ELECTRICITY ANNUAL PLANNING REVIEW

2003

JUNE 2003

DISCLAIMER

VENCorp's role in the Victorian electricity supply industry includes planning and directing augmentation of the transmission network. As part of that function, the National Electricity Code and the Victorian Electricity System Code require VENCorp to publish this review of 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 this document 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 possible plans for augmentation of the transmission network. This document has been prepared by VENCorp 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 monopoly provider of shared 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 (NEC). This Annual Planning Review examines the adequacy of the Victorian transmission network to meet the long term requirements of Victorian electricity customers and provides the first step in VENCorp's consultations with interested parties in relation to possible future transmission network augmentation. Issues relating to supply/demand balance in Victoria are the responsibility of NEMMCO and are covered in NEMMCO's Statement of Opportunities.

Load Forecasts

Three scenarios of Victorian load growth are provided for the next ten years. These are based on scenarios of electricity sales developed for VENCorp by the National Institute of Economic and Industry Research (NIEIR). The medium growth scenario provides forecasts of the sales that could be expected under the most likely economic growth conditions. NIEIR also provides forecasts of summer and winter maximum demands, which take into account ambient temperature conditions.

Between 2003 and 2008 the medium scenario averages a projected growth in electricity consumption of 1.5% per annum, a growth in summer maximum demand of 2.6% per annum and a growth in winter demand of 1.8% per annum. These forecasts are slightly lower than the forecasts provided for the next five years in the 2002 Annual Planning Review, and also confirm the continued divergence between growth in summer maximum demand and annual energy growth, predominantly due to increasing penetration of domestic and commercial air conditioning. Between 2008 and 2013 the medium scenario averages a projected growth in electricity consumption of 2.1% per annum, a growth in summer maximum demand of 3.2% per annum and a growth in winter demand of 2.1% per annum.

The system load growth scenarios, together with individual supply point loading information from the Distribution Companies, form the basis for the assessment of transmission adequacy over the planning horizon. Winter 2003 and summer 2003/04 maximum demand forecasts are shown below for the 10%, 50% and 90% POE[1], also included is the forecast energy usage for 2003/04.

1 Probability Of Exceedence is usually expressed in terms of 10, 50 or 90 percentile seasonal MDs which correspond to average daily temperatures. For instance a summer 10% POE MD correlates to an average temperature (average of the minimum overnight and maximum daily ambient temperature), being exceeded, in the long run average, on 10% of occasions (i.e. 1 summer in 10).

MAXIMUM DEMAND			
Probability of exceedence once or more in one Season (Summer / Winter)	**10%**	**50%**	**90%**
Winter average Melbourne temperature	4.8°C	6.0°C	7.2°C
Maximum Demand Winter Forecast (2003)	7824 MW	7668 MW	7375 MW
Summer average Melbourne temperature	32.8°C	29.4°C	27.1°C
Maximum Demand Summer Forecast (2003/04)	9417 MW	8758 MW	8351 MW
ENERGY			
Economic growth level	Base	High	Low
Economic growth rate (2003/04)	1.8%	3.2%	1.5%
Annual Energy consumption (2003/04)	49,082 GWh	49,537 GWh	48,253 GWh

Network Adequacy

The network adequacy chapter provides a description of the existing shared network and its ability to meet the actual and forecast 2002/03 summer peak demand conditions.

The chapter also includes a review of the shared network conditions such as peak demands, high spot prices, and significant system incidents that have occurred during summer 2003/03. An overview of the active and reactive supply demand balance at times of peak demand is also included to identify and highlight the importance of the Victorian forecast reserve level and summer aggregate generation capacity for 2003/04, and the current maximum supportable demand in Victoria. A summary of fault levels with the headroom available is included for a number of locations in the Victorian network. It is a VENCorp responsibility to ensure fault levels are always maintained within plant capability in the transmission network.

Network modifications, impending or implemented since VENCorp's 2002 Annual planning Review have been discussed to identify major changes that have occurred or are committed with the transmission network. The following network modifications are discussed:

- **SNOVICProject**
- **Cranbourne 220/66kV Development**
- **Latrobe Valley to Melbourne and Cranbourne Developments**
- **Toora Wind Farm Generation**
- **Challicum Hills Wind Farm Generation**
- **Keilor-West Melbourne lines**
- **Shunt Capacitor Banks**
- **BassLink**[2]
- **South Australia to New South Wales Interconnecter (SNI)**

The issue of network capability is most critical in summer, when the peak demand and peak reactive loading on the system occur coincidentally. As the load grows there is an ongoing requirement for additional capacitor banks on the system. VENCorp continues to augment the shared network with shunt capacitor banks to extend the maximum supportable demand based on an economic analysis as per VENCorp's application of the regulatory Test.

Options For Removal Of Network Constraints Within Victoria

VENCorp undertakes the responsibility for removal of transmission network constraints in accordance with its Licence obligations, the National Electricity Code and the Victorian Electricity System Code. Additionally the feasibility of transmission projects are assessed using the Regulatory Test as specified by the ACCC.

2 The BassLink project is a High Voltage DC link between Victoria and Tasmanian.

VENCorp considers the major, economic benefits associated with transmission investment are:

- a reduction in the amount of expected unserved energy;
- a reduction in the use of ‘out of merit order’ generation;
- a reduction in real and reactive transmission losses; and
- deferral of reactive plant.

The unserved energy resulting from network constraints has been assessed using a Value of Customer Reliability (VCR) that represents an economic value assigned to the end use of electricity of $10,000/MWh and $29,600/MWh to show the change from the basis used in the 2002 APR. Application of the VCR allows expected unserved energy to be economically quantified, thereby justifying investment decisions.

A probabilistic approach is applied in the assessment of cost and benefits of transmission augmentation. It considers the likelihood and coincidence of the contingency event and the onerous loading and ambient conditions. VENCorp’s detailed “Electricity Transmission Network Planning Criteria” is available at www.vencorp.com.au. Importantly, the application of an expected unserved energy implies that under some conditions it is actually economic to have load at risk following a credible contingency.

The design principles used by VENCorp for planning the transmission network 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 contingency, 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).
- 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 options to network augmentation.

For each constraint investigated one of the following three options apply:

- For large network augmentations a detailed public consultation will be undertaken for each of the projects in accordance with the Clause 5.6.6 of the National Electricity Code, defined for projects that have a capital cost greater than $10 millions dollars.
- Small network augmentations have a capital cost less than $10 millions dollars and greater than $1 million dollars. This APR forms the basis for consultation process in accordance with Clause 5.6.6A of the National Electricity Code. Interested parties are invited to make submissions regarding the proposed augmentations and any non-network options they consider as an alternative. The closing date for submissions is **Thursday 31st July 2003.**
- Some constraints have no economic network solution at this point in time.

Additionally this chapter provides a ten-year outlook to indicate possible constraints on a longer timeframe.

The following table details the potential constraints identified in this chapter.

Section	CONSTRAINT	AUGMENTATION TYPE	DATE	ESTIMATED COST ($K)
4.4	Supply to the Geelong area	Small Network Augmentation*	2003/04	4,500
4.5	Dederang Tie -Transformation	Required for SNI: If SNI doesn't proceed, SNA:	2004/05 2008/09	9,000 9,000
4.6	Supply to the Ringwood Terminal Station	Small Network Augmentation	2004/05	150
4.7	Supply from Moorabool 220 kV bus	No Economic Network Solution at this stage	Nil	Nil
4.8	Security of double circuit supplies to South East Metropolitan Area	No Economic Network Solution at this stage	Nil	Nil
4.9	Metropolitan Tie - Transformation	Large Network Augmentation	2008 or before	40,000
4.10	Supply to the Springvale and Heatherton areas	Small Network Augmentation	2005/06	300
4.11	Supply to the East Rowville and Cranbourne areas	No Economic Network Solution at this stage	Nil	Nil
4.12	Reactive Support for Maximum Demand Conditions	No Economic Network Solution at this stage	Nil	Nil
4.13	Hazelwood Tie -Transformation	No Economic Network Solution at this stage	Nil	Nil
4.14	Yallourn to Hazelwood to Rowville Transmission	No Economic Network Solution at this stage	Nil	Nil

* Project required to be implemented prior to next APR due to lead-time for purchase of transformer. Therefore this document forms the consultation for this project.

New Connections

VENCorp, as the provider of shared network services in Victoria, has a vital role in providing access to the shared transmission network to new participants connecting to the transmission network, including customers, generators and interconnectors. VENCorp's responsibilities and procedures in this regard are in line with the requirements of the National Electricity Code. The VENCorp website outlines the requirements for potential investors who wish to establish or modify an existing connection to the transmission network, including the requirement to enter into a use of system agreement with VENCorp. These details can be found at www.vencorp.com.au.

Inquiries

VENCorp is 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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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS

The following abbreviations are used through out this report:

ACCC	Australian Competition and Consumer Commission
APR	Annual Planning Review
BoM	Bureau of Meteorology
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
EHV	Extra High Voltage
GSP	Gross State Product
GWh	Giga Watt Hours
km	Kilometers
kV	Kilovolts
LOR2	Lack of reserve level 2
M	Million
MD	Maximum Demand
MVA	Megavolt Amps
MVAr	Megavolt Amps reactive
MW	Mega Watts
MWh	Mega Watt hours
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
POE	Probability of Exceedence
SOO	Statement of Opportunities
TNSP	Transmission Network Service Provider
TXU	Texas Utilities
UE	United Energy
VCR	Value of Customer Reliability

ELECTRICITY ANNUAL PLANNING REVIEW 2003

1 INTRODUCTION

VENCorp is the Transmission Network Service Provider for the shared transmission network in Victoria under the National Electricity Code (NEC) and as such has entered into an access undertaking with the ACCC 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[3] 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 sell shared transmission network services to network users on a basis consistent 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 Annual Planning Report must set out:

(1) The forecast loads submitted by a Distribution Network Service Provider,

(2) Planning proposals for future connection points,

(3) A forecast of constraints and inability to meet the network performance requirements, and

(4) Detailed analysis of all proposed augmentations to the network. These augmentations may be either small or large network augmentations.

3 The term 'shared network' is defined in more detail at the VENCorp website (www.vencorp.com.au), and in VENCorp's electricity transmission licence (www.esc.gov.au).

The National Electricity Code requires NEMMCO to publish a Statement of Opportunities on 31 July each year, which examines the supply/demand balance within each region of the national market and the transmission capability, which connects regions. VENCorp provides the load forecasts, network adequacy and network development as inputs to the NEMMCO document.

The scope of this VENCorp Electricity Annual Planning Review is therefore confined to assessing the adequacy of the Victorian shared transmission network to meet the Victorian load growth over the next 10 years.

In addressing this issue, this review considers:

the most recent information on forecast Victorian electricity demands;

- the most recent information on transmission plant performance;
- possible scenarios for growth in the demand of Victorian electricity consumers; and
- the impacts of committed projects for additional generation or augmentation of a transmission network or a distribution network.

The review also considers the transfer capabilities of the interconnectors between Victoria and South Australia, and Victoria and New South Wales, and their recent performance.

1.1 Purpose of the Review

The NEMMCO Statement of Opportunities provides the primary document for reviewing the supply/demand balance in each state and across the national electricity market. The VENCorp Annual Planning Review provides a review of the adequacy of the Victorian shared transmission network to meet load growth over the next 10 years. Both documents provide information to industry participants and potential participants on opportunities to invest in infrastructure or to connect loads or generation.

The Annual Planning Review does not define a specific future development plan for the shared network. It is intended to be the first stage of a consultation process aimed at providing an economically optimum level of transmission system capacity.

VENCorp is 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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1.2 Content of the Review

Chapter 2 of the review presents projections of future Victorian load which take into account:

- the variability of load with temperature; and
- different economic scenarios.

It also reconciles the recent performance of the load forecasts. This chapter additionally provides commentary on the important characteristics of Victorian electricity demand that influence the amount of energy at risk for a given transmission system capability.

Chapter 3 reviews the adequacy of the current network to meet demand and lists current and committed network developments. Chapter 4 provides information on potential transmission constraints over the next ten years and transmission augmentation options available to maintain the reliability of the network in the most economic manner are then considered.

The adequacy and reliability of the sub transmission and distribution networks, which are owned, operated, maintained and planned by the five distribution companies have not been considered in this document. These issues are subject to oversight by the Essential Services Commission (ESC). Distribution Companies are also responsible for the planning of the transmission connection assets from which they take supply and publish a connection asset planning document which is available on their specific websites.. This document provides information on the transformation capability (compared to historic and forecast loads) for each terminal station supplying the Distribution Companies. This information can be used to assess the level of energy at risk at the various terminal stations in the event of a transformer failure.

1.3 Recent Changes to the Review

In line with a continuous improvement focus and ensuring National Electricity Code compliance in July of 2002, VENCorp commenced a review into the format and content of its Electricity Annual Planning Review (APR) document. The review was conducted with both internal and external stakeholders asked to provide input; and to ensure compliance with the NEC requirement.

The 2003 APR is representative of the changes identified in the format and content review; any further suggestions or comments can be made by contacting:

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As identified in the format and content review a number of documents have now been removed from the APR and place on the VENCorp website. The documents removed are as follows:

- VENCorp's Electricity Industry Functions
- Intra-Regional Network Planning and Development Process
- Technical Compliance Monitoring
- Establishing or Modifying a Connection

These documents can be found at http://www.vencorp.com.au/

2 LOAD FORECASTS

2.1 Introduction

This chapter presents the load forecasts for Victoria, both summer and winter peak demands and annual energy for the next 10-year period. Previous forecasts and actual loads are compared and the characteristics of the Victorian demand are also discussed.

Load forecasts are a key element in assessing future transmission adequacy. The load forecasts presented here are also provided to NEMMCO under Clause 5.6.4 of the National Electricity Code for inclusion in the Statement of Opportunities.

VENCorp commissioned the National Institute of Economic and Industry Research (NIEIR) to produce macroeconomic forecasts for Victoria and to produce the electricity load forecasts presented here, based on these macroeconomic forecasts[4].

2.2 Summary of Economic and Load Forecasts

Energy consumption for the medium growth scenario is forecast to rise from 49,082 GWh in 2003/04 to 57,703 GWh in 2012/13, on a generated basis. The maximum summer demand is forecast to increase from 9,417 MW in 2003/04 to 11,840 MW in summer 2012/13 for the medium growth scenario and 10-percentile temperature.

Table 2.1 summarises the Victorian load growth rates as an average, by economic scenario, for the five-year period 2003/04-2007/08 and for the ten-year period 2003/04-2012/13.

Average Annual Forecast Load Growth	Economic Growth Scenario 2003/04 – 2007/08 (% pa)			Economic Growth Scenario 2003/04 – 2012/13 (% pa)		
	Medium	High	Low	Medium	High	Low
Summer 10% Maximum Demand	2.6	3.2	1.9	2.6	3.3	1.9
Winter 10% Maximum Demand[5]	1.8	2.4	1.2	2.0	2.8	1.4
Annual Energy Consumption	1.5	2.0	0.8	1.8	2.5	1.2

Table 2.1- Average Victorian Load Growth (% pa generated at power stations)

The energy and maximum demand forecasts in this document are of Victorian demand as measured at all scheduled power station generator terminals.[6] This is the same definition of demand as used by NEMMCO for their “at terminals” figure.

4 NIEIR, “Electricity and natural gas projections for Victoria to 2017”, May 2003

5 Winter 2003/04 describes June through August 2003.

6 A list of the scheduled generation and scheduled loads in the National Electricity Market is available from the NEMMCO website www.nemmco.com.au/operating/participation/participation.htm

2.3 Economic Forecasts

NIEIR based its forecasts of Victorian electricity consumption on its three Victorian economic outlook scenarios, corresponding to medium (or base), high and low economic growth.

Three sets of energy and maximum demand forecasts are presented, one for each scenario.

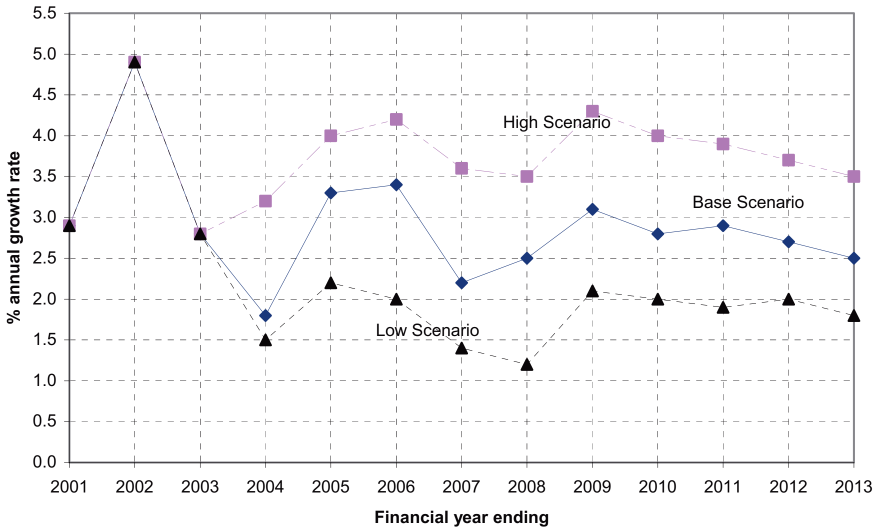


Figure 2.1- Victorian GSP Growth Rates

For each scenario, NIEIR uses its econometric model to assess expected Victorian macroeconomic activity as a component of the world and Australian economies. Forecasts of Victorian industry output by sector, capital stocks, dwelling formation numbers and population are obtained, forecasting in turn the Victorian Gross State Product (GSP). The GSP growth rates for the three scenarios to 2013 are displayed in Figure 2.1 for financial years ending 30 June.

NIEIR expects the Victorian GSP growth rates to average 2.6% per annum under the medium scenario between 2003 and 2013. The corresponding high and low economic scenario growth rates are 3.6% and 1.8% per annum respectively. NIEIR forecasts a medium scenario Victorian GSP growth of 1.8% in 2003/04, following growth of 2.8% in 2002/03 and 4.9% in 2001/02. Weaker consumption expenditure growth and a sharp decline in agricultural production and the dwelling construction sector underlie the more modest projected rise in Victorian GSP in 2003/04.

NIEIR forecasts stronger Victorian GSP growth resumes in 2004/05 and 2005/06 with growth projected to be in excess of 3.0%. A turnaround in the dwelling construction cycle and stronger consumption expenditure growth underlie growth in 2005/06.

Table 2.2 shows NIEIR's March 2003 medium, high and low economic scenario forecasts and actuals for GSP. The 2003 Annual Planning Review is based on this medium scenario forecast, but the high and low economic scenario, and corresponding electricity energy and peak demand, forecasts may assist assessment of transmission network impacts of economic growths differing from the medium scenario.

Figure 2.2 details the differences between the 2002 and 2003 medium economic scenarios provided by NIEIR.

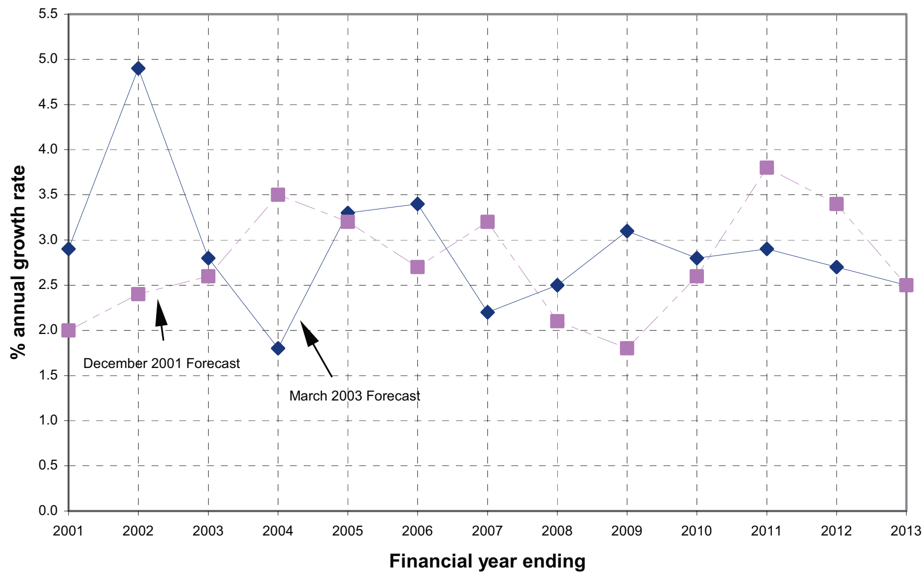


Figure 2.2 – Victorian GSP Medium Growth: Comparison of Forecasts

The economic growth actual and forecast data published by Access Economics in their January 2003 Economics Monitor, and those provided by the Vic Treasury 6 May 2003 Budget summary are also summarised in Table 2.2. The corresponding forecasts for 2002/03 provided in the Electricity Annual Planning Review 2002 and the latest revisions to these forecasts are also shown.

Year	Actuals		Forecasts		
	2001/02	2002/03	2003/04	2004/05	2005/06
NIEIR Medium Growth	2.6%	2.8%	1.8%	3.3%	3.4%
NIEIR High Growth	3.7%	2.8%	3.2%	4.0%	4.2%
NIEIR Low Growth	0.5%	2.8%	1.5%	2.2%	2.0%
ACCESS Economics[7]	3.6%		3.1%	2.8%	2.8%
Victorian Budget Update[8]	3.75%	3.3%	3.75%	3.5%	3.5%
Issue date	Dec 01-Apr 02	Mar-May 03	Jan-May 03	Jan-May 03	Jan-May 03

Table 2.2 - Economic Growth Actuals 2001/02 to 2002/03 and Forecasts, 2003/04 to 2005/06

Victorian Treasury points to economic growth led by an improved Victorian net export position and continued business investment, with slowing housing activity and associated conveyancing duty. Additional improvement will come from the breaking drought and a largely resolved Iraq conflict, but conversely exposure to national and international shocks, such as SARS will have some impact.

As at April 2003 Access Economics expects Victorian economic growth to fall with reduced housing starts, although offset by increased commercial construction. A Victorian population continuing to return from interstate and ongoing large engineering/infrastructure construction projects also contribute to growth. Main projects include rail/road (Spencer St/Southern Cross station and Scoresby bypass) and energy (Vic-SA SEA gas pipeline, Basslink and wind farms at Portland and near Ararat).

It must be stated that in reporting both the Access Economics and Victorian Treasury reports are not generated in the most recent timeframe and key issues, such as the war in Iraq, may not have been resolved at the time of production.

7 Data obtained from "Access Economics Budget Monitor – January 2003".
8 Data obtained from Victorian Treasury April 2003.

2.4 Basis and Methodology Underlying Load Forecasts

2.4.1 Forecasting Energy Use

NIEIR's econometric model is directly linked to its energy forecasting model, determining annual demands for each type of energy comprising factor inputs to the economy, including household usage. The energy forecasts also use actual annual electricity sales/use by each customer class, aluminium smelting, power station and mine own use and network losses.

NIEIR uses the forecasts of Victorian electricity sales and peak demand for aluminium smelting that the Smelter Trader provides to VENCorp.

Actual and forecast levels of electricity generation supplying load directly (ie not through the Victorian transmission or distribution system) or embedded in the distribution network are modelled so that energy supply and demand levels correspond.

2.4.2 Cogeneration, Independent Power Production and other Impacts

Based on its own assessments and information from others, NIEIR determines forecasts of electricity energy and peak demands met by generation not transmitted through the Victorian transmission and distribution system. NIEIR also assesses and includes effects of other relevant impacts, such as conservation and technological advances (e.g. Greenhouse gas abatement measures, appliance efficiency improvement, and fuel cell research) that can impact on future energy demand. Continuation of existing policies and activities leading to natural improvements in conservation and end-use efficiency improvements was assumed in relation to demand management and cogeneration levels.

Table 2.3 and Figure 2.3 show observed and forecast capacity and energy output levels of unscheduled cogeneration and Independent Power Producers' (IPPs') generation (other than cogeneration) embedded within Victorian distribution networks. The emerging wind embedded generation capacity, forecast to grow strongly over the next six years in line with overseas experience and Government initiatives, is also identified.

These generation outputs (including for own use) are recognised in NIEIR's econometric analysis as a factor input of Victorian GSP additional to electricity energy and peak demands tabulated in Section 2.8 that are supplied from scheduled generators. Table 2.3 shows that over the forecast period 2003/04 to 2013/14, aggregated unscheduled cogeneration and IPP contributions to load levels increase from 475 MW to 1041 MW capacity and 2107 GWh to 3774 GWh output, of which 1115 GWh to 2498 GWh is bought back and 962 GWh to 1247 GWh used by the producer.

Levels of cogeneration and IPP are driven by gas and electricity prices and the following policy initiatives:

- National Greenhouse Strategy (1998) promoting cogeneration through workshops and studies, providing shared funding for renewable energy technologies under the $21 M Renewable Energies Equity Fund (REEF), providing loans and grants for renewable energy projects with strong commercial potential under the $30 M Renewable Energy Commercialisation Program (RECP) and providing $10.5 M aggregate seed funding for a few leading edge renewable energy projects. Mandated Renewable Energy Targets (MRET) under *The Renewable Energy (Electricity) Act 2000* and associated acts will require wholesale purchasers of electricity in Australia to contribute proportionately towards the generation of an additional 9,500GWh of renewable energy per year by 2010, to be maintained to 2020; and
- Goods and Services Tax/A New Tax System (GST/ANTS) (1999) providing up to $264 M over four years for remote area power supplies to replace diesel generation, $31 M in photovoltaic system rebates (up to 50%/$5500 per household), and an additional $26 M for RECP and $400 M over four years to 2003/04 for projects that most cost effectively reduce greenhouse gas emissions- the Greenhouse Gas Abatement program (GGAP).

Year	Capacity (MW)				Actual / Forecast Output (GWh)				
	Cogen	IPP		Total	Cogen	IPP	Total	Buyback	Own Use
		Wind	Other						
2000/01	240	18	141	399	1248	380	1628	678	920
2001/02	240	39	141	420	1248	441	1689	739	920
2002/03	240	92	144	475	1248	610	1859	908	921
2003/04	256	142	145	543	1345	762	2107	1115	962
2004/05	262	217	155	634	1374	1019	2393	1387	976
2005/06	287	267	170	724	1433	1212	2645	1604	1011
2006/07	306	342	186	834	1483	1483	2966	1899	1038
2007/08	306	392	201	899	1483	1689	3172	2103	1039
2008/09	321	442	206	969	1562	1860	3422	2306	1087
2009/10	349	450	210	1009	1702	1892	3594	2397	1168
2010/11	352	455	212	1019	1715	1909	3624	2424	1170
2011/12	367	460	214	1041	1794	1926	3720	2449	1241
2012/13	372	465	218	1055	1816	1958	3774	2498	1247

Table 2.3 - Victorian Embedded Unscheduled Generation Capacity and Output 2000-2013

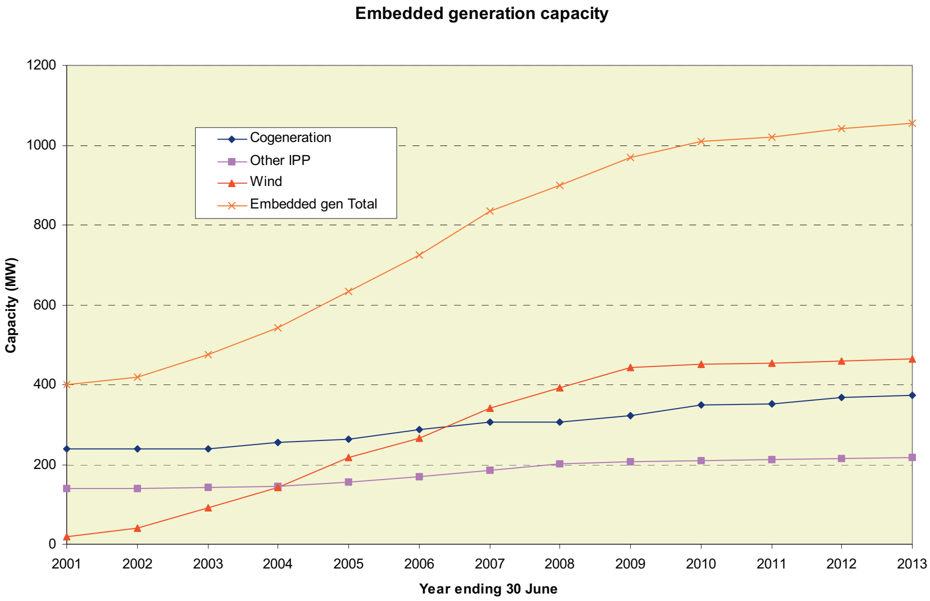


Figure 2.3 - Victorian Embedded Unscheduled Generation Capacity 2003-2014

2.4.3 *Impact of Cogeneration, Independent Power Production on forecasts*

Forecasts of summer MDs (Maximum Demands) for Victoria are developed by NIEIR using an approach, which takes account of:

(i) non-temperature sensitive load;

(ii) temperature sensitive load;

(iii) major industrial load; and

(iv) embedded generation (IPP).

Non-temperature sensitive load refers to non-temperature sensitive residential, commercial and industrial load. It may include some space cooling, however, these units are normally operating, even at relatively mild temperatures.

For the summer MD, temperature sensitive load consists of mainly of space cooling appliances such as refrigerative and evaporative and other ventilation equipment such as fans.

Major industrial load refers, in Victoria's case, to aluminium smelting.

Embedded generation in terms of MW of capacity (discounted by the rate of utilisation) is directly deducted from the summer MD forecasts. The following rates of capacity utilisation at system maximum demand were assumed in the forecasts.

Embedded cogeneration	20 per cent
Biomass and biogas	60 per cent
Wind	7 per cent
Mini hydro	30 per cent
Other non-renewable IPP	50 per cent

There is considerable uncertainty regarding the availability of embedded generation at times of system maximum demands.

The key uncertainty in terms of the forecasts is the availability of wind generation. As noted above, only 7 per cent of new installed wind generation capacity is deducted from the MD forecast.

2.4.4 Forecasting Peak Summer Demand

Peak summer electricity demands for purposes other than aluminium smelting are subdivided into components sensitive and insensitive to ambient temperature.

Growth in peak summer load that is sensitive to ambient temperature is dominated by increased sales and use of refrigerative air conditioning. NIEIR forecasts sales in refrigerative air conditioning units by a model using levels of residential and commercial building activity, real income, unit replacement and average ambient temperature over summer. Air conditioning unit sales are forecast for each economic scenario, and for cases of each summer being 10, 50 or 90-percentile[9] average temperature (ie nine sets of forecasts).

Forecast growth in temperature-sensitive peak summer load on a summer day of 10, 50 or 90 percentile average daily temperature is determined from these air conditioning unit sales forecasts, and from historical temperature-sensitive peak summer electricity demand increases, with historical electrical demand of aggregate air conditioner sales, over the last decade. This results in 27 sets of peak summer demand forecasts, however forecasts are presented here only for 50 percentile average temperature summers, found to correspond approximately to the previous Victorian basis of summer forecasts, and taking a middle path with regard to long run weather impacts on air conditioner sales.

Growth in peak summer non-smelter load insensitive to ambient temperature is forecast by projecting forward regressions of the ratio of this peak load to non-smelter energy.

Table 2.4 shows summer 10, 50 and 90 percentile average daily ambient temperatures and corresponding peak demand forecasts for medium growth for summer 2003/04.

Probability of exceedence once or more in one summer	10%	50%	90%
Melbourne average daily temperature	32.8°C	29.4°C	27.1°C
Maximum Forecast Demand	9417 MW	8758 MW	8351 MW

Table 2.4 - Maximum Demand Forecast, Medium Growth Scenario, Summer 2003/04

9 A given percentile season occurs if a more extreme level of the relevant parameter (average summer temperature in this case) occurs in the long run average than that percentage of occasions. For example a summer of 10 percentile average temperature is a summer with average temperature exceeded, in the long run average, on 10% of occasions (ie 1 summer in 10).

2.4.5 Forecasting Peak Winter Demand

Peak winter electricity non-smelter demands are subdivided into a temperature sensitive component due to air conditioning reverse cycle operation (forecast from the air conditioning methodology described above), a relatively less temperature sensitive component comprising other temperature sensitive load and temperature insensitive non-smelter load.

Growth in peak winter non-smelter load, excluding the air conditioning reverse cycle component, is forecast by projecting forward regressions of the ratio of this peak load, for 10, 50 and 90 percentile daily average temperature conditions, to non-smelter energy. Table 25 shows winter 10, 50 and 90 percentile average daily ambient temperatures and corresponding peak demand forecasts for winter 2003.

Probability of exceedence once or more in one winter	10%	50%	90%
Melbourne average daily temperature	4.8°C	6.0°C	7.2°C
Maximum Forecast Demand	7824 MW	7668 MW	7375 MW

Table 2.5 - Maximum Demand Forecast, Medium Growth Scenario, Winter 2003

2.5 Network Interface Locations of Forecasts

The total Victorian electricity demand can be defined at a number of interfaces:

- sales at retail customer meters;
- at the terminal station level of the main transmission/distribution networks interfaces;
- sent out from power stations; and
- at generator unit terminals and Victorian state borders.

Metering is available in a variety of forms at each of these interfaces, allowing (by difference) measurement of energy used in power stations, and transmission and distribution network losses, and facilitating corrections when specific metering elements fail. Victorian actual and forecast energies and peak demands reported are as delivered at generator terminals and (net import at) Victorian state borders, known as “a generated basis”.

For the purpose of defining total Victorian demand and energy, VENCorp has previously included all scheduled generation and Clover power station, a non-scheduled generator. To bring VENCorp in line with NEMMCO, for the purpose of calculating both maximum demand and energy, Clover power station has now been removed from load forecasts and historical load figures. The removal of Clover data from historical information and future forecast has been undertaken in the following manner:

- From February 2001 onward any maximum demand that included Clover power station has been amended by the output of Clover and the time of peak. Maximum demand figures prior to February 2001 have been lowered by 24 MW.
- All previous annual energy figures have been reduced by 30 GWh, which is the average energy figure for Clover power station in the past 3 years.
- Forecasts published in the 2003 APR have been lowered by 24 MW for summer and winter demand. Annual energy figures have been lowered by 30 GWh.

2.6 Comparison of Actual and Energy Demand Growth with the 2002 Annual Planning Review

In April 2002, VENCorp released the Electricity Annual Planning Review 2002 that included load forecasts produced by NIEIR in December 2001.

2.6.1 Growth in Energy Consumption

The actual growth in energy during 2001/02 fell by 0.3% against a predicted increase of 2.0% medium growth forecast in the Electricity Annual Planning Review 2002. One reason for this fall in energy against the predicted rise would be the unusually cool summer during 2001/02, where Victoria experienced long periods of very mild summer conditions.

For the following year (2002/03), the forecast growth rates in the Electricity Annual Planning Review 2002 were 1.7%, 1.2 % and 2.7 % respectively for the medium, low and high growth scenarios. A comparison of the energy consumption to date for this financial year (July 2002 to end-April 2003) with the same period in the 2001/02 financial year, shows an increase in energy consumption of 0.66% with no weather correction used. This differs from the previous APR where a fall of 0.9% was reported. To date, it appears that the warmer summer in 2002/03 contributed to the increased energy consumption.

The most recent full year forecasts (presented here) are for growth rates in 2003/04 are 1.7%, 0.0% and 2.6% for the medium, low and high growth scenarios, respectively compared to the corresponding 2002/03 forecast presented in the 2002 APR.

NIEIR has completed some early investigative work in the development of a standard weather year and therefore produced an annual energy consumption pattern around that year. Although further work is to be done in this area for future APR's, taking account of NIEIR's quantitative analysis of Victorian load and temperature data, together with an assessment of realised sales by class, the following temperature adjustments to energy were estimated for 2000/01 to 2002/03.

2000/01	450-500 GWh above standard weather
2001/02	50-100 GWh below standard weather
2002/03	175-225 GWh above standard weather

2.6.2 Growth in Maximum Demands

The Electricity Annual Planning Review 2002 forecast summer maximum demand (10% probability of being exceeded due to hotter weather) for 2002/03 was 9407, 9302 MW and 9116 MW (for high, medium and low economic growth scenarios, respectively).[10]

(a) Single Maximum Demand Day - Summer 2002/03

The maximum demand for summer 2002/03 of 8203 MW occurred in the half hour ending 5:30 pm summer time on Monday 24 February. Temperature ranged from a high overnight minimum of 24.5 °C to a maximum of 35.6 °C providing an average Melbourne temperature of 30.05°C, representing approximately a 34% (temperature) day. At this time, no demand side participation was evident. The coincident Victorian regional reference price was $ 45.42/MWh.

VENCorp linearly interpolated between the NIEIR 50% and 10% forecasts assessing the variance between forecast and actual for the particular MD day at 606 MW or 7.0% under the forecast. This method is seen as appropriate for forecasting assessment, but does not take into account individual specifics of the maximum demand day, eg a strong cool change, afternoon rain or long cloudy periods. The following factors may have contributed to the forecast variance of 606 MW:

Forecast Temperature Error

The Bureau of Meteorology (BoM) forecast overnight minimum and maximum temperatures for Sunday/Monday 24 Feb were 19°C and 32°C. The actual temperatures were 24.5°C and 35.6°C. This produced an average Melbourne daily temperature of 30.05°C.

10 These figures include Clover power station (24 MW).

The average daily temperature being 4.5°C above the forecast would not have contributed totally to the variance between the NIEIR forecast and the MD, but in previous years the variance between NIEIR and the actual MD has been smaller when forecast and actual temperatures are closer. The forecast being closer to actual allows for better planning of air conditioning usage, especially in this case when the actual temperatures were significantly higher than forecast, particularly the overnight temperature.

Day of the week

Another contributing factor is the likelihood of a 10% MD occurring on a Monday. Over the last ten years with the major growth in cooling load, the error between forecast and actual MD has been less than 5% when the MD has occurred on a Tuesday, Wednesday and Thursday. Of the previous ten years an MD occurred on a Monday on two occasions producing errors of 7% (2002/03) & 14% (1995/96). This is being investigated seeking a causal relationship such as low occupancy of large buildings on Sundays.

Temperature Investigations

VENCorp is investigating a range of issues relating to actual versus forecast MD's and ambient temperatures, including:

- Central Business District (CBD) Temperature V's Metropolitan Distributed Temperatures
- Temperatures Over One V's Two Days.
- Actual V's Forecast Temperatures.

The temperature differential around Port Phillip Bay can be as high as 5 degrees. Early indications are that with the proliferation of residential air conditioning load, forecasts may be improved by including a number of temperature locations around the Bay. A number of other states within the National Electricity Market (NEM) are moving away from using a single CBD temperature.

Impacts on MD's of using temperatures on the day of MD and the previous day are being investigated further.

Impacts on MD's of differences between actual and forecast temperatures for the day of MD are also being investigated. It is anticipated this may have become more of an issue as new technology introduces programmable residential air conditioners.

Conclusion

VENCorp is presently investigating the relationship between forecast v's actual variance and a more appropriate temperature location, also the numbers of days of temperature data used for forecasting. Additionally work is being conducted into generating a weekly load profile with temperature regressed out to show the probabilities of an MD occurring on specific weekdays.

(b) Highest Demand Days - Summer 2002/03

Figure 2.4 and Table 2.6 give an overview of the maximum demand forecast performance in summer 2002/03. Figure 2.4 includes typical "business" days in summer 2002/03 with the average of overnight minimum and daily maximum temperature reaching 25 °C or above.

In this context business days exclude weekends, public holidays and the four weeks from Monday 23 December 2002 to Friday 17 January 2003. Two days excluded from this Figure are Thursday 30 January and Wednesday 5 February as they both came at the end of hot periods of weather and had high overnight temperatures and moderate maximum temperatures. This was due to early cool changes. These days were removed as these conditions lead to a typically low peak demand for these average daily temperatures.

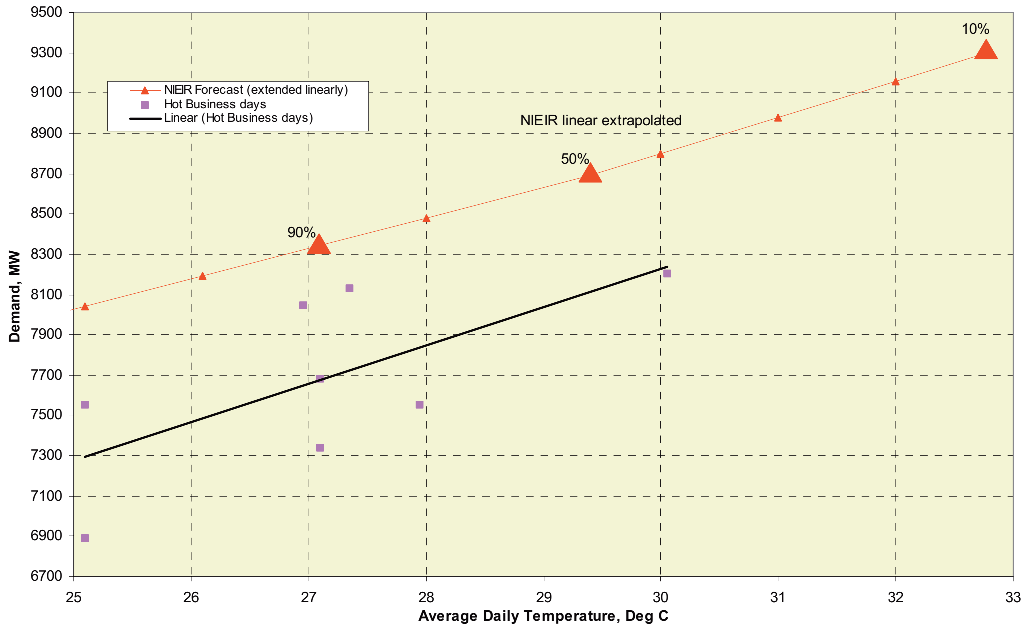


Figure 2.4 - Performance of NIEIR Maximum Demand Forecast, Summer 2002/2003

Date	Day	Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp	NIEIR Forecast (MW)[11]	Forecast variance (MW)
24-Feb-03	Mon	**8203**	24.5	35.6	30.05	**34.6%**	8809	-606
29-Jan-03	Wed	**8104**	16.3	38.4	27.35	**86.9%**	8363	-259
4-Feb-03	Tue	**8018**	18.7	35.2	26.95	**95.3%**	8296	-278
24-Jan-03	Fri	**7656**	15.1	39.1	27.10	**90.0%**	8320	-664
18-Mar-03	Tue	**7526**	22.2	33.7	27.95	**84.1%**	8448	-922

Table 2.6 - Higher daily demand days, Summer 2002/03

(c) Weekend Demand

Victoria set a record weekend electricity MD of 7453 MW in the half hour ending 3 pm summer time and a record daily energy demand of 152.6 GWh for a Saturday on 25 January, when Melbourne's temperature soared to 44.1 °C, as identified in Table 2.7. Other contributing factors were Melbourne's hot northerly winds, mainly clear skies and overnight "minimum" temperature of 26.8 °C. These temperatures represented an average temperature of 35.45 °C and equates to a 5.1% (temperature) day, or an average temperature achieved once in 20 years.

The previous Saturday record MD was set at 7002 MW in the half hour ending 5 pm summer time and 144.3 GWh daily energy demand on 3 February 2001. Melbourne's weather on that day featured temperature ranging from an overnight minimum of 25.7 °C to 38.2 °C, also with hot northerly winds and mainly clear skies.

Date	Day	Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp
25-Jan-03	Sat	**7427**	26.8	44.1	35.45	**5.1%**

Table 2.7 – Highest weekend demand day for Summer 2002/2003

11 VENCorp calculates the "NIEIR Forecast" and associated error by linearly interpolating the NIEIR forecasts.

This very high demand for a weekend, approximately 10% higher than any previous weekend, shows the temperature sensitive component of Victorian demand can be extremely high when average temperatures are consistently high across the major residential areas, as they were on this day.

