39.3	91.0	40.7	93.1	42.1	95.2	43.5	97.3	44.9	99.4	46.3	101.5	47.7	103.6	49.1
	50	72.0	28.9	79.4	33.4	85.5	37.2	87.5	38.5	89.5	39.9	91.5	41.2	93.5	42.5	95.6	43.9	97.6	45.2	99.6	46.6
West Melbourne 22 kV	10	80.6	42.7	85.5	46.9	91.6	52.2	97.0	56.9	102.3	61.5	105.2	64.1	108.1	66.7	111.0	69.3	114.0	72.0	117.0	74.7
	50	77.5	40.4	82.2	44.5	88.1	49.5	93.3	54.1	98.3	58.5	101.1	61.0	103.9	63.5	106.8	66.0	109.6	68.6	112.5	71.2
West Melbourne 66 kV	10	317.5	115.9	340.3	136.5	353.8	150.3	364.3	159.8	386.4	170.6	395.1	178.6	403.9	186.7	412.9	195.0	421.9	203.5	431.1	212.1
	50	305.8	107.5	327.6	127.3	340.6	140.6	350.7	149.7	372.1	160.2	380.5	167.8	389.0	175.6	397.6	183.6	406.3	191.7	415.1	200.0

Powercor Summer Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV	10	154.2	80.5	159.0	70.0	162.7	58.6	167.9	60.5	172.7	62.2	176.8	63.7	180.1	64.9	183.5	66.1	187.0	67.4	190.6	68.7
	50	154.2	80.5	159.0	70.0	162.7	58.6	167.9	60.5	172.7	62.2	176.8	63.7	180.1	64.9	183.5	66.1	187.0	67.4	190.6	68.7
Bendigo 22 kV	10	33.8	17.9	36.4	19.2	41.2	21.8	42.1	22.3	43.0	22.7	46.2	24.4	47.2	25.0	52.3	27.7	53.4	28.3	54.6	28.9
	50	32.8	17.4	35.4	18.7	40.2	21.3	41.1	21.7	42.0	22.2	45.2	23.9	46.2	24.4	51.3	27.1	52.4	27.7	53.6	28.4
Bendigo 66 kV	10	150.6	49.5	151.9	50.0	150.8	49.6	152.7	50.2	155.5	51.2	156.4	51.5	159.4	52.4	158.2	52.0	161.2	53.0	164.2	54.0
	50	143.6	47.2	144.9	47.7	143.8	47.3	145.7	47.9	148.5	48.9	149.4	49.2	152.4	50.1	151.2	49.7	154.2	50.7	157.2	51.7
Brooklyn 22 kV	10	60.2	40.9	57.7	39.3	58.6	39.9	59.5	40.6	60.4	41.2	61.4	41.8	62.3	42.5	63.3	43.1	64.4	43.8	65.5	44.6
	50	60.1	40.9	57.7	39.3	58.6	39.9	59.5	40.6	60.4	41.2	61.4	41.8	62.3	42.5	63.3	43.1	64.3	43.8	65.5	44.6

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV	10	154.2	51.8	159.0	53.4	162.7	42.2	167.9	30.3	172.7	31.4	176.8	32.3	180.1	33.2	183.5	33.9	187.0	34.7	190.6	35.4
	50	157.2	51.8	161.9	53.4	167.4	42.2	171.8	30.3	177.9	31.4	183.5	32.3	188.2	33.2	192.2	33.9	196.8	34.7	201.0	35.4
Bendigo 22 kV	10	24.6	8.3	28.0	9.5	30.1	10.2	34.7	11.8	35.4	12.0	36.2	12.3	39.2	13.3	40.1	13.6	44.6	15.1	45.6	15.5
	50	24.6	8.3	28.0	9.5	30.1	10.2	34.7	11.8	35.4	12.0	36.2	12.3	39.2	13.3	40.1	13.6	44.6	15.1	45.6	15.5
Bendigo 66 kV	10	128.7	14.0	130.3	14.2	131.5	14.3	130.7	14.2	132.1	14.4	134.6	14.6	135.4	14.7	137.9	15.0	137.2	14.9	139.8	15.2
	50	128.7	14.0	130.3	14.2	131.5	14.3	130.7	14.2	132.1	14.4	134.6	14.6	135.4	14.7	137.9	15.0	137.2	14.9	139.8	15.2
Brooklyn 22 kV	10	59.2	39.1	56.9	37.7	58.8	38.8	59.6	39.4	60.4	39.9	61.3	40.5	62.3	41.1	63.2	41.7	64.2	42.4	65.1	43.0
	50	59.2	39.1	56.9	37.6	58.7	38.8	59.6	39.4	60.4	39.9	61.3	40.5	62.2	41.1	63.2	41.7	64.2	42.4	65.1	43.0

Powercor Summer Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Brooklyn-SCI 66 kV	10	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
	50	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
Geelong 66 kV	10	345.1	105.6	358.0	109.6	362.9	111.1	369.7	113.2	373.3	114.3	378.7	115.9	382.1	117.0	385.5	118.0	389.1	119.1	392.6	120.2
	50	337.1	103.2	350.0	107.1	354.9	108.6	361.7	110.7	365.3	111.8	370.7	113.5	374.1	114.5	377.5	115.6	381.1	116.6	384.6	117.7
Horsham 66 kV	10	71.3	21.4	78.9	23.7	79.8	23.9	80.7	24.2	81.7	24.5	82.7	24.8	83.6	25.1	84.6	25.4	85.6	25.7	86.7	26.0
	50	69.3	20.8	76.9	23.1	77.8	23.3	78.7	23.6	79.7	23.9	80.7	24.2	81.6	24.5	82.6	24.8	83.6	25.1	84.7	25.4
Kerang 22 kV	10	11.6	3.7	11.9	3.8	12.2	3.9	12.3	3.9	12.5	4.0	12.7	4.1	12.9	4.1	13.1	4.2	13.3	4.2	13.5	4.3
	50	11.2	3.6	11.5	3.7	11.8	3.8	11.9	3.8	12.1	3.9	12.3	3.9	12.5	4.0	12.7	4.1	12.9	4.1	13.1	4.2
Kerang 66 kV	10	51.4	13.5	54.3	14.2	56.7	14.8	59.6	15.6	61.4	16.1	63.3	16.6	65.1	17.0	66.8	17.5	68.6	18.0	70.4	18.4
	50	50.4	13.2	53.3	14.0	55.7	14.6	58.6	15.3	60.4	15.8	62.3	16.3	64.1	16.8	65.8	17.2	67.6	17.7	69.4	18.2