(d) Seasonal Forecast Error

As with the linear extrapolation for the single maximum demand day, VENCorp also extrapolates MD's of summer week days with average temperatures above 25°C against the NIEIR forecast. This is seen as appropriate due to the range of demand variability for like temperatures. VENCorp has seen an increasing variability of demand for similar temperature days over the previous 2 to 3 years. In the past a demand range for like temperature day was in the vicinity of ± 200 MW. This figure has increased, to as high as ± 400 MW for summer 2002/03. This is highlighted in Figure 2.4 where 4 particular days, all with average temperatures very close to 27°C, ranged in demand from 7338 MW to 8129 MW.

VENCorp has assessed the seasonal error to be 659 MW or 7%. This was found by averaging the error between the NIEIR 10% MD forecast and the equivalent 10% MD for each MD point in Figure 2.4. The 10% equivalent MD's were found by extrapolating all days represented in Figure 2.4 to 10% (32.8 °C average temperature) conditions, against NIEIR forecasts.

(e) Maximum Demand Days Winter 2002

Forecast performance for Winter 2002 is shown in the Table 2.8. The four top demand days show the variance, after linear interpolation between the NIEIR forecast and actual ranging from 0.8% to 3.1% (55 MW to 219 MW). It must also be stated that of these four days the lowest temperature day was only an 82% POE or an average temperature of 7.05°C.

Date	Day	Maximum Demand (MW)	Daily min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp	NIEIR Forecast (MW)	Forecast variance (MW)
22-07-02	Mon	**7281**[12]	3.3	10.8	7.05	**82%**	7370	-89
27-06-02	Thu	**7193**	8.7	11.5	10.1	**99.3%**	7104	89
25-07-02	Thu	**7125**	2.3	12.3	7.3	**87%**	7344	-219
03-07-02	Wed	**7043**	7.3	13	10.15	**99.3%**	7098	-55

Table 2.8 - Higher daily demand days, Winter 2002

2.7 Customer Load Characteristics

The main features characterising the Victorian demand for electricity are:

- The significant variation of load over a day.
- Variation over a week heavily influenced from 0900-1800hrs by Melbourne average temperature, with variation over the day having a similar pattern for working days, and a modified lower level pattern for the weekend days.
- Historically winter daily maximum demands are typically 130 MW higher than expected if it rains in Melbourne, leading up to 6 pm, compared to when it is dry.[13]
- Seasonal, economic and holiday variation.

2.7.1 Daily Variation in Demand

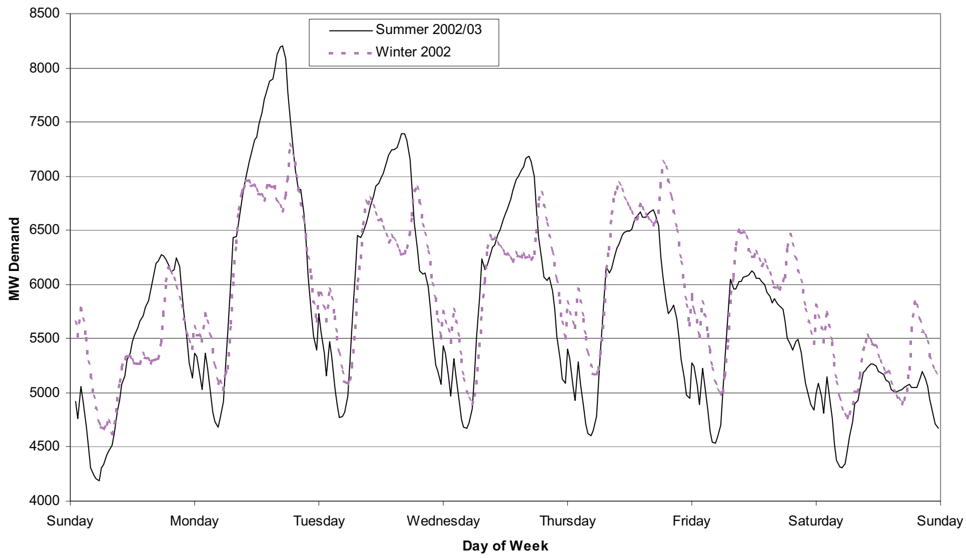


Figure 2.5 displays the load variation for the 2002/03 summer and 2002 winter weeks containing each season's maximum demand day. These weeks are as follows:

- Summer 2002/03, 23 February to 01 March with the season maximum demand occurring on Monday 24 February.
- Winter 2002, 21 July to 27 July with the season maximum demand occurring on Monday 22 July.

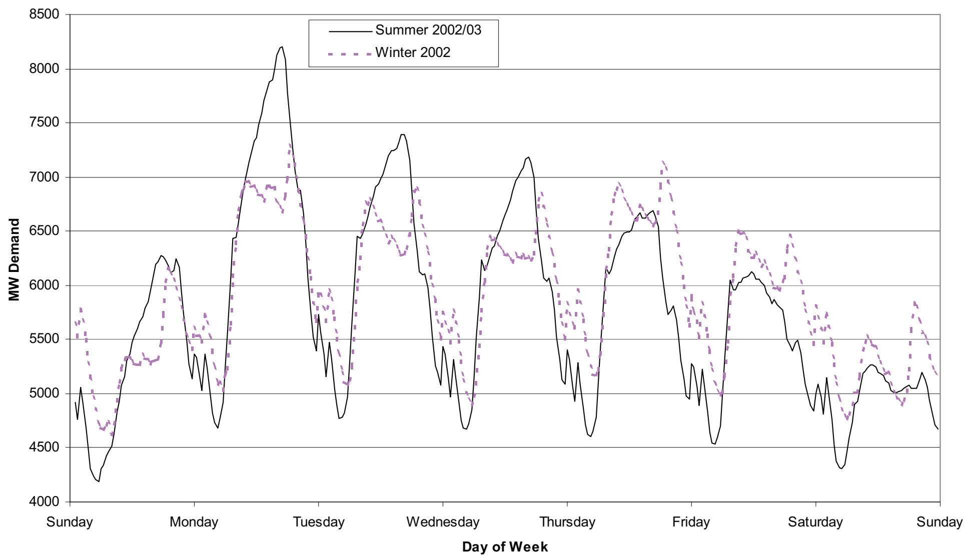


Figure 2.5 - Summer 2002/2003 and Winter 2002 Maximum Demand Weeks

The main features of the summer 2002/03 Maximum Demand week, with comparison to winter 2002 Maximum Demand week, are:

- The summer MD, 569 MW higher than the previous summer (8203 – 7634 MW), occurred in a week of Melbourne average temperatures gradually falling from Monday to Friday temperatures (30, 23, 22, 21 & 18.5° C). Correspondingly, daily potential MDs fell from 8203 - 5870 MW (a difference of 2333 MW). This differs

12 187 MW of Demand Side Participation observed on this day, potential demand of 7281 was recorded

13 This variation of daily winter maximum demand with rain was observed in winter 2001

from most previous years MD weeks, where the temperatures build, leading up to the MD day. In the case of 2001/02 summer this effect caused a rise in daily MD's of approximately 1700 MW from Monday to the season MD on Thursday.

- The higher response to temperature variation in summer- about 160-170 MW/°C, compared with about 70-75 MW/°C in winter.
- There are two major daily peaks in winter weekdays, morning and evening (with evening being the larger on cold days) compared with one peak in the afternoon on hot summer days.
- The winter and summer daily demand traces for 9.00pm in the evening to 10.00am of the following morning tend to be very similar in shape. Evening and overnight demand levels are similar on extreme summer and winter days, but up to about 500 MW lower for milder summer days than milder winter days. On hot summer days, the load trace does not have the characteristic mid-morning drop in demand usually obvious in the winter trace. Rather, the demand continues to rise through the morning and the afternoon, reaching a peak in the later afternoon. The early evening peak, which is obvious in the winter trace (and usually produces the daily maximum demand), is barely perceptible in the summer trace.

Figure 2.6 displays the Victorian demand and Richmond temperature traces for the summers 2000/01 (04 – 10 February), 2001/02 (10-16 February) and 2002/03 (23 February-1 March) maximum demand weeks.

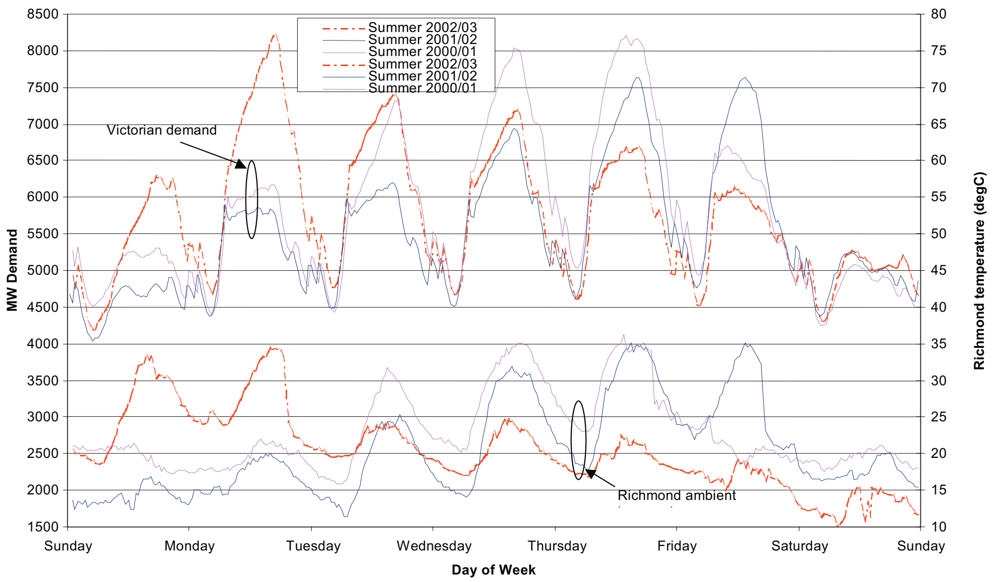


Figure 2.6- Summer 2000/01, 2001/02 and 2002/03 Maximum Demand Weeks and Temperature

As previously identified summer 2002/03 has a significantly different profile with a gradual fall in demand and temperature over the week, rather than the rising effect shown for the 2 previous years. Figure 2.7 displays the Victorian demand and Richmond temperature for the winter 2001 (10-16 June) and 2002 (21-27 July) maximum demand weeks.

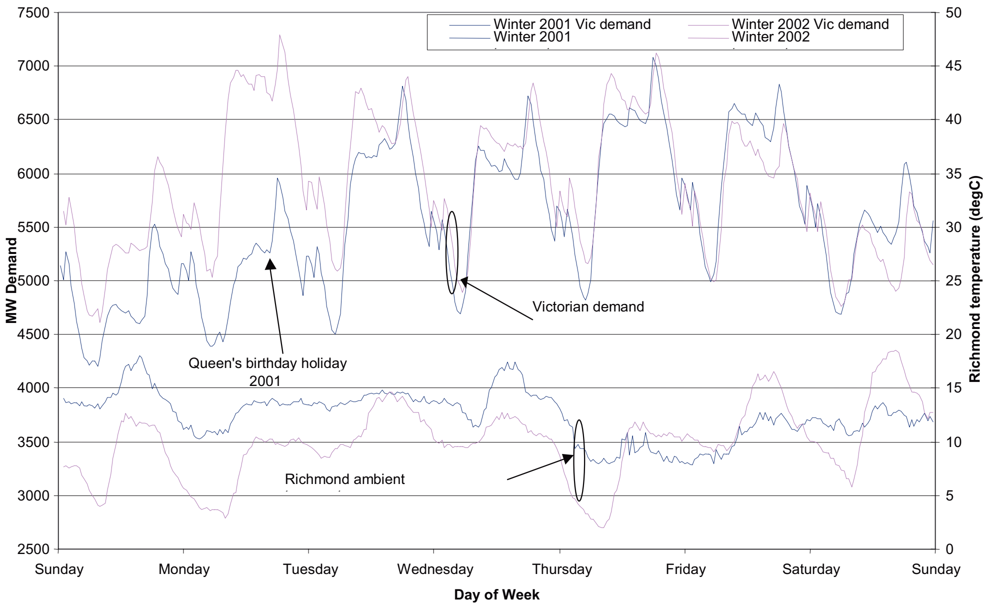


Figure 2.7- Winters, 2001and 2002 Maximum Demand Weeks and Temperature

In winter 2002 a new winter potential MD of 7294 MW was recorded for the half hour ending 6 pm on Monday 22 July, when Melbourne CBD temperature ranged from an overnight low of 3.3 °C to a daily peak 10.8 °C, averaging 7.05 °C. Actual MD was 7107 MW and 187 MW Demand Side Participation (DSP)[14] was observed. In contrast the 7080 MW winter 2001 MD (on Thursday 14 June at 6 pm for corresponding temperatures of 7.4 °C and 11.0 °C, averaging 9.2 °C.

The winter 2002 MD week was relatively cold within yet another overall mild winter, compared to the long run average. Daily average Melbourne CBD temperatures were 8.5 °C on Sunday, 7.05 °C on Monday (when the MD occurred) and 7.3 °C on Wednesday, when the MD reached 7125 MW. Highest daily average temperature for the week was 12.05 °C on Wednesday, when the MD was 6847 MW.

2.7.2 Seasonal Variation in Energy & Demand

As can be seen in Figure 2.8 energy consumption in Victoria continues to be greatest during the winter months with winter days frequently being in the order of 120-140 GWh. Although Maximum Demand occurs in summer, energy consumption is typically lowest during the summer months with daily usage typically between 110-120 GWh. The temperature sensitivity of daily energy on coldest and hottest days is also demonstrated.

14 Demand Side Participation (DSP) occurs when customers modify their consumption of electricity in response to a particular parameter, for example, an increase in spot prices in National Electricity Market (NEM) region. DSP may also occur in response to a Government or participant initiative, such as request to conserve electricity.

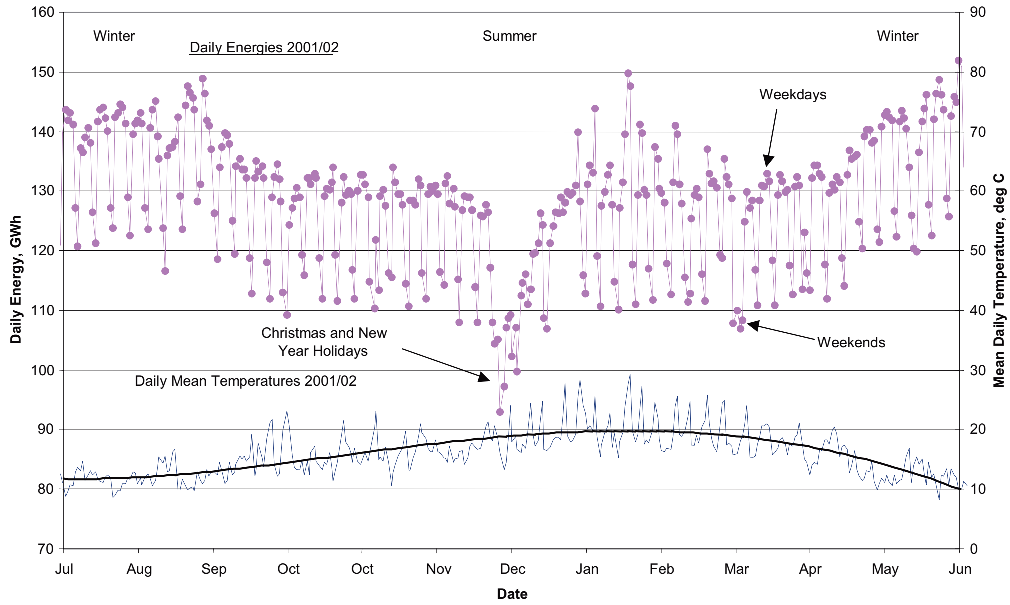


Figure 2.8– 2001/2002 Daily Energy and Mean Daily Temperatures

The variation in Victorian demand because of seasonal change and holidays is displayed in Figure 2.9 and Figure **2.10**, which show daily maximum demands for the financial years 2000/01 and 2001/02 respectively.

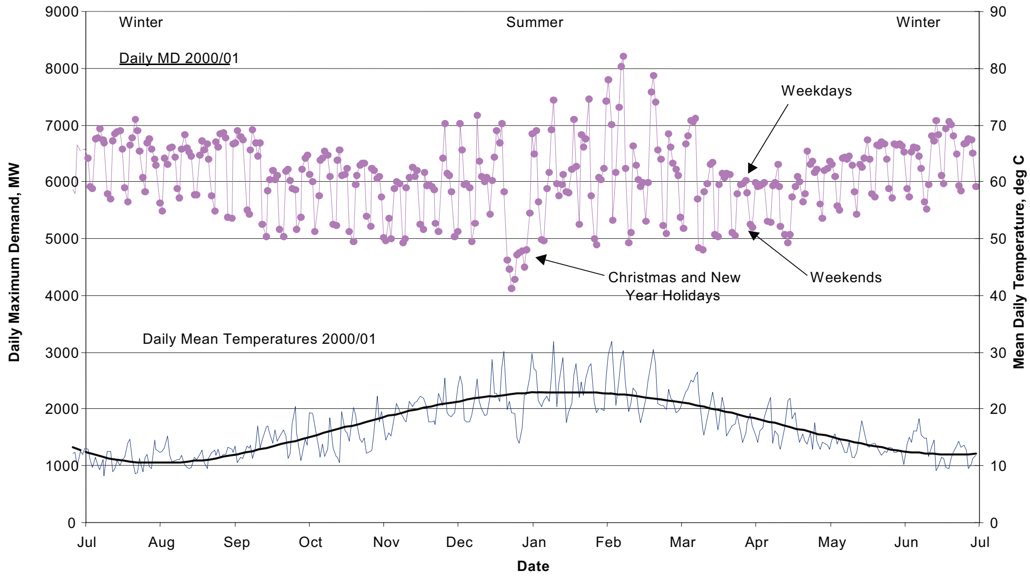


Figure 2.9 – 2000/2001 Daily Maximum Demand and Mean Daily Temperatures

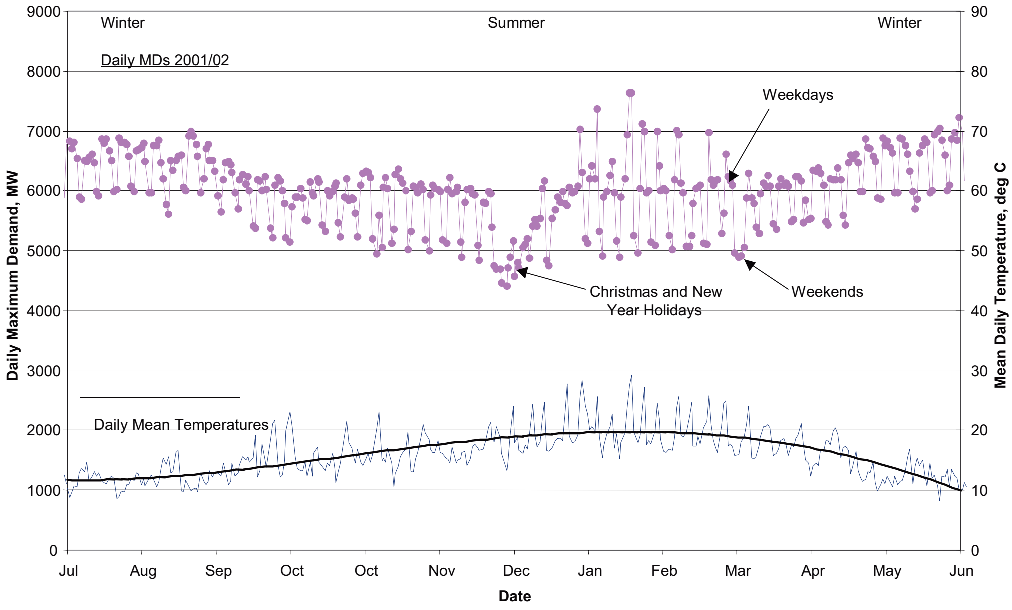


Figure 2.10 - 2001/2002 Daily Maximum Demand and Mean Daily Temperatures

Figure 2.9 and Figure 2.10 show that over a year the summer daily maximum demands respond more than winter daily maximum demands to temperature variation. For a one-degree increase in summer at 30°C mean daily temperature, the load increases by approximately 170 MW/°C. For a one-degree drop in winter at 8°C mean daily temperature the load increases by 70-75 MW/°C. Extremes in peak electricity usage by Victorian electricity consumers occur in summer. This situation has become more pronounced over recent years, due primarily to the increasing installation and use of residential air-conditioners, including fitting of units both to existing and new residences.

2.7.3 Load Duration Curve

Annual load duration curves displaying the percentage of time that the load is above a certain MW level are shown in Figures 2.11 and 2.12.

The following points are noted:

- The top 15% of maximum loads on the system occur for 1% of the time or about 88 hours per year.
- Excluding the 5% highest and 5% lowest demand levels, about 90% of the loads for the year fall within a comparatively narrow range of 4500 to 6500 MW.

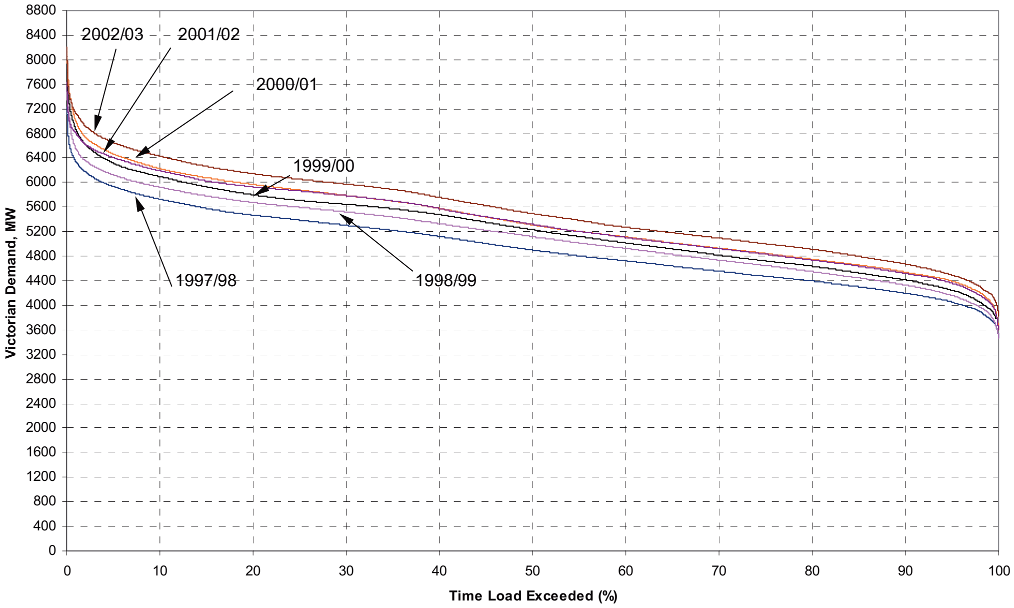


Figure 2.11 - 1997/98 - 2002/03[15] YTD Annual Load Duration Curve

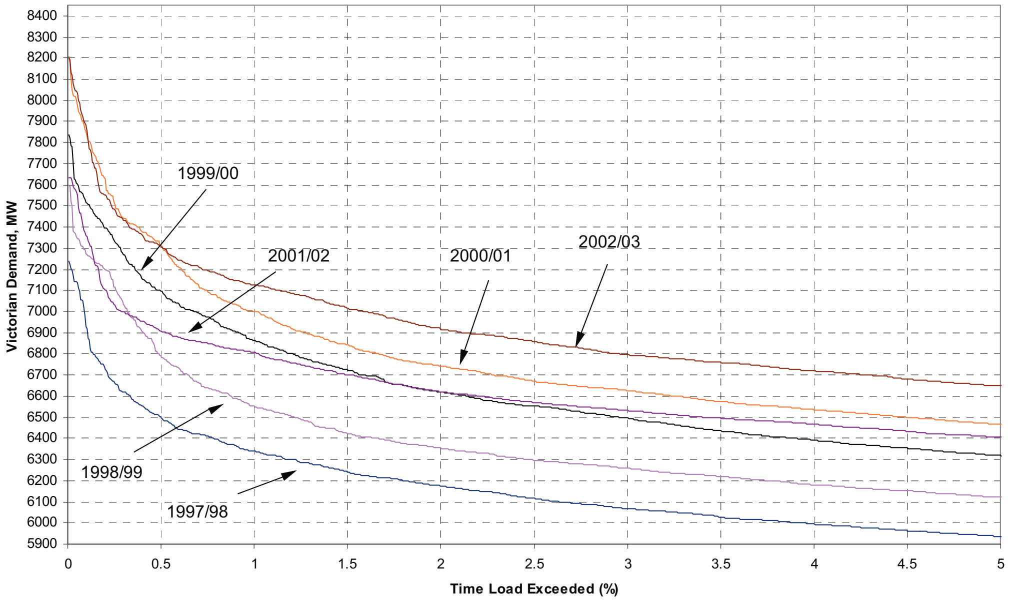


Figure 2.12 - 1997/98-2002/03 Expanded Annual Load Duration Curve

15 2002/03 load duration curve uses 1 Jul 02 - 30 Apr 03 actual demands and 1 May 02 - 30 Jun 02 demands scaled by 1.035, being the ratio of 1 Jul 02 – 30 Apr 03 Vic energy to 1 Jul 01 – 30 Apr 02 Vic energy.

2.7.4 *Monthly Energy Consumption*

Energy consumption varies over the course of the year. Monthly energies generated for Victorian use, including net import from interstate, for the years 1999/00-2002/03[16] are shown in Figure 2.13.

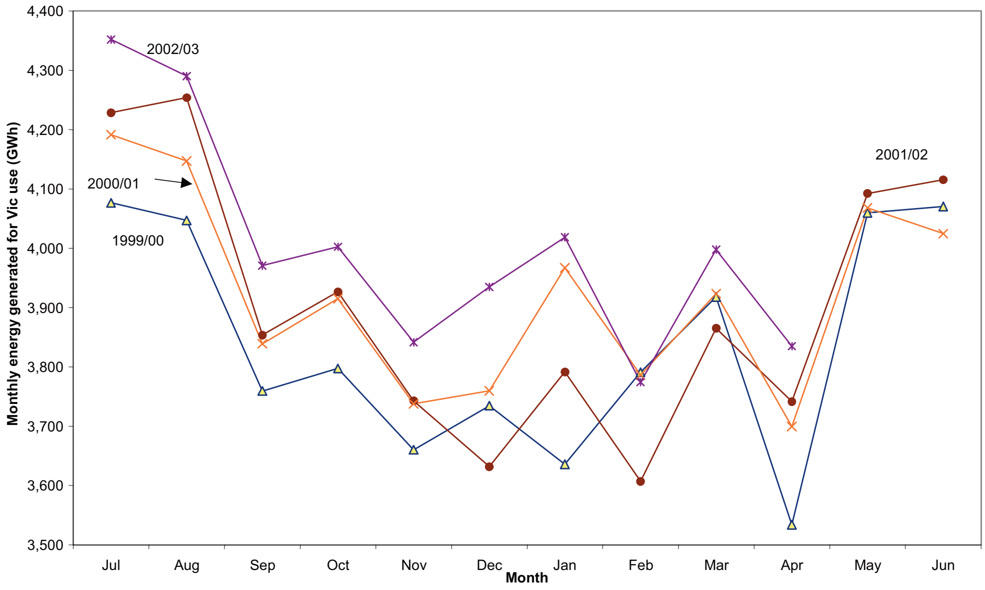


Figure 2.13 – Monthly Energy Generated / Imported for Victorian Use, 1999/00 – 2002/03

2.8 Energy and Demand Forecasts

Load forecasts for the next 10 years are required in the assessment of generation and transmission adequacy. VENCorp provides these forecasts to NEMMCO for publication in its Statement of Opportunities, to allow for review of generation adequacy.

Consistent with these projections and requirements, forecasts of maximum summer and winter demand are also provided for each scenario, for ambient temperatures with 90%, 50% or 10% probability of exceedence.

16 Monthly Energy figures for 2002/03 are from July to April inclusive.

2.8.1 *Energy Forecasts To 2013*

Figure 2.14 shows the actual energy and the energy forecasts for the three economic scenarios. Annual growth rate (medium scenario) 2002/03 is forecast to be 2.3% and subsequently range from 1.0% to 2.5% over the remaining ten years to 2012/13. These growth forecast are based on the economic forecast provided to VENCorp in April 2003.

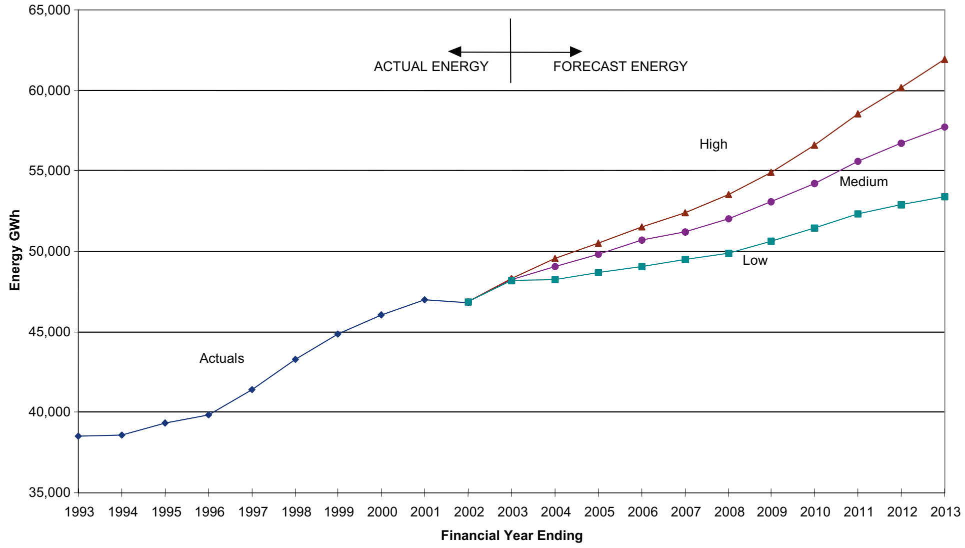


Figure 2.14 - Victorian System Annual Requirement: Three Scenarios

The energy forecasts are at generator terminals and include Anglesea Power station. Table 2.9 details the above energy forecasts and shows the growth rates from year to year.

Financial Year	ACTUAL	
	GWh	% rise
1992/93	38,497	
1993/94	38,566	0.18%
1994/95	39,306	1.92%
1995/96	39,804	1.27%
1996/97	41,430	4.08%
1997/98	43,275	4.45%
1998/99	44,861	3.66%
1999/00	46,053	2.66%
2000/01	46,972	1.99%
2001/02	46,821	-0.32%

Financial Year	MEDIUM		HIGH		LOW	
	GWh	% rise	GWh	% rise	GWh	% rise
2002/03[17]	48,249	2.3%	48,320	2.4%	48,161	0.7%
2003/04	49,082	2.3%	49,537	3.1%	48,253	2.3%
2004/05	49,823	1.5%	50,512	1.9%	48,682	0.9%
2005/06	50,691	1.7%	51,485	1.9%	49,083	0.8%
2006/07	51,209	1.0%	52,371	1.7%	49,510	0.9%
2007/08	52,040	1.6%	53,519	2.1%	49,869	0.7%
2008/09	53,050	1.9%	54,901	2.5%	50,608	1.5%
2009/10	54,187	2.1%	56,574	3.0%	51,450	1.6%
2010/11	55,567	2.5%	58,506	3.6%	52,309	1.6%
2011/12	56,743	2.1%	60,193	3.0%	52,908	1.3%
2012/13	57,703	1.7%	61,896	2.4%	53,372	1.1%

Table 2.9 - Energy forecasts at generator terminals (including Anglesea Power Station)

17 2002/03 base/high/low scenario energy forecasts comprise 1 July 2002 - 30 April 2003 actual energy added to the respective NIEIR 2002/03 base/high/low scenario energy forecasts for 1 May-30 June 2003.

2.8.2 *Maximum Summer Demand Forecasts to 2013*

Table 2.10 shows nine sets of maximum summer demand forecasts corresponding to average daily temperatures having 10%, 50% and 90% probability of exceedence under each of medium, high and low economic scenarios. For clarity Figure 2.15 shows only the peak demand forecasts for the medium economic scenario. All these forecasts assume average summer temperatures each year have 50% probability of exceedence, affecting future sales of air conditioning units.

SUMMER	Actual (MW)	Equiv. 10%							
1992/93	6489	6451							
1993/94	6134	6739							
1994/95	6509	6802							
1995/96	5922	6909							
1996/97	7115	7314							
1997/98	7213	7556							
1998/99	7576	7994							
1999/00	7815	8335							
2000/01	8179	8600							
2001/02	7621	8469							
2002/03	8203	8696							
SUMMER	10% Probability of Exceedence			50% Probability of Exceedence			90% Probability of Exceedence		
	Medium	High	Low	Medium	High	Low	Medium	High	Low
2003/04	9417	9483	9339	8758	8819	8687	8351	8408	8283
2004/05	9730	9854	9594	9045	9162	8919	8622	8734	8502
2005/06	9998	10170	9751	9286	9446	9055	8846	8999	8623
2006/07	10208	10461	9929	9472	9708	9211	9015	9242	8767
2007/08	10437	10767	10063	9676	9983	9324	9205	9498	8867
2008/09	10740	11149	10300	9952	10334	9540	9465	9829	9069
2009/10	11029	11536	10524	10214	10687	9742	9710	10162	9257
2010/11	11327	11939	10733	10488	11060	9932	9969	10515	9436
2011/12	11577	12277	10876	10716	11367	10057	10182	10803	9550
2012/13	11840	12684	11051	10954	11742	10213	10406	11159	9694

Table 2.10 - Summer Maximum Demand Forecasts

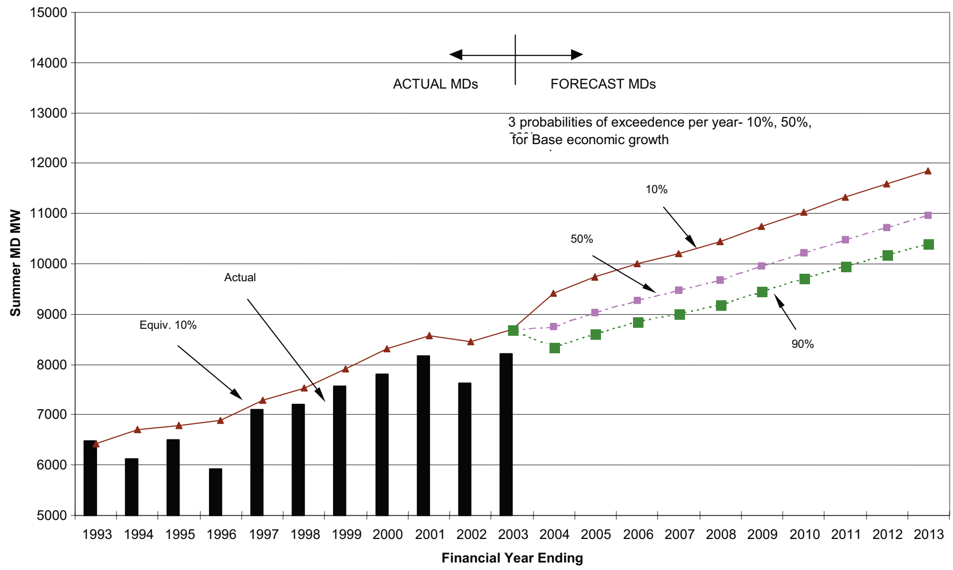


Figure 2.15 - Summer Maximum Demand: Three Growth Scenarios

2.8.3 *Maximum Winter Demand Forecasts to 2013*

As for summer, for winter Table 2.11 shows nine sets of maximum winter demand forecasts corresponding to average daily temperatures having 10%, 50% and 90% probability of exceedence under each of medium, high and low economic scenarios., while for clarity Figure 2.16 shows only the peak demand forecasts for the medium economic scenario.

WINTER Calendar year	Actual (MW)	10% Probability of Exceedence			50% Probability of Exceedence			90% Probability of Exceedence		
Calendar year		Medium	High	Low	Medium	High	Low	Medium	High	Low
1992	5981									
1993	5885									
1994	5890									
1995	6018									
1996	6059									
1997	6404									
1998	6662									
1999	6682									
2000	7091									
2001	7054									
2002	7281									
2003		7824	7882	7773	7668	7724	7619	7375	7430	7328
2004		7966	8069	7866	7801	7901	7704	7485	7582	7394
2005		8138	8266	7965	7963	8088	7797	7623	7740	7468
2006		8236	8425	8046	8054	8237	7872	7694	7865	7526
2007		8360	8608	8101	8170	8410	7921	7789	8011	7559
2008		8554	8863	8255	8355	8652	8067	7950	8224	7685
2009		8745	9136	8399	8535	8912	8203	8103	8450	7799
2010		8965	9442	8537	8745	9205	8334	8291	8714	7913
2011		9148	9707	8623	8920	9457	8414	8445	8939	7979
2012		9351	10023	8743	9113	9760	8527	8616	9211	8074
2013		9557	10330	8883	9309	10054	8660	8786	9469	8189

Table 2.11 - Winter Maximum Demand Forecasts

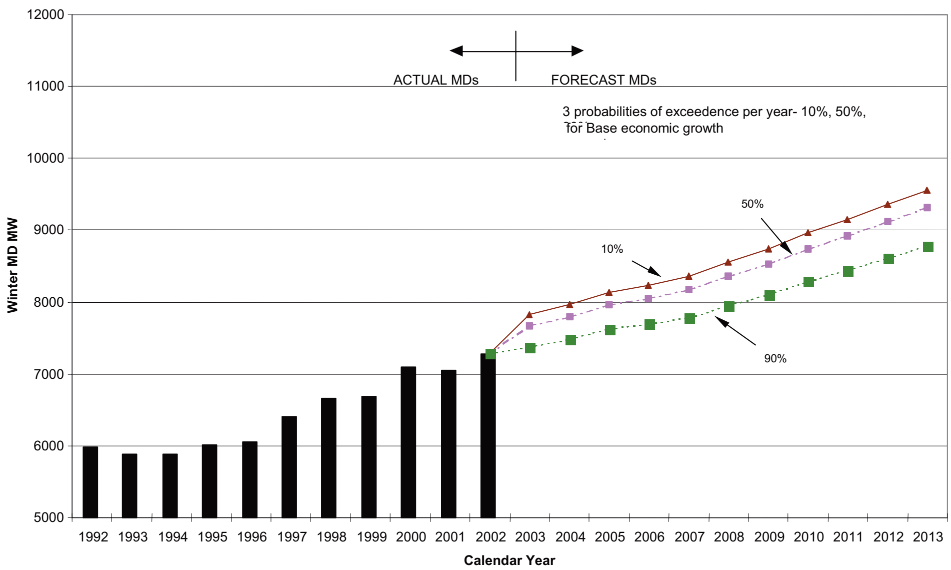


Figure 2.16 - Winter MDs: Three Growth Scenarios

2.8.4 Combined Vic/SA Maximum Summer Demand Forecasts to 2013

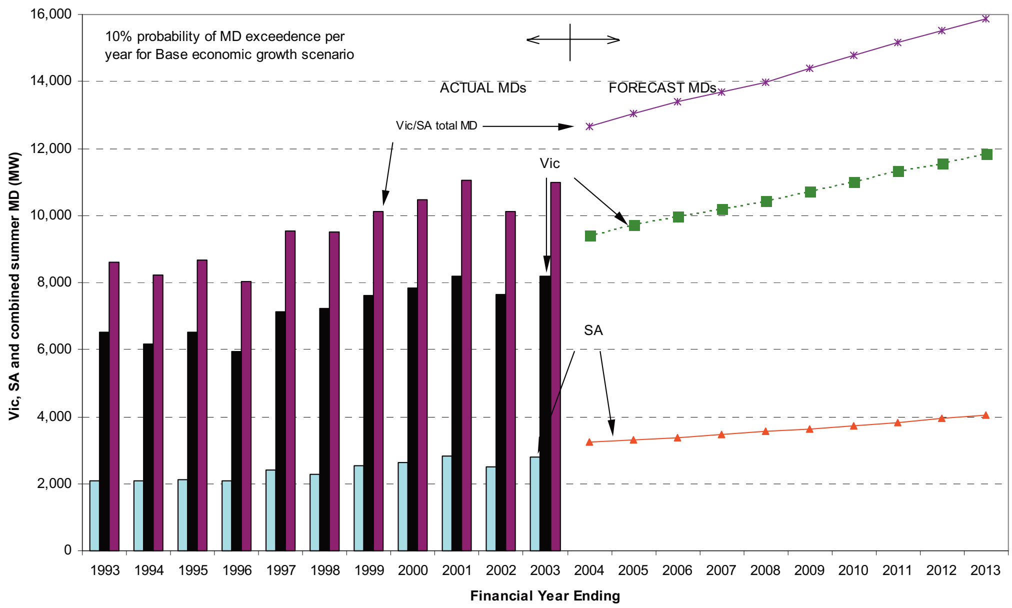


Figure 2.17 - Combined Vic/SA 10% POE Base economic scenario Summer MDs

Figure 2.17 shows the Victorian and South Australian summer MD forecasts for 10% POE and base economic growth conditions. The maximum possible combined MD for these conditions is obtained by totaling these individual MDs as shown. Directly adding these MDs is an over-simplification, but not a gross over-estimate of the 2-state coincident MD. Specifically, over the last 11 summers both states have recorded summer MDs on the same day three times (17 February 1992, 25 January 1994 and 19 February 1997) and on successive days three times (2-3 February 1993 and 2000 and 7-8 February 2001), the SA MD being on the first day. Despite the half hour solar and statutory Victorian and SA time differences daily MDs in the two states may generally be considered to be coincident.

2.9 Analysis of Trends in Winter and Summer Load Factors

As described in Section 2.7.3 the Victorian summer demand is characterised by a peakiness with the top 15% of maximum loads on the system occurring for 1% of the time or about 88 hours per year. This increase in peak demand is largely being driven by the increasing installation of domestic air conditioning.

In transmission network planning, the forecast maximum demand is a dominant factor in assessing future transmission augmentation. (Likewise, in the analysis of capacity reserve requirements, the forecast maximum demand is used to calculate the additional capacity requirements to maintain reserve levels.)

The continuing high growth in summer maximum demand forecast, about half due to increased cooling as shown in Figure 2.18, would result in the continued divergence between the summer peak demand and energy growth levels. For example the average annual growth in summer 10% maximum demand over the period 2003-2008 is 2.6% according to the medium economic growth scenario. In contrast the average forecast growths in annual energy consumption is 1.8% for the same period, and the winter 10% maximum demand growth is 1.76%.

Not only is the about half of peak demand growth due to low load factor cooling demand, but this low load factor temperature sensitive demand is becoming an increasingly significant component of the Victorian power system's peak demand.