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Brooklyn-SCI 66 kV	10	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
	50	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
Geelong 66 kV	10	316.3	46.3	331.1	48.5	341.0	49.9	345.5	50.6	352.1	51.6	355.5	52.1	360.4	52.8	363.5	53.2	366.7	53.7	369.8	54.2
	50	316.3	46.3	331.1	48.5	341.0	49.9	345.5	50.6	352.1	51.6	355.5	52.1	360.4	52.8	363.5	53.2	366.7	53.7	369.8	54.2
Horsham 66 kV	10	66.8	5.4	71.3	5.7	74.6	6.0	75.4	6.0	76.3	6.1	77.1	6.2	78.0	6.2	78.8	6.3	79.7	6.4	80.6	6.5
	50	66.8	5.4	71.3	5.7	74.6	6.0	75.4	6.0	76.3	6.1	77.1	6.2	78.0	6.2	78.8	6.3	79.7	6.4	80.6	6.5
Kerang 22 kV	10	12.2	2.0	12.3	2.0	12.5	2.0	12.6	2.0	12.8	2.0	13.0	2.1	13.1	2.1	13.3	2.1	13.4	2.1	13.6	2.2
	50	12.2	2.0	12.3	2.0	12.5	2.0	12.6	2.0	12.8	2.0	13.0	2.1	13.1	2.1	13.3	2.1	13.4	2.1	13.6	2.2
Kerang 66 kV	10	48.5	3.6	49.9	3.7	52.5	3.9	54.2	4.0	56.6	4.2	58.3	4.3	60.1	4.4	61.7	4.6	63.4	4.7	65.1	4.8
	50	48.5	3.6	49.9	3.7	52.5	3.9	54.2	4.0	56.6	4.2	58.3	4.3	60.1	4.4	61.7	4.6	63.4	4.7	65.1	4.8

Powercor Summer Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	40.7	22.7	41.6	23.2	42.4	23.6	43.3	24.1	44.2	24.6	45.2	25.1	46.1	25.7	47.1	26.2	48.1	26.8	49.1	27.3
	50	39.7	22.1	40.6	22.6	41.4	23.1	42.3	23.6	43.2	24.1	44.2	24.6	45.1	25.1	46.1	25.7	47.1	26.2	48.1	26.8
Red Cliffs 66 kV	10	123.7	35.2	128.3	36.6	133.2	37.9	140.8	40.1	144.7	41.2	148.5	42.3	152.4	43.4	156.5	44.6	160.6	45.8	164.8	47.0
	50	119.7	34.1	124.3	35.4	129.2	36.8	136.8	39.0	140.7	40.1	144.5	41.2	148.4	42.3	152.5	43.5	156.6	44.6	160.8	45.8
Shepparton 66 kV	10	272.2	108.6	277.4	110.7	285.1	113.8	290.8	116.0	296.7	118.4	302.7	120.8	308.9	123.2	315.2	125.8	321.7	128.3	328.3	131.0
	50	257.2	102.6	262.4	104.7	270.1	107.8	275.8	110.1	281.7	112.4	287.7	114.8	293.9	117.3	300.2	119.8	306.7	122.4	313.3	125.0
Tyabb 220 kV	10	65.9	37.5	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7
	50	65.9	37.5	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7
Terang 66 kV	10	163.9	67.7	168.6	69.6	174.0	71.8	177.2	73.2	180.5	74.5	183.9	75.9	187.3	77.4	190.9	78.8	194.4	80.3	198.1	81.8
	50	163.9	67.7	168.6	69.6	174.0	71.8	177.2	73.2	180.5	74.5	183.9	75.9	187.3	77.4	190.9	78.8	194.4	80.3	198.1	81.8

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	22.7	5.3	23.1	5.4	23.5	5.5	23.8	5.6	24.2	5.6	24.6	5.7	25.0	5.8	25.4	5.9	25.9	6.0	26.3	6.1
	50	22.7	5.3	23.1	5.4	23.5	5.5	23.8	5.6	24.2	5.6	24.6	5.7	25.0	5.8	25.4	5.9	25.9	6.0	26.3	6.1
Red Cliffs 66 kV	10	100.1	4.7	105.7	5.0	108.4	5.1	111.2	5.2	116.7	5.5	119.4	5.6	122.1	5.7	125.1	5.9	128.1	6.0	131.0	6.2
	50	100.1	4.7	105.7	5.0	108.4	5.1	111.2	5.2	116.7	5.5	119.4	5.6	122.1	5.7	125.1	5.9	128.1	6.0	131.0	6.2
Shepparton 66 kV	10	213.3	25.2	219.0	25.8	223.8	26.4	228.8	27.0	233.9	27.6	239.0	28.2	244.2	28.8	249.6	29.5	255.1	30.1	260.8	30.8
	50	213.3	25.2	219.0	25.8	223.8	26.4	228.8	27.0	233.9	27.6	239.0	28.2	244.2	28.8	249.6	29.5	255.1	30.1	260.8	30.8
Tyabb 220 kV	10	66.9	40.8	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0
	50	66.9	40.8	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0
Terang 66 kV	10	167.6	30.0	176.7	31.6	181.6	32.5	188.1	33.7	191.1	34.2	194.3	34.8	197.6	35.4	200.9	36.0	204.3	36.6	207.7	37.2
	50	167.6	30.0	176.7	31.6	181.6	32.5	188.1	33.7	191.1	34.2	194.3	34.8	197.6	35.4	200.9	36.0	204.3	36.6	207.7	37.2