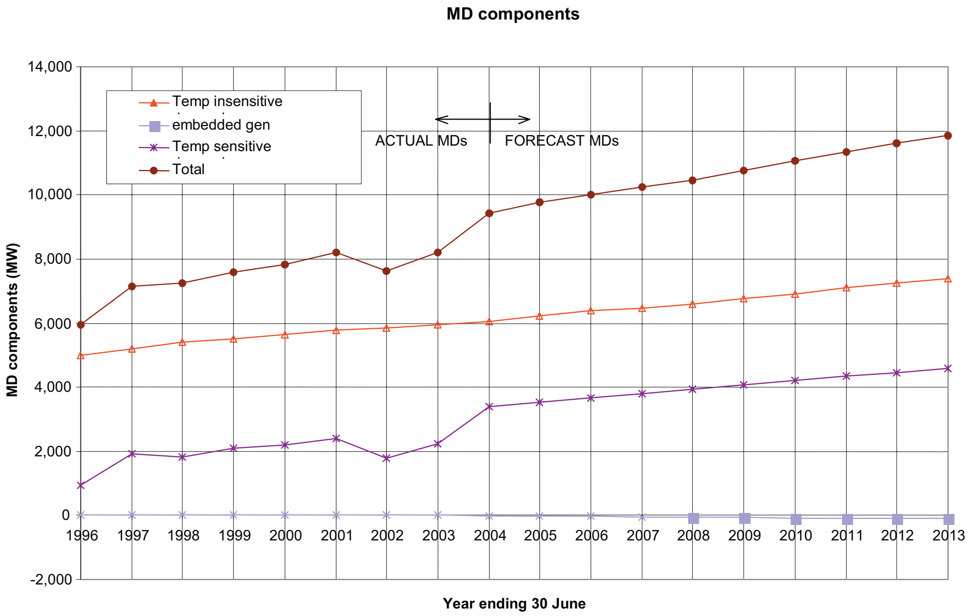


Figure 2.18 -Temperature sensitive and insensitive components of summer 10% POE MD forecast

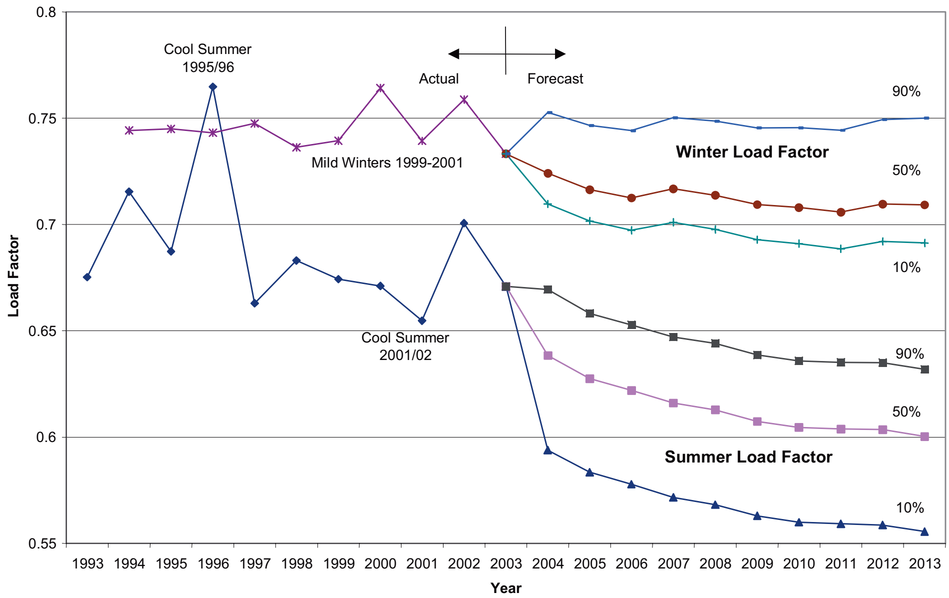


Figure 2.19 - Winter and Summer Load Factors

The longer term divergence in summer peak demand growth and energy growth can be demonstrated by considering the system load factor since 1993[18].

Figure 2.19 shows the variation in the summer and winter load factors from 1993 up to the present. The forecast seasonal load factors are also presented, corresponding to the medium growth scenario, 10%, 50% and 90% summer and winter maximum demand forecasts. Deviation from the trend can be noted for the actual load factors to 2002, particularly for the cool summer in 1995/96 and 2001/02 and the mild winters in 1999-2001.

The decrease in the forecast summer load factor (from 0.64 in 2003/04 to 0.60 in 2012/2013 for the 50% peak demand and from 0.60 to 0.55 over the same period for the 10% peak demand), clearly demonstrates the

18 The (summer) system load factor is the ratio of the annual energy demand at generator terminals in MWh to the maximum demand in MW multiplied by 8760 hours. A winter load factor can be similarly defined by using the winter maximum demand.

continuing divergence in the growth rates of summer maximum demand from the annual energy consumption and highlights the expected increasing peakiness in demand. The winter load factor is forecast to remain steady (90% POE) or reduce slightly (10% POE) over the coming 10 years, showing that the growth in energy is forecast to be similar to, or marginally below, the growth in winter maximum demand.

2.10 Comparison with Code Participants Provided Connection Point Forecasts

VENCorp provides another perspective on Victorian peak demand load forecasts in summer and winter by combining forecasts by distribution network service providers of peak demand at their (terminal station) points of connection to the transmission network. VENCorp does this by assessing the diversities between the system peaks, and the peak loads which are drawn by distributors from each connection point on various days at various times. VENCorp adjusts these forecasts for transmission losses and demand not supplied through the transmission and distribution networks, such as power station internal usage, to place them on the same basis as the peak demand forecasts NIEIR provides.

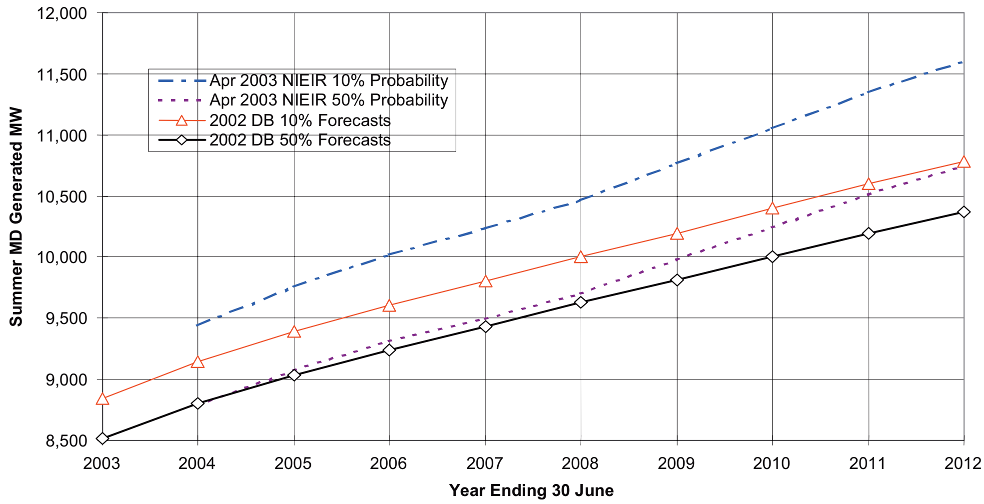


Figure 2.20 - Comparison of NIEIR and System Participants Peak Summer Load Forecasts

Figure 2.20 shows the peak demands that are expected to occur with medium economic growth, and ambient temperature conditions occurring on average one summer in two (ie 50% probability), and one summer in ten (ie 10% probability), comparing the latest (September 2002) terminal station demand forecasts (presented in Appendix 1) and the latest NIEIR (April 2003) forecasts.

The 50% summer peak demand forecasts by distributors are very similar to the NIEIR forecasts in the first 5 years, but fall increasingly below the NIEIR forecasts in the later years. The 10% summer peak demands forecast by NIEIR are 300 MW higher than the distributors forecast for 2003/04 and increase to approximately 460 MW over the following 4 years. NIEIR summer and winter 10% and 50% MD forecasts grow steadily over the next ten years, except for lower growth in 2006/07, 2007/08 and 2011/12, whereas the distributors forecast growth rates generally fall through the period. However while NIEIR’s average annual summer growth rates (2.6% for 10%, and 2.5% for 50% MDs) exceed the corresponding distributor growth rates (2.0% pa for both 10% and 50% MDs) both NIEIR and distributor winter demands over the decade grow at an average 2.0% pa for both 10% and 50% forecasts.

Figure 2.21 shows the corresponding, 10 and 50 percentile Victorian peak winter demand forecasts.

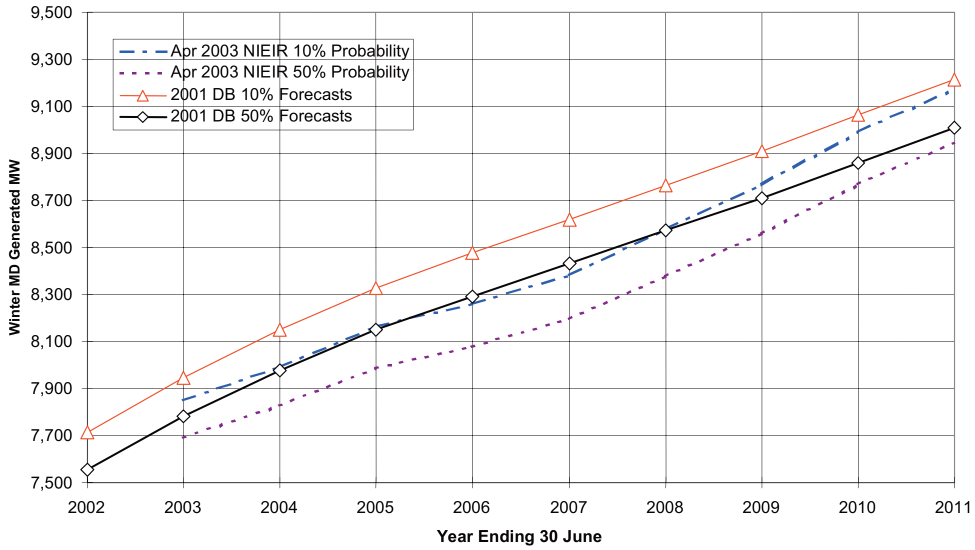


Figure 2.21 - Comparison of NIEIR and System Participants Peak Winter Load Forecasts

2.11 Peak Load Variability

The investigations noted in section 2.6.2.1 aim to identify major causes of the increased variability in Victorian hot day summer MDs and improve forecast accuracy. VENCorp continues to monitor equipment sales trend information for critical end uses, and will review this in the specific contexts of these investigations. VENCorp also continues to monitor demand-side effects that it can observe, but based on their expected correlations to forecast and/or actual pool price does not anticipate these contributed materially to the observed increased MD variability.

The rapidly increasing Victorian penetration of refrigerative air conditioning is resulting in the inherent variability of this growing proportion of peak demand being increasingly evident in variability of total peak (summer) demands. The maximum summer demand forecasts are based on this increasing penetration trend continuing, correspondingly giving rise to increased variability in overall maximum summer demand forecasts.

3 NETWORK ADEQUACY

3.1 Introduction

This chapter describes the existing transmission network and its ability to meet the actual and forecast 2002/03 summer peak demand conditions. It includes:

- a review of the shared network conditions during summer 2002/03,
- an overview of the active and reactive supply demand balance at times of peak demand,
- a summary of changes to the system that have been implemented since the last Annual Planning Review.
- a summary of fault levels and the available margin at Victorian terminal stations,

It aims to assist existing or potential network users in understanding potential transmission network constraints, in assessing future transmission augmentation requirements and in identifying locations with spare capacity for load growth or generation, or locations where demand management could defer the cost of network augmentation.

3.2 Existing Transmission Network

The Victorian transmission network consists of various transmission lines and transformers that link power stations to the distribution system. The transmission lines operate at voltages of 500 kV, 330 kV, 275 kV, and 220 kV. The 500 kV transmission lines primarily transport 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 lines service the metropolitan area and major regional cities of Victoria, while the 330 kV lines interconnect with the Snowy region and New South Wales. 275 kV lines provide for the interconnection with South Australia as per Figure 3.1.

The electricity transmitted through the high voltage transmission lines is converted to lower voltages at terminal stations where it then supports the distribution system. There are a total of 36 terminal stations in Victoria. The total circuit distance covered by transmission lines is approximately 6000 kilometres.

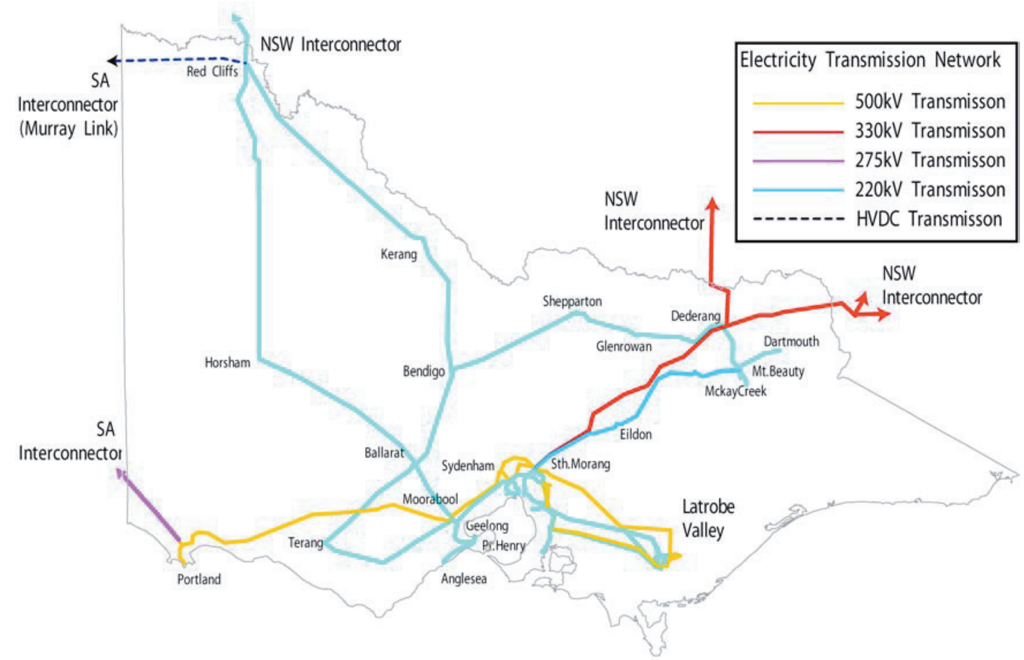


Figure 3.1 - Victorian Transmission Network

3.3 Summer 2002/03 conditions

As discussed in Section (a), the peak electricity demand experienced in Victoria was 8203 MW and this occurred on Monday 24 February 2003. The temperature conditions on this day were consistent with a probability of exceedence level of 34.6%. The maximum ambient temperature reached was relatively low at 35.6° C even though the average Melbourne temperature was 30.1° C.

The Victorian shared transmission network has been economically designed to meet forecast demand associated with 10% probability of exceedence temperatures. For summer 2002/03 this was 9302 MW for a medium economic growth scenario, so inherently, the transmission network was generally operated at well within its design capability.

Planned network outages associated with the implementation of the SNOVIC project, and forced network outages as a result of considerable bushfire activity impacted on both intra and inter regional transfer levels resulting in a certain degree of price volatility in Victoria.

The average half hour spot price in Victoria over the 2002/03 summer (Dec-Mar) was relatively low at $24/MWh compared to the 2001/02 summer average spot price of $27/MWh. This can be attributed to the overall lower energy usage during the summer period. The minimum half hour spot price of $0.9/MWh, occurred in the half hour ending 6:00am Eastern Australian Summer Time on Sunday 19 January 2003. The maximum half hour spot price of $4166.76/MWh, occurred in the half hour ending 16:30pm Eastern Australian Summer Time on Wednesday 19 March 2003.

3.4 System Active and Reactive Power Supply Demand Balance

As per Table 3.1, the Victorian forecast reserve level (with a nominal 250 MW transfer level to SA) at peak demand conditions with all generation available is 842 MW, which is well in excess of the regional LOR2[19] trigger level of 540 MW.

	VIC
Forecast Demand (10%Medium)	9302
Expected Demand Side Participation	108
Reserve Trigger Level	540
Supply Needed to Meet Reserve	9734
Local Generation	8386
Import Capability From Snowy/NSW	1900
Nominal Transfer to SA	250
Total Region Supply	10036
Reserve Level	842
Reserve Surplus	**302**

Table 3.1 - Summer 2002/03 supply demand balance for combined Victoria and SA regions

This is on the basis of the following generation definition:

Power Station	Summer Capacity 02/03
Anglesea	160
Bairnsdale	78
Energy Brix Complex	170
Hazelwood	1600
Hume(VIC)	50
Jeeralang A	212
Jeeralang B	237
Loy Yang A	2058
Loy Yang B	1000
Newport	510
Somerton GT	135
Southern Hydro	474
Valley Power	252
Yallourn W	1450
Total	**8386**

Table 3.2 - Summer Aggregate Generation Capacity for Victoria (Source: 2002 SOO).

The forecast demand level of 9302 MW is representative of conditions where:

- The transmission losses are approximately 405 MW (4.4%)
- The Used in Station load is approximately 535 MW (5.8%)
- Major Industrial load is approximately 1100 MW (11.8%)
- State Regional load is approximately 1490 MW (16.0%)[20]

19 Lack of reserve level 2 (LOR2) - when NEMMCO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding

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

- Western metropolitan area load is approximately 1600 MW (17.2)[21]
- Eastern metropolitan area load is approximately 3850 MW (41.4%)[22]
- Latrobe Valley area load is approximately 320 MW (3.4%)[23]

The maximum supportable demand in Victoria has been, and may continue to be, 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. The pre-defined level of maximum supportable demand is based on an economic analysis as per VENCorp's application of the Regulatory Test and therefore dictated by VENCorp's Value of Customer Reliability 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. At present the maximum supportable demand under the most favourable conditions is 9365 MW. VENCorp continues to augment the shared network with shunt capacitor banks to extend the maximum supportable demand as economically appropriate.

Table 3.3 and Table 3.4, show a typical before and after reactive power supply demand balance for forecast demand levels of 9302 MW as a consequence of loss of the 500 MW Newport generator.

Reactive Supply [MVAr]		Reactive Demand [MVAr]	
Generation	2342	3650	Loads
SVC's and Synchronous Condensers	86	214	Line Reactors
Line Charging	2705	5639	Line Losses
Shunt Capacitors	4644	274	Inter- regional Transfer
Total	9777	9777	Total

Table 3.3 - System Normal reactive power supply demand balance – 9302MW demand.

Reactive Supply [MVAr]		Reactive Demand [MVAr]	
Generation	3436	3638	Loads
SVC's and Synchronous Condensers	420	212	Line Reactors
Line Charging	2695	7056	Line Losses
Shunt Capacitors	4622	266	Inter- regional Transfer
Total	11173	11172	Total

Table 3.4 - Post Contingency reactive power supply demand balance – 9302 MW demand.

The significant increase in reactive line losses for this event, in the order of 1400 MVAr, is highlighted to emphasis the critical impact of such an event. The ability of the reactive sources to meet this step increase in demand in the short, medium and longer term while maintaining acceptable voltage levels and reserve margins is what defines the maximum supportable demand.

3.5 Shared Network Loading

This section provides a review of the shared network loadings that were experienced for summer 2002/03 and an indication of the network loadings that would have occurred if the forecast summer load was achieved. This information is presented in Figure 3.2 where loadings of shared transmission network lines and transformers, as a proportion of ratings are shown for the following three conditions:

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

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

23 Defined as load supplied out of Yallourn and Morwell

- Actual 2002/03 8203 MW MD;
- Forecast 2002/03 10% POE 9302 MW MD; and
- Forecast 2002/03 9302 MW MD with the single contingency outage producing the highest loading for each network element.

The table below summarises the system loading conditions under these actual MD and 10% POE forecast MD conditions.

Reactive Supply [MVAr]		**Reactive Demand [MVAr]**	
Generation	3436	3638	Loads
SVC's and Synchronous Condensers	420	212	Line Reactors
Line Charging	2695	7056	Line Losses
Shunt Capacitors	4622	266	Inter- regional Transfer
Total	11173	11172	Total

Table 3.5 - Actual and 10% POE forecast 2002/03 MD system loading conditions

Allowing for hot summer conditions likely to produce a 10% POE MD, continuous ratings used are for 40 °C ambient temperature conditions. Line ratings are based on the standard 0.6 m/s wind speed except in the case of Rowville-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.

The contingency loadings presented are within short time transformer and line ratings, although these are not shown. A range of post contingent actions to reschedule generation, reconfigure the network, and/or shed load, using automatic controls or remote manual intervention are available to ensure that the after a critical contingency the transmission system remains in a satisfactory state. In particular this ensures that transmission operates at all times within ratings. In some cases action is needed within minutes of a critical contingency occurring under maximum demand conditions to retain operation within ratings. Within 30 minutes additional action may be needed to return the transmission system to a secure state, allowing the transmission system to remain in a satisfactory state should a further outage occur.

The shared network loadings highlight the following areas, which are discussed in greater detail in the next chapter.

- Hazelwood transformation
- Latrobe Valley to Melbourne 220 kV transmission
- Rowville transformation
- Moorabool / Keilor transformation / Keilor-Geelong circuits
- Dederang transformation
- Rowville-East Rowville circuits
- Rowville-Springvale circuits
- Rowville to Thomastown 220 kV circuits.

Network Actual and Forecast 2002/03 MD Loadings - normal system and critical single outages			
Transmission Link	**Actual**	**10% MD**	**Critical outage**
220 kV lines			
Bendigo-Kerang	21	27	52
Kerang-Red Cliffs	14	15	37
Horsham-Red Cliffs	10	12	38
Ballarat-Horsham	27	28	52
Shepparton-Glenrowan-Dederang	53	66	85
Bendigo-Shepparton	65	77	98
Ballarat-Bendigo	18	6	82
Moorabool-Ballarat/Terang	47	47	87
Rowville-Malvern	33	39	78
Rowville-Springvale-Heatherton	63	73	127
East Rowville-Tyabb/BHP Steel	16	20	47
Rowville-East Rowville	47	55	110
Geelong-Point Henry/Anglesea	55	55	97
Keilor western metro double circuit loop	57	47	84
Keilor-Geelong	25	38	121
Thomastown-Keilor	33	21	41
Rowville-Thomastown (4-5 parallel circuits)	40	46	115
Latrobe Valley-Melbourne 220 kV	89	89	108
Main Tie transformers			
Dederang 330/220 kV	100	86	116
Moorabool 500/220 kV	67	63	74
Keilor 500/220 kV	67	75	98
South Morang 330/220 kV	72	72	116
South Morang 500/330 kV	11	5	49
Rowville 500/220 kV	74	79	100
Hazelwood 500/220 kV	58	73	100
500 kV Lines			
South Morang/Thomastown-Dederang	75	76	123
Moorabool-Heywood/APD	17	22	45
Sydenham-Moorabool	30	35	63
South Morang-Sydenham/Keilor	48	50	65
Latrobe Valley-Melbourne 500 kV	52	53	74

<= 90% **90% <= 100%** **>100%** **Loadings as % of 40 °C Rating**

Figure 3.2 - Network Actual and Forecast 2002/03 MD Loadings

3.6 Connection Asset Loading

The responsibility for planning of distribution related connection assets resides with the Distribution Businesses. Jointly they publish an annual report on the performance and capability of their connection assets entitled 'Transmission Connection Planning Report'. This report is available via the Distribution Businesses' respective websites. VENCorp provides the following summary of connection asset loading over the Summer 2002/03 period for information purposes.

Station	Voltage	Actual Summer 2002/03 loading	Forecast Summer 2002/03 loading
Altona\Brooklyn*	66	Red	Red
Ballarat*	66	Green	Green
Bendigo	66	Yellow	Green
Bendigo	22	Green	Green
Brooklyn*	22	Yellow	Red
Brunswick*	22	Green	Red
East Rowville (inc FTS) *	66	Red	Red
Fishermen's Bend	66		
Glenrowan*	66	Green	
Geelong*	66	Yellow	Red
Horsham*	66	Yellow	Red
Heatherton*	66	Yellow	Red
Kerang	66	Red	Red
Kerang	22		
Keilor	66	Green	Yellow
Mount Beauty (ex CLPS) *	66		
Malvern	66	Yellow	Red
Malvern*	22	Green	Yellow
Morwell (incl LY) *	66	Red	Red
Red Cliffs	66	Red	Red
Red Cliffs	22	Red	Red
Richmond*	66	Yellow	Red
Richmond	22		
Ringwood*	66	Red	Red
Ringwood*	22	Red	Red
Shepparton	66		
Springvale*	66	Red	Red
Tyabb*v	66	Red	Red
Terang*	66	Red	Red
Templestowe*	66	Green	Yellow
Thomastown 1&2 Group*	66	Red	Red
Thomastown 3&4 Group*	66	Green	Red
West Melbourne*	66		Green
West Melbourne*	22	Green	Green
Wodonga*	22	Green	Green
Wodonga (ex HPS) *	66		
Yallourn	11		

Loading < 80% of firm rating	
90% > Loading > 80% of firm rating	Green
100% > Loading > 90% of firm rating	Yellow
Loading > 100% of firm rating	Red

Table 3.6 - Loading Levels of Connection Assets

* Indicates that either embedded generation or load transfer capability is available. These will both reduce the potential overload, and may remove the requirement for load shedding following the critical contingency.

3.7 Fault Level Control

VENCorp has the responsibility to ensure that fault levels are always maintained within plant capability in the transmission network. The following table summarises the headroom available at a number of locations in the Victorian network.

Switchyards where the Maximum Prospective Short Circuit Current at the Busbar is Above 80% of the Minimum Circuit Breaker Interrupting Capability

Terminal Station Switchyard	220 kV	66 kV	22 kV
Ballarat			N/A
Brooklyn			
Brunswick		N/A	
East Rowville			N/A
Fishermans Bend			N/A
Geelong			N/A
Hazelwood		N/A	N/A
Heatherton			N/A
Keilor			N/A
Malvern			
Morwell			N/A
Mount Beauty			N/A
Redcliffs			
Richmond			
Ringwood			
Rowville		N/A	N/A
Springvale			N/A
Templestowe			N/A
Thomastown			N/A
West Melbourne			

Non Existent Switchyard	N/A
Fault Level is < 80% of CB Rating	
Fault Level is 80 - 90% of CB Rating	
Fault Level is > 90% of CB Rating but < 100%	

Table 3.7- Overview of Fault Levels at Victorian Terminal Stations

Maximum prospective short circuit currents are determined with all system normal elements in service and all generators, including peaking plant, on-line.

At present, there are no locations within the Victorian transmission network where the interrupting capability of a circuit breaker is inadequate, or less than the worst case fault current it may be required to interrupt.

The high number of locations where the maximum short circuit current is greater than 90% of the switchyards minimum interrupting capability is an indication of the historical development of the transmission network in Victoria and the way new generation has been integrated into the system.

VENCorp has managed increasing fault levels by operational arrangements (i.e. splitting busses and automatic control schemes) and circuit breaker replacement. At present, the network is adequately and economically designed to meet forecast load levels. This will continue to be the case until significant transmission augmentation is required or significant new generation is developed.

Importantly though, increasing fault levels will continue to be a key consideration in the development of metropolitan terminal stations. Particularly when considering the potential for new (embedded or transmission connected) generation since the application and increasing complexity of operational arrangements, and the inherent reduction in plant redundancy that typically results, may no longer always provide the most economic solution.

3.8 Network Modifications and Developments

The following information is provided to identify major changes that have occurred or are committed compared with the transmission network discussed in VENCorp's 2002 APR.

3.8.1 SNOVIC

In early 2001, at the request of Victorian Government, VENCorp undertook a study into the feasibility of upgrading the Snowy to Victoria interconnector to improve access to additional supply capacity. VENCorp concluded that a 400 MW interconnection upgrade by summer 2002/03 for and estimated capital cost of $44M would provide the greatest net market benefit of all the options considered.

The Victorian Government subsequently asked VENCorp to act as the proponent for the 400 MW Snowy to Victoria interconnector upgrade project for the purposes of gaining regulatory approvals through Inter Regional Planning Committee (IRPC). This process commenced in May 2001 and in December 2001 NEMMCO granted the SNOVIC project regulated status.

Works involved upgrading the thermal capacity of the Murray to Dederang 330 kV lines, additional switching at Dederang Terminal Station and within the Victorian State grid, installation of reactive plant and the implementation of automatic control schemes to minimise the need for primary plant augmentation.

In December 2003, the SNOVIC project was successfully completed, on time and within budget to ensure that the additional 400 MW import capability along the Victoria to Snowy interconnector was made available during the 2002/03 summer period.

3.8.2 Cranbourne 220/66 kV Development

In December 2001, the distribution companies United Energy (UE) and Texas Utilities (TXU) Networks made a connection application to VENCorp in accordance with the National Electricity Code for the establishment of a new transmission connection point at Cranbourne. This related to the need to reinforce the security of supply to the Mornington Peninsula, Berwick, Pakenham, and Cranbourne areas and was identified as part of the distribution businesses connection asset-planning role. The optimum timing for project service was determined to be summer 2003/04 and works have been initiated to implement the proposed augmentations.

Cranbourne Terminal Station is currently being developed as the newest Victorian terminal station. The land had been set-aside for this purpose for some time to take advantage of the existing transmission assets. The works involve cutting in and switching of the East Rowville to Tyabb 220 kV lines and installation of two new 150 MVA 220/66 kV transformers.

This development not only supports the significant load growth in the surrounding area, but also allows other heavily loaded terminal stations to be somewhat offloaded, providing considerable benefits to the eastern metropolitan distribution system.

3.8.3 Latrobe Valley to Melbourne and Cranbourne Developments

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 ACCC Regulatory Test and from this process it was identified that the 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 1000 MVA transformer should be installed at the Cranbourne Terminal Station. The optimum timing of the project is December 2004 and VENCorp is proceeding to procure the contestable network services through a competitive tender process and the associated non-contestable works with the two incumbent network owners, SPI PowerNet and Rowville Transmission Facility Pty Ltd.

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

Works include conversion of the Hazelwood to Rowville No.3 line to operation at 500 kV, development of a 500 kV switchyard and installation of a 1000 MVA, 500/220 kV transformer at Cranbourne Terminal Station, reconfiguration and circuit breaker replacement in the Latrobe Valley network and re-instatement of the Hazelwood-Jeeralang No.2 220 kV line.

3.8.4 Toora Wind Farm

In September 2002, Stanwell Corporation completed the development of the Toora wind farm, located in Gippsland about 180 km southeast of Melbourne. The wind farm consists of twelve 67 m high towers with an aggregate supply capacity of 21 MW. It is currently one of the largest wind farms in Australia and is connected to TXU Networks distribution system, which is in turn supplied from Morwell terminal station. Considering the embedded nature of the wind farm, it tends to support local load and offload the transmission network. There were no significant impacts on the fault levels in shared network and no transmission augmentations were necessary.

3.8.5 Challicum Hills Wind Farm

Pacific Hydro Ltd is in the process of installing an embedded wind farm at Buangor near Ararat in Western Victoria. The wind farm comprises 35 wind generators with an aggregate supply capacity of 52.5 MW. The wind farm will be embedded in PowerCor's distribution system between Horsham and Ballarat Terminal Stations and again have a tendency to support local load and offload the transmission network. The commissioning process is expected to commence in June 2003. There were no significant impacts on the fault levels in shared network and no augmentations were necessary.

3.8.6 Keilor-West Melbourne lines

Due to the existing bus split arrangements in the Keilor 220 kV switchyard, outage of one of the Keilor-West Melbourne (KTS-WMTS) 220 kV parallel circuits has the potential to overload the parallel circuit. The potential overload is mainly dependent on:

- The demand drawn from West Melbourne and Fisherman's bend terminal stations,
- The level of Newport generation and
- Ambient temperature conditions

The most onerous condition is with no Newport generation, coincident with peak summer conditions and demand. The critical contingency is the loss of one of the Keilor-West Melbourne (KTS-WMTS) 220 kV parallel circuits. The resulting constraint and options were identified and listed in VENCorp's 2002 APR.

At present, VENCorp is finalising discussions with SPI PowerNet on the preferred network solution, which results in a permanent upgrade of the thermal capacity of these lines resulting from a minor re-tensioning exercise. This option provides the greatest net market benefits primarily due to the very low cost of the works. The work is scheduled for completion by December 2003 and is awaiting final Board approvals. The upgrade will result in the Keilor to West Melbourne 220 kV lines being designed for maximum conductor operating temperatures of 82°C compared with 65.6° C which corresponds to 2100/2750 A @ 35/5°C ambient temperatures, respectively.

3.8.7 Shunt Capacitor Banks

In December 2002, a 100 MVAr 220 kV shunt capacitor bank was installed at Dederang Terminal Station, a 50 MVAr 66 kV shunt capacitor bank was installed at Templestowe Terminal Station and a 45 MVAr 66 kV shunt capacitor bank was installed at Tyabb Terminal Station in order to remove a constraint associated with voltage collapse following various critical contingencies under maximum demand conditions.

Furthermore, a 200 MVAr 220 kV shunt capacitor bank is being installed at Rowville with an expected completion date of December 2003.

This reactive support program was justified as part of a long term plan as detailed in the 2002 APR, and the service was sourced through a competitive tender process to build own and operate the required plant in accordance with the Regulatory Test.

3.8.8 Basslink

Basslink has been proposed as a 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. Basslink is a Market Network Service Provider and is planned for service in November 2005.

Its design capacity is 480 MW continuous import from Tasmania and up to 600 MW short term, and 416 MW export to Tasmania.

Preliminary assessment has been made of the effect of Basslink on Victorian export limits based on transient stability and indicative transfer limits have been calculated based on voltage control and thermal considerations.

3.8.9 SNI

The South Australian – New South Wales interconnector (SNI) is an AC interconnection between Buronga in New South Wales and Robertstown in South Australia which has received regulatory approval but not full planning approval at this stage. The proposed commissioning date is during fourth quarter 2004. The development includes augmentation works in New South Wales, South Australia and Victoria and will nominally provide up to 200 MW increased capacity into the combined Victoria and South Australian regions.

SNI will cause a greater flow through the Victorian outer state grid, mostly from Dederang to Red Cliffs. This will provide additional loading on the Dederang transformation and circuit loading along that route. An additional transformer will be required at Dederang and is included in the SNI defined works. Fault levels in the outer state grid will also increase as a result of SNI and this will be managed as part of that project. While the feasibility of SNI has been determined, more detailed analysis on import capability, loading levels and limit equations has yet to be undertaken.

4 OPTIONS FOR REMOVAL OF NETWORK CONSTRAINTS WITHIN VICTORIA

4.1 Introduction

This section discusses the options for removal of network constraints within Victoria and presents the information required under the NEC for proposed augmentations. A ten-year outlook based on a range of generation scenarios is also included.

As a Transmission Network Service Provider in Victoria, VENCorp is responsible for planning the Victorian shared electricity transmission network on behalf of its users. VENCorp 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 and it assesses the feasibility of transmission projects using the Regulatory Test as specified by the ACCC. In practice, this reflects in VENCorp applying the economic principle that any shared transmission investment will only be justified once its identified and quantified benefits exceed the costs of implementing the project i.e. the project must have a positive net market benefit.

VENCorp considers the benefits associated with transmission investment are:

- a reduction in the amount of expected unserved energy;
- a reduction in the use of ‘out of merit order’ generation;
- a reduction in real and reactive transmission losses; and
- deferral of reactive plant.

In its planning role, VENCorp does not adopt a 100% reliability standard based on N-1 conditions. An N-1 standard implies that a least cost planning approach is applied to ensure that no load will be shed for loss of a critical element. In Victoria, a value of customer reliability (VCR) has been adopted that represents an economic value assigned to the end use of electricity. Application of the VCR allows expected unserved energy to be economically quantified, thereby providing a basis for justifying investment decisions. Importantly, the application of a net market benefit approach implies that under some conditions it is actually economic to have load at risk following a credible contingency.

A probabilistic approach is applied in the assessment of expected unserved energy. It considers the likelihood and coincidence of the contingency event and the onerous loading and ambient conditions.

VENCorp’s detailed “Electricity Transmission Network Planning Criteria” is available at www.vencorp.com.au.

The design principles used by VENCorp for planning the transmission network 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 contingency, 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).

- 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 options to network augmentation.
- The unserved energy resulting from network constraints has been assessed using a Value of Customer Reliability (VCR) of $10,000/MWh and $29,600/MWh.

For large network augmentations detailed public consultation will be undertaken for each of the projects in accordance with the Clause 5.6.6 of the NEC.

For small network assets, this APR forms the basis for consultation in accordance with Clause 5.6.6A of the NEC. Interested parties are invited to make submissions regarding the proposed augmentations and any non-network options they consider as an alternative. The closing date for submissions is Thursday 31st July 2003.

Submissions should be addressed to:

Executive Manager, Energy Infrastructure (Mr John Howarth)

PO Box 413 World Trade Centre Vic 8005

Phone: 03 8664 6565

Fax: 03 8664 6511

Email: john.howarth@vencorp.vic.gov.au

Website: http://www.vencorp.com.au/

Following consideration of any submissions in accordance with Code consultation procedures, VENCorp will publish its conclusions and recommended course of action. Unless changes to its proposals are necessary, VENCorp will proceed with the approval processes required to implement these proposed new small network assets in the required timeframes.

The ten-year outlook is provided to indicate the possible constraints towards the end of ten years. This longer-term outlook is very dependent on how and where generation develops to meet load and how load peaks are managed in the market in the future. It should be noted that determination of precise timings for any of these projects will involve detailed economic assessment closer to the lead time for these project, which will also explore any operational and control actions which could defer the requirement for investment.

4.2 Market Modelling Basis

To implement its probabilistic planning criteria, VENCorp simulates the National Electricity Market in order to determine the use of the shared network in such an environment. A Monte-Carlo based modeling 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 modeling for the 2003 Annual Planning Review include:

- Simulations – To ensure that the dispatch output from the market model converged to a level to ensure adequate statistical inferences could be made, 100 simulations were carried out for all scenarios.
- 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, 50, and 90 percentile peak demand scenarios being considered based on a medium economic (energy) growth outlook.
- Demand / Energy Forecasts – NEMMCO's 2002 Statement of Opportunity and VENCorp's 2002 APR were used as the source of regional energy and demand forecasts.

- Generation – The summer and winter capacities of all dispatched NEM generators were modeled from NEMMCO's 2002 Statement of Opportunity. Forced outage rates and mean repair times were based on publicly available material from Regulatory Test assessments such as SNI and SnoVic. Planned outage programs were based on historical market behavior and MT PASA forecasts.
- Generation Bidding – Short Run Marginal Costs based on publicly available material from Regulatory Test assessments such as SNI and SNOVIC have been applied.
- Inter-regional marginal loss factor equations and intra-regional loss factors were based on NEMMCO's 2002/03 loss factor publication.
- Hydro Generation – Forced Outage Rates were not modeled for hydro units. Energy targets for Snowy and Southern Hydro Generation were enforced, as per NEMMCO's 2002 Statement of Opportunity.
- New Entry Criteria – New Generators were entered into the market based on the principle of 'Reliability Driven Generation' to ensure that all regions maintained adequate reserve margins.

4.3 Identified Network Constraints

The following table details the potential constraints that have been identified, additionally showing the type of augmentation and estimated costs:

Section	CONSTRAINT	AUGMENTATION TYPE	DATE	ESTIMATED COST ($K)
4.4	Supply to the Geelong area	Small Network Augmentation*	2003/04	4,500
4.5	Dederang Tie -Transformation	Required for SNI: If SNI doesn't proceed, SNA:	2004/05 2008/09	9,000 9,000
4.6	Supply to the Ringwood Terminal Station	Small Network Augmentation	2004/05	150
4.7	Supply from Moorabool 220 kV bus	No Economic Network Solution at this stage	Nil	Nil
4.8	Security of double circuit supplies to South East Metropolitan Area	No Economic Network Solution at this stage	Nil	Nil
4.9	Metropolitan Tie -Transformation	Large Network Augmentation	2008 or before	40,000
4.10	Supply to the Springvale and Heatherton areas	Small Network Augmentation	2005/06	300
4.11	Supply to the East Rowville and Cranbourne areas	No Economic Network Solution at this stage	Nil	Nil
4.12	Reactive Support for Maximum Demand Conditions	No Economic Network Solution at this stage	Nil	Nil
4.13	Hazelwood Tie -Transformation	No Economic Network Solution at this stage	Nil	Nil
4.14	Yallourn to Hazelwood to Rowville Transmission	No Economic Network Solution at this stage	Nil	Nil

Table 4.1 - Identified Constraints And Augmentation Type.

* Project required to be implemented prior to next APR due to lead-time for purchase of transformer. Therefore this document forms the consultation for this project.

4.3.1 Constraint Evaluation Process

Each constraint identified steps through the following process:

- Reasons for the constraint, including sensitivities, critical events, critically loaded plant and capabilities;
- impacts of constraint, deterministic, then probabilistic over three years 2003/04–2005/06–2007/08;

- identification of network solutions and costs, additionally any non-network solutions;
- identification of all benefits of solutions;
- economic analysis to provide range of NPV's for each option; and
- identification of preferred option, timing, rankings, LNA or SNA, sensitivity to VCR.

4.4 Supply to the Geelong Area

Under system normal conditions, the Moorabool 220 kV bus is supplied from the 500/220 kV 1000 MVA transformer at Moorabool, as shown in Figures 4.1 and 4.2. During peak demand conditions, the transformer will carry around 700 MW. Around 350 MW flows towards Ballarat/Terang to support the State Grid, and the remainder flows towards Geelong.

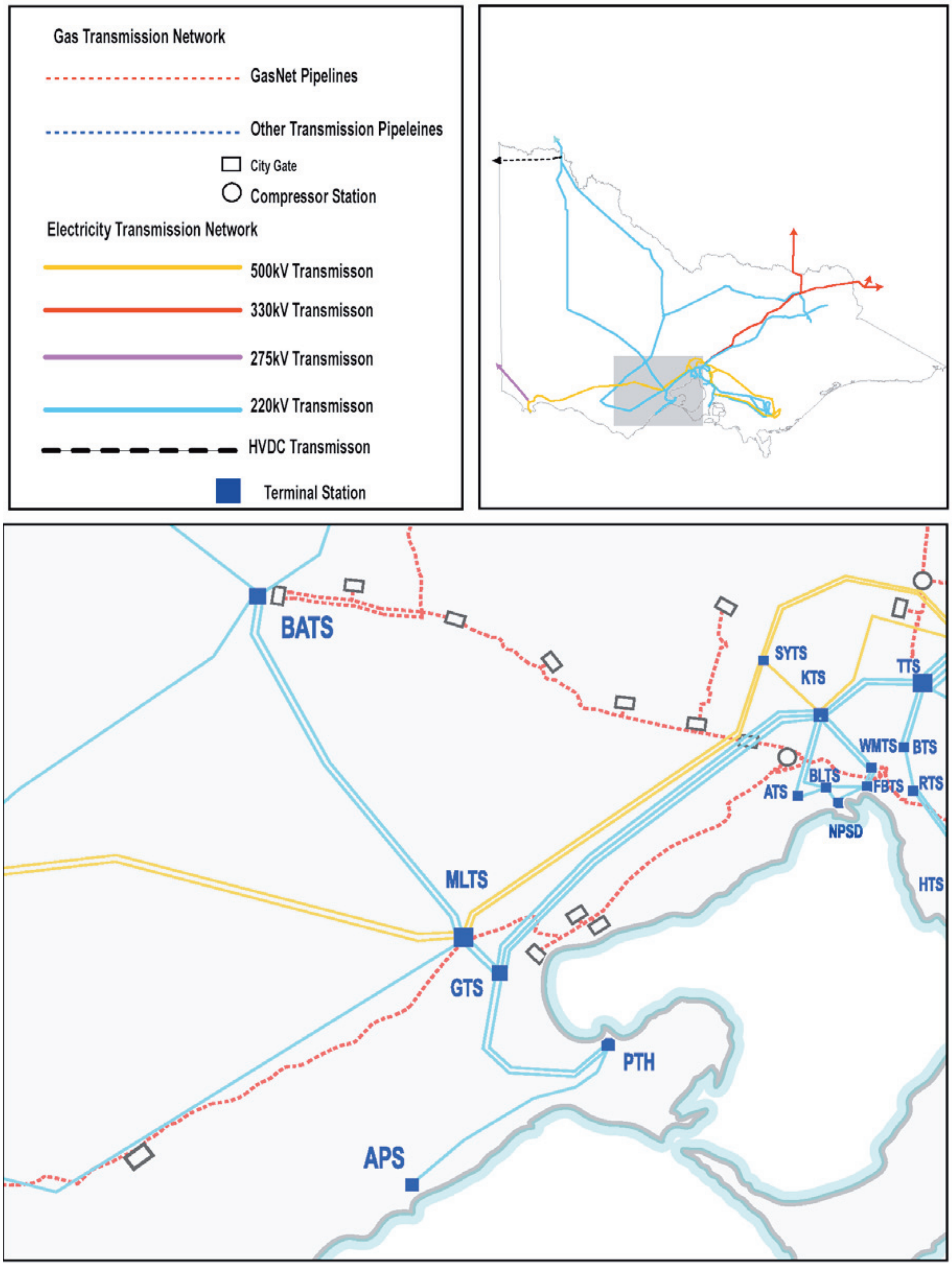


Figure 4.1- Geographic Representation of the Supply to the Geelong Area.