TXU Summer Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [57]	10	91.4	48.1	92.8	48.8	94.2	49.6	95.7	50.3	97.1	51.0	98.6	51.7	100.0	52.5	101.5	53.2	102.9	53.9	104.4	54.6
	50	87.0	45.8	88.4	46.5	89.8	47.2	91.1	47.9	92.5	48.6	93.9	49.3	95.3	50.0	96.6	50.6	98.0	51.3	99.4	52.0
Mount Beauty 66 kV [58]	10	36.6	5.2	37.2	5.5	37.9	5.9	38.6	6.2	39.2	6.5	39.9	6.9	40.6	7.2	41.2	7.5	41.9	7.9	42.6	8.2
	50	33.3	4.7	33.9	5.0	34.5	5.3	35.1	5.6	35.7	5.9	36.3	6.2	36.9	6.5	37.5	6.9	38.1	7.2	38.7	7.5
Wodonga 22 kV	10	26.5	14.7	26.8	14.8	27.0	14.9	27.3	15.1	27.6	15.2	27.8	15.3	28.1	15.5	28.4	15.6	28.6	15.7	28.9	15.9
	50	26.0	14.4	26.3	14.5	26.5	14.6	26.8	14.8	27.0	14.9	27.3	15.0	27.5	15.2	27.8	15.3	28.1	15.4	28.3	15.5
Wodonga 66 kV [59]	10	62.1	21.0	62.7	21.3	63.2	21.6	63.8	21.9	64.4	22.1	64.9	22.4	65.5	22.7	66.1	23.0	66.6	23.3	67.2	23.6
	50	60.9	20.6	61.4	20.9	62.0	21.2	62.5	21.4	63.1	21.7	63.7	22.0	64.2	22.3	64.8	22.5	65.3	22.8	65.9	23.1
Yallourn 11 kV	10	21.5	13.3	3.6	2.2	3.6	2.2	3.7	2.3	3.7	2.3	3.8	2.3	3.8	2.4	3.9	2.4	4.0	2.5	4.0	2.5
	50	21.1	13.1	3.5	2.2	3.6	2.2	3.6	2.2	3.7	2.3	3.7	2.3	3.8	2.3	3.8	2.4	3.9	2.4	3.9	2.4

TXU Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [57]	10	109.2	33.4	109.6	33.6	111.1	34.3	112.6	35.1	114.1	35.8	115.6	36.6	117.1	37.3	118.6	38.1	120.1	38.8	121.6	39.6
	50	104.0	31.8	104.4	32.0	105.8	32.7	107.3	33.4	108.7	34.1	110.1	34.8	111.5	35.6	113.0	36.3	114.4	37.0	115.8	37.7
Mount Beauty 66 kV [58]	10	53.4	7.5	54.8	8.2	56.2	8.9	57.6	9.6	59.0	10.3	60.4	11.0	61.8	11.7	63.2	12.4	64.6	13.1	65.9	13.8
	50	50.8	7.1	52.2	7.8	53.5	8.4	54.8	9.1	56.2	9.8	57.5	10.4	58.8	11.1	60.1	11.8	61.5	12.4	62.8	13.1
Wodonga 22 kV	10	29.1	6.0	29.4	6.1	29.7	6.3	30.0	6.4	30.3	6.6	30.6	6.8	30.9	6.9	31.2	7.1	31.5	7.2	31.9	7.4
	50	28.5	5.9	28.8	6.0	29.1	6.2	29.4	6.3	29.7	6.5	30.0	6.6	30.3	6.8	30.6	6.9	30.9	7.1	31.2	7.2
Wodonga 66 kV [59]	10	47.3	23.4	46.7	23.1	47.1	23.3	47.5	23.5	47.9	23.7	48.3	23.9	48.7	24.1	49.1	24.3	49.6	24.5	50.0	24.7
	50	46.4	22.9	45.8	22.6	46.2	22.8	46.6	23.0	47.0	23.2	47.4	23.4	47.8	23.6	48.2	23.8	48.6	24.0	49.0	24.2
Yallourn 11 kV	10	22.8	11.1	4.1	2.0	4.2	2.0	4.3	2.1	4.5	2.2	4.5	2.2	4.6	2.2	4.7	2.3	4.8	2.3	4.9	2.4
	50	22.4	10.8	4.0	1.9	4.1	2.0	4.2	2.1	4.4	2.1	4.5	2.2	4.5	2.2	4.6	2.2	4.7	2.3	4.8	2.3

57 Lake William Hovell embedded generator is considered as a negative load.

58 Forecasts are on the basis Clover power station (24 MW) embedded generation is not operating.

59 Forecast excludes generation from Hume Power Station.

Peak Summer Forecasts by Shared Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [60]	10	430.9	167.3	452.2	175.0	458.0	176.7	450.8	172.9	459.8	176.2	469.7	179.8	480.4	183.8	491.2	187.7	502.4	191.9	514.0	196.1
	50	407.3	158.4	428.4	166.0	434.5	167.8	428.1	164.4	437.0	167.6	446.8	171.2	457.3	175.1	468.0	179.0	479.0	183.1	490.5	187.3
Brunswick 22 kV	10	88.5	54.7	90.2	55.8	90.2	55.8	91.1	56.5	92.5	57.4	94.3	58.6	96.0	59.7	97.8	60.9	99.6	62.1	101.4	63.3
	50	82.4	50.9	84.0	51.9	84.1	52.0	84.9	52.6	86.3	53.5	87.9	54.6	89.5	55.7	91.1	56.8	92.8	57.9	94.5	59.0
Cranbourne 66 kV [61]	10	210.6	82.7	220.5	87.2	231.0	91.9	241.9	96.9	253.0	101.9	262.3	106.0	271.7	110.2	281.2	114.5	291.1	119.0	301.5	123.6
	50	202.1	79.1	213.3	83.9	223.3	88.4	233.6	93.1	244.2	97.9	253.1	101.8	262.1	105.8	271.1	109.8	280.6	114.1	290.5	118.5
East Rowville 66 kV [62]	10	463.9	171.3	483.4	179.1	502.7	186.9	521.6	194.7	541.3	202.8	561.2	210.8	580.7	218.6	599.1	226.2	617.0	233.5	635.6	241.1
	50	447.2	164.8	465.8	172.2	484.1	179.6	502.1	187.0	520.8	194.7	539.8	202.2	558.4	209.7	575.8	216.9	592.9	223.8	610.6	231.1
Fishermans Bend 66 kV	10	243.6	106.6	259.7	119.0	272.7	129.3	283.6	138.2	291.7	145.3	299.9	152.4	308.0	159.6	316.1	166.9	324.2	174.2	332.3	181.7
	50	231.6	97.8	247.0	109.6	259.3	119.4	269.6	127.9	277.4	134.6	285.1	141.4	292.8	148.2	300.5	155.2	308.1	162.1	315.7	169.2

Peak Winter Forecasts by Shared Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [60]	10	368.0	123.6	391.4	131.0	402.5	134.5	407.3	135.3	402.8	133.2	410.5	135.6	419.1	138.3	427.9	141.1	437.0	143.9	446.4	146.9
	50	362.5	121.8	385.8	129.1	396.9	132.6	401.8	133.5	397.5	131.5	405.2	133.9	413.7	136.6	422.6	139.3	431.6	142.1	441.0	145.1
Brunswick 22 kV	10	85.6	41.3	86.1	41.6	87.5	42.3	87.4	42.3	88.0	42.7	89.1	43.3	90.3	43.9	91.6	44.6	92.9	45.3	94.2	45.9
	50	82.2	39.7	82.8	40.0	84.1	40.7	84.0	40.7	84.6	41.0	85.6	41.6	86.8	42.2	88.0	42.8	89.3	43.5	90.5	44.2
Cranbourne 66 kV [61]	10	0.0	0.0	192.4	53.5	200.0	56.9	207.7	60.6	217.1	64.6	226.6	68.9	234.0	72.1	241.5	75.3	249.5	78.7	257.8	82.3
	50	0.0	0.0	186.9	51.8	194.1	55.1	201.6	58.5	210.5	62.4	219.6	66.4	226.7	69.5	233.9	72.6	241.6	75.9	249.5	79.3
East Rowville 66 kV [62]	10	502.8	126.6	378.4	93.0	388.9	97.2	398.7	101.2	411.2	106.0	423.6	110.8	435.3	114.9	446.5	118.8	459.2	123.0	472.4	127.4
	50	486.8	122.2	367.4	90.0	377.3	94.0	386.6	97.9	398.6	102.4	410.4	106.9	421.6	110.9	432.3	114.6	444.6	118.7	457.3	122.9
Fishermans Bend 66 kV	10	219.0	71.3	232.0	80.7	247.6	91.9	257.9	99.6	267.8	107.2	275.5	113.5	283.1	119.7	290.8	126.1	298.4	132.5	306.1	138.9
	50	212.7	67.1	225.3	76.2	240.5	87.1	250.5	94.6	260.1	102.0	267.6	108.0	275.1	114.1	282.5	120.3	289.9	126.5	297.4	132.8

60 Air Liquide load is included in load forecasts. Air Liquide may be directly supplied from ATS 66 kV bus in 2003.

61 Cranbourne terminal station is expected to supply mainly Berwick, Pakenham and Frankston area loads transferred from East Rowville and Heatherton terminal stations.

62 Forecast assumed load transfer to the new CBTS after next summer season. 15 MW of embedded generation is considered as negative load.

Peak Summer Forecasts by Shared Terminal Station

Terminal Station	POE	2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Keilor 66 kV	10	480.8	225.5	497.3	233.4	522.6	245.6	540.0	253.6	555.7	260.8	571.4	267.9	586.9	275.0	602.2	281.9	617.9	289.1	634.4	296.6
	50	453.2	212.6	469.1	220.2	493.5	231.9	510.5	239.7	525.9	246.7	541.4	253.7	556.5	260.6	571.5	267.4	587.0	274.4	603.1	281.8
Loy Yang 66 kV [63]	10	37.0	32.2	37.3	32.4	37.5	32.7	37.8	32.9	38.1	33.1	38.3	33.4	38.6	33.6	38.9	33.9	39.1	34.1	39.4	34.4
	50	36.5	31.7	36.8	32.0	37.0	32.2	37.3	32.4	37.5	32.7	37.8	32.9	38.0	33.1	38.3	33.4	38.6	33.6	38.8	33.8
Morwell/Loy Yang 66 kV [64]	10	360.2	101.2	364.5	103.3	368.8	105.4	372.9	107.5	377.1	109.6	381.2	111.7	385.5	113.8	389.8	115.9	394.0	118.1	398.3	120.2
	50	350.0	98.4	354.2	100.5	358.3	102.6	362.4	104.6	366.4	106.6	370.4	108.7	374.6	110.7	378.7	112.8	382.8	114.9	387.0	116.9
Richmond 66 kV	10	512.1	248.1	529.4	262.9	539.3	271.2	548.8	279.1	558.2	287.0	568.0	295.1	577.7	303.3	587.4	311.4	597.1	319.7	606.9	328.0
	50	476.9	220.4	493.0	234.2	502.3	241.8	511.1	249.2	519.9	256.6	529.0	264.1	538.1	271.7	547.1	279.3	556.1	286.9	565.3	294.6
Ringwood 22 kV	10	96.2	44.1	98.9	45.4	101.7	46.7	104.3	47.9	106.7	49.0	109.3	50.3	111.9	51.5	114.3	52.7	116.5	53.7	118.6	54.7
	50	93.2	42.7	95.9	43.9	98.5	45.1	101.0	46.3	103.3	47.4	105.9	48.6	108.5	49.8	110.8	50.9	112.9	51.9	115.0	52.9