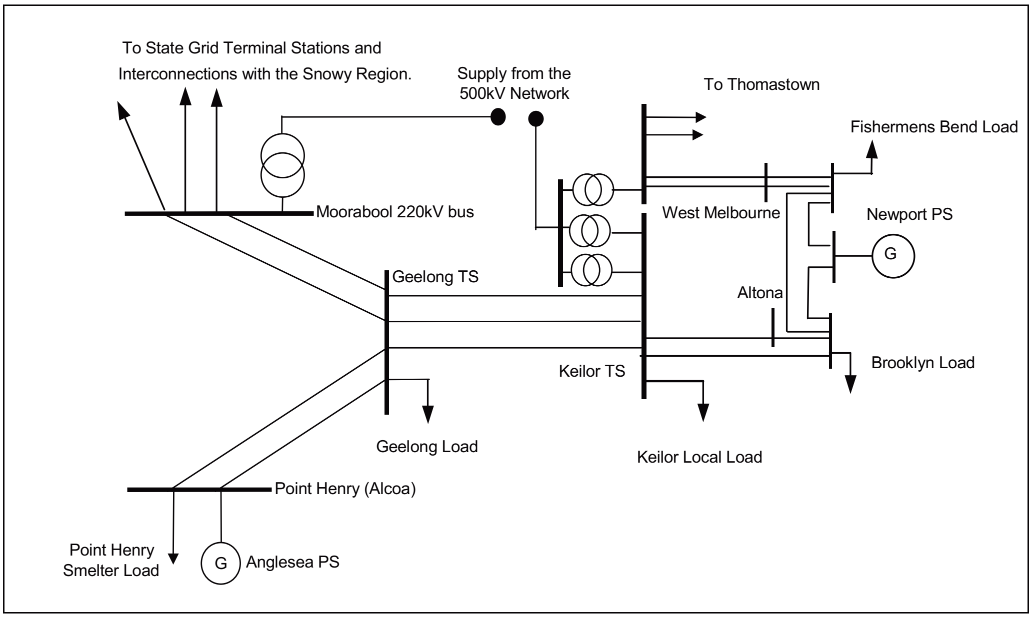


Figure 4.2 - Supply to the Moorabool 220 kV bus.

The Moorabool transformer comprises 3 single-phase units. There are no single contingency network outages that will result in over loading of the Moorabool transformer. However, an outage of the Moorabool transformer has significant impacts on power flows and voltages in the region. The most critically loaded elements are Keilor-Geelong 220 kV lines and Keilor 500/220 kV transformers.

4.4.1 Reasons for Constraint

(a) Constraints on Keilor-Geelong 220 kV lines

The Geelong area load, comprised of significant local demand plus the Point Henry smelter load less available generation from Anglesea Power Station, effectively becomes supplied radially via the three Keilor-Geelong 220 kV circuits when the Moorabool transformer is out of service. These circuits are also required to support a significant portion of the State Grid load. Very little support is given to the Geelong area from the electrically distant sources at Dederang and Red Cliffs, however this side of the State Grid loop does pick up a significant portion of the northern and north-western State Grid Terminal Station loads.

Under Moorabool transformer outage conditions, the loading on the three Keilor-Geelong 220 kV lines is dependent on:

- Anglesea generation levels, which causes an increase in line loading as it is reduced Geelong area and State Grid loads, which causes an increase in line loading as they are increased; and
- Ambient temperature, which lowers the line ratings as it increases. Southern Hydro generation, which causes an increase in line loading as it is reduced;
- the interchange between Victoria and NSW, which causes an increase in line loading as import decreas-es.

The most sensitive of these is the ambient temperature, the output of Anglesea Power station and the local area load. For an outage of the Moorabool transformer, the loading on the lines could be beyond their continuous capability, even with high Anglesea generation at times of peak demand and load shedding in the Geelong/Point Henry area may be necessary to bring flow within acceptable limits.

(b) Constraints on Keilor 500/220 kV transformers

The three 500/220 kV transformers at Keilor feed to the load in the Western Metropolitan area, and Geelong/State Grid and Point Henry smelter loads via Keilor-Geelong lines. Outage of Moorabool transformer can potentially load the Keilor transformers above continuous rating.

Under Moorabool transformer outage conditions, the loading on the three Keilor 500/220 kV transformers is dependent on:

- Newport generation levels, which causes an increase in transformer loading as it is reduced;
- Anglesea generation levels, which causes an increase in transformer loading as it is reduced;
- Western metropolitan area, Geelong area and State Grid loads, which causes an increase in transformer loading as they are increased;
- Southern Hydro generation, which causes an increase in transformer loading as it is reduced; and
- the interchange between Victoria and NSW, which causes an increase in transformer loading as import decreases.

The most critical of these is the output levels of Newport generator and Anglesea power station and the Geelong/western metropolitan area loads.

4.4.2 Thermal ratings of the plant

Table 4.2, provides the thermal ratings of the constraining plant as a result of Moorabool transformer outage.

Plant	Thermal rating – continuous	Thermal rating – short term
Keilor 500/220 kV transformer (each)	750 MVA	810 MVA – 2 hours
Keilor-Geelong 220 kV line (each)	710 Amps @35°C ambient 623 Amps @40°C ambient	Depends on ambient temperature and pre-contingency loading

Table 4.2 - Thermal ratings of constrained plants

4.4.3 Demand and Energy at Risk

Table 4.3, provides the demand at risk for the worst case with all plant in service and following outage of the Moorabool transformer. It is assumed that for peak summer demand conditions, all Victorian generators are in service with Anglesea, Newport and Vic Southern Hydro generators at full output, 1900 MW import from NSW/Snowy and zero transfer on Murraylink.

Column 3 refers to secure operating state at system normal. In this state following outage of the Moorabool transformer, the loading on the Keilor 500/220 kV transformers is expected to remain within their short-term rating and loading on the Keilor-Geelong lines is expected to remain within their 10-min short-term rating.

Column 4 refers to load reduction required following outage of the Moorabool transformer to maintain the loading of Keilor transformers and Keilor-Geelong lines within their continuous ratings. With this reduction the system would be in a satisfactory operating state but not secure.

Column 5 refers to the load reduction required to reach a secure operating state following outage of the Moorabool transformer. This is the amount of load reduction so that the system would remain in a satisfactory operating state following the next most credible contingency. The next critical contingency is outage of a Keilor 500/220 kV transformer or outage of a Keilor-Geelong line.

Load reduction in the Geelong/Point Henry areas is most effective and this will remove both constraints (Keilor transformers & Keilor-Geelong lines) simultaneously. Additional load reduction necessary to remove the constraint of Keilor transformer is carried out at Keilor.

With prior outage of a Newport generator or Anglesea generator the load at risk will be higher than that shown in Table 4.3. The load at risk can be reduced by supporting State Grid area from South Australia via Murraylink. Each MW import to State Grid via Murraylink can avoid the load shedding in Geelong/Keilor area by about 0.5 MW.

		Load at Risk			
Year	**Constraint**	**Secure operating state with system normal**	**Satisfactory operating state following MLTS transformer outage**	**Secure operating state following MLTS transformer outage**	**Cumulative**
2003/04	KTS 500/220 kV transformer	None	None	600 MW	600 MW
	KTS-GTS line	None	170 MW	90 MW additional	
2005/06	KTS 500/220 kV transformer	None	50 MW	650 MW additional	700 MW
	KTS-GTS line	None	210 MW	110 MW additional	
2007/08	KTS 500/220 kV transformer	30 MW	150 MW additional	680 MW additional	860 MW
	KTS-GTS line	None	260 MW	120 MW additional	

Table 4.3 - Load at risk due to outage of Moorabool transformer

4.4.4 *Probability of plant outage*

Table 4.4, provides the probability of plant outages, which are used for the assessment of the expected unserved energy at risk.

Plant	Probability of outage
Moorabool transformer	Short term outage - 0.03% (based on historical data) Long-term outage 1 in 50 years with a duration of 9 months (i.e 1 in 150 years with a duration of 9 months per single phase unit)
Each Keilor 500/220 kV transformer (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 14 days (i.e 1 in 150 years with a duration of 14 days per single phase unit)
Each Keilor-Geelong line	0.165% (based on historical data)

Table 4.4 – Probability of plant outage

4.4.5 *Expected Unserved Energy and Generation/Import Rescheduling*

The expected unserved energy is calculated based on constraints on Keilor-Geelong 220 kV lines and Keilor transformers over a range of demand and generation levels in each year with Moorabool transformer outage. In any given hour if there is a constraint, first Newport and Anglesea generation and transfer from NSW/Snowy would be rescheduled to remove the constraint. Following these actions, if the constraint still exists then it would be removed by load shedding. The value of generation/import rescheduling is calculated based on short run marginal costs. By taking into account of probability of plant outages, the value of expected unserved energy and expected rescheduled generation/ transfer level are given in the Table 4.5.

Plant	Probability of outage
Moorabool transformer	Short term outage - 0.03% (based on historical data) Long-term outage 1 in 50 years with a duration of 9 months (i.e 1 in 150 years with a duration of 9 months per single phase unit)
Each Keilor 500/220 kV transformer (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 14 days (i.e 1 in 150 years with a duration of 14 days per single phase unit)
Each Keilor-Geelong line	0.165% (based on historical data)

Table 4.5 - Value of expected unserved energy and expected generation rescheduling for Moorabool transformer outage

4.4.6 Network Solutions

The following network solutions are options to reduce the expected unserved energy:

- a fast load shedding scheme to prevent overloading of Keilor 500/220 kV transformers
- a spare phase transformer at Moorabool
- wind monitoring scheme on Keilor-Geelong 220 kV lines
- 2nd 500/220 kV transformer at Moorabool

(a) Fast load shedding scheme

When the system has been returned to the secure operating state following a Moorabool transformer outage, the next critical contingency is the forced outage of a Keilor 500/220 kV transformer. Without a fast load shedding scheme it would be necessary to reduce the loading of all three Keilor transformers in anticipation of this next stage. A fast load shedding scheme would enable this load reduction to take place after the outage of a Keilor transformer, thus the probability of this load reduction is reduced significantly.

The potential loading of the Keilor transformer can be around 1100 MVA for summer 2003/04 and up to 600 MW would need to be removed for the Keilor transformer to remain in a satisfactory operating state following an outage of a Keilor 500/220 kV transformer. For summer 2007/08, the potential loading of the Keilor transformers increases to about 1200 MVA and the amount of load shedding could be up to 860 MW. The most effective locations for load shedding are Point Henry/Geelong area and Keilor.

The feasibility of fast load shedding scheme is currently under investigation. Viability of this scheme relies on each of the Keilor 500/220 kV transformers being capable of loading up to 1200 MVA for the duration of the initiation of control action and operation of circuit breakers to shed the required amount of load.

(b) Spare phase transformer

The Moorabool transformer has 3 single-phase transformers. A spare single-phase transformer will reduce the duration for a major outage from 9 months to about 14 days; hence reduce the energy at risk. However, since it takes up to 14 days to replace a failed single-phase transformer, the spare phase transformer will not completely avoid a period where there are constraints on Keilor-Geelong line and Keilor 500/220 kV transformers.

(c) Wind monitoring scheme on KTS-GTS 220 kV lines

A static wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. On hot summer days the wind speed is typically higher than this. A wind speed of higher than 2.5 m/s would provide sufficient increase in line capacity to support the peak flow on the Keilor-Geelong lines during the Moorabool transformer outage. However as this scheme does not reduce the load, the Keilor 500/220 kV transformers remain a constraint.

(d) 2nd Moorabool 500/220 kV transformer

A second 1000 MVA 500/220 kV transformer at Moorabool would avoid constraint on Keilor-Geelong lines and Keilor 500/220 kV transformers. With two Moorabool transformers, there would be no energy at risk following outage of a Moorabool transformer. This additional new transformer would also provide significant improvement in voltage levels in the Geelong area under critical outage conditions and reduce the future requirement for additional reactive support in this area.

4.4.7 Expected unserved energy with network solutions

Table 4.6, shows how much the combined value of expected unserved energy and expected rescheduled generation/import following outage of the Moorabool transformer reduces with each of the network solutions. The value of generation/import rescheduling is calculated based on short-run marginal cost and value of expected unserved energy is calculated with $10,000/MWh and $29,600/MWh separately.

		Option 1 Fast load shedding scheme ($K)		Option 2 Spare phase transformer ($K)		Option 3 Wind monitoring scheme ($K)		Option 4 2nd MLTS 1000 MVA 500/220kV transformer ($K)	
Year	**Value of unserved energy**	**$10K /MWh**	**$29.6K /MWh**	**$10K /MWh**	**$29.6K /MWh**	**$10K /MWh**	**$29.6K /MWh**	**$10K /MWh**	**$29.6K /MWh**
2003/04	Reduced expected unserved energy	981	2,903	809	2,395	148	439	1,090	3,225
	Reduced rescheduled generation	0	0	60	60	25	25	79	79
	Reduced reactive requirement	0	0	0	0	0	0	0	0
	Total benefit	**981**	**2,903**	**869**	**2,455**	**173**	**463**	**1,169**	**3,305**
2005/06	Reduced expected unserved energy	3,406	10,081	2,325	6,882	260	769	3614	10,697
	Reduced rescheduled generation	0	0	92	92	28	28	121	121
	Reduced reactive requirement	0	0	0	0	0	0	300	300
	Total benefit	**3,460**	**10,081**	**2,417**	**6,974**	**288**	**797**	**4,035**	**11,118**
2007/08	Reduced expected unserved energy	6,064	17,948	3,568	10,562	377	1,115	6,482	19,187
	Reduced rescheduled generation	0	0	128	128	36	36	167	167
	Reduced reactive requirement	0	0	0	0	0	0	600	600
	Total benefit	**6,064**	**17,948**	**3,696**	**10,690**	**413**	**1,152**	**7,249**	**19,955**

Table 4.6 - Value of reduced expected unserved energy and rescheduled generation/import

4.4.8 Cost of Network Solutions

The estimated capital cost of each of the network solutions is shown in Table 4.7:

Network Solutions	Estimated capital cost ($K)
1. Fast load shedding scheme (if feasible)	$500
2. Spare phase transformer	$4,000
3. Wind monitoring scheme	$800
4. 2nd 500/220 kV 1000 MVA transformer at Moorabool (including O&M costs)	$26,000

Table 4.7 - Estimated capital cost of network solutions

4.4.9 Economic Analysis

A net market benefit assessment is carried out for a 5-year period for each of the network options using a discount rate of 8% to calculate the NPV, and with a value of unserved energy $10,000/MWh and $29,600/MWh separately. The values based on $29,600/MWh are summarised in Table 4.8 to Table 4.15.

If a fast load shedding is feasible then it is assumed that it is available with all other network solutions. The net benefit for each of the network solutions with a fast load shedding scheme is provided in Table 4.8 to Table 4.15.

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	2,900	5,940	10,080	14,010	17,950
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	**2,900**	**5,940**	**10,080**	**14,010**	**17,950**
Cost ($K)	0.07	0.07	0.07	0.07	0.07
Net benefit ($K)	**2,830**	**5,860**	**10,010**	**13,940**	**17,870**
NPV of net benefit ($K)	**38, 000 (12,600)[24]**				

Table 4.8 - Net benefit of fast load shedding scheme

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	360	510	670	970	1,280
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	360	510	670	970	1,280
Cost ($K)	360	360	360	360	360
Net benefit ($K)	**10**	**15**	**31**	**62**	**920**
NPV of net benefit ($K)	**1,460 (40)[24]**				

Table 4.9 - Net benefit of a spare single-phase transformer following implementation of fast load shedding scheme

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	240	330	420	610	800
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	**240**	**330**	**420**	**610**	**800**
Cost ($K)	120	120	120	120	120
Net benefit ($K)	**120**	**210**	**300**	**490**	**680**
NPV of net benefit ($K)	**1, 350 (220)[24]**				

Table 4.10 - Net benefit of a wind monitoring scheme following implementation of fast load shedding scheme

24 The values shown within the bracket for NPV are based on $10,000/MWh.

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	20	30	30	50	60
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	**20**	**30**	**30**	**50**	**60**
Cost ($K)	120	120	120	120	120
Net benefit ($K)	**-100**	**-90**	**-90**	**-70**	**-60**
NPV of net benefit ($K)	**-300 (-400)**[25]				

Table 4.11 - Net benefit of a wind monitoring scheme following implementation of fast load shedding scheme and spare single-phase transformer

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	400	560	740	1,070	1,410
Additional benefit ($K)	-	-	300	450	600
Total benefit ($K)	**400**	**560**	**1,040**	**1,520**	**2,010**
Cost ($K)	2,310	2,310	2,310	2,310	2,310
Net benefit ($K)	**-1,910**	**-1,750**	**-1,270**	**-790**	**-300**
NPV of net benefit ($K)	**-5,100 (-6,900)** [25]				

Table 4.12 - Net benefit of the second 1000 MVA 500/220 kV transformer following implementation of fast load shedding scheme

Since feasibility of a fast load shedding scheme is currently under investigation, net benefit assessment is carried out without this scheme separately. The net benefit for each of the network solutions without a fast load shedding scheme is provided in Table 4.13 to Table 4.15.

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	2,460	4,.710	6,970	8,830	10,690
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	**2,460**	**4,710**	**6,970**	**8,830**	**10,690**
Cost ($K)	360	360	360	360	360
Net benefit ($K)	**2,100**	**4,360**	**6,620**	**8,480**	**10,330**
NPV of net benefit ($K)	**24,200 (7,500)**[25]				

Table 4.13 - Net benefit of spare single-phase transformer (without a fast load shedding scheme)

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	460	630	800	970	1,150
Additional benefit ($K)	-	-	-	-	-
Total benefit ($K)	**460**	**630**	**800**	**970**	**1,150**
Cost ($K)	120	120	120	120	120
Net benefit ($K)	**340**	**510**	**680**	**850**	**1,030**
NPV of net benefit ($K)	**2,600 (650)**[25]				

Table 4.14 - Net benefit of wind monitoring scheme (without a fast load shedding scheme)

25 The values shown within the bracket for NPV are based on $10,000/MWh.

	2003/04	2004/05	2005/06	2006/07	2007/08
Benefit ($K)	3,300	6,500	10,820	15,090	19,350
Additional benefit ($K)	-	-	300	450	600
Total benefit ($K)	**3,300**	**6,500**	**11,120**	**15,540**	**19,950**
Cost ($K)	2,310	2,310	2,310	2,310	2,310
Net benefit ($K)	**1,000**	**4,190**	**8,810**	**13,230**	**17,650**
NPV of net benefit ($K)	**33,200 (6,100)** [26]				

Table 4.15 - Net benefit of the second 1000 MVA 500/220 kV transformer (without a fast load shedding scheme)

4.4.10 Ranking of Network Solutions

The Table 4.16 summarises the NPV of net benefits given in the above Table 4.8 to Table 4.15. The ranking of the network solutions is provided in the Table 4.17.

If a fast load shedding is feasible, then it is ranked No.1 with a value of unserved energy either $10,000/MWh or $29,600/MWh. With the fast load shedding scheme a spare single-phase transformer provides highest net benefit.

If a fast load shedding scheme is not feasible, the spare single-phase transformer is ranked No.1 with a value of unserved energy $10,000/MWh. However, the 2nd 500/220 kV 1000 MVA transformer option is ranked No.1 with $29,600/MWh.

Network Solutions	**NPV of net benefit [$K]**			
	With a fast load shedding scheme		**If a fast load shedding scheme not available**	
	$10K/MWh	**$29.600K/MWh**	**$10K/MWh**	**$29.600K/MWh**
1. Fast load shedding scheme	12,600	38,000	Not applicable	
2. Spare single-phase transformer following fast load shedding scheme	40	1,460	Not applicable	
3. Wind monitoring scheme following fast load shedding	220	1,350	Not applicable	
4. Wind monitoring scheme following fast load shedding & spare-single phase transformer	-400	-330	Not applicable	
5. 2nd 1000 MVA 500/220kV transformer following fast load shedding scheme	-6,900	-5,100	Not applicable	
6. Spare single-phase transformer	Not applicable		7,500	24,200
7. Wind monitoring scheme	Not applicable		700	2,600
8. 2nd 1000 MVA 500/220kV transformer	Not applicable		6,100	33,200

Table 4.16 - Summary of net present value of network solutions

26 The values shown within the bracket for NPV are based on $10,000/MWh.

Network Solutions	Ranking of Network Solutions			
	With a fast load shedding scheme		If a fast load shedding scheme not available	
	$10K/MWh	$29.600K/MWh	$10K/MWh	$29.600K/MWh
1. Fast load shedding scheme	1	1	Not applicable	
2. Spare single-phase transformer following fast load shedding scheme	3	2	Not applicable	
3. Wind monitoring scheme following fast load shedding	2	3	Not applicable	
4. Wind monitoring scheme following fast load shedding & spare-single phase transformer	4	4	Not applicable	
5. 2nd 1000 MVA 500/220kV transformer following fast load shedding scheme	5	5	Not applicable	
6. Spare single-phase transformer	Not applicable		1	2
7. Wind monitoring scheme	Not applicable		3	3
8. 2nd 1000 MVA 500/220kV transformer	Not applicable		2	1

Table 4.17 - Ranking of network solutions

4.4.11 *Timing of the network solutions*

Table 4.18 shows the timing of the highly ranked options. A fast load shedding scheme is justifiable for summer 2003/04 with either $10,000/MWh or $29,600/MWh. With this scheme, a spare single-phase transformer is justifiable for summer 2005/06 with $10,000/MWh. With a value of unserved energy $29,600/MWh, the spare single-phase transformer is advanced by two years to 2003/04. However, the lead-time is insufficient to enable procurement of a spare single-phase transformer for 2003/04 but can be made available for 2004/05. With the fast load shedding scheme the 2nd 500/220 kV 1000 MVA transformer is not justifiable at least until 2007/08.

If a fast load shedding scheme is not feasible, a spare single-phase transformer is justifiable for summer 2003/04 with a value of unserved energy $10,000/MWh. However with a value of unserved energy $29,600/MWh the 2nd 500/220kV 1000 MVA transformer is justifiable for summer 2003/04.

Network Solutions	Ranking of Network Solutions			
	With a fast load shedding scheme		If a fast load shedding scheme not available	
	$10K/MWh	$29.600K/MWh	$10K/MWh	$29.600K/MWh
Fast load shedding scheme	2003/04	2003/04	-	
Spare single-phase transformer following fast load shedding scheme	2005/06	2003/04	-	
Spare single-phase transformer	-		2003/04	
2nd 1000 MVA 500/220kV transformer	-			2003/04

Table 4.18 - Timing of preferred network solutions

4.4.12 *Non-network Solutions*

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

- Demand side management in both the Geelong and Keilor areas
- New generation in the Geelong/Moorabool and Western metropolitan areas (wind generators which are already connected to the network are taken into account). By 2005/06, up to 700 MW new generation in Geelong/Keilor areas may be required to fully remove the constraints.

At the time of publication of this APR, there is no committed non-network solutions that have been identified.

4.4.13 Preferred Solution

VENCorp has identified a preferred network solution in accordance with the regulatory test.

The preferred network solution is a fast load shedding (if feasible) by December 2003 and a spare single-phase transformer by December 2004 at an estimated cost of $4.5M

If a fast load shedding scheme is not feasible, the preferred network solution is the 2nd 500/220 kV 1000 MVA transformer at Moorabool. A separate public consultation will be carried out for the 2nd transformer and identify any other non-network solutions, which would determine the most optimum timing and provide a final recommendation.

The augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

VENCorp does not expect the preferred solution will have a material inter-network impact. As such, no augmentation technical report has been sought from the Inter-regional Planning Committee, nor has consent to proceed from other transmission networks.

4.5 Dederang Tie-Transformation

There are three 330/220 kV transformers in service at Dederang Terminal Station. These transformers support load in the northern state grid area, which predominantly includes Mount Beauty, Glenrowan, Shepparton and Bendigo Terminal Stations. The load in this area is also supported by Southern Hydro's generators at Dartmouth, Eildon, Kiewa, McKay Creek and to a lesser extent, due to its further distance, Eildon Power Station. Refer to Figures 4.3 and 4.4.

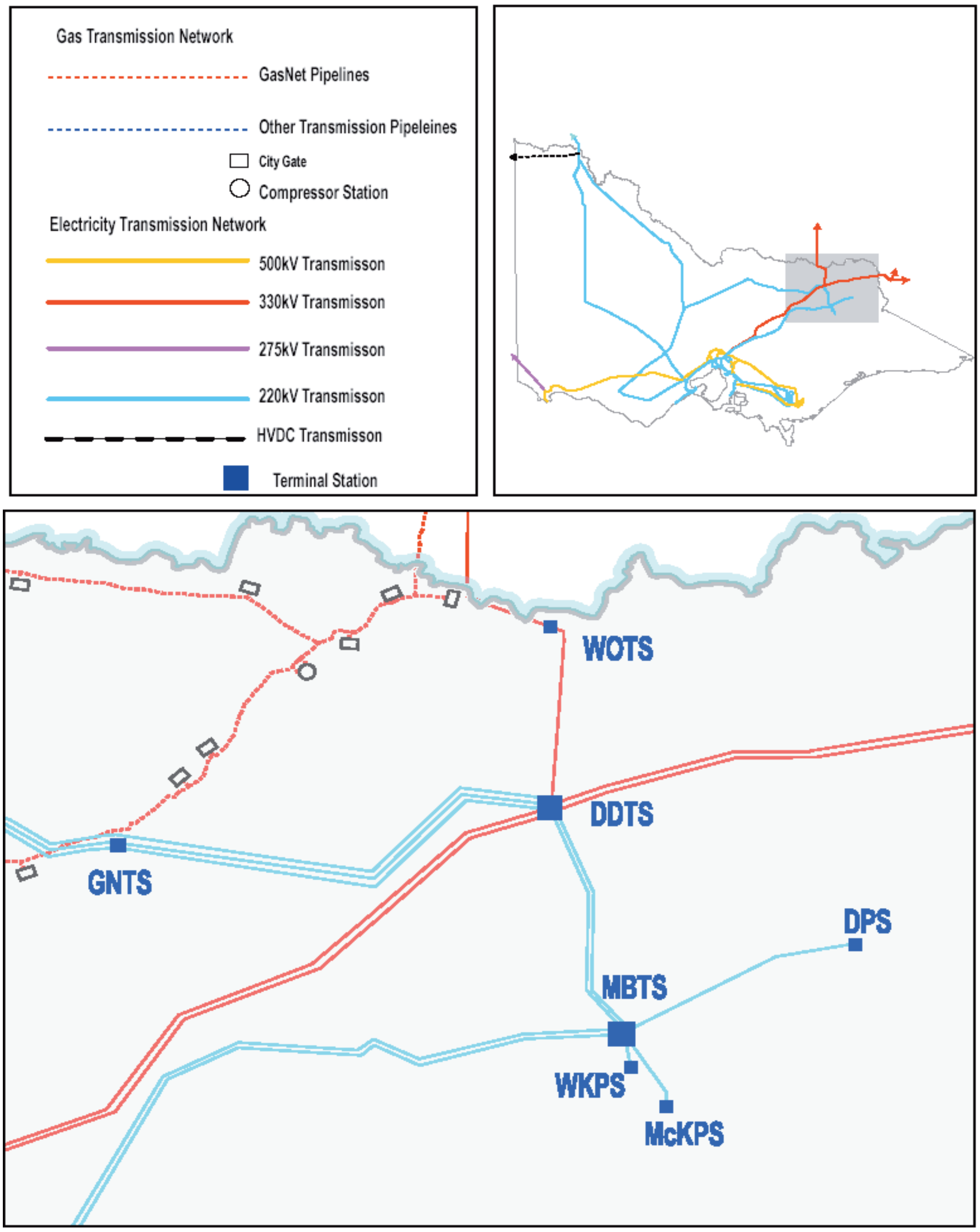


Figure 4.3 - Geographical Representation of the Supply to the Dederang 220kV bus and the Northern State Grid.

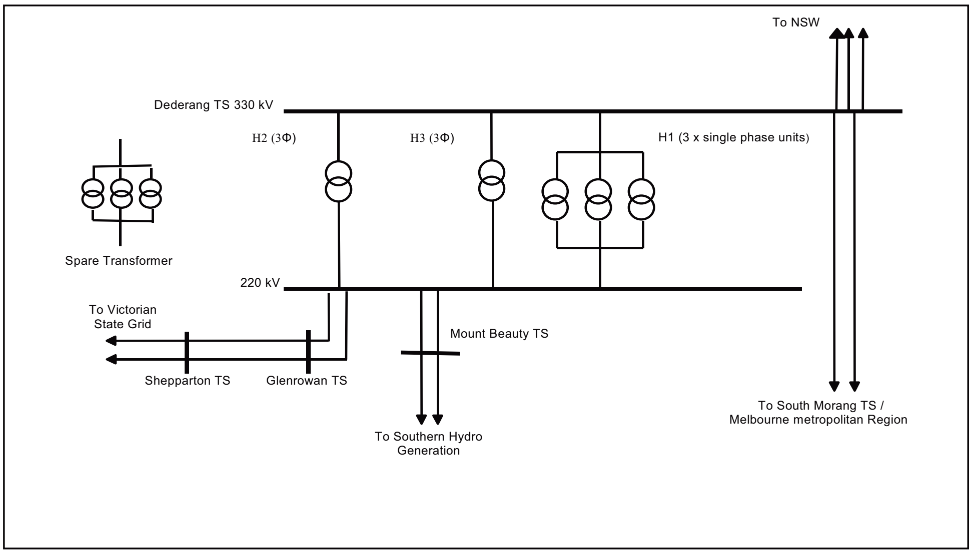


Figure 4.4 - Electrical Representation of the Supply to the Dederang 220 kV bus and the Northern State Grid.

4.5.1 Reasons for Constraint

The transformers, and associated 220 kV lines in the state grid, also provide a parallel path to the main 330 kV lines forming Victoria's interconnection with the Snowy and NSW regions. Hence, transfer levels between the regions strongly influence the power flows on the Dederang transformers.

The thermal capability of these transformers is one of the limiting mechanisms on the inter-regional transfer from the Snowy/NSW regions into Victoria. This is particularly the case with the prior outage of one of the units.

The implementation of SNI (the AC interconnector between the Snowy/ NSW regions and SA, presently planned for commissioning in late 2004) will also utilises the Dederang transformers. As part of the SNI approval process, it was identified that a fourth transformer is required at Dederang on the basis of the step change increase in system normal power flows. The advanced installation of this fourth transformer as a result of SNI will alleviate potential constraints under prior outage conditions and therefore the need for additional augmentation. VENCorp will continue to monitor the approval process of SNI and to determine the risk of constraints associated with these transformers. This section considers the impact of transformer prior outages assuming SNI and the fourth Dederang transformer are not implemented by December 2004.

4.5.2 Thermal Ratings of Plant and Probability of Plant Outages

Table 4.19, provides the thermal ratings and relevant data of the constraining plant at Dederang.

Plant	Type / Age	Thermal Rating – continuous	Thermal Rating – short time
Dederang H1 330/220kV	3 x 1phase / 1955	225	315 for 20min
Dederang H2 330/220kV	1 x 3phase / 2002	340	400 for 20min
Dederang H3 330/220kV	1 x 3phase / 1977	240	400 for 20min

Table 4.19 - Thermal ratings of Dederang transformers

There is a spare transformer that can be used to reduce the duration of long term forced outages of any of the three in service units. It is of similar vintage the H1 transformer (1955) and also rated 225 MVA continuously. It is comprised of three single phase units but due to its age and condition there is no intention to use this set of transformers as a permanent bank.

The forced outage rate for the current arrangement of transformers is

$$\left(3/150 + 2/100 \times 10 \times 24/8760\right) = 0.1096\%$$

on the basis that there are three single phase transformers and two three phase transformers in service which have failure rates of 1/150 and 1/100 years, respectively. The expected duration for any long term forced outage is 10 days on the basis the spare transformer can be installed within this time frame.

Note, VENCorp is reviewing the applicable failure rate for the older single-phase 1955 transformers, as there have been two recent failures of this type resulting in SPI PowerNet installing a new three-phase unit in 2002. Furthermore, should another of these units fail, there will be no spares available for the three phase units.

4.5.3 Impact of the Constraint

The following prior outage constraint equation is published on VENCorp's website in the Transfer Limits Manual (section VI-5). It is currently implemented in the National Electricity Market Dispatch Engine and would be invoked within 30 minutes of loss of a DDTS transformer.

Snowy to Vic Import Limit = $1833 + 3.167 \times \text{Kiewa Generation} + 1.5 \times \text{Eildon Generation} - 0.2667 \times \text{Victorian Demand}$

Equation (4.1)

Where:

- Kiewa Generation is the generation at Dartmouth (DPS), West Kiewa (WKPS) and McKay Creek power stations (McKPS).
- Eildon Generation is the generation at Eildon power station.
- Victorian Demand is the regional sent out generation minus net export.

This constraint is defined by ensuring the flow on the remaining single transformer is satisfactory and within its short time rating after a subsequent forced transformer outage.

Using the example conditions of no Kiewa or Eildon generation and Victorian Demand of 6500 MW, Victoria's import capability would reduced from a nominal 1900 MW under system normal conditions to around 100 MW if one of the transformers were unavailable. With 300 MW of Kiewa generation out of a maximum capacity of 330 MW, and 100 MW of Eildon generation out of a maximum capacity of 120 MW, the import limit would be substantially increased to1200 MW.

Table 4.20, summarises VENCorp's forecast of the impact of the DDTS transformer outage with a VCR of $29.6K with the existing configuration. Note, the use of the term 'Expected' implies the probability of the event has been applied as a multiplying factor.

	2003/04	*2005/06*	*2007/08*
Average Annual Constrained Energy with outage, [MWh]	585,918	739,860	732,793
Average Annual Value of Constrained Energy with outage, [$K]	208,465	179,823	239,656
Average Annual Unserved Energy with outage, [MWh]	8,953	9,578	15,904
Average Annual Value of Unserved Energy with outage, [$K]	264,995	283,515	470,753
Expected Average Annual Constrained Energy, [MWh]	642	811	803
Expected Average Annual Value of Constrained Energy, [$K]	228	197	263
Expected Average Annual Unserved Energy, [MWh]	9.8	10.5	17.4
Expected Average Annual Value of Unserved Energy, [$K]	290	311	516
Expected Average Annual Value of Constrained & Unserved Energy, [$K]	**$ 519**	**$ 508**	**$ 779**

Table 4.20 - Expected cost of DDTS transformer outage with VCR of $29.6K

Table 4.21, summarises VENCorp's forecast of the impact of the DDTS transformer outage with a VCR of $10K with the existing configuration.

	2003/04	2005/06	2007/08
Average Annual Constrained Energy with outage, [MWh]	585,918	739,860	732,793
Average Annual Value of Constrained Energy with outage, [$K]	208,465	179,823	239,656
Average Annual Unserved Energy with outage, [MWh]	8,953	9,578	15,904
Average Annual Value of Unserved Energy with outage, [$K]	89,525	9,5782	159,038
Expected Average Annual Constrained Energy, [MWh]	642	811	803
Expected Average Annual Value of Constrained Energy, [$K]	228,454	19,7066	262,637
Expected Average Annual Unserved Energy, [MWh]	9.8	10.5	17.4
Expected Average Annual Value of Unserved Energy, [$K]	98,110	104,967	174,288
Expected Average Annual Value of Constrained & Unserved Energy, [$K]	$ 327	$ 302	$ 437

Table 4.21 - Expected cost of DDTS transformer outages with VCR of $10K

4.5.4 Network Solutions and Preliminary Cost Estimates.

A number of network solutions have been identified to reduce or remove the constraint through the Dederang transformers. They include:

- Modification of DBUSS-transformer operation, for prior outage conditions. Expected capital cost of around $100K. This option may reduce the severity of the constraint on import but will not eliminate it.
- Installation of 4th DDTS transformer, while maintaining the existing spare, and associated fault level mitigation. Expected capital cost of around $9M. This option will eliminate the constraint in the short and medium term. This option is part of the SNI project works and therefore will be implemented when SNI is commissioned – due late 2004.

4.5.5 Non-Network Solutions

Generation or DSM on the load side of the Dederang transformers plays a significant role in the inter-regional constraint equation, as indicated by Equation 4.1. An increase of 1 MW from Southern Hydros generators in the Kiewa region increases the import capability in a ration of 1:3.167. If this were available at the appropriate times, the need for further network augmentation could be deferred considerably.

4.5.6 Economic Analysis and Preferred Solution.

If SNI is not commissioned, then a fourth transformer at Dederang would be justified for service around December 2008, with a capital cost of $9M.

VENCorp will monitor the approval process for SNI and if required will conduct a detailed economic assessment and consultation process for this project.

VENCorp expects that any augmentation effecting the Dederang tie transformation capacity or power flows will have a material inter-network impact. This will be addressed in a timeframe consistent with the justified works when the required Inter-regional Planning Committee augmentation technical report or appropriate consents are sought.

4.6 Supply to Ringwood Terminal Station

4.6.1 Reasons for Constraint

Ringwood terminal station (RWTS) is supplied via two 220 kV transmission lines, one from Thomastown terminal station (TTS) and the other from Rowville terminal station (ROTS) as shown in Figure 4.5 and Figure 4.6. A second 220 kV line (shown in Figure 4.6 as a dashed line), which connects between Templestowe terminal station and Rowville terminal station, passes through the Ringwood site but is not switched.

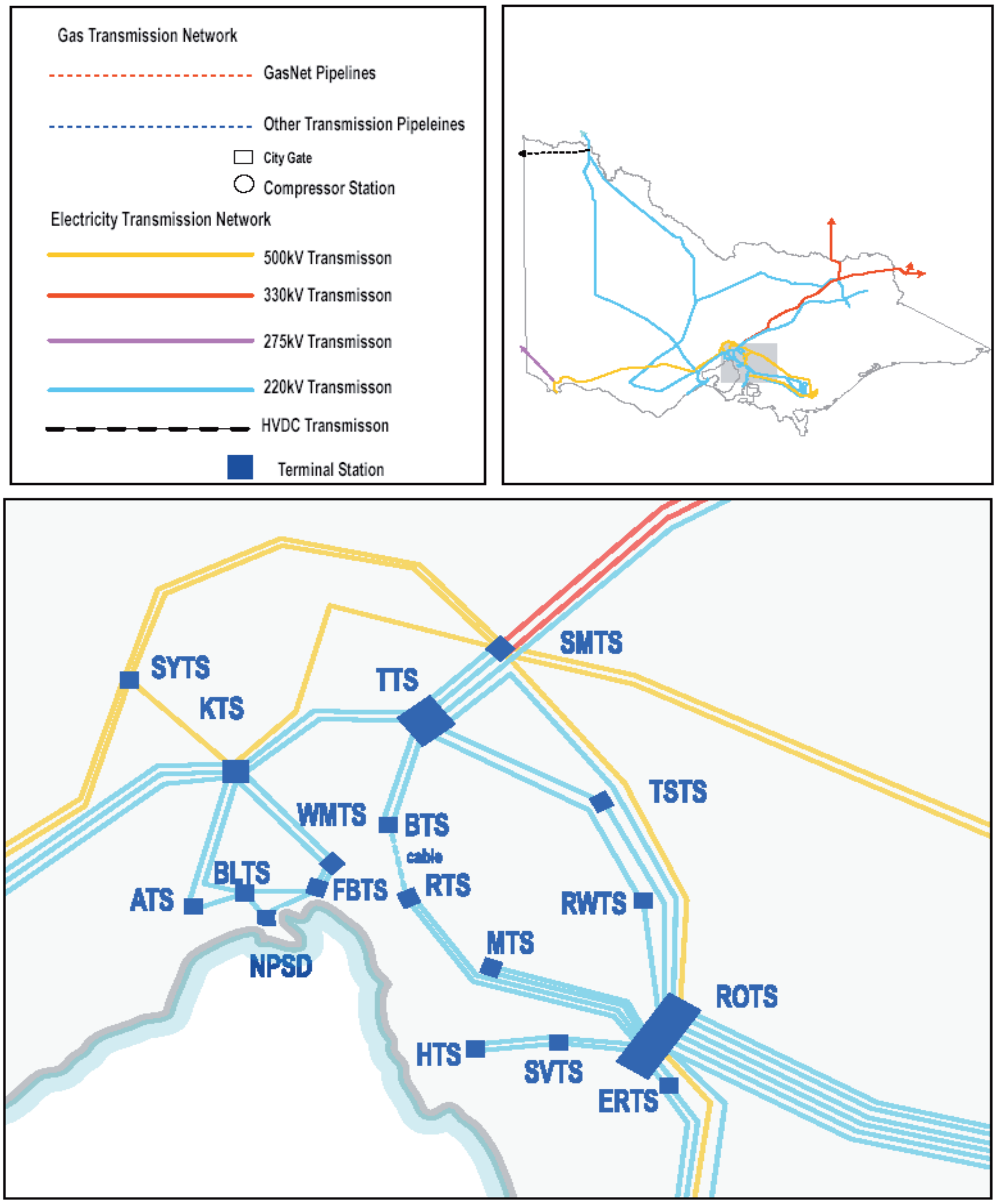


Figure 4.5 – Geographical representation of the Supply to the Ringwood Area.

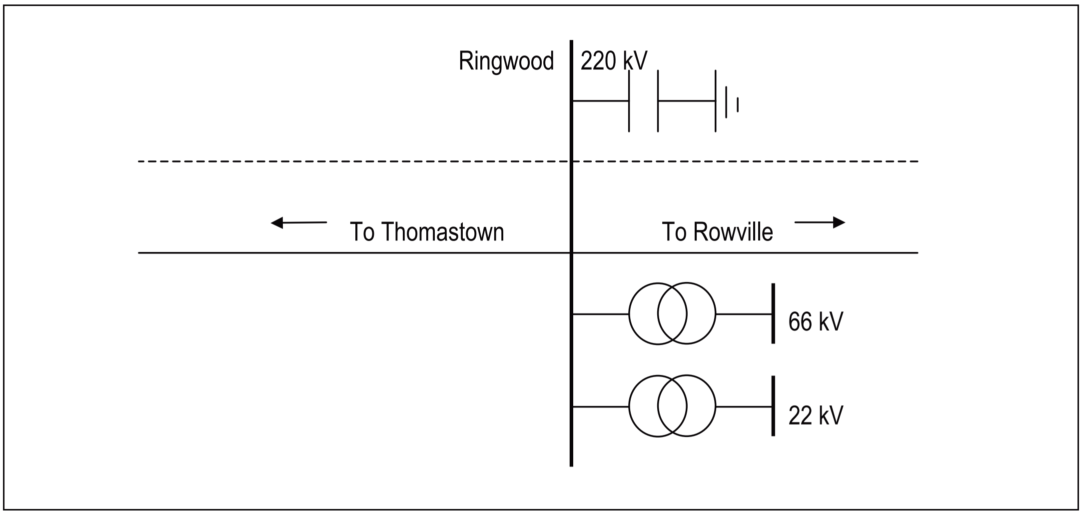


Figure 4.6 - Electrical representation of the Supply to the Ringwood Area.

The combined 66 & 22 kV feeder load at Ringwood terminal station is forecast to be around 575 MVA for Summer 2003/04 based on 10% probability loading and temperature conditions. Under these conditions the Rowville to Ringwood 220 kV line has a rating of 736 MVA, and the Thomastown to Ringwood line has a rating of 442 MVA. Under system normal conditions the lines share the loading and there is adequate capacity to meet the peak summer loads. However, if an outage of the Rowville to Ringwood line were to occur during peak loading and temperature conditions, the Thomastown to Ringwood line would not be able to support the full load.

4.6.2 Impacts of Constraint

The constraint has arisen due to load growth at Ringwood terminal station. Based on 10% loading levels and ambient temperature, the coincident 66 & 22 kV load at Ringwood was first forecast to exceed the line rating for summer 1999/00. Since this time, the short time rating of the transmission line has provided sufficient time for manual operator action to reduce post-contingent line loading if the event occurs during onerous conditions. Given the low exposure and the low probability of the transmission outage at a critical time, this has been the most economic solution.

The time for operator action is being reduced by the increase in load at Ringwood and the higher pre-contingent loading on the Thomastown-Ringwood line due to the increasing superimposed power flow between Thomastown and Rowville. Once the time for operator action is reduced below 10 minutes then alternative arrangements will be required to manage this situation.

The status of local reactive plant (1 x 220 kV, 200 MVAr shunt capacitor bank and 2 x 66 kV, 50 MVAr shunt capacitor banks) also influences the power flows into Ringwood terminal station, however under the most onerous loading conditions these shunt capacitors are expected to be in service and therefore alleviate the dependence on the lines.

This constraint is not directly influenced by the dispatch of the NEM and does not result in a material inter-regional network impact. Neither Basslink, the SNI project or the Latrobe Valley to Melbourne transmission upgrade project impact significantly on the exposure to this constraint.

4.6.3Forecast Conditions, Demand and Energy at Risk

VENCorp forecasts the worst case loading conditions for the summer 2003 - 2004 period to be:

- Ringwood aggregate 66 & 22 kV load: 525 + j233.2 MVA
- The pre-contingent Thomastown-Ringwood 220 kV line flow is: 250 MVA
- The pre-contingent Ringwood 220 kV bus voltage is: 222 kV
- The post-contingent Thomastown-Ringwood 220 kV line flow is: 528 MVA

- The post-contingent Ringwood 220 kV bus voltage is: 218 kV
- The ambient temperature could be: 42 deg C
- The Thomastown-Ringwood line rating would be: 442 MVA
- The ratio of post contingency loading to capability is: 119 %
- The amount of time available to reduce the loading following a contingency is: 14 Min
- The minimum amount of time required for operator action to reduce loading is: 10 Min
- The amount of pre-contingency load at risk is: 0 MVA
- The amount of post-contingency load at risk is: 86 MVA

Note that even under the most pessimistic loading conditions, no pre-contingency load shedding would be required for summer 2003/04 until the ambient temperature reaches 44 degrees ambient or higher.

The following table summarises the aggregate amount of energy at risk for each year analysed. This considers both pre-contingent load shedding required to maintain loading on the critical Ringwood to Thomastown line below its 10 minute rating, and post contingent load shedding, which would occur following an outage of the Rowville-Ringwood line, in order to maintain loading on the critical Ringwood to Thomastown line within its continuous rating.

	Pre-contingency load shedding (to prevent loading of the line beyond its 10 minute rating)			
Year	**Expected hours exposed / year**	**Average overload [MW]**	**Maximum overload [MW]**	**Expected Unserved Energy [MWh]**
2003/04	0.0	0.0	0.0	0.0
2004/05	0.3	18.9	34	5.8
2005/06	2.0	29.1	84	58.2
2007/08	4.0	39.5	115	159

Table 4.22 – Expected Unserved Energy due to pre-contingent load shedding.

	Post-contingency Load shedding following a contingency to reduce the line loading to within its continuous rating			
Year	**Expected hours exposed / year**	**Average overload [MW]**	**Maximum overload [MW]**	**Energy at Risk [MWh]**
2003/04	23.4	44.8	163	1046
2004/05	31.2	47.7	180	1487
2005/06	40.0	51.1	198	2045
2007/08	70.3	50.2	230	3532

Table 4.23 – Energy At Risk due to post contingent load shedding.

The benchmark probability of the line outage occurring is 0.20 outages per year with an average duration of 10 hours per event. Records show that the line has had 16 events over the past 17 years (0.90 outages per year) with an average duration of 4.6 hours.

Assuming the actual historical performance figures, the expected unserved energy if no action is taken is shown in Table 4.24.

Year	Pre-contingency [MWh]	Post Contingency [MWh]	Total Value of Expected Unserved Energy [$K]	
			$10K/MWh	$29.6K/MWh
2003/04	0.0	0.5	5	14.8
2004/05	5.8	0.70	65	192
2005/06	58.2	1.0	592	1,750
2007/08	159	1.7	1,600	4,760

Table 4.24 – Total Expected Unserved Energy at Ringwood Terminal Station.

4.6.4 Network Solutions

A number of network solutions have been identified to reduce or remove the constraint on the 220 kV supply to Ringwood. They include:

Option 1 Installation of a rapid load shedding scheme at Ringwood terminal station to maintain the loading of the Thomastown to Ringwood line within its thermal capability following an unplanned contingent outage of the Rowville to Ringwood line at times of high temperature and load. This will permit loading of the line beyond its 10-minute rating and remove any requirement for pre-contingent load shedding. However, this option will not avoid the need for load shedding following forced outage of the Rowville to Ringwood line occurred during a high demand period on hot summer days. If a load shedding scheme is selected as the preferred solution VENCorp will consult with the distributors on the arrangements for load shedding, in order to minimise the impact of the load shedding scheme on the distributor's customers.

Option 2 Installation of wind monitoring equipment along critical sections of the Ringwood to Templestowe 220 kV line. As high ambient temperatures are likely to be associated with higher than average wind speed, this will reduce the probability that load shedding will be required, however it does not provide any firm increase in supply capability.

Option 3 Uprating the critical section of the existing overhead 220 kV line. Only the portion of the Ringwood to Thomastown between the Templestowe site and Thomastown (60% of the total line length) defines the line's overall capability. Increasing the capability of this section of the overhead line from a nominal 530MVA to 700MVA would provide sufficient capability to eliminate the exposure to load at risk in the short to medium term based on existing forecasts, i.e. over the next 10 years.

Option 4 Establishment of additional 220 kV switching at Templestowe terminal station. The Ringwood to Thomastown line passes by Templestowe terminal station. The portion of the existing Ringwood to Thomastown line between the Ringwood and Templestowe sites has a rating of 700 MVA. Switching the Ringwood to Thomastown line in at Templestowe would create two new lines - the Ringwood to Templestowe line and the Templestowe to Thomastown line. This would provide two circuits to Ringwood, each with a continuous rating of 700 MVA, which would provide sufficient capability to eliminate the exposure to load at risk in the short to medium term based on existing forecasts, i.e. over the next 10 years. Furthermore, this option also significantly improves the supply to Templestowe terminal station by increasing the number of 220 kV circuits, which supply the station from two to four.

Option 5 Establishment of additional 220 kV switching at RWTS. Similarly to option 3, the Rowville to Templestowe line passes by Ringwood terminal station. By switching this line in at Ringwood, two additional lines will support the loading at this location. This augmentation provides sufficient capability to eliminate the exposure to load at risk in the short to medium term based on existing forecasts, i.e. over the next 10 years.

4.6.5 Non-Network Solutions

Load transfer or demand management at Ringwood would need to be sufficient to keep demand within the 10 minute pre-contingency rating of the transmission line and to reduce the energy at risk post contingency to a level that avoided the justification of implementing a network solution.

Generation at Ringwood would need to be sufficient and available to keep demand within the 10-minute pre-contingency rating of the transmission line and to reduce the energy at risk post contingency to a level that avoided the justification of implementing a network solution.

4.6.6 Economic Analysis and Ranking of Options

A rapid load shedding scheme as described in option 1 is around $150K. Option 2, wind monitoring, is expected to be around $500K. Option 3, line uprating is estimated to be around $4M while Options 4 and 5 would both be around $5M.

The benefits of augmentation are reduction in the amount of expected unserved energy due to load shedding. There are no benefits from rescheduled generation or any tangible reduction in active or reactive losses in the transmission system. Table 4.25 identifies the benefits of the network solutions:

Year	Value of Unserved Energy (VCR)	Do Nothing	Option 1 [$K]	Options 2-5 [$K]	Additional benefit of Options2-5 over Option 1 [$K]
2003/04	$10K/MWh	-	0	$5	$5
	$29.6K/MWh	-	0	$14.8	$14.8
2004/05	$10K/MWh		$57	$65	$8
	$29.6K/MWh		$170	$192	$22
2005/06	$10K/MWh	-	$582	$592	$10
	$29.6K/MWh	-	$1,720	$1,750	$29
2007/08	$10K/MWh	-	$1,590	$1,600	$17
	$29.6K/MWh	-	$4,700	$4,760	$50

Table 4.25 - Economic benefit of various augmentation options.

The fast load shedding scheme provides a net benefit in summer 2004/05, and is the lowest cost option. On an economic basis, it would be ranked as the No.1 network augmentation. The economic assessment in Table 4.25 shows that it should be implemented for service by summer 2004/05.

Options 2 – 5 provide only small benefits beyond Option 1 and based on higher costs are not justified at this time. These network options are currently ranked 2, 3, 5 and 4, respectively.

4.6.7 Preferred Solution

No action is planned for Summer 2003/04. VENCorp has identified that installation of a fast load shedding scheme at Ringwood terminal station by December 2004 at a capital cost of approximately $150K would pass the regulatory test.

The augmentation would satisfy the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

VENCorp does not expect the preferred solution will have a material inter-network impact. As such, no augmentation technical report will be sought from the Inter-regional Planning Committee, nor will consent to proceed from other transmission networks.

4.7 Supply from the Moorabool 220 kV bus

4.7.1 Reasons for Constraint

The two Moorabool - Ballarat 220 kV lines form one of the two main 220 kV supply points for the 'State Grid'[27] area in Northern and Western Victoria. Power generally flows northwards from Moorabool into the state grid on these lines, which are identified in figure 4.7.

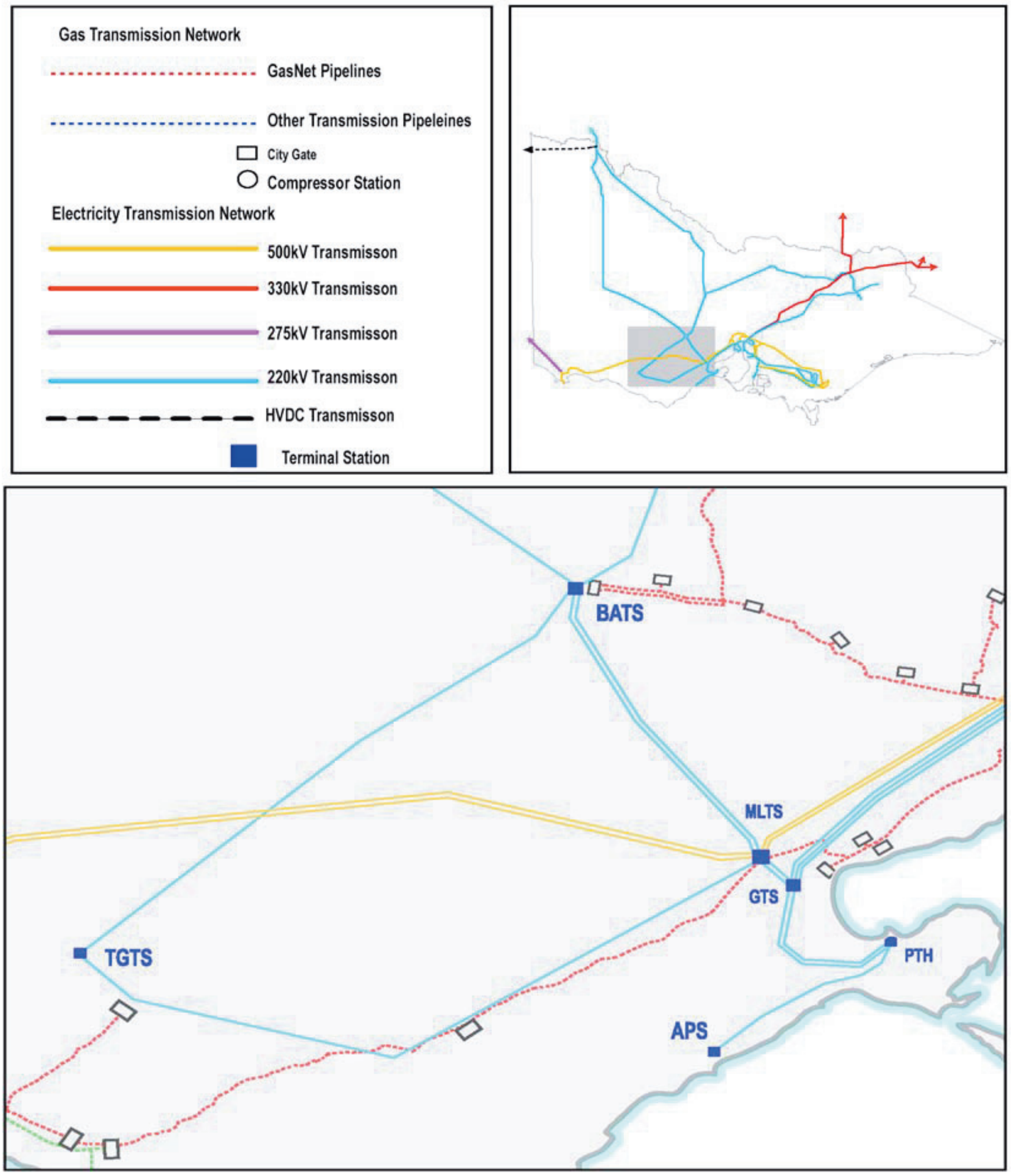


Figure 4.7 - Geographical representation of Supply from Moorabool to Ballarat and the southern State Grid.

The two Moorabool – Ballarat 220 kV circuits are on separate tower lines and have different thermal ratings. The original tower line (No. 1 circuit) is a single circuit line rated 270 MVA at 35 degrees. The second tower line was constructed as a double circuit line during the 1980s with only one circuit (No 2 circuit) strung to defer costs. This circuit has a continuous rating of 450 MVA at 35 degrees. Space remains on this tower line for construction of its second circuit.

The critical contingency for loading on these circuits is loss of the higher rated No 2 circuit resulting in potential overload of the lower rated parallel No 1 circuit. The capability of these circuits is limited by the overhead conductor sag, and varies significantly with ambient temperature and wind speed.

A third 220 kV circuit passes from Moorabool through Terang to Ballarat via a significantly longer route. The bulk of the power transfer into the state grid from Moorabool is via the two Moorabool to Ballarat direct lines. The lines between Moorabool and Ballarat through Terang primarily support load at Terang, and loading on these circuits does not significantly affect loading on the two direct Moorabool to Ballarat connections.

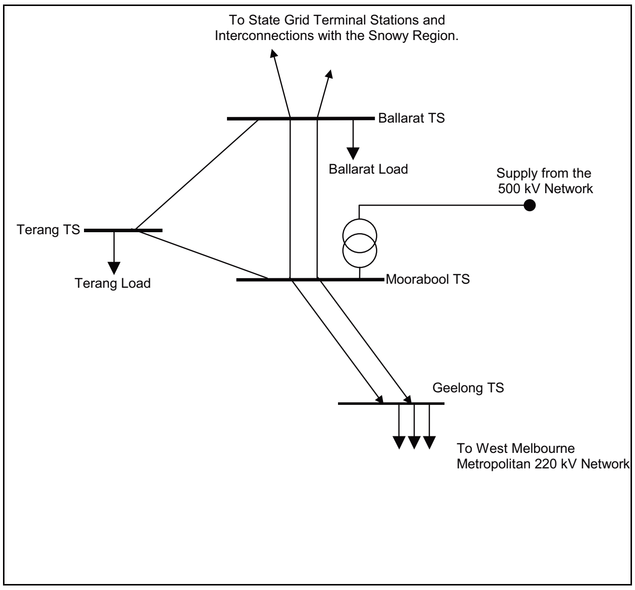


Figure 4.8 - Electrical representation of Supply from Moorabool to Ballarat and the southern State Grid.

Northerly flow into the state grid area on the Moorabool – Ballarat 220 kV lines is influenced by:

- State grid load, with flow on the Moorabool – Ballarat lines increasing with state grid load. This is the most significant factor for loading on the Moorabool – Ballarat lines.
- Interconnection flow between Victoria and NSW. For a given load level in the state grid, flow on the Moorabool-Ballarat lines is increased by heavy export from Victoria to NSW and reduced with increasing import from NSW.
- Southern Hydro Generation, which acts similar to import from NSW and reduces loading on the Moorabool – Ballarat lines as it increases.

In practice, very high state grid loading does not normally occur coincident with high export from Victoria to NSW and high ambient temperatures. The limit equations which determine Victorian export to NSW only allow high levels of export during periods of low to moderate Victorian demand. Victoria typically exports heavily to NSW overnight during periods of lower ambient temperature and demand, or on weekends, when Victorian and state grid demands are also more moderate.

During periods of high state grid load and high ambient temperature, Victoria is typically importing from the NSW region. Modeling suggests that there is exposure to onerous loading conditions only when high Victorian demand and low to moderate import levels combine with high ambient temperatures and low line ratings. This condition could result in potential loading of the Moorabool – Ballarat lines beyond the continuous rating of the No 1 circuit. However the levels of loading are within the short time rating of the No 1 circuit and therefore there is no need to take action unless there is an unplanned outage of the No 2 circuit during this critical loading period. In the low probability event that the No 2 circuit is tripped out during this period, the loading can be reduced to the continuous rating by demand reduction in the state grid area, or an increase in import levels from NSW. If Murraylink was exporting to South Australia when the contingency occurred, transfers on Murraylink will be rapidly run back to zero, which would provide a degree of load relief on the remaining circuit.

27 Regional Victoria (from Hamilton to Mildura to Glenrowan) excluding Gippsland and further east, is supplied from 220 kV 'State Grid'

Existing contingency analysis and other on-line monitoring tools are sufficient to alert system operators when the potential for exposure to this contingency exists and no limit equations are currently provided to constrain Victoria to NSW transfers based on the rating of these lines.

Projects which increased Victoria to NSW export capability could increase exposure to this contingency, depending under what system conditions the increase in export capability was available.

4.7.2 Forecast Conditions, Demand and Energy at Risk

The following is a snapshot of the possible exposure during a period of high demand and high ambient temperature over Summer 2003/04. The critical contingency is loss of the Moorabool – Ballarat No 2 220 kV line.

- Victorian Demand is 9400 MW
- The State Grid load is 945 MW
- The ambient temperature is 42 °C.
- The export to SA on Murraylink is 0 MW
- The import from NSW to VIC is 1400 MW
- The combined flow north on the Moorabool – Ballarat 220 lines is 305 MVA
- The Moorabool – Ballarat No 1 pre contingent flow would be 133 MVA
- The Moorabool – Ballarat No 1 post contingent flow would be 244 MVA
- The Moorabool – Ballarat No 1 continuous line rating would be 223 MVA
- The ratio of post contingency loading to capability is: 109%
- The amount of time until the conductor reaches design temperature: 21 Min
- The minimum amount of time required to reduce loading if generation rescheduling is required is: 15 Min
- The amount of load above the short time rating is: 0 MVA
- The amount of load above the continuous rating is: 21 MVA

4.7.3 Failure Rate of the Moorabool – Ballarat 220 kV lines.

The two direct Moorabool to Ballarat 220 kV lines are 64 km long. There have been 9 unplanned outages of the critical higher rated No 2 Ballarat to Moorabool 220 kV line since 1985, with an average duration of 1.49 hours for each outage. This gives an outage rate of 0.51 events per year, compared to a benchmark figure of around 0.96 events per years, with a benchmark average duration of no more than 10 hours per event. The benchmark probability of unplanned outage is 1.096×10^{-4}, which is around 25% higher than the actual rate of unplanned outage.

4.7.4 Assessment of Energy at Risk

Table 4.26, identifies the results of market modeling studies undertaken to quantify the exposure to this constraint.

	2003 - 2004	2005 - 2006	2007 – 2008
Expected Hours Exposed	26	62	81
Energy at risk (MWh)	267	1368	1940
Maximum MVA Overload	28	52	60
Expected Constrained Energy (MWh)	0.03	0.15	0.21
Value of Expected Constrained Energy ($K)(1)	0.1	0.45	0.64
Value of Expected Constrained Energy ($K)(2)	2.7	13.3	18.9

(1) Here it is assumed that the constrained energy is removed by rescheduling of Vic – NSW flow. Around 15 MW of rescheduling is required to remove 1 MVA of constrained energy, at an assumed value of $200/MWh for rescheduling. i.e Re-dispatch cost is around $3000/MVAh above rating.

(2) Here it is assumed that the overload is removed by load shedding at Ballarat. Around 3 MW of load shedding is required to achieve 1 MVA of load relief on the line, and each MW of load shedding is valued here at $29,600/ MWh.

Table 4.26- Expected Constrained Energy due to Moorabool-Ballarat No 1 line overloads.

Table 4.26, identifies the expected number of hours per year the Moorabool – Ballarat No1 line is exposed to potential overload due to trip of the parallel No 2 circuit, the amount of energy at risk during these periods, and the amount of expected constrained energy, taking into account the probability of the critical line outage occurring co-incident with a period of high loading.

4.7.5 Network Solutions

The following network solutions have been identified to reduce or remove the constraint on 220 kV power flow from Moorabool to Ballarat.

- Installation of a third Moorabool to Ballarat 220 kV circuit. The existing No 2 circuit is built on double circuit towers, with only one side of the towers presently strung. A second circuit could be strung on the vacant side of the tower. The estimated cost of this option and the associated 220 kV switching is around $8M.
- Increasing the capacity of the lower rated No 1 circuit, through re-tensioning the conductors to achieve a higher maximum conductor temperature, wind monitoring, or completely re-conductoring the circuit.

Wind monitoring and BATS 220 kV reconfiguration to increase loading of the Moorabool to Terang to Ballarat lines would also be reviewed.

4.7.6 Non Network Solutions

Load transfers, demand management or generation within the state grid, especially at Ballarat, would provide load relief on the Moorabool – Ballarat 220 kV circuits. Around 3 MW of load relief in the state grid is required to reduce loading on the critical line by 1 MVA.

Rescheduling of the flow on the Vic – NSW interconnector can be used to reduce loading on the critical circuit following a contingency, with around 15 MW of interconnection rescheduling required to reduce loading on the critical line by 1 MVA. A minimum of 15 minutes is required for any such rescheduling following a contingency.

4.7.7 Preferred Solution

Studies indicate that there is insufficient energy to justify a network solution to this constraint within the 5 year period. Given the small-expected exposure to this contingency, it is proposed to rely on the use of existing contingency analysis and other online monitoring facilities to alert system operators of the potential for this overload. If the contingency were to occur during a critical period, manual action after the event such as load shedding in the state grid area, or increasing NSW to Vic flow would be sufficient to relieve the overload.

4.8 Security of double circuit supplies to South East Metropolitan Area

4.8.1 Reasons For Constraint

The Springvale (SVTS), Heatherton (HTS), East Rowville (ERTS), Tyabb (TBTS) and Malvern (MTS) terminal stations, and the BHP Steel plant at Western Port each relies on radial double circuit 220 kV line supply, as shown in Figure 4.9. Failure of one or more double circuit towers, leading to an extended outage of both circuits on a tower line, is a possible, although very low probability event, which could lead to an extended supply outage. Specific network developments already, proposed and under investigation to improve security of these supplies, together with their security impacts, are presented below.

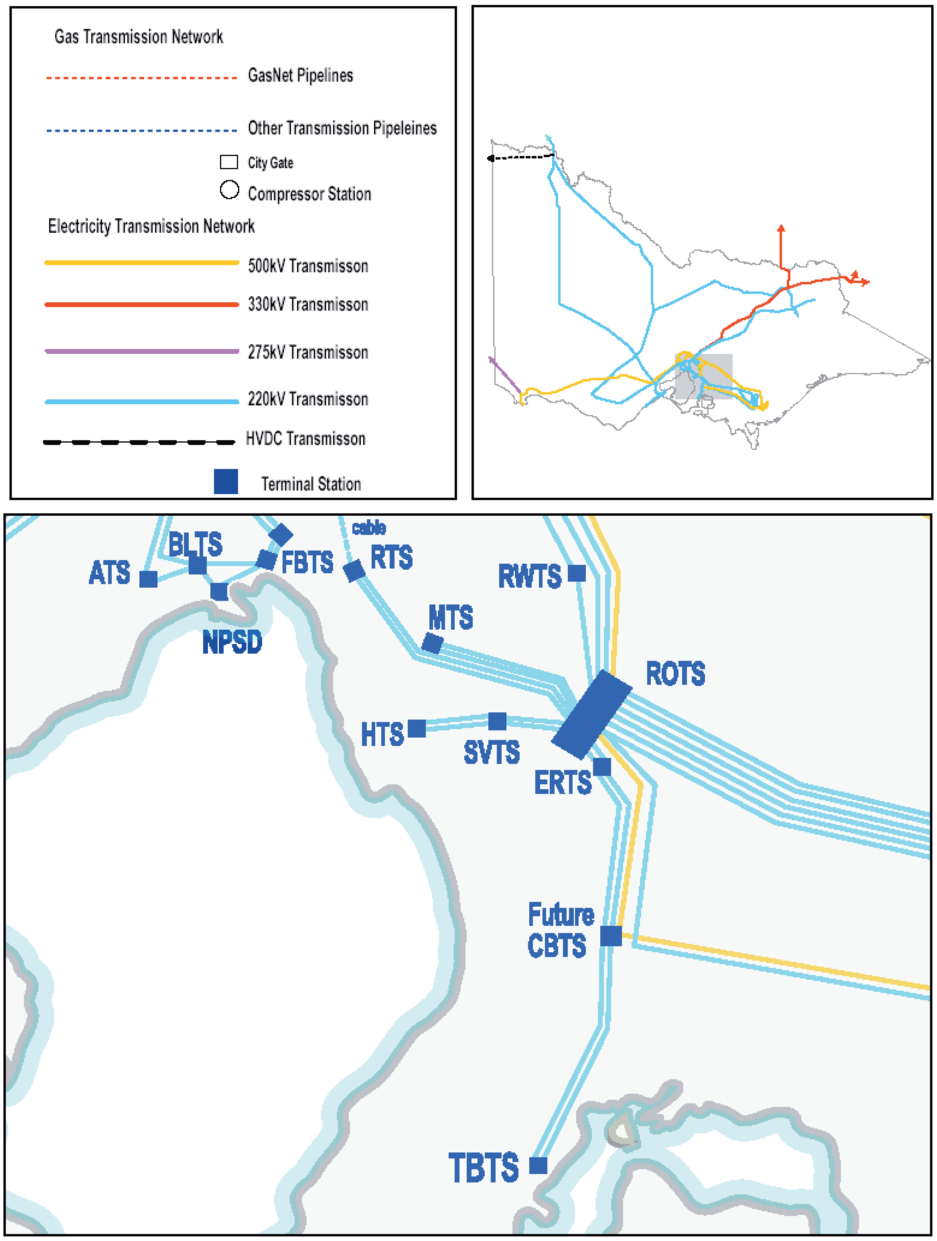


Figure 4.9 - Geographical representation of Supply to the southeast Metropolitan Area.

4.8.2 Impacts of Constraint

Table 4.27, identifies the peak loadings of each of these double circuit lines with loads under 10% probability of exceedence summer conditions. The table shows the effect of the 220/66 kV Cranbourne terminal station commencing service in summer 2004 and the Cranbourne 500/220 kV transformation due for service in December 2004 on loadings on these circuits.

Line(both circuits assumed out of service)	Length (km)	Peak load not supplied for double circuit line outage (MW)					
		Feb 2004 pre CBTS 220/66		Feb 2005 post CBTS 220/66		Feb 2005 post CBTS 500/220	
		Before transfers	After transfers	Before transfers	After transfers	Before transfers	After transfers
ROTS-SVTS	7	799	579	767	497	767	497
SVTS-HTS	8	351	231	303	133	303	133
ROTS-ERTS	2	828	678	923	723	0	0
ERTS-CBTS	19	275	155	482	362	0	0
CBTS-TBTS	23	275	155	283	163	283	163
TBTS-BHP Steel	2	64	64	64	64	64	64
ROTS-MTS	15	183	123	189	129	189	129

Table 4.27 - Load at risk for double circuit 220 kV line outages including distribution relief

"Before transfers" loadings are prior to any emergency action to transfer load. "After transfers" loadings follow progressive distribution networks reconfigurations to transfer load.

To minimise the consequences and recover supply the following emergency plans have been put in place by United Energy, Texas Utilities Networks, SPI PowerNet and VENCorp:

- emergency by-pass measures, utilising temporary structures and mobile cranes, developed in conjunction with SPI PowerNet, allow for restoration of full supply within 12 hours in over half of the possible tower failure cases;
- emergency measures developed in conjunction with SPI PowerNet to restore full supply to Malvern within 6 hours for a Rowville to Malvern double circuit outage;
- emergency measures developed by United Energy and TXU 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); and
- Cranbourne 220/66 kV terminal station, jointly planned by TXU; United Energy and VENCorp, is being constructed by SPI PowerNet for service from February 2004, with additional subtransmission capability to transfer load away from East Rowville, Heatherton and Cranbourne by United Energy and TXU.

4.8.3 Network Solutions and Costs

These partial remedies were justified on the basis that customers value load not supplied to areas such as Melbourne's southeast at an average of $10,000/MWh. Transmission options were not economically justified. The economic justification for further emergency measure has been reassessed based on $29,600/MWh.

Table 4.28, jointly prepared with United Energy, shows transmission and distribution options with indicative benefits (valuing customer load not supplied at $29,600/MWh) and indicative network charges over 30 years. Again transmission options are either not justified economically or are unlikely to be acceptable to the community, due to the significant lengths of overhead construction in urban areas.

Analysis suggests that security of the load could potentially be improved by the construction of additional 66 kV ties. However, given the small exposure to loss of double circuit line, further investigation is required to determine if this is an economic solution to reduce the energy at risk.

Option	Description	Summer rating (MVA)		Network charge ($K)	Benefit ($K)
		Continuous	2 hour		
1	Malvern-Heatherton 8 km 220 kV underground cable	400	650	35,000	11,000
2	Heatherton-Cranbourne 26 km 220 kV overhead line (if feasible)	800	800	15,000	13,000
3	Heatherton-Cranbourne 26 km 220 kV underground cable	400	650	95,000	13,000
4	Extra distribution transfers	120	120	3,000-5,000	3,000-5,000

Table 4.28 - Network security improvement options with indicative benefits and costs

4.8.4 *Preferred Solution*

There is no economic network solution at current costs. VENCorp will continue to monitor loading levels and augmentation costs on an annual basis.

4.9 Metropolitan Tie-Transformation

4.9.1 Reasons for Constraint

Completion of the Latrobe Valley to Melbourne transmission upgrade project includes development of a new 500 kV switchyard at Cranbourne and installation of an additional metropolitan 500/220 kV transformer. This is scheduled for completion in December 2004. This project provides some benefit in reducing the dependence on the Rowville 500/220 kV transformer by offloading it slightly, however it is only a moderate reduction since the new transformer is a replacement for the strong 220 kV injection point which was the 500 kV line operating at 220 kV. Figure 4.10, geographically shows metropolitan transmission.

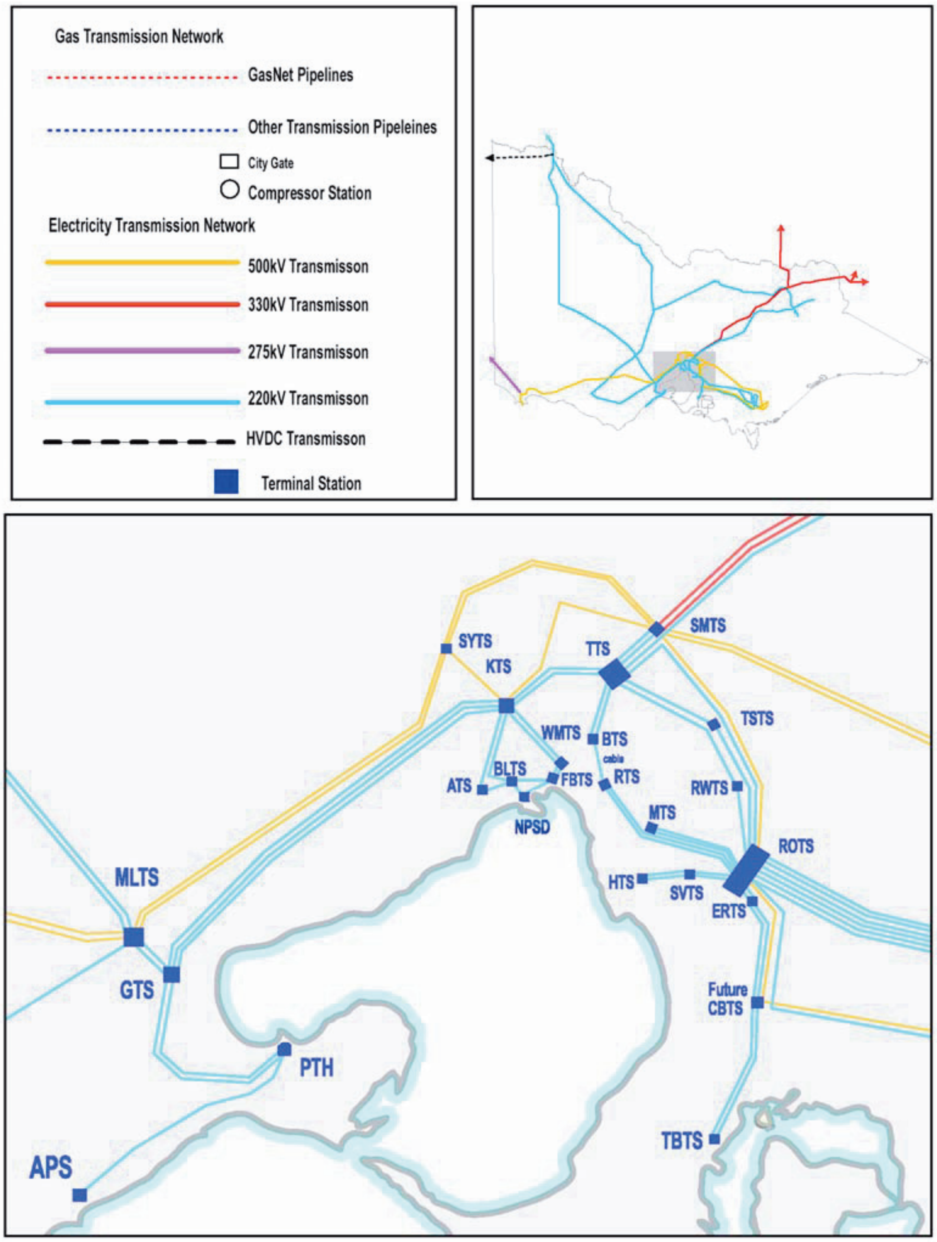


Figure 4.10- Geographical Representation of Metropolitan Tie-Transformation.

Figure 4.11 schematically represents the transformation in the metropolitan area after December 2004.

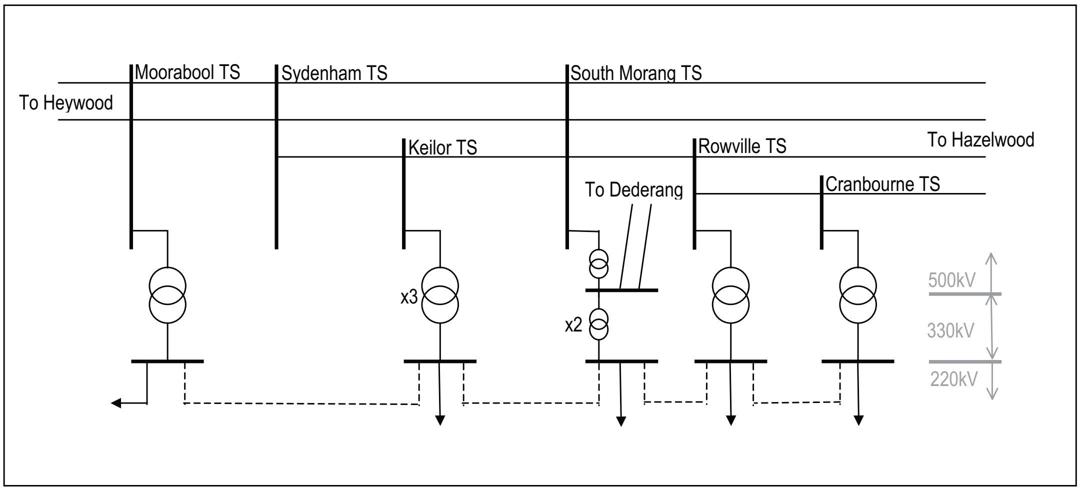


Figure 4.11 - Electrical Representation of Metropolitan Tie-Transformation.

Located at Cranbourne, Rowville, South Morang, Keilor and Moorabool, the metropolitan tie transformers are heavily utilised items that form a critical part of the transmission system supplying Victorian Terminal Stations. Load growth in the metropolitan area, particularly during peak demand conditions in summer, is driving the need for further transformation from 500 kV or 330 kV down to 220 kV.

Table 4.29 summarises the system normal loading on each of these transformers under peak demand forecast conditions over the next four years.

Plant	Rating	% Loading 04/05	% Loading 05/06	% Loading 06/07	% Loading 07/08
Cranbourne 500/220 A1	1000	82	86	94	105
Rowville 500/220 A1	1000	85	88	91	97
South Morang 500/330 F2	1000	25	24	5	40
South Morang 330/220 H1	750	74	75	75	82
South Morang 330/220 H2	750	66	68	69	79
Keilor 500/220 A2	750	72	73	80	94
Keilor 500/220 A3	750	64	66	69	72
Keilor 500/220 A4	750	64	66	69	72
Moorabool 500/220 A1	1000	69	70	73	78

Table 4.29 - Forecast loading on the metropolitan tie transformers (% of continuouis ratings) for system normal conditions.

4.9.2 Impacts of Constraint

A number of observations can be drawn from these forecast flows.

- The tie transformers share power flows considerably well.
- All the tie transformers are heavily loaded under peak demand conditions, with the exception of the South Morang F2 transformer which is critical during moderate demand and high export conditions.
- The location of the latest transformer at Cranbourne, the nature of the metropolitan load growth and the increasing dependence on generation from the Latrobe Valley (BassLink, etc) will place increasingly more pressure on this particular transformer compared with the others.
- By the end of the five year outlook, the transformers at Rowville and Cranbourne will potentially be loaded close to or above their respective continuous ratings for system normal conditions.

These observations suggest that the need for an additional metropolitan tie transformation is becoming increasingly significant and that VENCorp must undertake a comprehensive review of the timing and need for solutions to offload the existing transformers. This is consistent with previous studies, which showed a need for additional transformation shortly after the 500 kV line upgrade project.

Furthermore, the last observation gives a strong signal that some form of augmentation will be required prior to December 2008 at the latest. By this time, there will be very limited opportunity to transfer load away from these transformers or redispatch generation to alleviate this extreme loading. The consequence is likely to be load shedding during system normal conditions, where as little as 20 MWh of Expected Unserved Energy would be valued at around $600K, based on a VCR of $29.6K. The benefit of alleviating this amount of Expected Unserved Energy is expected to cover the costs of another metropolitan 500/220 kV tie transformer.

In addition to system normal constraints, there are number of outage conditions that can lead to high loading on the critical metropolitan tie transformers. The impact of theses outages can be and is somewhat offset by operational measures and the utilisation of the strong 220 kV ties between metropolitan terminal stations, however the following table is provided to indicate the vast array of contingencies that will be considered in VENCorp's detailed study.

Critical Element	Critical Outages
CBTS A1 transformer	ROTS A1 transformer
	CBTS-ROTS 500 kV Line
	HWTS-ROTS 500 kV Line
	HWTS-SMTS 500 kV Lines (x2)
	RTS-BTS 220 kV Cable
	YPS or HWPS-ROTS 220 kV Lines (x3)
ROTS A1 transformer	CBTS A1 transformer
	SMTS H1 or H2 transformer
	ROTS-SMTS 500 kV Line
	HWTS-CBTS 500 kV Line
	HWTS-SMTS 500 kV Lines (x2)
	RWTS-TTS 220 kV Line
	TSTS-TTS 220 kV Line
	YPS-ROTS 220 kV Lines (x3)
SMTS F2 transformer	- (not critical at peak demand/high import)
SMTS H1/H2 transformer	SMTS H2/H1 transformer
	ROTS A1 transformer
	CBTS A1 transformer
	KTS A2 transformer
KTS A2 transformer	SMTS H1 transformer
	EPS-TTS 220 kV line
KTA A3/A4 transformer	KTS A4/A3 transformer
	MLTS A1 transformer
MLTS A1 transformer	KTS A4/A3 transformer

Table 4.30– Listing of critical elements and their corresponding critical outages

The operation of metropolitan generation, namely Newport and Somerton Power Stations also influences the loading on the critical transformers, tending to flatten the utilisation characteristics since they are tend to be off when demand is relatively low.

4.9.3 Network Solutions and Costs

Identified network solutions primarily focus on the integration of additional 500/220 kV transformation in the metropolitan area, with the intention of optimising the location and connection arrangement giving due consideration to:

- Alleviating high system normal loading;
- Alleviating the exposure to unserved energy and dependence on complicated operational solutions after critical outages, especially if the outages have the potential to be long term;
- Management of metropolitan fault levels
- Increasing security of supply

Locations being considered are Cranbourne, Rowville, Ringwood, Templestowe and South Morang.

Preliminary studies indicate that Rowville is the most promising site for further development at present. Cranbourne is not ideal in the medium term as the 220 kV network exiting this terminal station is not adequate to cater for the required transfers to Rowville. Ringwood and Templestowe would require the green field development of 500 kV switchyards and additional switching and line upgrades at remote stations. South Morang development may be limited by 220 kV line capacity exiting the yard.

Timing of the next metropolitan tie transformer is dependent on metropolitan load growth. A detailed assessment still needs to be carried out taking into account the outcomes of the constraint associated with supplying the Geelong area after outage of the Moorabool transformer. Any augmentation as a result of the Geelong area constraint will influence, but not eliminate, the need for further transformation in the metropolitan area.

Depending on its specific location, new metropolitan generation connected at 220 kV or below, or the application of demand side management, may defer the need for additional transformation. So too may other network augmentation options such as transmission development at 220 kV. These will be considered as part of VENCorp's full application of the regulatory test.

The need for additional transformation may be deferred by development of demand management or new generation in the metropolitan Melbourne area. Any new generation may be embedded within the distribution network or connected directly to the transmission system within the metropolitan Melbourne area. Deferral would be in the order of one year for each 150~200 MW of generation or demand side management provided. Further details of any generation proposals including the exact location and availability of the generation or controllable load would need to be provided for any deferral of new transformation to be more accurately defined.

4.9.4 Preferred Solution

The preferred network solution will involve a large network asset and its justification and approval will be consistent with the requirements of the NEC and involve the required consultation process. Tentative timing for such works is summer 2008 or sooner. Capital cost for an additional metropolitan transformer and associated works would be approximately $40M.

Depending on the location of augmentation, new metropolitan transformation may have a material inter-network impact. This will be addressed in a timeframe consistent with the justified works when the required Inter-regional Planning Committee augmentation technical report or appropriate consents are sought.

4.10 Supply to the Springvale and Heatherton areas

4.10.1 Reason for Constraint

Springvale terminal station and Heatherton terminal station are supplied radially from Rowville terminal station via the Rowville-Springvale-Heatherton double circuit 220 kV lines, as per Figures 4.12 & 4.13.