Peak Winter Forecasts by Shared Terminal Station

Terminal Station	POE	2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Keilor 66 kV	10	400.1	152.9	409.7	156.8	424.4	162.5	446.3	171.3	459.8	176.3	473.4	181.2	485.5	185.6	498.5	190.2	511.3	194.8	524.6	199.6
	50	392.6	150.0	402.0	153.8	416.6	159.5	438.2	168.1	451.6	173.1	465.1	178.0	477.2	182.4	490.2	187.0	502.9	191.5	516.2	196.3
Loy Yang 66 kV [63]	10	37.2	29.9	37.5	30.1	37.7	30.3	38.0	30.6	38.3	30.8	38.5	31.0	38.8	31.2	39.1	31.4	39.4	31.7	39.7	31.9
	50	36.7	29.5	36.9	29.7	37.2	29.9	37.4	30.1	37.7	30.3	38.0	30.5	38.3	30.8	38.5	31.0	38.8	31.2	39.1	31.4
Morwell/Loy Yang 66 kV [64]	10	401.7	90.9	405.8	92.9	410.3	95.1	414.8	97.4	419.3	99.7	423.8	101.9	428.3	104.2	432.9	106.5	437.4	108.7	442.0	111.0
	50	390.3	88.4	394.2	90.4	398.6	92.6	403.0	94.8	407.4	97.0	411.7	99.2	416.1	101.4	420.6	103.6	425.0	105.8	429.4	108.0
Richmond 66 kV	10	436.2	143.1	452.5	155.7	463.4	164.3	471.3	170.5	479.7	176.8	488.2	183.2	496.8	189.7	505.5	196.2	514.3	202.9	523.2	209.5
	50	420.5	132.5	436.1	144.6	446.6	152.9	454.2	158.8	462.3	164.9	470.4	171.0	478.7	177.3	487.1	183.6	495.5	189.9	504.1	196.3
Ringwood 22 kV	10	83.6	35.8	86.6	36.9	88.8	37.6	90.8	38.3	93.5	39.1	96.1	40.0	99.0	41.0	102.2	42.0	105.5	43.1	108.9	44.3
	50	80.8	34.7	83.6	35.6	85.7	36.3	87.6	37.0	90.1	37.8	92.6	38.6	95.4	39.5	98.4	40.5	101.5	41.6	104.7	42.7

[63] Forecasts allow for continuous Loy Yang power station load of 10 MW and 15 MW of open-cut load. For an outage of unit transformer Loy Yang load could increase by up to 50 MW.

[64] Forecasts are on the basis that Morwell G1-3 units (80 MW), Duke (80 MW) and Toora wind farm (21 MW) generators are not operating, but that full output is provided by small embedded generators (26 MW), ie: considered as negative loads. Forecasts allow for continuous Loy Yang power station load of 10 MW and 15 MW of open-cut load. For an outage of unit transformer Loy Yang load could increase by up to 50 MW.

Peak Summer Forecasts by Shared Terminal Station

Terminal Station	POE	2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ringwood 66 kV	10	439.0	179.4	456.7	186.6	475.4	193.8	490.6	200.7	506.4	207.9	517.0	212.5	527.7	217.1	537.6	221.4	547.6	225.7	557.9	230.2
	50	417.7	169.8	434.6	176.6	452.5	183.5	466.9	190.0	481.8	196.8	491.9	201.1	502.1	205.5	511.4	209.5	520.9	213.6	530.6	217.8
Springvale 66 kV [65]	10	449.1	96.9	461.9	99.7	476.8	103.0	487.7	105.4	499.2	107.9	512.3	110.8	524.6	113.5	535.3	115.9	546.3	118.3	557.1	120.8
	50	439.7	93.8	452.0	96.5	466.5	99.6	477.0	101.9	488.0	104.4	500.8	107.1	512.7	109.8	523.0	112.0	533.6	114.4	544.0	116.8
Templestowe 66 kV	10	316.1	124.3	334.6	132.1	344.8	137.0	353.5	141.2	362.5	145.5	371.3	149.6	379.9	153.8	387.5	157.4	395.3	161.2	403.3	165.0
	50	299.9	115.2	317.9	122.8	327.5	127.4	335.8	131.3	344.3	135.4	352.5	139.2	360.6	143.1	367.8	146.6	375.2	150.1	382.7	153.7
Thomastown Bus 1&2 66 kV [66]	10	331.6	173.9	341.3	179.0	360.9	189.2	367.7	192.6	379.5	198.7	388.9	203.5	398.6	208.5	408.6	213.6	418.9	218.9	429.4	224.3
	50	314.0	164.7	323.3	169.5	341.8	179.1	348.2	182.4	359.5	188.2	368.4	192.8	377.6	197.5	387.1	202.3	396.8	207.3	406.8	212.5
Thomastown Bus 3&4 66 kV [67]	10	337.0	182.0	352.2	190.1	359.2	193.7	375.8	202.6	387.4	208.7	395.9	213.2	404.7	217.8	413.6	222.5	422.7	227.3	432.0	232.2
	50	319.1	172.3	333.5	180.0	340.2	183.4	355.8	191.8	366.8	197.6	375.0	201.8	383.3	206.2	391.7	210.7	400.4	215.3	409.2	219.9

Peak Winter Forecasts by Shared Terminal Station

Terminal Station	POE	2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ringwood 66 kV	10	357.2	95.7	368.6	99.1	377.9	101.9	387.0	104.7	397.0	107.7	407.5	110.8	415.3	113.0	423.2	115.2	431.1	117.5	439.3	119.8
	50	347.7	93.0	358.8	96.3	367.8	99.0	376.6	101.8	386.3	104.7	396.4	107.7	404.0	109.8	411.6	112.0	419.3	114.2	427.2	116.4
Springvale 66 kV [65]	10	352.6	36.6	360.4	37.5	366.7	38.2	372.6	38.9	381.9	39.8	390.3	40.8	400.0	41.8	409.2	42.8	419.0	43.8	429.0	44.9
	50	344.6	35.4	351.9	36.2	357.8	36.9	363.4	37.5	372.1	38.4	380.1	39.3	389.2	40.2	398.0	41.2	407.3	42.2	416.8	43.2
Templestowe 66 kV	10	266.0	77.7	274.1	81.0	279.3	83.2	284.9	85.8	291.6	88.4	298.1	90.9	303.4	92.9	309.0	95.0	314.9	97.2	320.8	99.4
	50	255.6	73.0	263.3	76.1	268.2	78.3	273.5	80.6	279.8	83.1	286.0	85.5	291.0	87.4	296.4	89.4	301.9	91.5	307.6	93.6
Thomastown Bus 1&2 66 kV [66]	10	273.7	135.8	290.4	144.0	299.2	148.4	316.7	157.0	323.2	160.2	333.3	165.2	341.8	169.4	350.1	173.5	358.7	177.8	367.6	182.2
	50	263.0	130.5	279.0	138.3	287.5	142.5	304.3	150.8	310.4	153.8	320.1	158.6	328.2	162.7	336.2	166.6	344.4	170.7	352.9	174.9
Thomastown Bus 3&4 66 kV [67]	10	290.8	118.6	299.2	122.6	310.5	128.0	314.6	130.0	326.9	135.9	334.8	139.6	340.7	142.5	346.7	145.4	352.8	148.3	359.0	151.3
	50	279.3	114.0	287.4	117.9	298.3	123.1	302.2	125.0	314.1	130.6	321.6	134.2	327.2	137.0	333.0	139.8	338.9	142.6	344.8	145.5