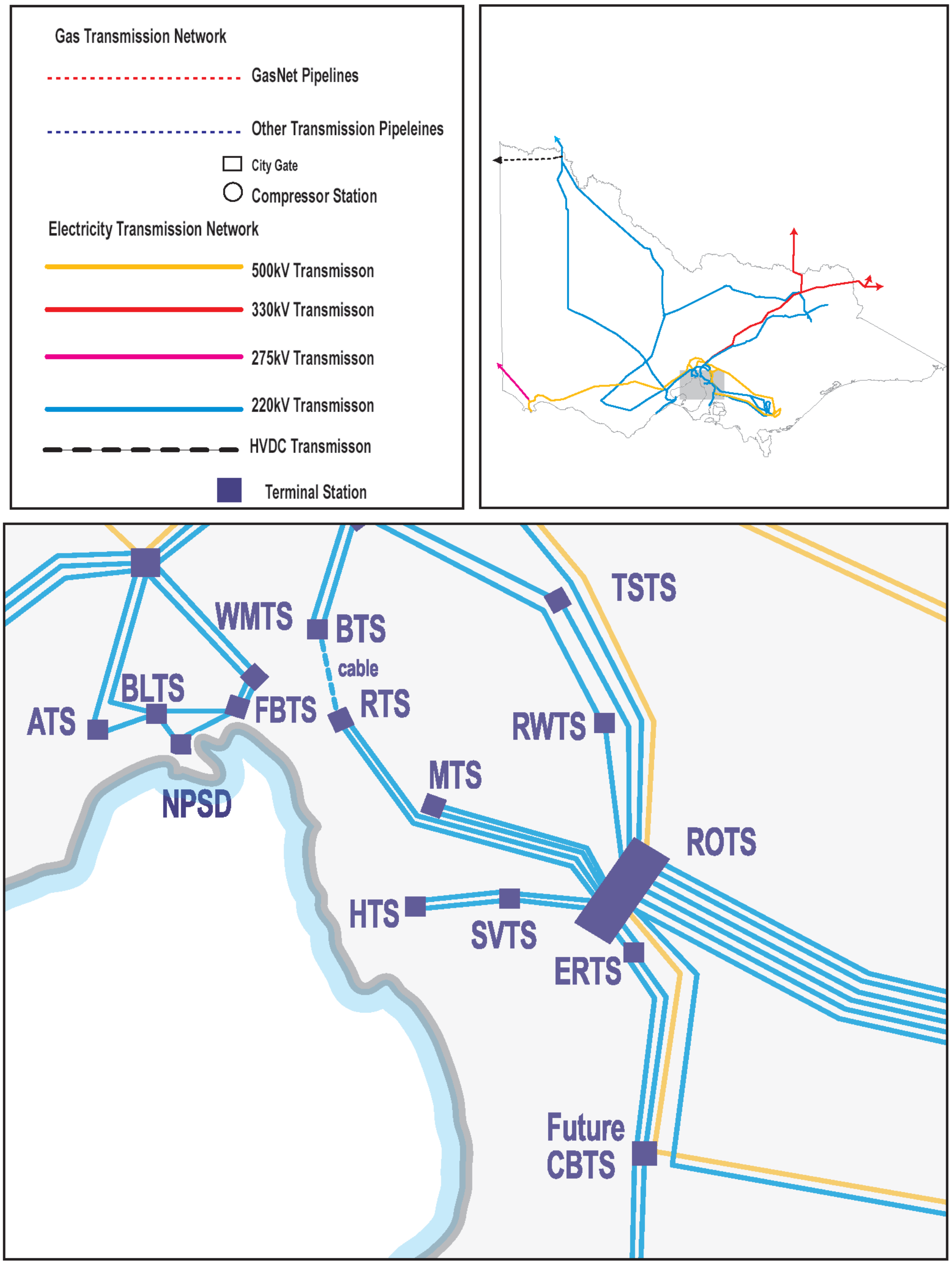


Figure 4.12 - Geographical representation of Supply to Springvale and Heatherton Areas.

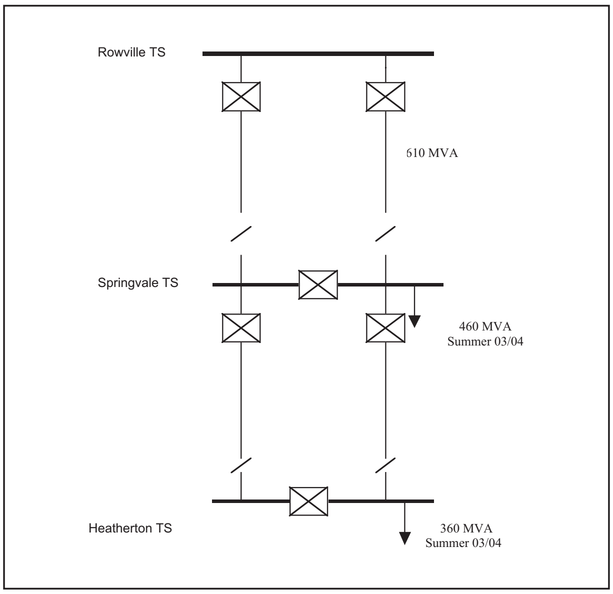


Figure 4.13 - Electrical representation of Supply to Springvale and Heatherton Areas.

Each of these circuits carries 50% of the total combined load at Springvale and Heatherton under normal conditions. The critical contingency for supply to Springvale and Heatherton is outage of one of the two parallel circuits, resulting in thermal overload of the remaining circuit. These circuits each have a nominal continuous rating of 610 MVA at 35^{o}C.

An additional factor affecting the transfer capability between Rowville and Springvale is the thermal rating of the 220 kV line isolators at Springvale. These specific isolators have been assigned a nominal continuous rating of 800 MVA and 3 minute rating of 840 MVA at 35^{o}C. No other termination equipment has been assigned a short time rating.

4.10.2 Impact of the Constraint

The highest load on these circuits occurred during summer 2000/01 when the peak combined load supplied from Springvale and Heatherton reached around 670 MVA. Recent milder summers and some load transfers have resulted in lower loads in 2001/02 and 2002/03. Line loading is forecast to be around 800 MVA for Summer 2003/04 based on 10% probability of exceedence temperature conditions. However, United Energy is proposing to transfer load from Heatherton to the new station at Cranbourne. If this occurs prior to Summer 2003/04 the line loading will be around 750 MVA.

There are 5 off 66 kV 50 MVAr shunt capacitor banks spread between Springvale and Heatherton. Under the most onerous loading conditions these shunt capacitors are expected to be in service and therefore reduce the loading on the Rowville to Springvale circuits.

High ambient temperatures influence this constraint in two ways, firstly by reducing the capability of the transmission circuits, and secondly by increasing the local demand as a result of increased air conditioning load.

At present, this potential constraint is being addressed by:

- The wind in the vicinity of the lines is monitored and a dynamic rating is assigned to the Rowville – Springvale 220 kV circuits based on actual wind speed. Before this scheme was installed a conservative wind speed of 0.6 m/sec was assumed in rating the lines. However, typically periods of high ambient temperature are associated with wind speeds of at least 1.2 m/sec, increasing the current carrying capacity by 14% and reducing the risk of loading exceeding rating following an outage on one circuit.
- An automatic control scheme continuously calculates the conductor temperature of the critical circuits so that loading beyond the calculated continuous rating can be applied without exceeding the maximum conductor temperature. This scheme advises how long before the load must be returned to the continuous

rating and if manual action has not been taken it can automatically shed load at Springvale to ensure that the circuits do not exceed their design temperature after a contingency. By automatically reducing load on the overhead line following a contingency, these facilities allow operation of the overhead line beyond the minimum 10 minute rating normally required to allow for manual load shedding.

These mechanisms are providing an economic solution with the present levels of energy at risk.

4.10.3 Forecast Conditions, Demand and Energy at Risk.

VENCorp forecasts the 10% probability loading conditions for the 2003/04 summer period to be: Note that this load forecasts assumes no load transfer away from Heatherton prior to summer 2003/04.

- Springvale & Heatherton aggregate 66 kV load: 799 + j191 MVA
- The pre-contingent Rowville - Springvale line flow is: 1040 A per circuit
- The post-contingent Rowville - Springvale line flow is: 2087 A
- Ambient temperature: 42^{o}C
- The wind speed could be: 0.6 – 1.2 metres/second.
- The Rowville - Springvale continuous line rating for these wind speeds is: 1300 - 1530 A
- The three minute rating of the Springvale line isolators would be: 2077 A
- The amount of time available to reduce the loading on the line is: 3.4 – 8.2 Min (0.6-1.2 m/sec wind)
- The amount of pre-contingency load at risk is: 4 MVA
- The amount of post-contingency load at risk is: 300 – 210 MVA (0.6 – 1.2 m/sec wind)

This assessment indicates that a small amount of load transfer away from Springvale or Heatherton may be required to avoided pre-contingent load shedding during Summer 2003/04. It was planned that this load transfer would be achieved as part of the Cranbourne Terminal Station development prior to Summer 2003/04, however if this can not be achieved VENCorp will discuss other options to avoid precontingent load shedding with the relevant distributors.

The amount of post contingent load shedding depends critically on the wind speed. The minimum amount would be determined by the Springvale isolator limit, which does not change with wind speed, and the maximum amount would be for atypical conditions when low wind speeds occur coincident with high ambient temperatures and load.

The information in the following tables is derived from a probabilistic assessment of Expected Unserved Energy. It is broken down into pre-contingent load shedding and post contingent load shedding and takes account of the constraints caused by the 220 kV line isolators at Springvale, and the Rowville to Springvale overhead lines.

	Wind Speed [m/sec]	Energy at risk [MWh]	Hours of Exposure	Expected Unserved Energy [MWh]	Value of EUE [$K]	
					$10K/MWh	$29.6K/MWh
2003/04	1.2	3584	60	0.9	9	26.6
	0.6	22900	380	5.8	58	168
2004/05	1.2	2190	34	0.6	5.5	16.5
	0.6	13500	230	3.4	34	99
2005/06	1.2	3150	46	0.8	8.2	23.7
	0.6	19700	320	5.0	50	144
2006/07	1.2	4377	62	1.1	11.1	33
	0.6	27700	452	7.0	70	208
2007/08	1.2	5890	86	1.5	15.0	44.3
	0.6	37900	630	9.6	96	280

Table 4.31 - Post Contingency Energy at Risk

Table 4.31 indicates the expected unserved energy due to the rating of the Rowville to Springvale circuits. All this energy is due to the rating of the overhead line, which limits the continuous rating of these circuits at all ambient temperatures. The energy beyond the firm rating of these circuits (energy at risk) is shown for wind speeds of 0.6 and 1.2 m/sec. When this energy at risk is multiplied by the probability of one circuit being unavailable, it provides an indication of the expected unserved energy. Note that this assessment assumes that load is transferred from Heatherton to Cranbourne after summer 2003/04.

The two Rowville to Springvale 220 kV lines are 7.4 km long. There have been 7 unplanned outages of either of these lines since 1985, with an average duration of 4.39 hours for each outage. This gives an outage rate of 0.38 event per year for both lines, compared to a benchmark figure of around 0.22 events per year, with a benchmark average duration of no more than 10 hours per event. The benchmark probability of one of the two circuits being unavailable in a given hour is: 2.534e-4. The historical outage rate of these lines is around 25% below this benchmark rate.

	Pre-contingency					
	Expected Hours Exposed	Average overload [MW]	Maximum overload [MWh]	Expected Unserved Energy [MWh]	Value of EUE [$K]	
					$10K/MWh	$29.6K/MWh
2003/04	0.6*	6.8	17.5	4.0	40.0	120
2004/05	0	0	0	0	0	0
2005/06	0.2	7.1	12.4	1.7	16.8	50.0
2006/07	2.2	11.2	35.0	24.8	248	734
2007/08	5.7	17.2	58.0	100	1000	2980

* The exposure to pre-contingency load shedding for Summer 2003/04 only occurs at ambient temperatures of 42 OC or higher.

Table 4.32 – Pre Contingency Energy at Risk

Table 4.32 indicates the expected pre-contingent load shedding required due to the rating of the Rowville – Springvale circuits. The EUE shown here is predominantly due to the need to shed load prior to the event to prevent overload of the Springvale end isolators of the Rowville – Springvale 220 kV lines beyond their short time rating immediately following a contingency. Note that the reduction in EUE from 2003/04 to 2004/05 is due to planned load transfers away from Heatherton prior to Summer 2004/05.

4.10.4 Network Solutions and Costs.

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

- Replacement of the Springvale end isolators on Rowville-Springvale circuits. Once the combined Springvale/Heatherton load begins to reach the rating of these isolators, the amount of pre-contingent load shedding rapidly rises. This can be seen in the rapid rise in EUE due to pre-contingent load shedding between 2004/05 and 2005/06. An indicative cost for this option is around $300K.
- An increase in the continuous rating of the Rowville to Springvale 220 kV lines. An increase in the design temperature of the Rowville – Springvale 220 kV lines from 65OC to 82OC, following after replacement of the line isolators at Springvale, would reduce the EUE by over 90% over the 10-year period to 2012 – 2013. Preliminary design work for this option has indicated that modification to at least 7 transmission towers would be required to achieve this rating. An indicative cost for this option is around $700K.

Table 4.33 identifies the reduction in expected unserved energy for each of the network solutions individually, and for both of them combined. A wind speed of 1.2 m/sec is assumed when listing the reduction in load shedding following a contingency

		Reduction in EUE [$k]			
		Replace Isolators		Upgrade overhead line	
		$10K/MWh	$29.6K/MWh	$10K/MWh	$29.6K/MWh
2003/04	Pre contingency	40	120	0	0
	Post contingency	0	0	9	26.6
	Total benefit	40	120	9	26.6
2004/05	Pre contingency	0	0	0	0
	Post contingency	0	0	5.5	16.5
	Total benefit	0	0	5.5	16.5
2005/06	Pre contingency	16.8	50	0	0
	Post contingency	0	0	8.2	23.7
	Total benefit	16.8	50	8.2	
2006/07	Pre contingency	248	734	0	0
	Post contingency	0	0	11.1	33
	Total benefit	248	734	11.1	33
2007/08	Pre contingency	1000	2980	0	0
	Post contingency	0	0	15.0	44.3
	Total benefit	1000	2980	15.0	44.3

Table 4.33 - Value of Reduction in EUE for Network Options

4.10.5 Non Network Solutions

Load transfer or demand management at Springvale or Heatherton sufficient to keep demand below the short time overload rating of the isolator i.e. 805 MVA at 35°C would avoid or defer the need for replacement of the isolator. To avoid load shedding post contingency sufficient load transfer or demand management would be needed to keep the lines within their continuous rating i.e. 610 MVA at 35°C.

Generation connected at Springvale or Heatherton, or in the distribution networks connected to these stations, available at times of high load and sufficient to reduce the line flow within the isolator and line ratings would avoid or defer the need for network augmentation.

4.10.6 Economic Analysis

The benefits of augmentation are reduction in the amount of load shedding. Table 4 identifies the benefits of the network solutions.

The cost of replacing the isolators is around $30K per annum. Replacing the isolators will remove the precontingent load at risk. When the benefit of removing this risk exceeds the annual cost it will become economic to replace these isolators.

The cost of uprating the line is around $70K per annum. Uprating of the line is unlikely to be justified in the next 5 years.

4.10.7 Preferred Solution.

The amount of load shedding required and hence the benefits of any network solution are critically dependent on the combined Springvale and Heatherton load. This will be impacted by the amount of load transfer away from Heatherton following the commissioning of Cranbourne Terminal Stations and the production of revised load forecasts. An assessment will be made following the service of Cranbourne Terminal Station, and the provision of associated load forecasts for Cranbourne and Heatherton Terminal Stations.

Based on the information available at the time of writing, the preferred solution is replacement of the 220 kV Rowville to Springvale line isolators prior to Summer 2005/06 at an estimated cost of $300K.

The existing load shedding facilities will need to be retained to allow operation of the Rowville to Springvale line beyond its 10-minute ratings.

4.11 Supply to the East Rowville and Cranbourne areas

4.11.1 Reasons for Constraint

The double circuit East Rowville-Rowville 220 kV line forms a radial supply for all load supplied from East Rowville Terminal Station (ERTS), Tyabb Terminal Station (TBTS), the soon to be established Cranbourne Terminal Station (CBTS), and BHP Steel at Western Port. This can be seen in Figure 4.4. The combined load at these stations is forecast to be around 900 MVA for the summer 2003/04 10% demand. As each of the East Rowville to Rowville 220 kV circuits has a rating of 800 MVA at 35 deg, the peak load at these stations can not be supported at times of high ambient temperature with one line out of service.

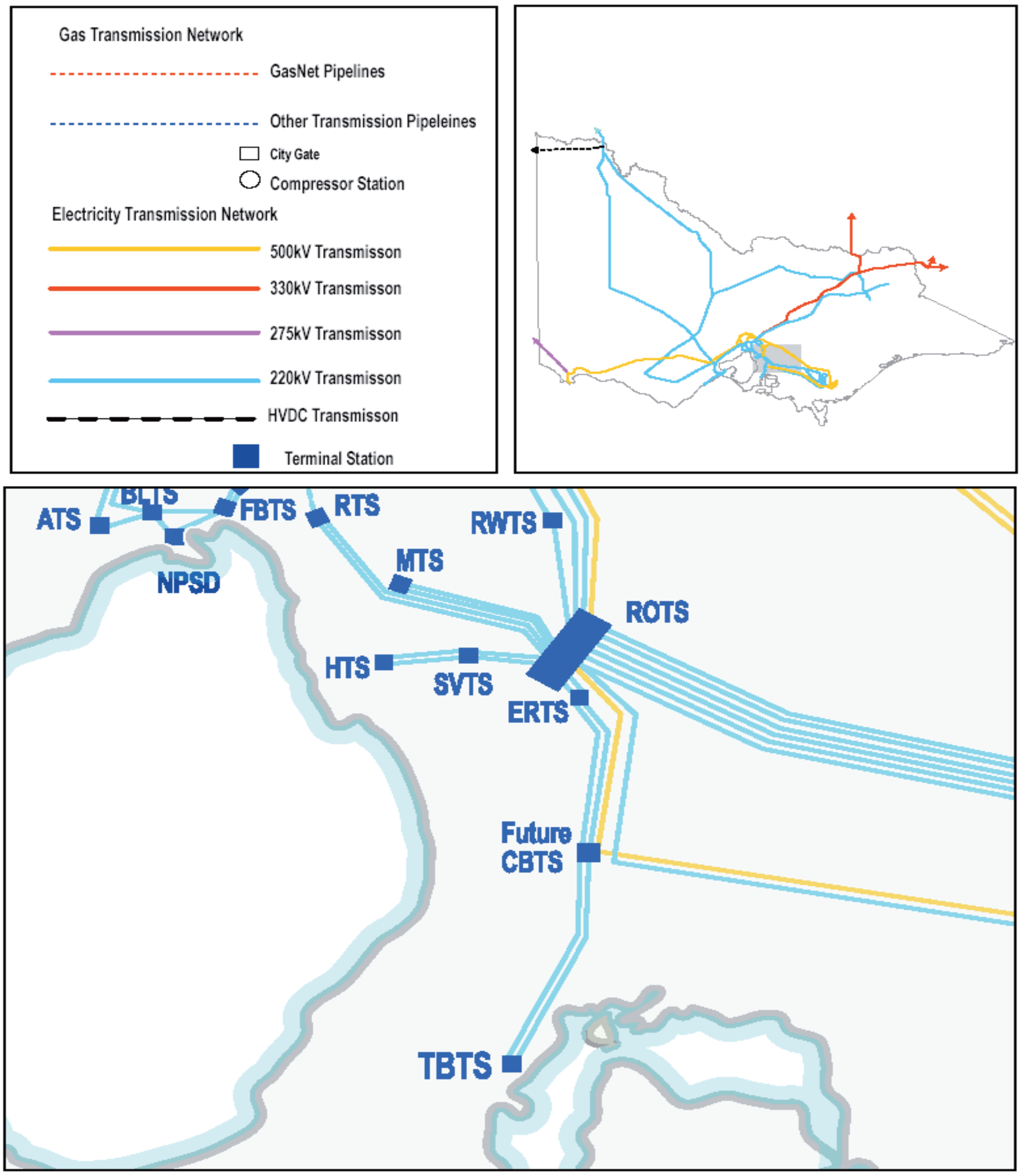


Figure 4.14 - Geographical representation of Supply to East Rowville and Cranbourne Areas.

4.11.2 Impacts of Constraint

The existing network supplying East Rowville, Tyabb and BHP Steel is shown in Figure 4.15. Due to the 220 kV switching arrangement at East Rowville and Tyabb, an unplanned outage of either Rowville to East Rowville 220 kV circuit will result in tripping of one of the 220/66 kV transformers at East Rowville terminal station and possibly some reverse power flow on one of the transformers at Tyabb. If this outage were to occur at a time of high load, then automatic controls schemes would operate at East Rowville and Tyabb to shed load to avoid over loading of the transformers. This load shedding would also be sufficient to keep the loading on the Rowville to East Rowville 220 kV transmission circuits within rating.

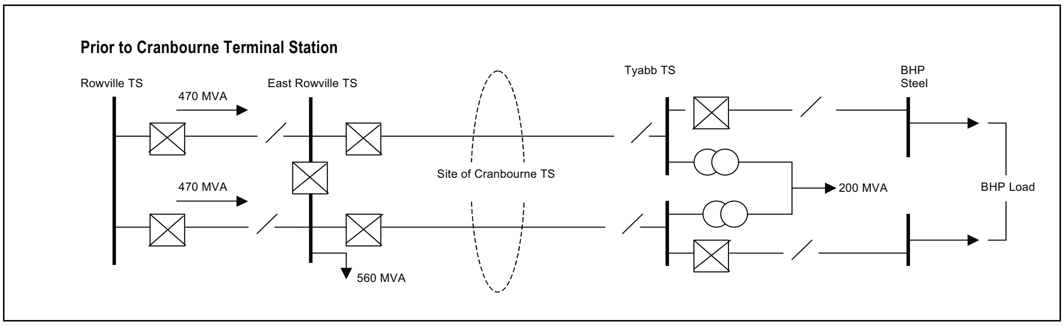


Figure 4.15 – Prior to the establishment of Cranbourne Terminal Station

When the new 220/66 kV terminal station is established at Cranbourne (Figure 4.14 and 4.16) approximately February 2004, the potential for transformer over-loading due to reverse power flow at Tyabb will be avoided due to the new 220 kV bus and associated switching at Cranbourne. Following transfer of load from East Rowville to Cranbourne, transformer over-loading at East Rowville will also be significantly reduced or avoided entirely following the outage of an East Rowville to Rowville line and a transformer at East Rowville, so the automatic overload control scheme at East Rowville will no longer be activated for this contingency.

However, as the total load supported by the East Rowville to Rowville 220 kV lines will not change, manual load shedding may be required following loss of an East Rowville to Rowville 220 kV line, to replace the load relief that has previously automatically occurred following loss of one of these circuits.

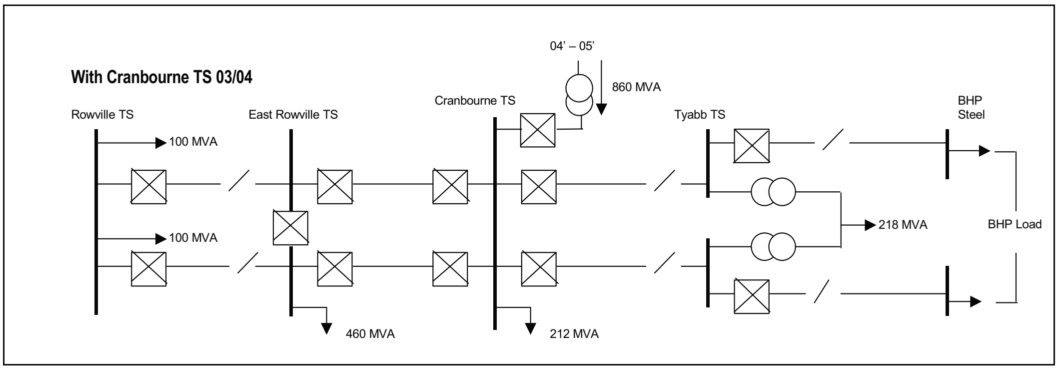


Figure 4.16 - From December 2004 following establishment of 500/220 and 220/66 kV transformation at Cranbourne Terminal Station.

The situation will again change prior to Summer 2004/05 with the planned establishment of a 500/220 kV 1000 MVA transformer at Cranbourne by December 2004.

The new 500/220 kV transformer will form a third, high capacity, 220 kV supply into the radial load block formed by East Rowville, Cranbourne, Tyabb and BHP Steel as shown in Figure 4.16. This will result in the 220 kV supply to this load block remaining within rating under all system normal and outage conditions.

4.11.3 Forecast Conditions, Demand and Energy at Risk

The following is a snapshot of the exposure during a period of high demand over Summer 2003/04:

- The Rowville – East Rowville 220 kV lines are supporting a peak aggregate 66 kV load of: 867+ j328 MVA
- The pre-contingent Rowville – East Rowville line flow is: 445 MVA
- The pre-contingent East Rowville 220kV bus voltage is: 220 kV
- The post-contingent Rowville – East Rowville 220 kV line flow is: 890 MVA

- The post-contingent East Rowville 220kV bus voltage is: 220 kV
- If the ambient temperature is: 42 deg
- The Rowville – East Rowville 220 kV line rating would be: 730 MVA
- The ratio of post contingency loading to capability is: 122%
- The amount of time available to reduce the loading is: 14 Min
- The minimum amount of time required to reduce loading is: 10 Min
- The amount of pre-contingency load at risk is: 0 MVA
- The amount of post-contingency load at risk is: 160 MVA

The East Rowville – Rowville 220 kV lines are only 1.4 km long. There have been 6 unplanned outages of either of these lines since 1986, with an average duration of 3.8 hours for each outage. This gives an outage rate of 0.35 events per year compared to a benchmark figure of around 0.21 events per year, with a benchmark average duration of no more than 10 hours per event.

A probabilistic assessment of the energy at risk over Summer 2003/04 due to this constraint is shown in Table 4.34 and Table 4.35:

	Pre-contingency load shedding (to prevent loading the line beyond the 10 minute line rating)			
Year	**Expected hours exposed**	**Average overload [MW]**	**Maximum overload [MW]**	**Expected Unserved Energy [MWh]**
2003/04	0	0	0	0

Table 4.34 – Load shedding prior to any contingency to remain within the 10 minute line rating.

	Post-contingency load shedding (load shedding only occurs following a contingency)			
Year	**Expected Hours Exposed**	**Average overload [MW]**	**Maximum overload [MW]**	**Energy at Risk [MWh]**
2003/04	40.3	50.5	199	2036

Table 4.35 – Load shedding following a contingency to remain within the continuous line rating.

Based on this information shown in Tables 4.34 and 4.35, and considering the historic rate of line outage, the value of the expected unserved energy is as shown in Table 4.36.

Year	Pre-contingency [MWh]	Post Contingency [MWh]	Total Value of Expected Unserved Energy [$K]	
			$10K/MWh	$29.6K/MWh
2003/04	0	0.1	$1.0	$2.8

Table 4.36 - Total Expected Unserved Energy - Summer 2003/04

Table 4.36 indicates that there is no load at risk due to pre-contingent load shedding as a result of this constraint. Given the small value of the expected unserved energy as a result of load shedding following an outage, and the complete removal of the constraint with the installation of the Cranbourne 500/220 kV transformer in December 2004, no network augmentation is justified for summer 2003/04.

4.11.4 *Preferred Solution*

Prior to establishment of the 220/66 kV Cranbourne terminal station, the existing automatic load shedding facilities at East Rowville and Tyabb will act to protect the line. For the remainder of summer 2003/04 after load is transferred from East Rowville to the CBTS 220/66 kV station, manual load shedding will be used to reduce loading if an outage of one of the Rowville to East Rowville circuits occurs at a critical time. At all times sufficient time (> 10 minutes) will be available for manual load shedding during Summer 2003/04.

4.12 Reactive Support for Maximum Demand Conditions

4.12.1 *Reasons for Constraint*

Adequate reactive power support at appropriate locations is required to meet increased load growth and maintain the system voltage stability. The consequence of not having adequate reactive support is system wide voltage collapse resulting in a need to constrain power flows to acceptable levels. The critical contingencies are:

- outage of the 500 MW generator at Newport
- outage of a 500 kV line from Latrobe Valley to Melbourne
- outage of a Murray-Dederang 330 kV line
- outage of a Dederang-South Morang 330 kV line
- outage of the Moorabool transformer
- outage of 220 kV line in north-west Victoria

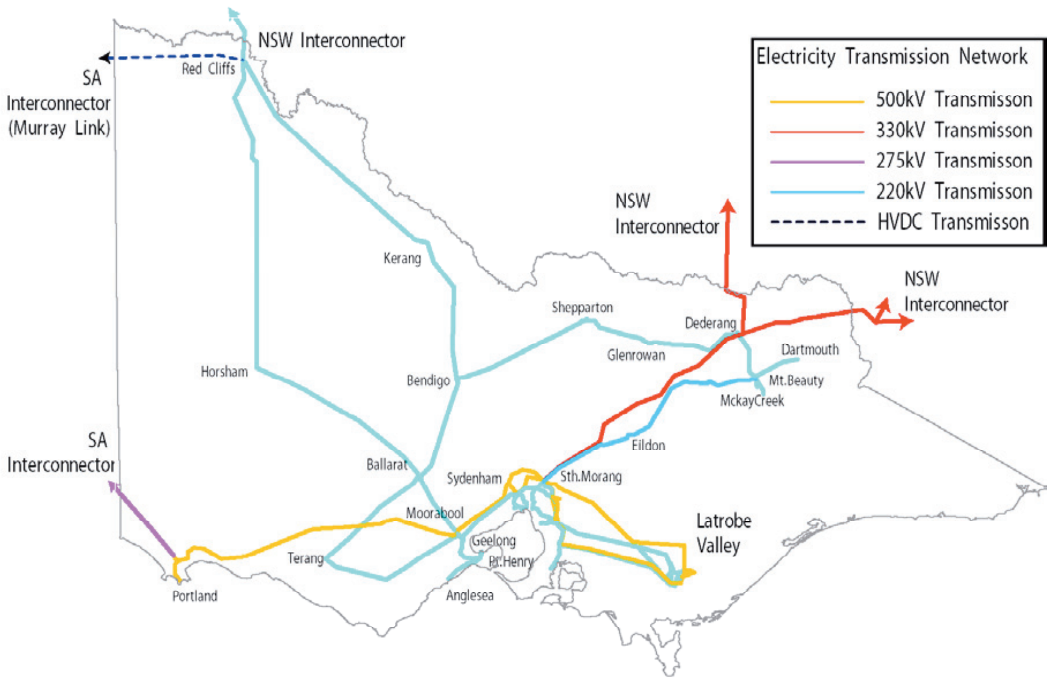


Figure 4.17 – Map of Victorian Transmission Network

4.12.2 *Network Reactive Capability*

Table 4.37, provides the system demand due to constraint on voltage collapse (network reactive capability) and the forecast system maximum demand for the next five years.

Year	Network Reactive Capability	Medium growth Maximum Demand Forecast (10% POE)
2002/03	9365 MW	
2003/04	9590 MW	9417 MW
2004/05	9800 MW	9730 MW
2005/06	9800 MW	9998 MW
2006/07	9800 MW	10208 MW
2007/08	9800 MW	10437 MW

Table 4.37 - Network reactive capability.

The existing network reactive capability is 9365 MW. For summer 2003/04, improved power factors at points of connection plus the installation of a 220 kV, 200 MVAr shunt capacitor bank at Rowville Terminal Station increases the network reactive capability to 9590 MW.

For summer 2004/05, the proposed Latrobe Valley to Melbourne 4th line project with a 1000 MVA 500/220 kV transformer at Cranbourne (described in section 3.8.3) reduces the network reactive losses and thereby increases the demand that can be supported without additional reactive plant to 9800 MW.

The need for additional reactive support in each of the years beyond summer the 2004/05 level will be determined through a complete probabilistic approach by assessing the volume of energy at risk for a variety of different network capabilities. A net market benefit will determine the amount of reactive support that can be justified in each year.

4.12.3 Network Solutions

The following network solutions can increase the network reactive capability:

- Installation of shunt and/or series capacitors at transmission level

  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 has to be controlled by designing an appropriate series reactor with each capacitor bank. The issue of harmonic resonance is requiring increasingly more detailed technical analysis and this is also tending to increase the reactive augmentation costs as larger series reactors are needed.

  The continued installation of large capacitor banks combined with the improvement of Distribution Businesses/Customers power factor may lead to problems with local voltage control and this may further limit the use of large shunt capacitor banks.

  The existing level of dynamic reactive plant is considered adequate. However VENCorp will carry out its assessments for future reactive requirements having regard to the existing dynamic plant and its economic life.

  - Installation of shunt capacitors by Distribution businesses
  - Under-voltage load shedding scheme – this can increase the network reactive capability before a contingency but will not avoid load shedding following a contingency

4.12.4 Non-network solutions

The following non-network solutions can also increase the networks reactive capability or contain the maximum demand within the network reactive capability:

- Power factor correction by customers – this will be reflected in Distribution Businesses annual load forecast at each point of connection
- New generators in the Metropolitan and/or state grid areas

- Ancillary services arrangements
- Demand side management

4.12.5 *Preferred Solution*

No reactive support augmentations are needed prior to summer 2005/06. Future requirements will be continuously reviewed with the latest load forecast and power factor improvement at the points of connection.

4.13 Hazelwood Tie-Transformation

4.13.1 *Reason for Constraint*

The transformation capacity at Hazelwood Terminal Station (HWTS) can present a system normal thermal limitation on generation connected at the 220 kV level in the Latrobe Valley. The proposed configuration of the Latrobe Valley network after the implementation of the Latrobe Valley to Melbourne line upgrade project is shown in Figures 4.18 and 4.19. This configuration optimises the local transfer capability by maintaining transformation and line redundancy while ensuring fault level implications (and thereby) costs are minimised.

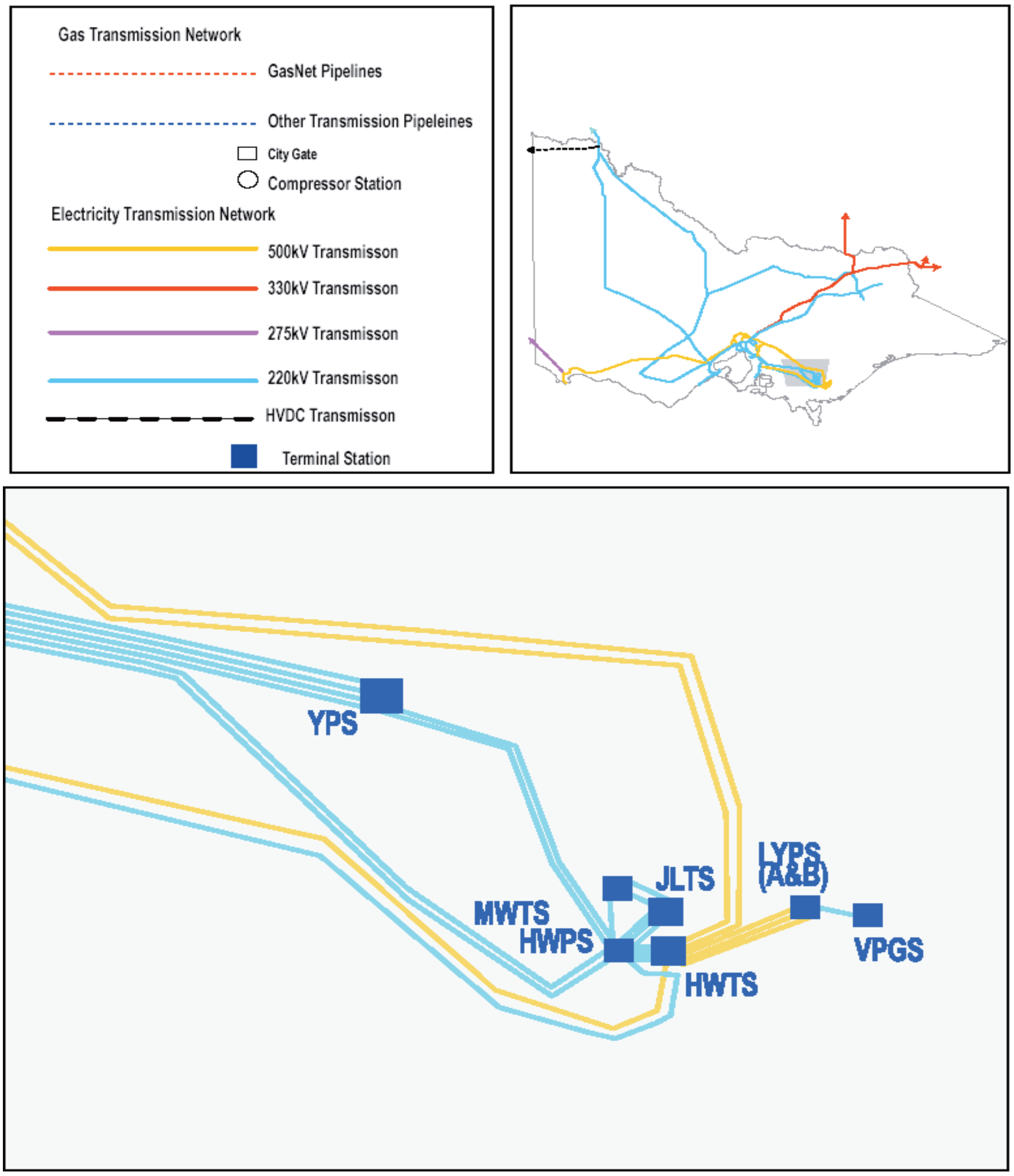


Figure 4.18 - Geographical representation of Hazelwood Tie-Transformation.

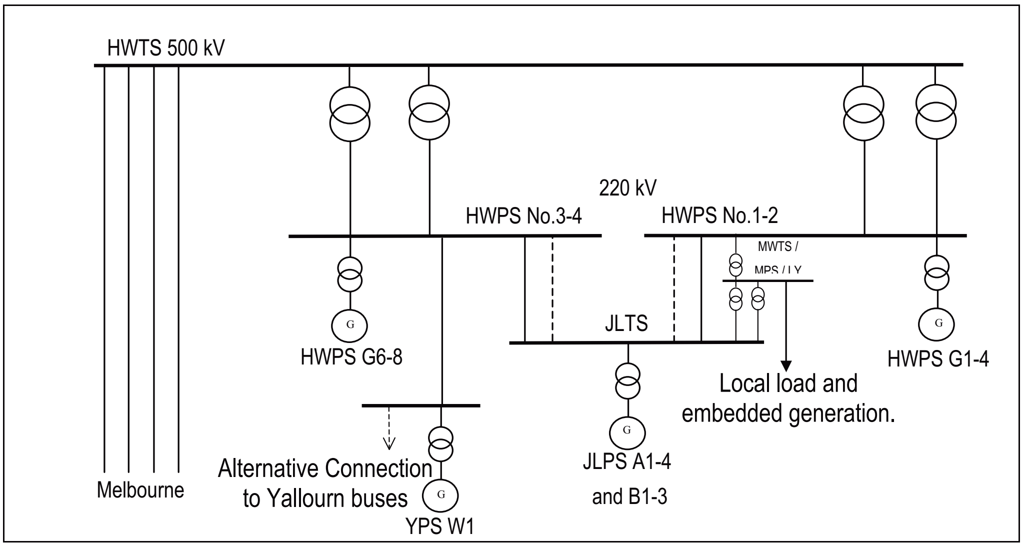


Figure 4.19 - Electrical representation of Hazelwood Tie-Transformation.

The four 220/500 kV HWTS tie transformers have continuous ratings of 600 MVA each, as shown in Figure 4.19. This thermal capability is independent of ambient temperature and the units have not been assigned short time overload capability. On the basis of these ratings, the existing amount of net generation connected to the 220 kV windings of these transformers will be greater than their firm N-1 capability of 1800 MVA.

The Yallourn W1 generator has a flexible connection arrangement to the shared network. Under system normal conditions, it will be connected to the HWPS buses and contribute to loading on the critical transformers. However, if the constraint is forecast or actually binds, the output of Yallourn W1 will be transferred to the 220 kV network via its alternative connection if system conditions are acceptable.

4.13.2 Impact of the Constraint

To maintain post contingency flows on the remaining three transformers to acceptable levels for loss of a parallel unit, the generation feeding the transformers may need to be constrained before the event.

Equation 4.2 is provided to relate the acceptable levels of generation feeding the four transformers to local load and it can be used to indicate when the HWTS transformer constraint may become binding. Note, this equation will only apply after the Latrobe Valley to Melbourne transmission upgrade project has been completed, however the net effect of the constraint prior to this project was very similar

Acceptable Generation = 1895 + Embedded Load	**Equation (4.2)**

Where:

Acceptable Generation [MW] is the summated capacity from HWPS G1-8, JLPS A1-4, JLPS B1-3, MPS G4, G5, Yallourn W1[28]; and

Embedded Load [MW] is the summated real power flow on the MWTS B1, B2 and B3 220/66 kV transformers.

The embedded load at MWTS ranges from 110-320 MW on a daily basis and is influenced by embedded generation from MPS G1-3, Bairnsdale Power Station, Esso's unit at Longford, the Toora windfarm and a number of small hydro plants.

28 If it is switched to the 500 kV network.

As the transfer capability is temperature independent and therefore relatively flat, this constraint has become increasingly relevant in recent times, especially with the integration of new embedded generation in the Morwell sub-transmission network which has absorbed a lot of the headroom that was once available with these transformers. In practice, the limit rarely becomes binding as typically the Jeeralang gas turbines only run when market prices are high and this is generally when demand and therefore MWTS load is high.

Under transformer outage conditions, operational arrangements are implemented to convert the network into a parallel mode. This has the effect of minimising the dependence on the HWTS transformers by utilising spare capacity in the 220 kV lines to Melbourne. This is not a suitable arrangement during system normal conditions as transmission losses are increased nor a suitable arrangement at times of high ambient temperature because the capacity of 220 kV lines under such conditions is well matched to the existing generation using them.

The exposure to constrained energy as a result of forced long term transformer outages is minimised as here is a spare phase available locally for three of the four critical transformers.

4.13.3 Forecast Conditions, Demand and Energy at Risk.

For the worst case scenario when Embedded Load is as low as, say 105 MW, the Acceptable Generation is determined from Equation 1 to be 2000 MW. This compares with actual generation capacity of 1650 + 450 + 90 = 2190[29] and results in a possible constraint of about 190 MW. There could be two system consequences to such a constraint:

- Out of merit order generation being dispatched elsewhere (e.g. NSW/Snowy), and
- Load shedding if there were a coincident supply shortfall.

It is expected that in practice, the vast majority of the constraint could be alleviated without the need for the relatively expensive second option of load shedding.

Any new generation connecting to the shared network under open access arrangements at a point that utilises the four HWTS transformers (i.e. at 220 kV at HWPS or JLTS or at 66 kV at MWTS) would compete directly with the existing generation for dispatch into the National Electricity Market. Its output would need to be included in the Acceptable Generation term of Equation 4.2.

4.13.4 Network Solutions and Costs.

Possible network solutions to remove the HWTS tie-transformer constraint:

- Development and implementation of a control scheme to control post contingency transformer flows (dependant on technical capability of transformers). Expected capital cost of around $500K.
- Installation of additional 220/500 kV transformation and consequential fault level mitigation. Expected capital cost of around $25M.
- Augmentation to utilise any spare capacity in the 220 kV transmission from the Latrobe Valley to Melbourne (although this compounds the potential constraint on these lines during high ambient temperature conditions). Expected capital cost of approximately $5M.

4.13.5 Economic Analysis.

Table 4.38 identifies the results of market modelling to quantify the exposure to this constraint.

29 Yallourn W1 will use its alternate 220kV network connection should the HWTS transformer limit bind

	2003/04	2005/06	2007/08
Average Annual Hours of Overload	32	75	106
Worst single overload, MW	193	266	277
Expected Constrained Energy, MWh	3,492	8,764	14,626
Value of Expected Constrained Energy, [$K]	46.8	93.0	146.3

Table 4.38 Forecast exposure to the HWTS transformer constraint.

The increasing Expected Constrained Energy from this constraint is associated with the growing dependence on the generation behind the limit and the small increases in generation capability from the Hazelwood Power Station units expected in the forthcoming years. The market modelling indicates that the constraint can always be alleviated by increased generation elsewhere and that no load shedding is required, hence the Value of the Expected Constrained Energy is based on fuel cost premiums associated with out of merit order generation being used.

If technical possible, and depending on the perceived risk and capability of the transformers causing the constraint, a control scheme to reduce post contingency flows may be justified. This will ensure pre-contingency constraints are not necessary. VENCorp will continue to investigate this option in conjunction with the SPI PowerNet.

At present, VENCorp does not consider there is sufficient net market benefit to augment the network, particularly given the expected high costs of the network solutions. However, as one of the transformers does not have a replacement spare, there is some exposure to extended outages that must also be considered when evaluating the optimal solution.

The considerable interest in wind farms in the South Gippsland area may influence the need for a network solution in the future, as significant amounts of additional and fluctuating base load generation connected behind this constraint will result in it binding more frequently. Any generation connected at 66 kV in the Gippsland area will contribute to this constraint. For sensitivity analysis purposes, Table 4.39 indicates the influence of having a new 100MW windfarm connected behind the constraint with an assumed base load output of 35% capacity.

	2003/04	2005/06	2007/08
Average Annual Hours of Overload	36	90	123
Worst single overload, MW	228	301	312
Expected Constrained Energy, MWh	4,640	11,633	18,683
Value of Expected Constrained Energy, [$K]	61.6	122.8	186.8

Table 4.39 - Forecast exposure to the HWTS transformer constraint with a hypothetical wind farm in the Latrobe Valley.

4.13.6 Preferred Solution.

There is no economic network solution at this stage. It may be possible to justify an automatic control scheme in around 2005/06, subject to its technical feasibility and associated risk profile. The alternative of an additional 500/220 kV transformer depends on generation development behind the constraint and the reliance of Victorian demand on the constrained generation. VENCorp will continue to review the justification for this augmentation.

4.14 Yallourn to Hazelwood to Rowville Transmission.

4.14.1 Reasons for Constraint.

Yallourn Power Station (YPS) has a nominal generating capacity of 1450 MW. Generally, this power is carried to load centres in the metropolitan area via six 220 kV transmission lines in the central easement from the Latrobe Valley to Rowville Terminal Station, as shown in Figure 4.20. Each of these lines is nominally rated 305 MVA at 35°C ambient temperature, giving a transmission capacity that is very well matched to the power station output at high ambient temperatures.

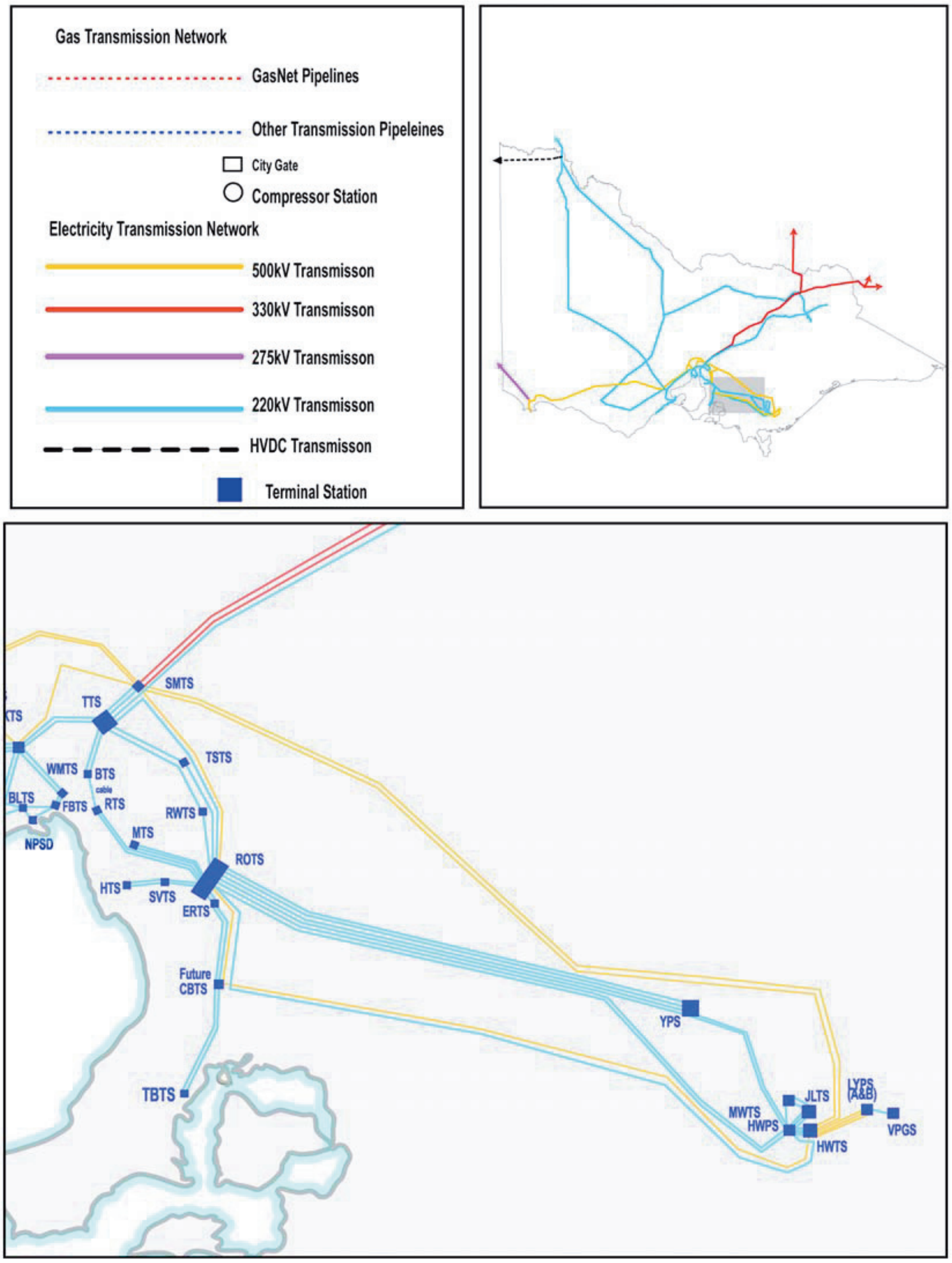


Figure 4.20 - Geographical representation of Yallourn to Hazelwood to Rowville transmission.

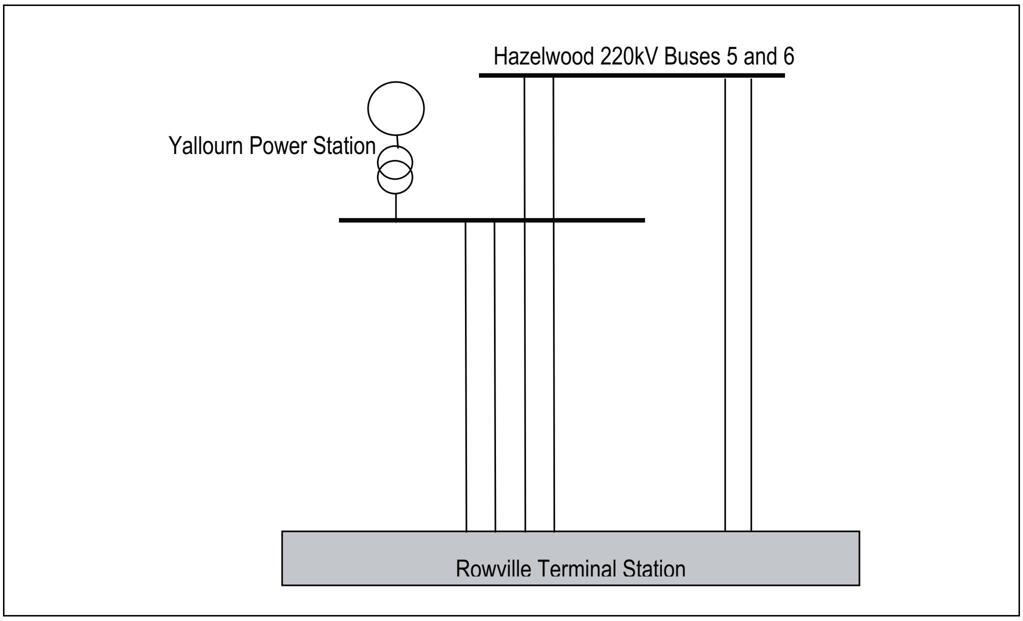


Figure 4.21 - Electrical representation of Yallourn to Hazelwood to Rowville transmission.

As per Figure 4.20 and Figure 4.21, the transmission system between the Yallourn Power Station and load centres in the metropolitan area is formed by four direct lines from Yallourn to Rowville and two other lines which first bypass Hazelwood Power Station Switchyard using buses 5 and 6. There is no electrical connection made with the other buses at Hazelwood, and as such under normal modes of operation the six 220 kV lines are dedicated to Yallourn Power Station.

4.14.2 *Impact of the Constraint*

With a prior outage of any one of the six 220 kV lines, the thermal capability of the remaining five 220 kV lines could impose a constraint on Yallourn generation for ambient temperatures greater than 37° C.

Figure 4.22 shows the portion of the historical ambient temperature duration curve in Melbourne over the last 4.5 years for temperatures greater than 32° C. It shows that ambient temperatures greater than 37° C occurred for less than 0.086% of the time over any given year, which is around 7.5 hours.

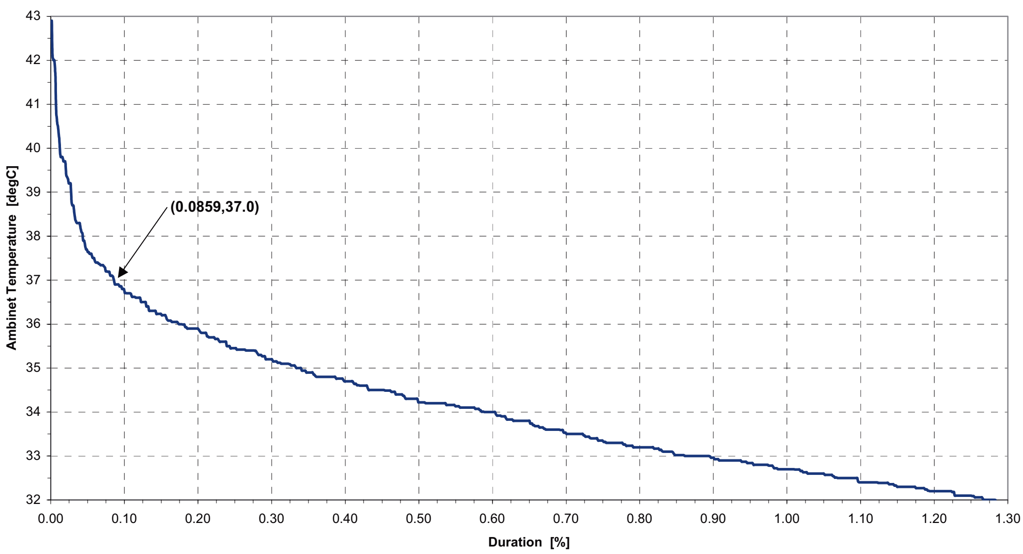


Figure 4.22 - Historical Melbourne ambient temperature over last 4.5 years.

The benchmark forced outage rate for anyone of the six 220 kV lines is:

$$(1.5\times 10\times 645)/(8760\times 100)=1.105\% \ .$$

There is a significant window of opportunity to take planned line outages as this can occur satisfactorily at temperatures less than 37°C and securely at temperatures less than around 25°C, even with full Yallourn output. Furthermore, planned outages could also be co-ordinated with generation maintenance.

4.14.3 Forecast Conditions, Demand and Energy at Risk.

- VENCorp forecasts the worst case loading conditions to be:
- Yallourn net generation: 1370+ j200 MVA (allowing for local load)
- The pre-contingent Yallourn-Rowville line flow is: 240 MVA / line
- The post-contingent Yallourn-Rowville line flow is: 290 MVA / line
- The ambient temperature could be: 42 °C
- The Yallourn-Rowville line rating would be: 250 MVA / line
- The ratio of post contingency loading to capability is: 116%
- The amount of time available to reduce the loading is: 30 Min
- The amount of time required to reduce loading is: 15 min (through NEMDE)
- The amount of pre-contingency generation at risk is: 0 MVA
- The amount of post-contingency generation at risk is: 40*5=200 MVA / across all 5 lines
- Considering the likely coincidence of onerous ambient temperatures and the outage of one of the six lines, there is not a lot of energy associated with this constraint. Furthermore, if it were to bind, it would result in Yallourn generation being constrained. There could be two system consequences to such a constraint:
- Out of merit order generation being dispatched elsewhere, and
- Load shedding if there were a coincident supply shortfall.
- It is expected that in practice, the vast majority of the constraint could be alleviated without the need for the relatively expensive second option of load shedding.

4.14.4 Network Solutions and Costs.

Possible network solutions to remove the Yallourn-Rowville constraint:

- Wind monitoring the six 220 kV lines to provide increased thermal capability on an opportunistic basis. Expected capital cost of around $500K.
- Upgrading the six 220 kV lines by raising critical towers. Expected capital cost of around $10M.
- Upgrading the six 220 kV lines by restringing with higher rated conductor. Expected capital cost of around $20M.

Building a seventh 220 kV line. Expected capital cost of around $25M.

- Transferring Yallourn generation to the 500 kV network via Hazelwood PS and the 220/500 kV transformers at Hazelwood Terminal Station (although this compounds the significance of the HWTS transformer constraint). Expected capital cost of around $5M.

4.14.5 Economic Analysis.

With a constraint that only binds at temperatures greater than 37°C coincident with the low probability of a critical line outage, VENCorp does not consider there is sufficient net market benefit to overcome the potential constraint between Yallourn and Rowville at present, particularly given the expected high costs of the network solutions.

The following numerical example is provided to indicate the economic consequences of the Yallourn-Hazelwood-Rowville 220kV transmission line constraint over a given year:

- Value of Expected Constrained Energy = Pr(Event) * Pr(temperature>37° C) * 8760 * average constrained energy >37° C * average fuel cost premium.
- Value of Expected Constrained Energy = 0.01105 * 0.000859 * 8760 * 55MWh * $200
- Value of Expected Constrained Energy = $915

Due to the base load nature of the Yallourn Power Station and its normal connection to the shared network, this constraint is not getting worse over time.

Should additional generation compete with Yallourn for this transmission in the future, then at that time there may be an economic basis to upgrade the networks capability to ensure minimum cost dispatch is maintained and to eliminate any risk of load shedding due to a problem maintaining a supply-demand balance.

4.14.6 *Preferred Solution.*

There is no economic basis to augment the shared network at present. VENCorp will continue to review the impact of this constraint.

4.15 Ten Year Plan

The intention of this section is to give an indication of potential network constraints that may occur in the period up to 2013/14, together with transmission options to remove the constraints, assuming the full forecast Victorian demand is to be supported.

For this study the network has been modelled with a demand of 12000 MW. Assuming 250 MW export to South Australia, 500 MW Victorian local reserve requirement and import increased to 2100 MW (due to SNI), about 2,500 MW of new generation capacity (including Basslink) will need to be added by 2013/14. As the location and size of generation will impact on the transmission needs, a range of supply scenarios, which load up different parts of the network, have been examined. These are as shown in Table 4.40.

	Increased LV Gen	Increased Import from NSW/Snowy	Metro Generation/DSM
Scenario 1	1900 MW	0 MW	600 MW
Scenario 2	1500 MW	400 MW	600 MW
Scenario 3	500 MW	1400 MW	600 MW
Scenario 4	1800 MW	400 MW	300 MW
Scenario 5	900 MW	400 MW	1200 MW

Table 4.40 - Supply scenarios for 10-year outlook

In considering this period, the network constraints and solutions outlined for the period up to 2007/08, and described earlier in this chapter, are included. For the constraints beyond this period a probabilistic analysis of the amount of energy at risk due to these network constraints has not been undertaken so the timing is only indicative and would be confirmed by full economic assessment closer to the requirement.

4.15.1 *Increased Latrobe Valley Generation*

In the case of Latrobe Valley 1900 MW generation, it is assumed that all 1900 MW can be made available to the market. As described earlier, the Hazelwood terminal station transformers are a limit on the dispatch of generation at 220 kV and until this limit is removed the addition of further generation connected at the 220 kV in the Latrobe Valley will not add to the supportable demand. Basslink is assumed to be part of the increased Latrobe Valley generation.

4.15.2 *Metropolitan Generation/Demand Side Management*

The effect of generation or significant demand side management within the metropolitan area is modelled by including new generation on the 220 kV network at Moorabool, Keilor, and Rowville. 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. Based on the interest shown in recent times an amount of 600 MW has been assumed, with sensitivity checked for 300 MW and 1200 MW.

4.15.3 Increased Import

The import level following the service of both SNOVIC 400 and SNI is assumed to be 2100 MW into the combined Victorian/SA region. The amount shown as increased import is on top of the 2100 MW. 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 2500 MW and 3500 MW, and these works form the basis of the 400 MW and 1400 MW increase in import applied in the scenario studies.

These scenarios were selected because they give a reasonable extreme for the transmission system. However a range of other scenarios are possible, and they would likely result in different transmission requirements.

4.15.4 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 10 years is given below:

- In scenarios with high levels of new generation added in the Latrobe Valley, the existing 500 kV lines (after the current project to bring the fourth 500 kV line to 500 kV operation is complete) provide sufficient power transfer capability into the metropolitan area. However, 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 this power into the metropolitan 220 kV network. One, and possibly a second, additional metropolitan 1000 MVA 500/220 kV transformer is expected to be required by the end of the ten year period in scenarios where a significant amount of additional capacity is obtained from the Latrobe Valley. 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.
- In the scenarios where additional capacity is obtained from Snowy/NSW, enhancement of the existing interconnection would be required. All the scenarios considered here assumed either no increase at all in the Snowy to VIC interconnection capability beyond the existing committed level of 2100 MW, or a substantial upgrade, which would provide either 400 MW and 1400 MW of additional interconnection capability. The 1400 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.
- New generation developments and transmission system 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) and operational measures such as segregation of the transmission network to limit fault current in feed will likely continue over the next 10 years. The appropriate balance between circuit breaker replacement and operational measures to manage fault levels will require ongoing investigation, and this work will be integrated with SPI PowerNet plans for circuit breaker replacement as part of their asset management procedures. 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. Demand management would not cause fault levels to rise.
- Some uprating and/or re-configuration of the 220 kV transmission circuits within the Melbourne metropolitan area is likely to be required, particularly 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.

- 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 may become necessary during this period, depending on the balance of new capacity between the Latrobe Valley, embedded generation and import. 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.

Table 4.41, gives a summer of the works required to remove transmission constraints emerging over the next 10-year period for each of the five supply scenarios.

Constraint	Network Solution	Estimated Capital 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 line project, works to upgrade 4th 500 kV line, Latrobe Valley work, associated work for 1000 MVA transformer at CBTS	40	December 2004	December 2004	December 2004	December 2004	December 2004	Project in progress.
DDTS transformers for outage of a DDTS transformer. 4th transformer causes fault levels to increase at MBTS	4th DDTS 330/220 kV transformer and MBTS 220 kV switchgear replacement	12	SNI or approximately 2008	SNI or approximately 2008	SNI or approximately 2008	SNI or approximately 2008	SNI or approximately 2008	4th DDTS transformer is required to support 2100 MW import proposed with SNI which is proposed for service by late 2004.
Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformers for outage of Moorabool transformer	Control scheme at KTS (if feasible) Spare MLTS 500/220 kV single phase transformer 2nd MLTS 1000 MVA 500/220 kV transformer	0.5 4.5 25	December 2003 December 2004 December 2006	December 2003 December 2004 December 2006	December 2003 December 2004 December 2006	December 2003 December 2004 December 2006	December 2003 December 2004 December 2006	The spare could also serve as a spare for the ROTS and CBTS 500/220 kV single-phase transformer banks and will probably be retained as spare after the 2nd MLTS transformer is installed.

Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	One 500/220 kV 1000 MVA transformer in the eastern metropolitan area.	40	Approximately 2007	Approximately 2007	Approximately 2007	Approximately 2007	Approximately 2007	
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	One 1000 MVA 500/220 kV transformer at SMTS	50	Approximately 2012					
SMTS – TTS 220 kV circuit for outage of parallel circuit	Formation of a South Morang 220kV bus & cutting of existing Rowville – Thomastown 220kV circuit into South Morang 220kV bus to form 3rd SMTS-TTS 220kV circuit	4	Approximately 2012	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	About 2006 or with increased import from NSW
South Morang-Dederang 330 kV line and series capacitors for outage of parallel circuit	Upgrade of South Morang – Dederang 330kV line to 82^{O}C operation & increase in rating of South Morang – Dederang series compensation to match line uprate	4		At time of Interconnection Upgrade by 400MW	At time of Interconnection Upgrade by 400MW	At time of Interconnection Upgrade by 400MW	At time of Interconnection Upgrade by 400MW	Timing with increased import from NSW

Low power flow from Wodonga to Dederang and voltage collapse	60~65% series compensation on Wodonga – Dederang 330 kV lines & 150MVAr shunt cap at Wodonga	9		At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	Timing with increased import from NSW
Eildon-Thomastown line for outage of South Morang-Dederang line	Upgrade of Eildon – Thomastown 220 kV line to 70^{O}C operation & 25% series compensation on the Eildon – Thomastown 220 kV line	4		At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	Timing with increased import from NSW
SMTS 330/220 kV transformer for outage of a parallel transformer	3rd 700 MVA 330/220 SMTS transformer	17		At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	At time of Interconnection Upgrade by 400 MW	Timing with increased import from NSW
SMTS 330/220 kV transformer for outage of a parallel transformer	4th 330/220 kV transformer at SMTS	17			At time of Interconnection Upgrade to 1400 MW			Timing with increased import from NSW
SMTS-DDTS line for outage of a parallel circuit	3rd SMTS-DDTS 330 kV circuit	100			At time of Interconnection Upgrade to 1400 MW			Timing with increased import from NSW

SMTS-TTS line for outage of a parallel circuit	Cutting of existing Eildon – Thomastown 220 kV circuit onto South Morang 220 V bus to form 4th SMTS-TTS 220 kV circuit	4			At time of Interconnection Upgrade to 1400 MW			Timing with increased import from NSW
Voltage collapse at DDTS and SMTS	Controlled series compensation of SMTS-DDTS lines	(included in the 3rd circuit cost)			At time of Interconnection Upgrade to 400 MW			Timing with increased import from NSW
Hazelwood transformers constrain for system normal	Additional 220/500 kV transformation at Hazelwood.	0.5 (if feasible) 25	3-10 years	3-10 years	3-10 years	3-10 years	3-10 years	Economic timing depends on generation development behind the constraint and the reliance of Victorian demand on the generation
Fault level issues	Upgrade selected 220 kV switchgear in the metropolitan area	20	On-going as required	On On-going as required	On going as required	On-going as required	On going as required	$25 M for Scenarios xx
ROTS-SVTS circuit for outage of parallel circuit.	Upgrade ROTS-SVTS-HTS 220 kV supply	0.3 0.7	December 2005 Approximately 2008	December 2005 Approximately 2008	December 2005 Approximately 2008	December 2005 Approximately 2008	December 2005 Approximately 2008	Replace isolators Tower works
ROTS-TTS circuit for outage of ROTS-RWTS circuit at high summer load.	Upgrade RWTS 220 kV supply	0.15 4	Dec 2004 Approximately 2011	Dec 2004 Approximately 2011	Dec 2004 Approximately 2011	Dec 2004 Approximately 2011	Dec 2004 Approximately 2011	Fast load shedding Switching of lines

BATS-MLTS circuit for outage of parallel BATS-MLTS circuit at high load.	String 3rd MLTS-BATS 220 kV line	8	Approximately 2010	Approximately 2010	Approximately 2010	Approximately 2010	Approximately 2010	Sting second circuit on an existing double circuit tower.
BETS-SHTS circuit for outage of a BATS-BETS circuit as high load.	BETS-SHTS 220 kV line upgrade	4	-	-	At time of Interconnection Upgrade to 1400 MW			
DDTS-GNTS circuit for outage of parallel DDTS-GNTS circuit.	Switch DDTS-SHTS 220 kV line at GNTS	3	Approximately 2011	Approximately 2011	Approximately 2011	Approximately 2011	Approximately 2011	
BATS-BETS line for outage of BETS-SHTS line at high summer load.	BATS-BETS 220 kV line upgrade	4	Approximately 2009	Approximately 2009	Approximately 2009	Approximately 2009	Approximately 2009	
ROTS-RTS circuit for outage of parallel circuit	ROTS-RTS 220 kV line upgrade	4	Approximately 2009	Approximately 2009	Approximately 2009	Approximately 2009	Approximately 2009	
KTS-WMTS circuit for outage of parallel circuit	KTS-WMTS 220 kV line upgrade	5	Approximately 2010	Approximately 2010	Approximately 2010	Approximately 2010	Approximately 2010	
ROTS-MTS circuit outage for parallel circuit	ROTS-MTS 220 kV line upgrade	3	Approximately 2013	Approximately 2013	Approximately 2013	Approximately 2013	Approximately 2013	Redevelopment of MTS
GTS-MLTS circuit outage for parallel circuit	GTS-MTS 220 kV line upgrade	2	About 2010	About 2010	About 2010	About 2010	About 2010	
System voltage collapse for trip of	1500 MVAr to 2500 MVAr Reactive	35-55	On-going	On going	On going	On going	On going	

Newport generation, 500 kV line, 330 kV line or 220 kV line in the state grid area at time of peak summer load.	Support (including currently committed)							
Line terminations, protection etc limiting capability of plant to economically meet demand.	Miscellaneous Works2	30	On-going	On-going	On-going	On-going	On-going	On-going

Table 4.41 - Summary of network constraints over the next 10 years

	Estimated Total Capital Cost		
Scenario	**Years 1 –5**	**Years 6-10**	**Total**
1	$185M	$156M	$341M
2	$218M	$101M	$319M
3	$218M	$226M	$444M
4	$218M	$106M	$324M
5	$218M	$86M	$304M

Table 4.42 - Estimated Total Capital Cost for Network Solutions

The supply into the 220 kV network will require augmentation over the 10-year period, and the different scenarios show some variation in how this is achieved. In the scenarios 1 & 4, which assume significant Latrobe Valley generation, this increased supply into the 220 kV network is mainly from the 500/220 kV transformer augmentation. One 1000 MVA transformer is seen as a minimum, with a second 1000 MVA transformer also possible by the end of the 10-year period, depending of the amount and location of any new generation connected at 220 kV or lower. Higher levels of generation connected at the 220 kV or lower will defer the need for additional transformation feeding the 220 kV network.

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.

There are a number of projects that are common to all development scenarios. In particular upgrades to several 220 kV circuits may be required, and underlying load growth drives much of this work. Again, the location and timing of any new generation connected at 220 kV and below can have a significant impact on the timing and requirement for a number of these augmentations.

The increased reactive support required in all scenarios is due to load growth, to compensate increased reactive losses and to maintain system voltage stability. Management of fault level will become an issue as more transmission and generation plants added to the system. Particularly this will become a significant issue if more generators are connected in the metropolitan area.

In scenarios 2, 3, 4 & 5, which assume increase in interconnector capability, the supply into the 220 kV network is augmented with 330/220 kV transformation. Scenario 3 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.

The different balance between embedded generation, Latrobe Valley generation and increased import from NSW/Snowy 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.

4.15 Non-Constraint Issues

4.15.1 System Continuity Planning

Although the network is designed to minimise the risk of failure of multiple elements from a single event, there are a number of low probability events with high consequential loss that can be brought about by major equipment failures or external influences.

A review of credible events, vulnerabilities and threats carried out during 2002/03 categorised events into those that could be caused by major plant or equipment failures and those that could be caused as a result of terrorism or sabotage.

A number of strategies were identified to:

- reduce plant exposure and vulnerability;
- reduce consequential damage and system impact; and
- provide for fast recovery on critical facilities.

The strategies include development of continuity plans, increased protection of plant through surveillance and screening, identification of strategic spares within the network and available from other utilities for repairing or replacing damaged facilities, and the development of emergency by-pass facilities for lines and stations.

In the order of $6M is economically justified when likelihood, supply loss and reduction in repair and restoration times are assessed.

VENCorp will be working together with SPI PowerNet to implement those continuity plans that are identified as being economically justified.

4.15.2 Upgrade of Dynamic System Monitoring Equipment

VENCorp has Dynamic System Monitors installed at 14 key locations on the EHV transmission network. They continuously monitor the dynamic performance of the power system and automatically trigger for voltage, frequency and power disturbances. Installation of these monitors commenced in 1994 and are generally located at points of generation and at points of interconnection.

The equipment is approaching the end of its serviceable life and a replacement program is expected to be initiated in the next few years. It is anticipated the replacement program will include an increase in the number of dynamic system monitors and to enhance their performance to improve monitoring throughout the Victorian network. This program is expected to cost in excess of $1M.

ELECTRICITY ANNUAL PLANNING REVIEW

2003

APPENDICES

JUNE 2003

A1 TERMINAL STATION DEMAND FORECASTS.

TERMINAL STATION DEMAND FORECASTS 2002/03 - 2012/13

ENERGY INFRASTRUCTURE DEPARTMENT
VICTORIAN ENERGY NETWORKS CORPORATION

DISCLAIMER

VENCorp's role in the Victorian electricity supply industry includes planning and directing augmentation of the transmission network. To enable VENCorp to carry out that function, certain participants in the electricity supply industry must provide long-term forecasts of demand at each of their connection points to VENCorp in accordance with clause 260 of the Electricity System Code and clause 5.6.1 of the National Electricity Code.

The purpose of this document is to comply with VENCorp's obligations (under clause 260.1.3 of the Electricity System Code and clause 5.6.2A section b.1 of the National Electricity Code), to aggregate those demand forecasts and make that information available to system participants. This document is not intended to be used and should not be used for other purposes, such as decisions to invest in future generation, transmission or distribution capacity.

VENCorp has not independently verified and checked the accuracy, completeness, reliability and suitability of the information provided by the participants under clause 260 of the Electricity System Code and clause 5.6.1 of the National Electricity Code. 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 information used by VENCorp in preparing it.

The document presents aggregate forecasts of demand at terminal stations over the next ten years, which are based on distributor and EHV consumer forecasts, various assumptions and upon information provided to VENCorp by other parties, the accuracy of which may not have been checked or verified. Those assumptions may or may not prove to be correct. The forecasts may change from year to year and the information provided to VENCorp by other parties may be inaccurate, incomplete or unreliable.

VENCorp makes no representation or warranty as to the accuracy, reliability, completeness or suitability for particular purposes of the information in this document. VENCorp and its employees, agents and consultants shall have no liability (including liability to any person by reason of negligent misstatement) for any statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or any omissions from, the information in this document, except insofar as liability under any statute cannot be excluded.

A1.1 Introduction

VENCorp has prepared and makes available load forecasts for points of connection within the transmission network as required by the Electricity System Code (section 260.1.3) and clause 5.6.2a section b.1 of the National Electricity Code. This document provides for each terminal station:

- the peak active power demands forecast to occur for summer and winter on average one year in two (50% probability of exceedance) and one year in ten (10% probability of exceedance), for each of the financial years 2002/2003 to 2012/2013 inclusive;
- the reactive power demands forecast to occur at the same times as the terminal station's peak active demands (both 50% POE and 10% POE); and
- the daily active and reactive load curves for its days of peak active power demand.
- the peak active and coincident reactive actual demands for summer and winter.

VENCorp has prepared these forecasts using the 10% POE and 50% POE forecast peak levels of active load and coincident levels of reactive load provided by System Participants in June 2002. System Participants forecast the peak levels of active load (based on 15 minute energy), and the associated reactive load levels that they expect to be supplied to their licensed distribution area from each terminal station in summer and winter for the coming ten years.

The forecast demands which the Distribution Businesses provided VENCorp in June 2002 were also an input to the Distribution Businesses' subsequent connection planning report, which may result in further changes to planned transmission network connections and their forecast demands.

A1.2 Determination of Aggregate Terminal Station Demand Forecasts

Where only one System Participant has a point of connection at a terminal station, demand forecasts are presented as provided by the System Participant.

Where more than one System Participant has a point of connection at a terminal station, VENCorp has scaled each demand forecast by a diversity factor determined by VENCorp from historical information. The scaled demand forecasts are summed to obtain aggregate demand forecasts for these terminal stations.

Where appropriate, in VENCorp's view, it requests the relevant System Participant to review their forecasts, but VENCorp only amends these forecasts as updated by System Participants.

A1.3.1 Determination and application of Diversity Factors

VENCorp determines and applies two sets of diversity factors namely; Station diversities and System diversities. Station diversities are multiplied by the System Participant forecast peak loads at terminal stations, which supply more than one System Participant. This in turn provides the **aggregate terminal station seasonal demand forecasts** as seen in the Appendix. System diversities are multiplied by System Participant forecast peak loads at all terminal stations, to forecast the contribution from each terminal station towards the Victorian system peak seasonal demand. Once each terminal station's contribution is summated the resulting seasonal forecast demands contribute a major component towards the **aggregate system seasonal demand forecasts** that are compared with the NIEIR and previous years' forecasts.

Explicitly these diversity factors estimate the portion of station and system MD for the maximum active (MW) demand and coincident reactive demand that is supplied to each System Participant at each of the terminal stations.

Each Station diversity factor for active power is the ratio of a System Participant's active demand at a terminal station (supplying multiple participants) at the time of the terminal station's MD (maximum MW demand) to the System Participant's MD (maximum MW demand), at that terminal station. Both parts of the ratio also need to relate to the same season and percentile (probability) conditions. The System Participant's estimated portion of the station's MD is that participant's relevant (ie of appropriate season and percentile) forecast MD at the station multiplied by this Station diversity factor.

For example, consider the case where a terminal station supplies System Participants A and B. This terminal station has a maximum demand at 3 pm on a summer day and System Participant A's demand on the station at this time is 90 MW and 60 MVAr. However the maximum summer demand at this station for System Participant A is 100 MW and 80 MVAr at 10 am on another day. The forecast load is assumed to represent the 10 am value and is diversified to 3 pm on the day the station has its peak summer load with a diversity factor of 0.90 (90 / 100 MW). A similar approach is taken for Participant B at this point of connection.

The reactive load reported in the forecast is coincident with the maximum active load. Therefore the diversity factor for the reactive demand is defined as the ratio of the System Participant's reactive load at the time of the terminal station's MW MD to the reactive load at the time of the System Participant's MW MD. This corresponds to the same times of maximum demand used to calculate the MW diversity factor. Using the example above, System Participant A's MVAR diversity factor is 0.75 (60 / 80 MVAR).

Diversity factors are calculated by examining the historical active and reactive loads at times of high active load for each of multiple participants supplied from the station, for the station, and for the system, for both summer and winter over a number of years. More importance is placed on recent years.

Metering data sourced from Metering Data Agent (Data and Measurement Solutions) is used to provide the historical records for this analysis.

A1.3 Forecast Notes

A1.3.1 Altona and Brooklyn

The Altona and Brooklyn 66 kV demands (excluding Brooklyn B5 transformer supply) are presented as a single aggregate demand because both stations jointly supply this aggregate demand, and their relative contributions vary with network conditions.

A1.3.2 East Rowville, Frankston, Morwell and Loy Yang

Load supplied from Frankston terminal station forms a component of the load supplied from the East Rowville terminal station. Similarly Loy Yang (LY) station load is a component of the Morwell terminal station load. Therefore, the forecast Frankston terminal station load is included in East Rowville terminal station load forecasts and the forecast Loy Yang station load is included in the Morwell terminal station load forecasts.

A1.3.3 Thomastown

Thomastown (TTS) terminal station is reported as two separate load blocks: Thomastown Bus 1&2 (TTS12) and Thomastown Bus 3&4 (TTS34). This is to align forecasts with transformation loadings for the usual station configuration.

A1.3.4 Eastern Standard Time

Time of day where shown in this document is Australian Eastern Standard Time: that is Daylight Saving Time is not used for summer.

A1.3.5 Embedded Generation

In forecasting terminal station peak demand, System Participants have allowed for distribution network embedded generation according to their assessment of the availability of this at the time of peak demand. In general all or part of the smaller generators have been treated as negative load. However the traditional 'power station' generators at Morwell, Hume and Clover and all larger (centrally dispatched) new/planned generators, such as at Bairnsdale and Somerton, embedded in the distribution network have not been treated so. This envisages that these installations not treated as negative load will be considered individually, on a case-by-case basis, in performing planning.

A1.3.6 Loy Yang Power Station Unit Supplies

If an outage of a Loy Yang power station unit transformer occurred up to approximately 50 MW additional load could be drawn from Morwell terminal station. This is not included in the demand forecast but is noted in the comments with the Loy Yang station forecasts and also in the Morwell terminal station forecasts as this potential load needs to be recognised in planning the connection assets at Morwell.

A1.3.7 Treatment of Capacitance And Reactance

Reactive loading forecasts presented are the reactive loading levels expected to be imposed on terminal stations by licensed distribution areas. Thus they incorporate the reactive losses of the distribution network, including any reactors, and are offset by line and cable charging and those capacitors in the distribution network assessed by System Participants to be in service at the relevant time. Terminal station capacitors, compensators, reactors and transformation reactive losses are not considered as part of the load.

A1.4 Comparison of 2001 and 2002 Aggregate System Demand Forecasts.

The forecasts provided by the System Participants were adjusted and aggregated to reflect the load expected on the days of system maximum demand in summer and winter. In general the forecasts have decreased noticeably, especially for the earlier years being forecast. However the middle to later years being forecast seem to have stabilised to a certain extent, as the aggregate forecasts prepared in 2002 show little change from the aggregate forecasts prepared in 2001.

Figure A1 shows the difference between this year's aggregate summer active demand forecasts and the aggregate forecasts in 2001. The differences are substantial for the first year forecast (2003), exceeding 100 MW in both 10% POE and 50% POE forecasts. The differences noticeably diminish beyond 2003 until 2008 when the differences become positive, and by 2011 the summer forecast differences have increased to more than 50 MW. The ranges of these differences are –150 MW to 60 MW for the 10% POE forecasts and –140 MW to 60 MW for the 50% POE forecasts.

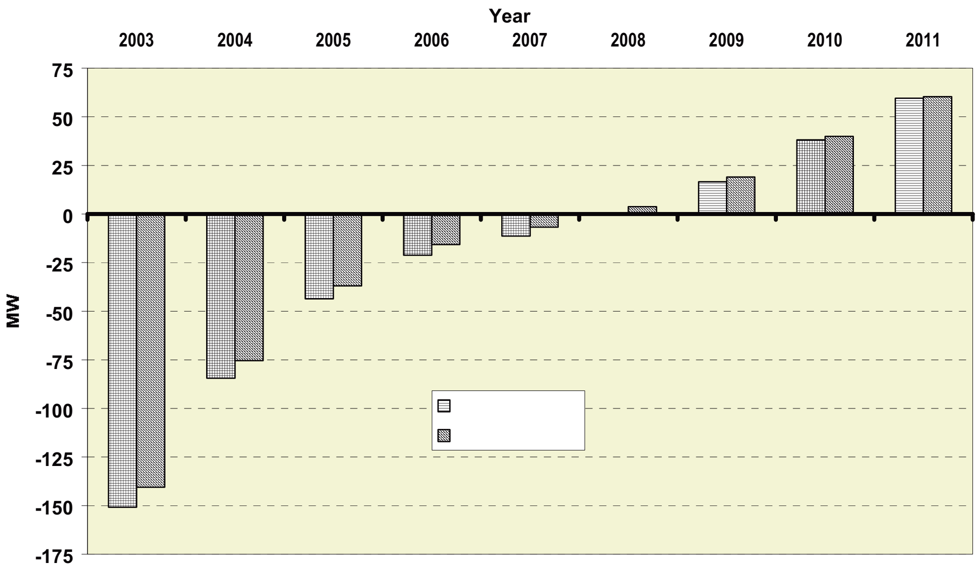


Figure A1 - Summer active demand differences - forecasts issued 2002 and 2001

Figure A2 shows the difference between this year's aggregate winter active demand forecasts and the aggregate forecasts issued in 2001. The differences are down for 2002 in the 10% POE and 50% POE forecasts, however beyond 2003 the forecast differences are all positive with a steady increase each year. The ranges of these differences are –40 MW to 120 MW for the 10% POE forecasts and -60 MW to 90 MW for the 50% POE forecasts.

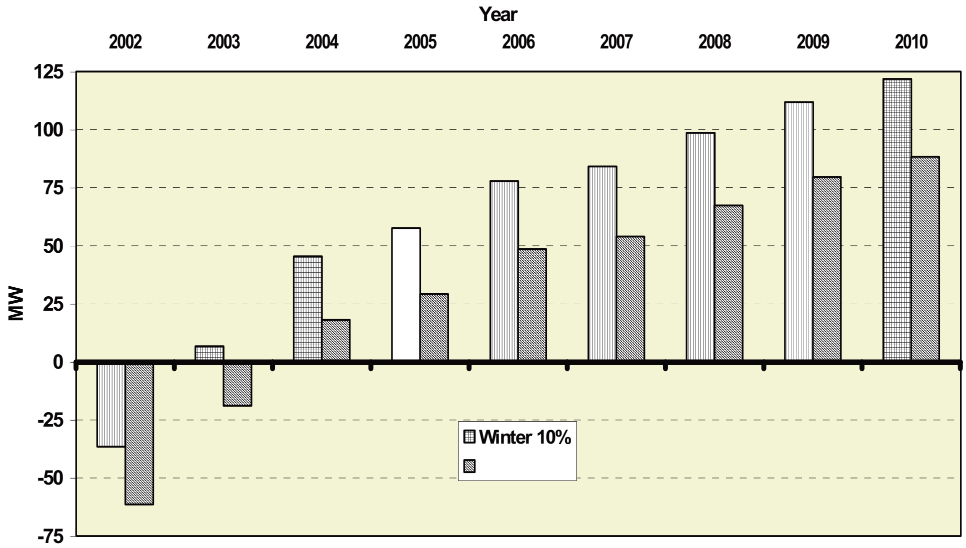


Figure A1 - Winter active demand differences - forecasts issued 2002 and 2001

A similar comparison was made between the reactive forecasts for both summer and winter prepared in 2001 and 2002.

Figure A3 shows that the aggregate summer reactive demand forecasts in 2002 are significantly lower than the aggregate forecasts in 2001 by about 300 MVAr at the 10% POE level and by about 280 MVAr at the 50% POE level. The differences for the outlook diminish by over 150 MVAr by 2011. The large differences between the summer reactive forecasts in the 2001 and 2002 reports can be partially attributed to power factor improvements across the system and reductions in the active load forecasts.