65 16 MW of embedded generation is considered as negative load.

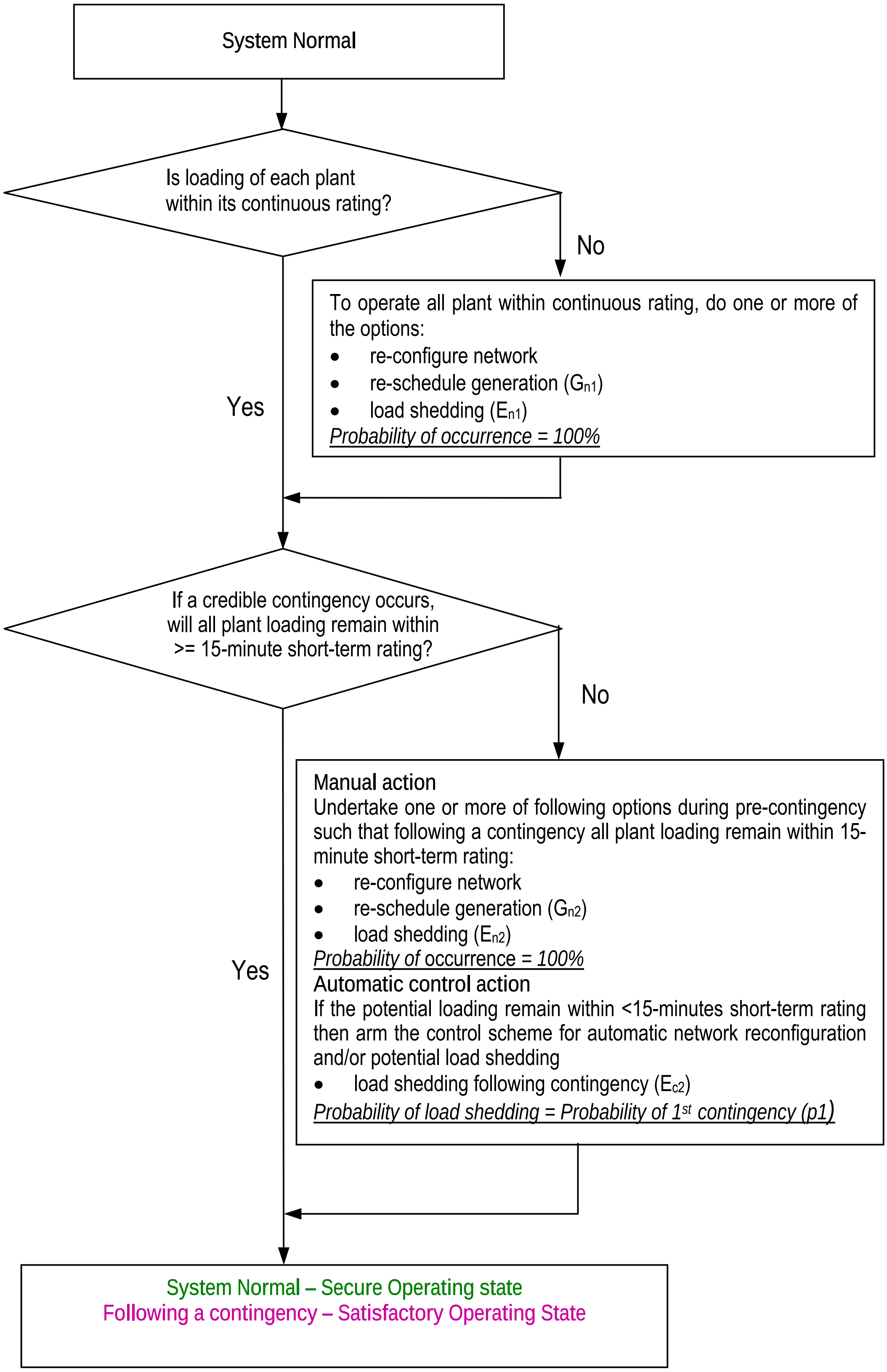
66 Somerton power station is not included in the forecasts. However, other small embedded generators (21 MW in total) are considered as negative loads (i.e.: assumed to be exporting energy).

67 10 MW of embedded generation is considered as negative load.

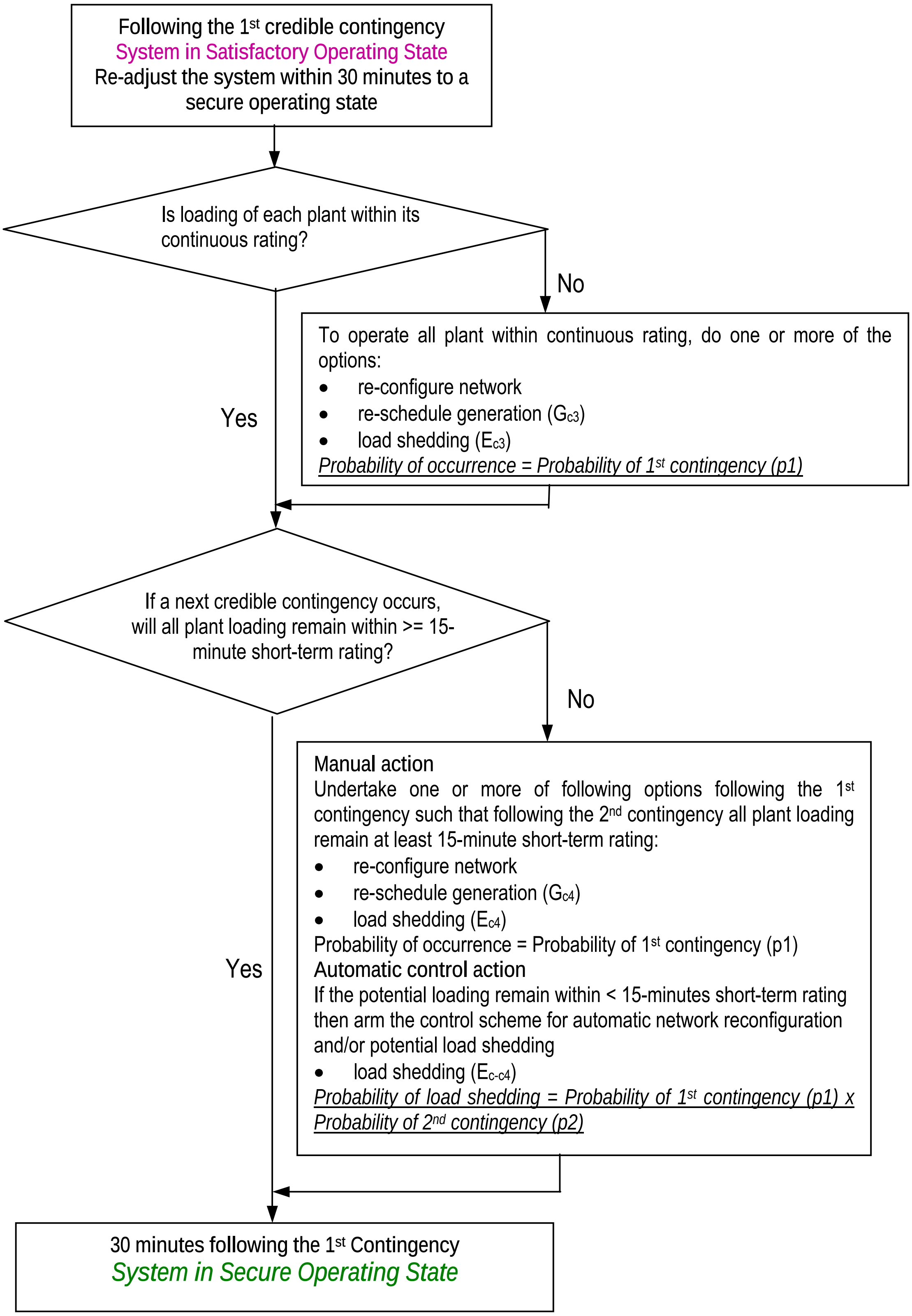
C PLANNING FLOWCHART

ASSESSMENT OF SECURE OPERATING STATE

System Normal



Within 30 minutes following the 1st Credible Contingency



Definitions of secure operating state and satisfactory operating state are as referred in the National Electricity Code.

Probabilistic Assessment

Expected rescheduled generation = $G_{n1} + G_{n2} + G_{c3} \times p1 + G_{c4} \times p1$

Expected unserved energy = $E_{n1} + E_{n2} + E_{c2} \times p1 + E_{c3} \times p1 + E_{c4} \times p1 + E_{c\text{-}c4} \times p1 \times p2$ + expected unserved energy due to inadvertent operation of the control scheme + expected unserved energy due to failure of the control scheme + risk due to failure of the control scheme.

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D GLOSSARY

ABBREVIATIONS	
APR	Annual Planning Report
ACCC	Australian Competition and Consumer Commission
ANTS	Annual National Transmission Statement
BOM	Bureau of Meteorology
CPI	Consumer Price Index
DB	Distribution Business
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
EHV	Extra High Voltage
ESC	Essential Services Commission
FCAS	Frequency Control Ancillary Service
GSP	Gross State Product
GWh	Giga Watt hours
HV	High Voltage
k	Thousand
km	Kilometers
kV	Kilovolts
LOR	Lack of Reserve
LRA	Long Run Average
M	Million
MD	Maximum Demand
MVA	Mega Volt Amperes
MVAr	Mega Volt Amperes Reactive
MW	Mega Watts
MWh	Mega Watt hours
NCAS	Network Control Ancillary Service
NEC	National Electricity Code
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
POE	Probability of Exceedence
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
SVC	Static Var Compensator
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Networks Corporation
VNSC	Victorian Network Switching Centre

DEFINITIONS	
Contestable Augmentation	An augmentation for which the capital cost is reasonably expected to exceed $10M and can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable).
Contingency	Either a forced or planned outage.
Credible Contingency	Any planned or forced outage that is reasonably likely to occur. Examples, outage of a single transmission line, transformer, generating unit, reactive plant, etc through one or two phase faults.
Critical Contingency	The specific forced or planned outage that has the greatest potential to impact on the network at any given time.
Flow Path	Those elements of the transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
Forced Outage	An outage of a transmission element (transmission line, transformer, generator, reactive plant, etc) caused by failure of primary or secondary equipment or operating error for which there is less than 24 hours notice or due to lightning and storms.
Load Shedding	Disconnection of customer load.
Non-Contestable Augmentation	Augmentations which would not be considered to be economically or practically classified as contestable augmentations.
Non-Credible Contingency	Any planned or forced outage for which the probability of occurrence is considered very low. Examples, outage of a single transmission line, transformer, generating unit, reactive plant, etc through three phase faults, multiple generating unit failures, double circuit tower failures, busbar faults, etc.
Planned Outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours notice.
Post-Contingent	The timeframe after a contingency occurs.
Pre-Contingent	The timeframe before a contingency occurs.
Prior Outage Conditions	A weakened transmission state where a transmission element is unavailable for service due to either a forced or planned outage.
Satisfactory Operating State	Operation of the network such that all plant is operating at or below either its continuous rating or its applicable short term rating.
Secure Operating State	Operation of the network such that should a credible contingency occur, the network will remain in a 'satisfactory' state.
State Grid	The regional transmission network in the northwest area of Victoria, including Moorabool, Ballarat, Terang, Horsham, Red Cliffs, Kerang, Bendigo, Shepparton, Glenrowan, Dederang, Mt Beauty and Eildon Terminal Stations and all 220 kV transmission lines connecting these sites.
System Normal Constraint	A constraint that arises even when all plant is available for service.

TERMINAL STATION NAMES	
APD	Portland Aluminium (customer owned station)
APS	Anglesea Power Station
ATS	Altona Terminal Station
BATS	Ballarat Terminal Station
BETS	Bendigo Terminal Station
BLTS	Brooklyn Terminal Station
BTS	Brunswick Terminal Station
CBTS	Cranbourne Terminal Station
DDTS	Dederang Terminal Station
DPS	Dartmouth Power Station
EPS	Eildon Power Station
ERTS	East Rowville Terminal Station
FBTS	Fishermans Bend Terminal Station
FVTS	Fosterville Terminal Station (customer owned station)
GNTS	Glenrowan Terminal Station
GTS	Geelong Terminal Station
HYTS	Heywood Terminal Station
HOTS	Horsham Terminal Station
HTS	Heatherton Terminal Station
HWPS	Hazelwood Power Station
HWTS	Hazelwood Terminal Station
HYTS	Heywood Terminal Station
JLA	Western Port (customer owned station)
JLTS	Jeeralang Terminal Station
KGTS	Kerang Terminal Station
KTS	Keilor Terminal Station
LY	Loy Yang Substation
LYPS	Loy Yang Power Station
MBTS	Mount Beauty Terminal Station
MKPS	McKay Creek Power Station
MLTS	Moorabool Terminal Station
MPS	Morwell Power Station
MTS	Malvern Terminal Station

TERMINAL STATION NAMES	
MWTS	Morwell Terminal Station
NPSD	Newport Power Station
PTH	Point Henry (customer owned station)
RCTS	Red Cliffs Terminal Station
ROTS	Rowville Terminal Station
RTS	Richmond Terminal Station
RWTS	Ringwood Terminal Station
SHTS	Shepparton Terminal Station
SMTS	South Morang Terminal Station
SVTS	Springvale Terminal Station
SYTS	Sydenham Terminal Station
TBTS	Tyabb Terminal Station
TGTS	Terang Terminal Station
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
VPGS	Valley Power Gas Station
WKPS	West Kiewa Power Station
WMTS	West Melbourne Terminal Station
WOTS	Wodonga Terminal Station
YPS	Yallourn Power Station

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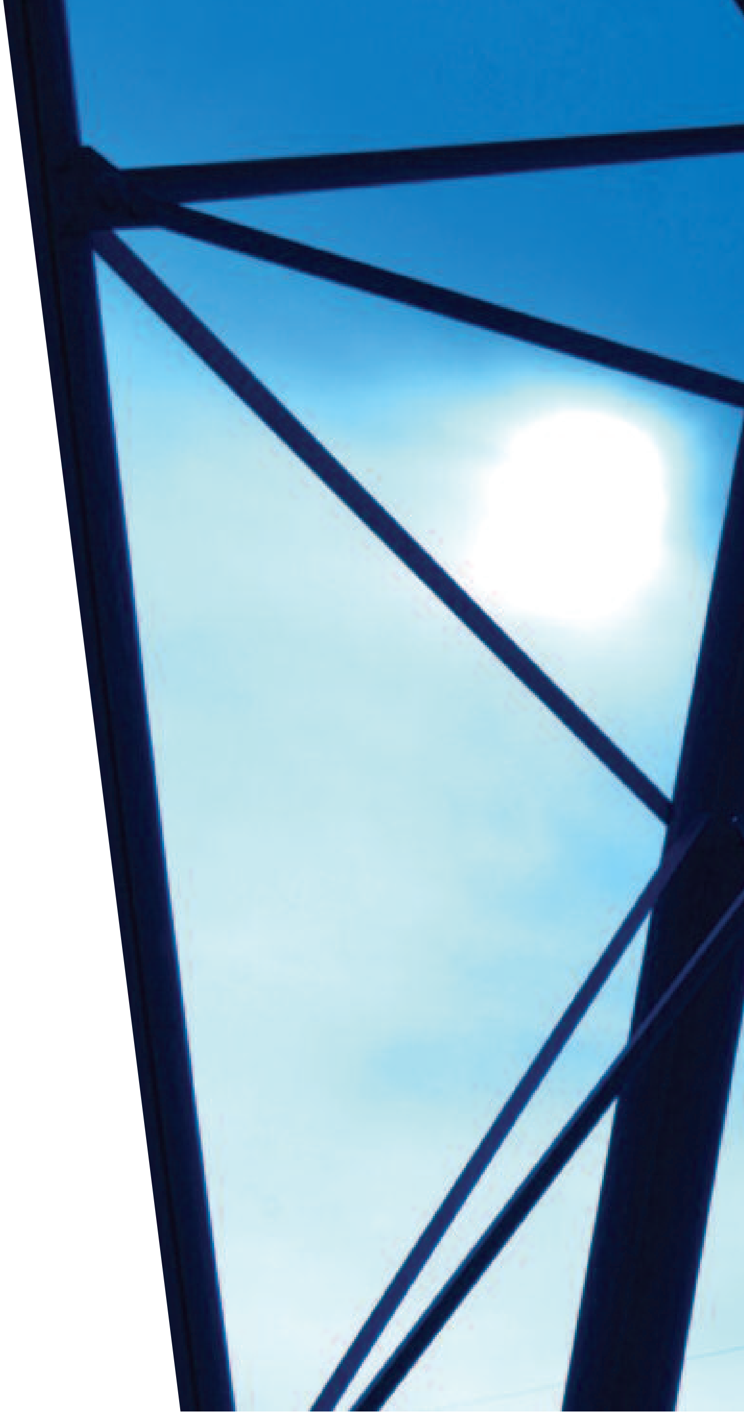

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