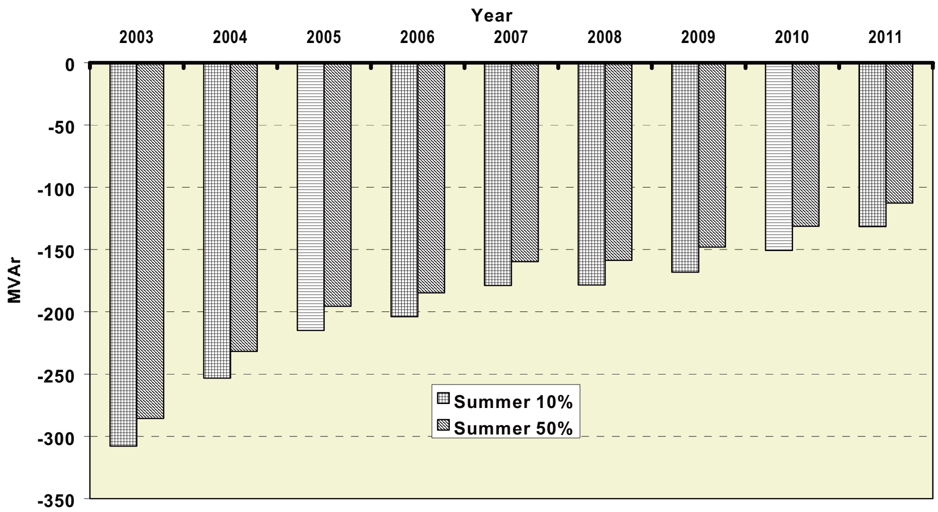


Figure A2 - Summer reactive demand differences - forecasts issued 2002 and 2001

Figure A4 shows that the aggregate winter reactive demands forecast in 2002 are significantly lower than the aggregate forecasts in 2001 by about 200MVAr. The differences for the outlook diminish by over 125 MVAr by 2011. The large differences between the winter reactive forecasts in the 2001 and 2002 reports can be partially attributed to power factor improvements across the system and reductions in the active load forecasts.

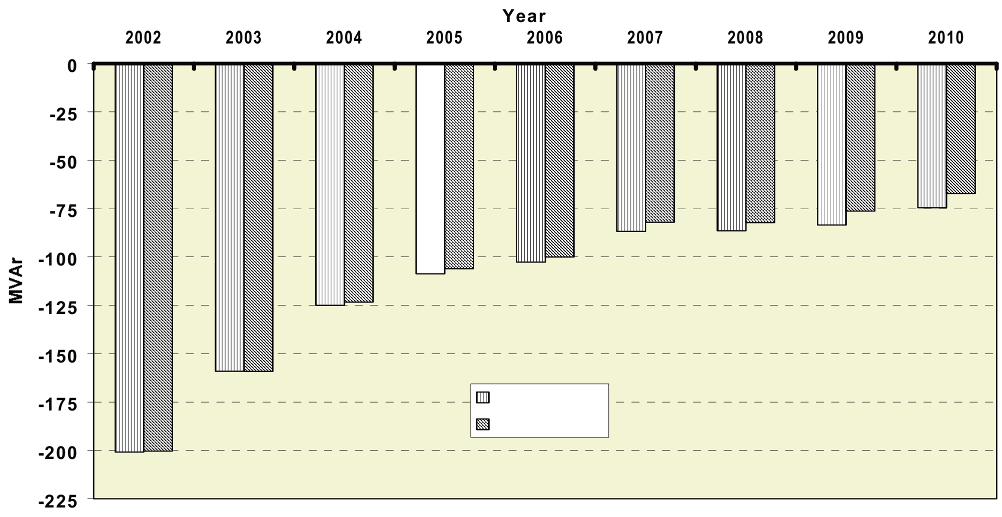


Figure A3 - Winter reactive demand differences - forecasts issued 2002 and 2001

A1.5 System Peak Demand Forecasts and Comparison with NIEIR Demand Forecasts

The Victorian electricity system peak demand forecasts, based on the System Participants' forecasts, are derived by combining the terminal station forecasts, diversified to day and time of system peak demand as described in section A1.2. Adjustments include for transmission system losses and Victorian electricity system demand not supplied through the distribution networks, such as power station internal usage. The forecast summer and winter peak demands based on the System Participants' 10% POE and 50% POE forecasts are shown in Figures A5 and A6.

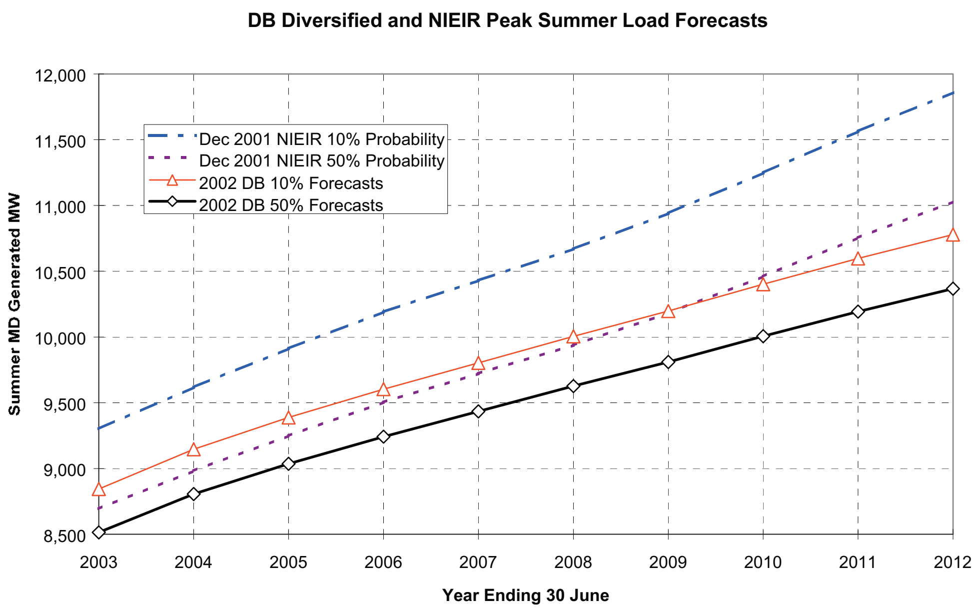


Figure A5 - System Participant and NIEIR Victorian summer peak electricity load forecasts

Victorian electricity system peak demand forecasts, published in April 2002 in VENCorp's Electricity Annual Planning Review[30], are also included in Figures A5 and A6. NIEIR forecasts for the "medium" economic growth scenario, with average daily ambient temperatures having 50% and 10% probability of being exceeded and

30 VENCorp retained the National Institute of Economic and Industry Research ("NIEIR") to develop Victorian peak electricity demand forecasts which were provided in late 2001. VENCorp Electricity Annual Planning Review 2002, which includes these forecasts, is available from the VENCorp web site www.vencorp.com.au.

leading to peak load conditions for a season are shown. This indicates the assessment of the sensitivity of peak summer and winter loads to ambient temperatures.

As shown in Figure A5, the 50% POE summer demands forecast by System Participants are similar to the NIEIR forecasts in the first 4 years and fall increasingly below the NIEIR forecasts in the later years. NIEIR forecasts almost linear increase of both 10% POE and 50% POE summer peak demands, whereas System Participants forecast these peak demands to grow at a decreasing rate. The 10% POE summer demands forecast by NIEIR are about 455 MW higher than the System Participants forecasts for 2002/03 and about 470 MW higher for 2003/04. This gap then widens at an increasing rate to over 1000 MW for 2011/12. The large discrepancy for the summer 10% POE system peak demand forecasts for 2002/03 can be mostly attributed to the System Participants' aggregate forecasts being significantly reduced by over 130 MW, and NIEIR's forecasts being increased by over 160 MW. Furthermore the difference between the 2002/03 summer 10% POE system peak demands for the System Participants' forecasts and NIEIR forecasts last year were in the order of 150 MW, which highlights the other significant portion of segregation between the forecasts.

From a growth rate point of view, NIEIR's 10% POE and 50% POE summer peak demand forecasts show year-to-year growth rates decreasing from 3.4% initially, to 3.0% in 2005/06 and then reducing to 2.3% in 2008/09 before increasing to 2.6% in 2011/12. Corresponding System Participant growth rates fall steadily from 3.3% to 1.7% over the ten years. The average growth rates of these peak demands over the ten year period is forecast to be 2.7% by NIEIR, and 2.2% by System Participants.

VENCorp is of the view that the 50% POE NIEIR summer forecasts and the 50% POE System Participants' summer forecasts are within the expected accuracy given the assumptions. However, the implied temperature sensitivity of the System Participants' summer forecasts between the 50% POE and 10% POE is much lower than experienced in recent years.

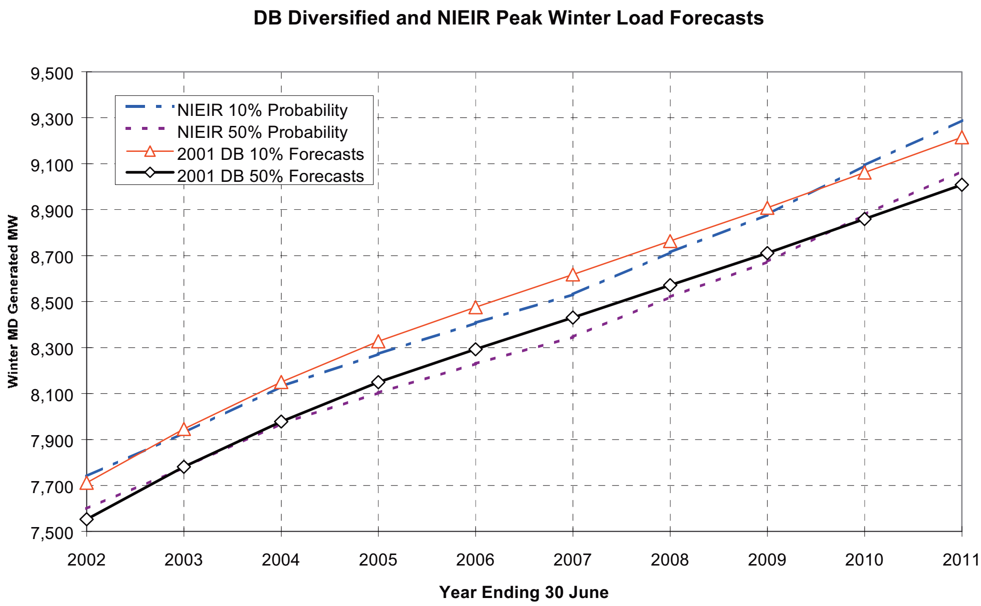


Figure A4 - System Participant and NIEIR Victorian winter peak electricity load forecasts

The winter peak demand forecasts provided by the System Participants show rates of growth similar to, but slightly lower (averaging 0.22% pa each year, and therefore also on average) than, their summer forecasts, and similar on average to NIEIR's winter forecasts. However, while System Participant winter forecast growth rates decrease steadily as described for summer, NIEIR's winter forecasts (both 10% POE and 50% POE) growth rates vary only marginally. Over the decade they decrease from 2.4% pa initially to 1.4% pa and then increase to 2.1% pa by 2011. Over the ten-year outlook, the 10% POE and 50% POE winter demands are forecast by the System Participants and NIEIR to grow on average at 2.0% pa.

A1.6 Reactive Demand Forecasts

Figure A7 shows the aggregate reactive demands forecast by System Participants to be drawn from terminal station points of connection (usually stations' lower voltage terminals) at the times of Victorian system peak summer and winter active power demand. The higher levels of motorised cooling load in summer are considered mainly responsible for the higher reactive demand in summer compared to winter.

This aggregate (10% POE) reactive load is forecast to increase from 3,075 MVAR to 3,990 MVAR over the 10 years to 2011/12 while the corresponding active power drawn from terminal stations is forecast to rise from 7,210 MW to 9,075 MW, indicating little change in the power factor of the aggregate terminal station load over the period.

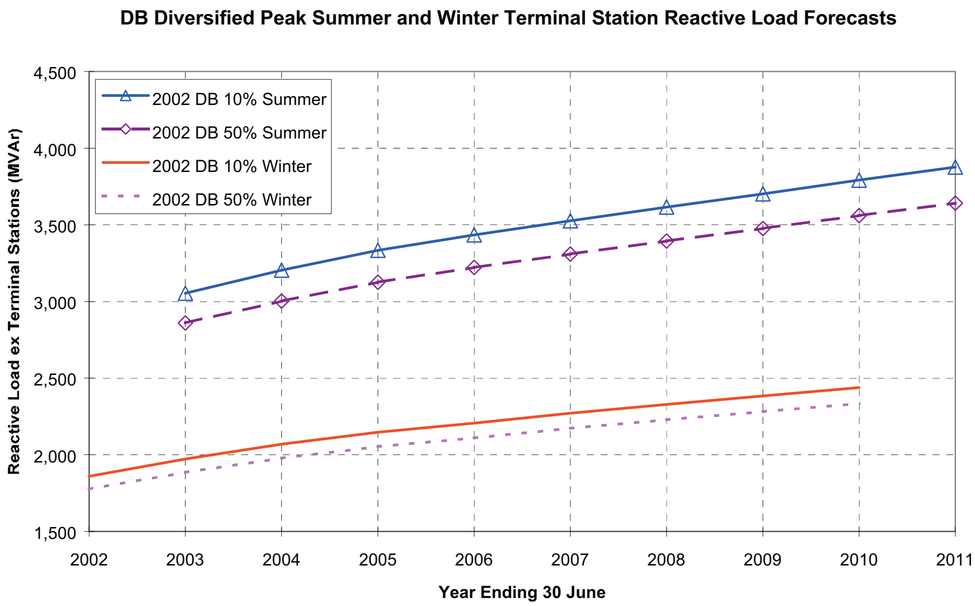


Figure A5 - Forecast of Reactive Load Drawn from Terminal Station Low Voltage Busbars

A1.7 Terminal Station Load Forecasts and Comparison with Actual Loads

A comparison was carried out between the load forecasts, by terminal station, presented in the 2001 report and the actual recorded peak loads supplied for summer 2001/02.

Figure A8 compares the peak actual and forecast active load, showing (in each main bar) the actual MW load at each of the terminal stations and (as the top and bottom respectively of each subsidiary bar) the 10% POE and 50% POE forecast values. Similarly Figure A9 compares the 10% POE and 50% POE reactive load forecasts and actual reactive loads for each of the terminal stations in summer 2001/02.

VENCorp assessed the temperature conditions, when peak Victorian potential maximum demand of 7634 was recorded for the half hour ending 4:30 pm on Thursday, 14 February 2002 for summer 2001/02. Melbourne's overnight minimum temperature was 18.9 °C and the daily maximum temperature was 36.4 °C a daily average temperature of 27.65 °C. This was the fourth highest Melbourne daily average temperature for summer 2001/02, assessed to be an 85th percentile summer in relation to maximum electricity demand. In previous summers over 100 MW of demand side participation has been recorded, and in the past this has been considered to have not had a material impact on most terminal station peak summer active demands. For 2001/02 this issue was not applicable, as there was no recorded demand side participation on the day of system MD.

Actual aggregate terminal station loading at the summer 2001/02 system peak was 5976 MW and 2100 MVAr, compared to forecasts of 6806 MW and 3057 MVAr (50% POE) and 7124 MW and 3267 MVAr (10% POE).

A comparison was also carried out between the load forecasts, by terminal station, presented in this report and the actual recorded peak loads supplied for winter 2002.

VENCorp has assessed the temperature conditions, when peak Victorian potential maximum demand of 7294 MW was recorded for the half hour ending 6 pm on Monday, 22 July 2002 for winter 2002. Melbourne's overnight minimum temperature was 3.3 °C and the daily maximum temperature was 10.8 °C a daily average temperature of 7.05 °C. This was the lowest Melbourne daily average temperature for winter 2002, assessed to be an 86th percentile winter in relation to maximum electricity demand.

Similar to Figures A8 and A9, Figures A10 and A11 compare the peak actual and forecast active and reactive load for winter 2002, showing the actual loads, aggregated across the system, are broadly consistent with the forecasts, in light of the very mild winter conditions.

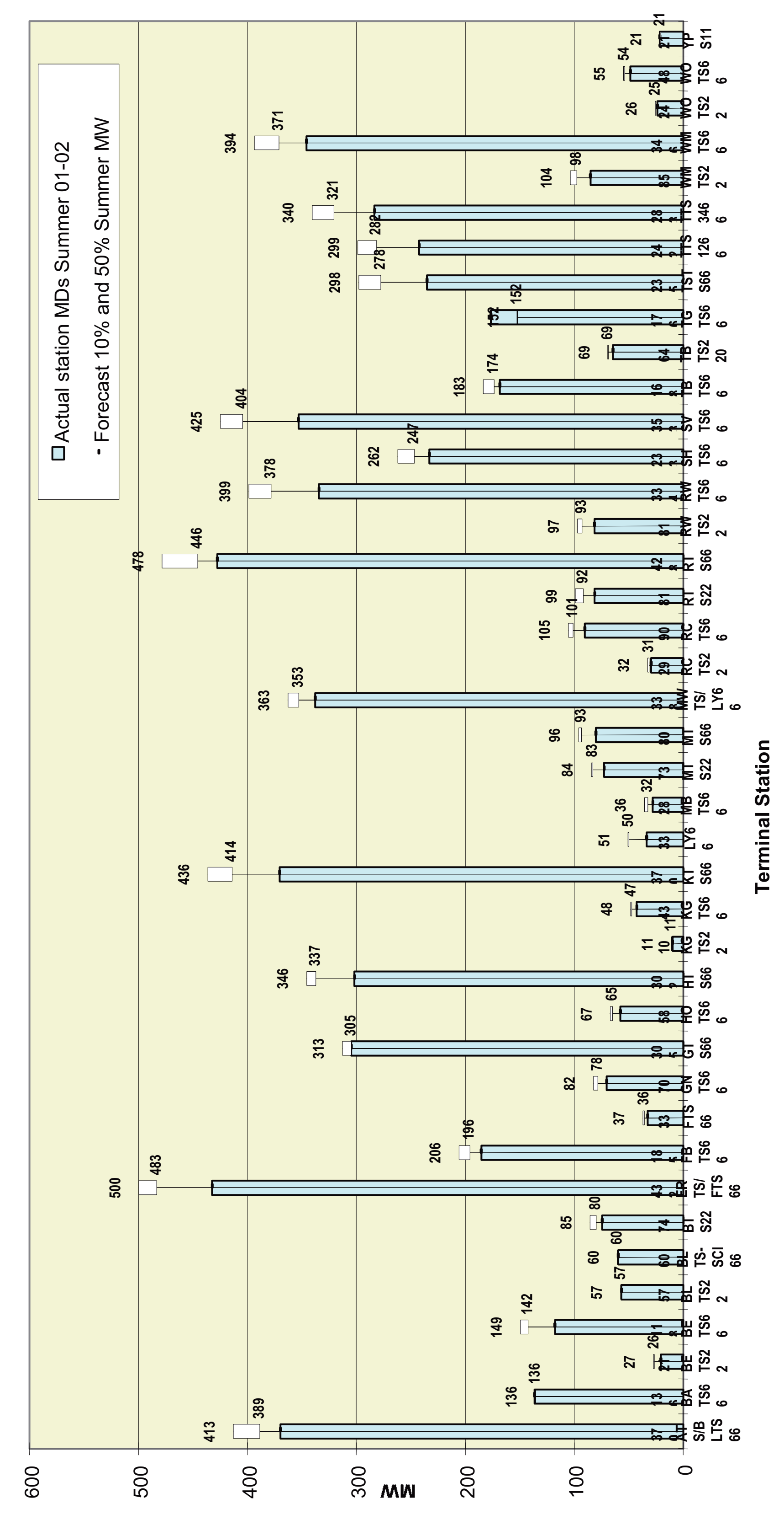


Figure A6- Station actual Summer 01-02 MDs and forecasts issued in 2001

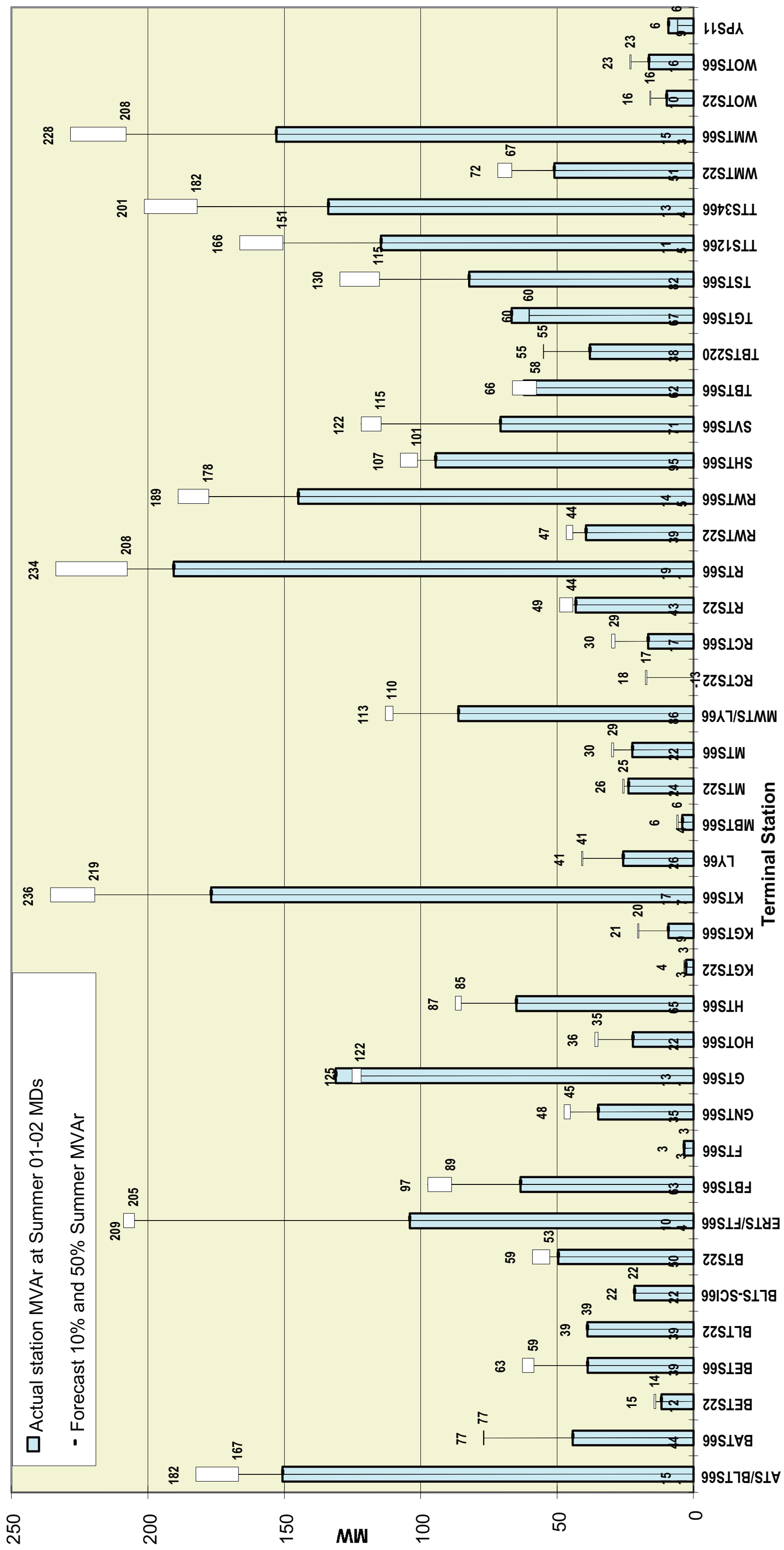


Figure A7 - Station actual reactive load at time of Summer 01-02 station MDs and 2001 forecasts

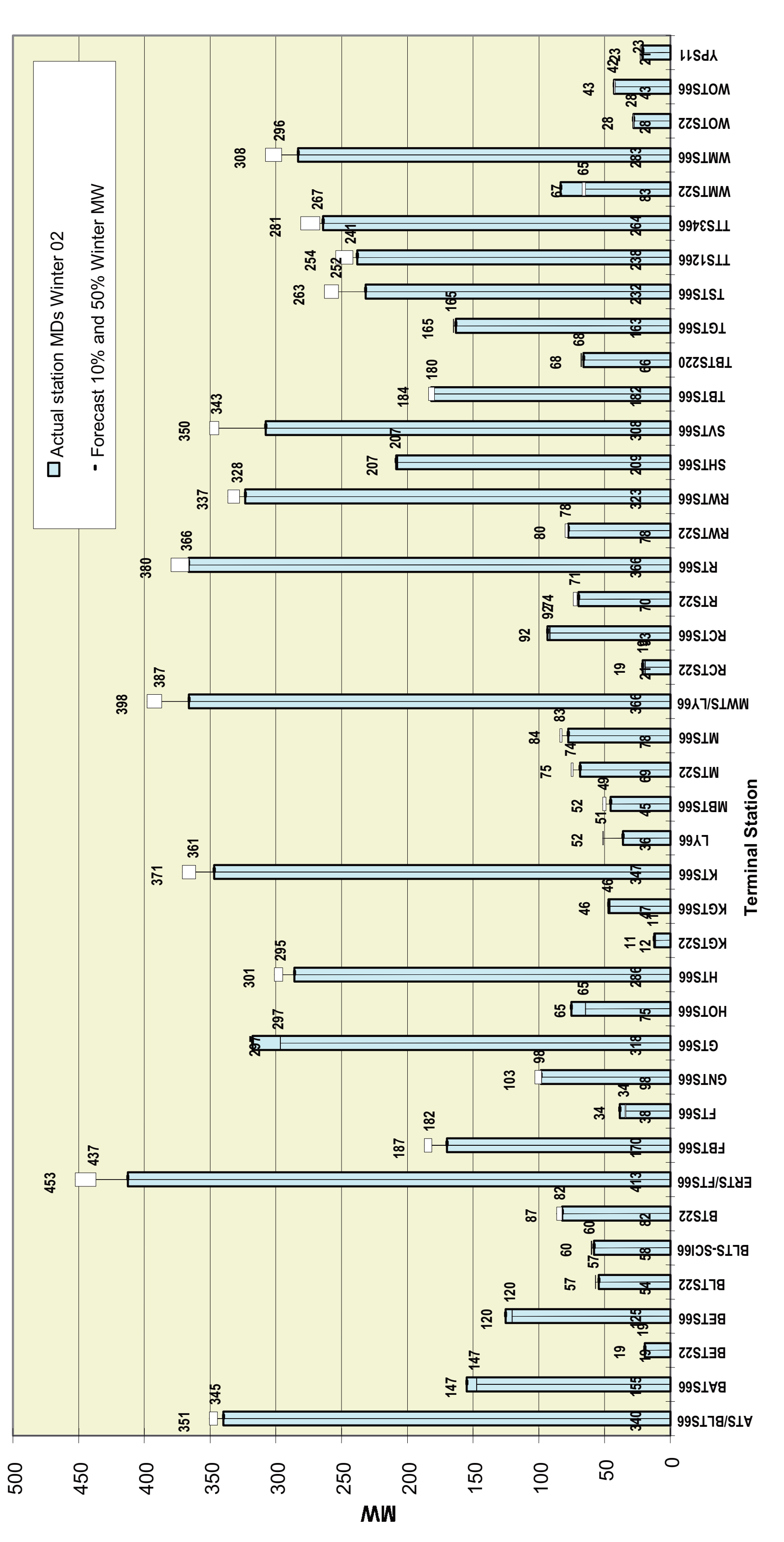


Figure A8 - Station actual Winter 2002 MDs and forecasts issued in 2002

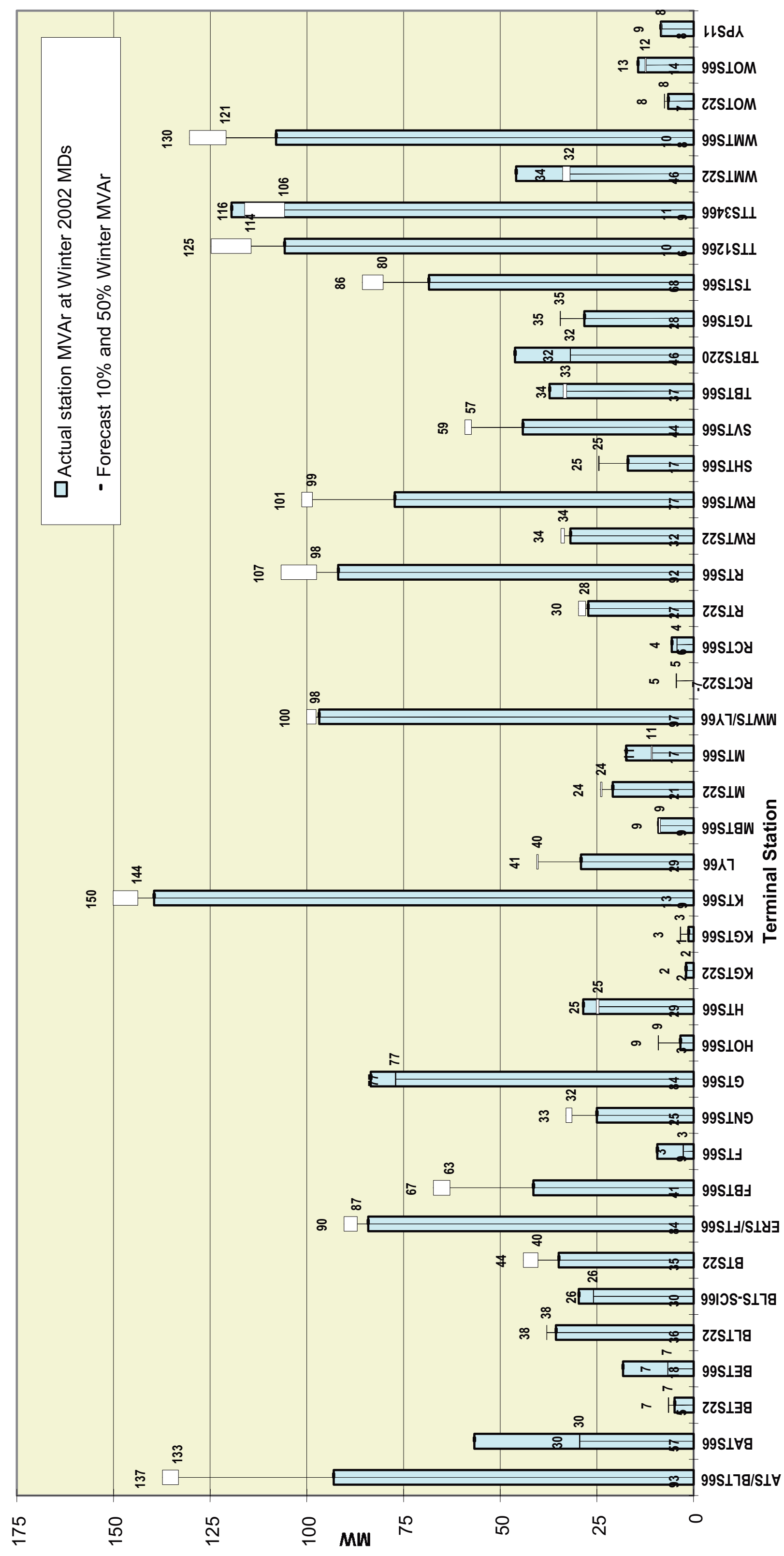


Figure A9 - Station actual reactive load at time of Winter 2002 station MDs and 2002 forecasts

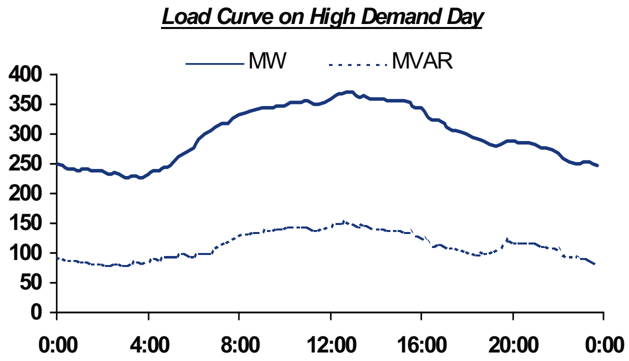
AGGREGATE TERMINAL STATION DEMAND FORECASTS

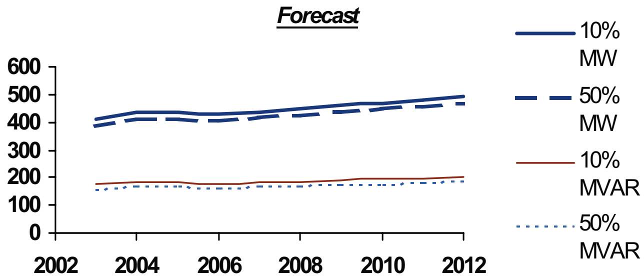
Altona/Brooklyn Terminal Station

Summer Demand

Previous MD	**MW**	**MVAR**
15 Feb 2002 1:00 PM	369.80	150.60

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	410.4	174.5	386.0	159.5
2004	433.0	183.1	408.4	167.9
2005	437.7	183.8	413.5	169.0
2006	429.1	177.9	405.7	164.0
2007	438.1	181.5	414.7	167.4
2008	448.7	185.7	425.1	171.5
2009	459.1	189.8	435.3	175.5
2010	470.0	194.2	446.1	179.6
2011	481.1	198.6	457.0	183.9
2012	492.2	203.0	467.9	188.1

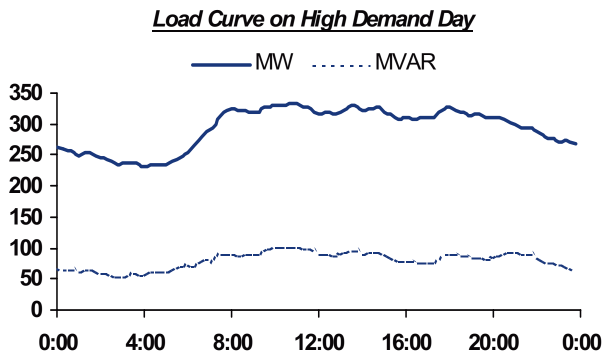


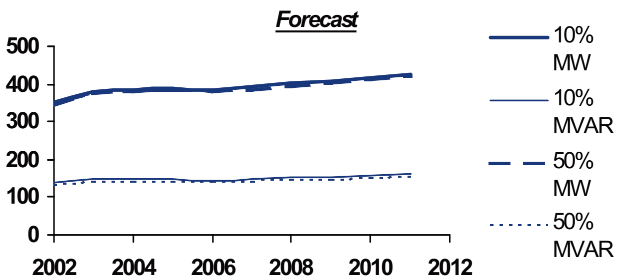


Winter Demand

Previous MD	**MW**	**MVAR**
15 Jun 2001 10:45 AM	332.06	100.91

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	350.7	137.3	344.5	133.2
2003	381.4	147.4	375.2	143.2
2004	385.1	149.0	378.9	144.8
2005	390.9	149.9	384.7	145.8
2006	384.4	145.4	378.5	141.6
2007	392.0	148.1	386.1	144.2
2008	400.5	151.0	394.5	147.2
2009	409.2	154.2	403.2	150.2
2010	418.2	157.3	412.2	153.3
2011	427.4	160.5	421.3	156.5





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

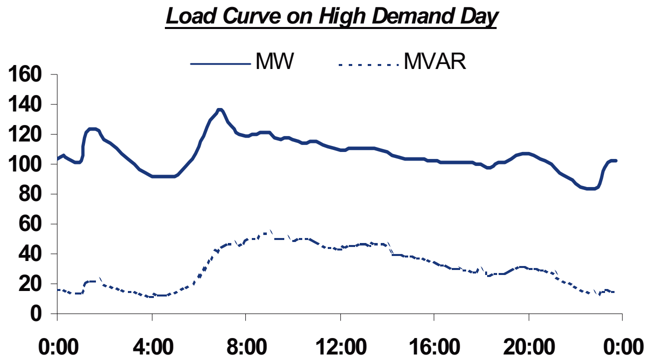
These estimates include load demand from Citipower's zone substation Tavistock Place (TP). In winter 2002, a large customer is being relocated to outside AGL's area resulting in 6 MW reduction. AGL plans to transfer about 8 MW of load from BLTS66 to KTS in 2005 (zone substation BY). AGL plans to transfer about 17 MW of load from BLTS66 to WMTS in 2006. Forecast includes known additional new load to the system.

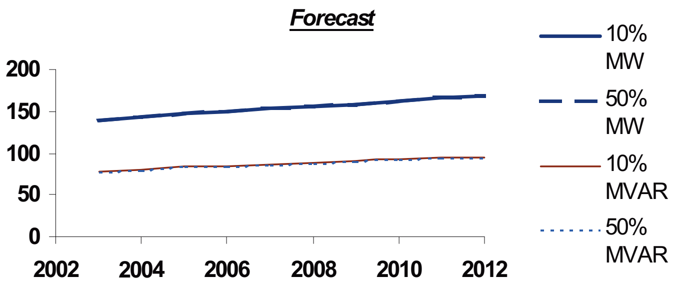
Ballarat Terminal Station 66kV Bus

Summer Demand

Previous MD	MW	MVAR
01 Nov 2001 7:00 AM	136.50	44.20

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	138.2	78.4	138.2	78.4
2004	142.8	81.0	142.8	81.0
2005	146.7	83.2	146.7	83.2
2006	149.7	84.9	149.7	84.9
2007	152.8	86.6	152.8	86.6
2008	155.8	88.3	155.8	88.3
2009	158.9	90.1	158.9	90.1
2010	162.1	91.9	162.1	91.9
2011	165.4	93.8	165.4	93.8
2012	168.6	95.6	168.6	95.6

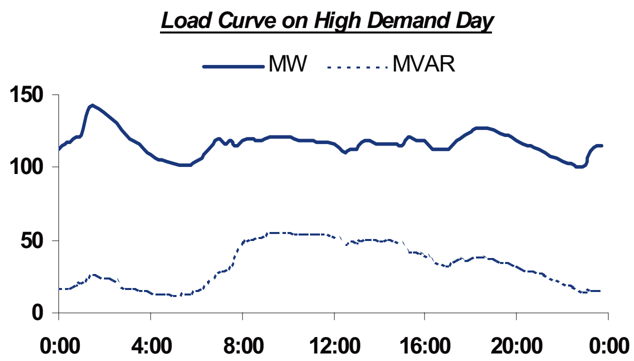


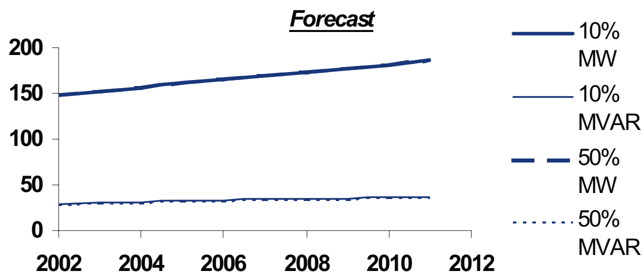


Winter Demand

Previous MD	MW	MVAR
17 Aug 2001 1:30 AM	142.31	26.66

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	147.3	29.5	147.3	29.5
2003	152.6	30.5	152.6	30.5
2004	156.5	31.3	156.5	31.3
2005	161.5	32.3	161.5	32.3
2006	165.3	33.1	165.3	33.1
2007	169.2	33.8	169.2	33.8
2008	173.2	34.6	173.2	34.6
2009	177.3	35.5	177.3	35.5
2010	181.5	36.3	181.5	36.3
2011	185.7	37.1	185.7	37.1





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

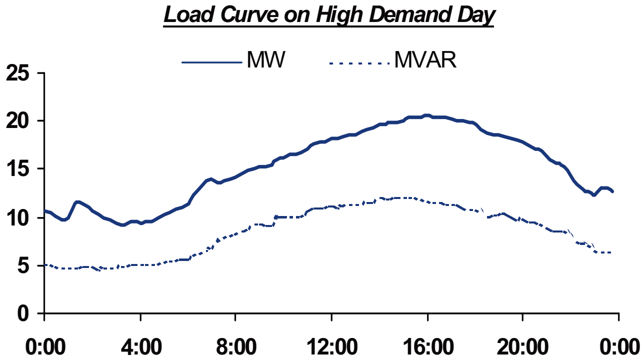
Comments:

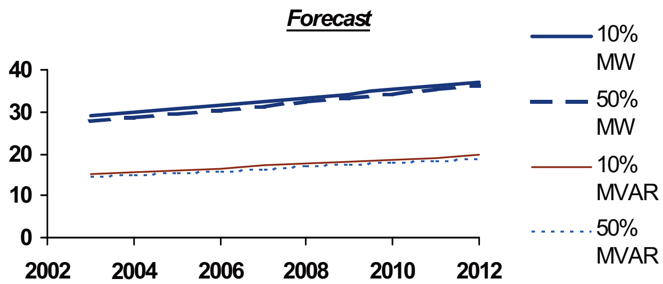
Bendigo Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
01 Feb 2002 4:00 PM	20.60	11.80

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	28.9	15.3	27.9	14.8
2004	29.7	15.7	28.7	15.2
2005	30.6	16.2	29.6	15.7
2006	31.4	16.6	30.4	16.1
2007	32.3	17.1	31.3	16.6
2008	33.3	17.6	32.3	17.1
2009	34.2	18.1	33.2	17.6
2010	35.2	18.6	34.2	18.1
2011	36.2	19.1	35.2	18.6
2012	37.2	19.7	36.2	19.1

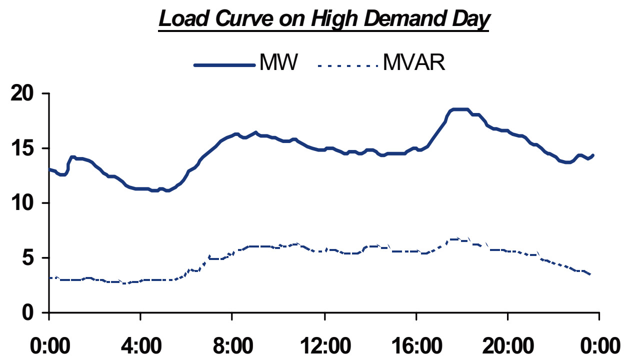


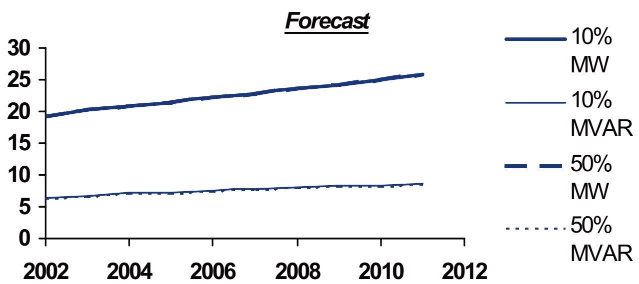


Winter Demand

Previous MD	MW	MVAR
30 May 2001 6:15 PM	18.60	6.63

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	19.2	6.5	19.2	6.5
2003	20.2	6.8	20.2	6.8
2004	20.9	7.1	20.9	7.1
2005	21.5	7.3	21.5	7.3
2006	22.1	7.5	22.1	7.5
2007	22.8	7.7	22.8	7.7
2008	23.5	8.0	23.5	8.0
2009	24.2	8.2	24.2	8.2
2010	24.9	8.4	24.9	8.4
2011	25.7	8.7	25.7	8.7





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

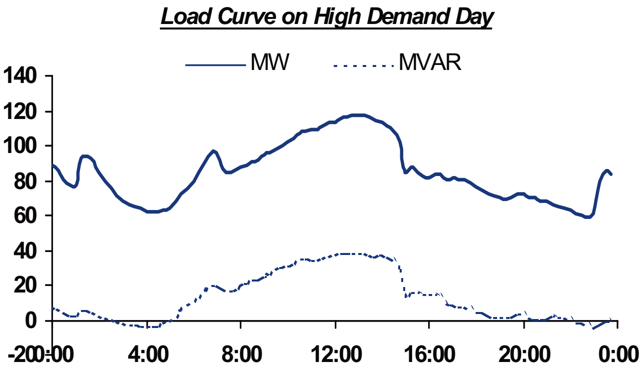
Demand figures are based on 15 minute energy forecasts

Comments:

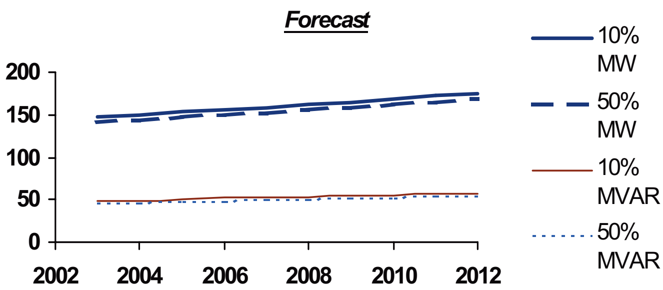
Bendigo Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:15 PM	117.80	38.80

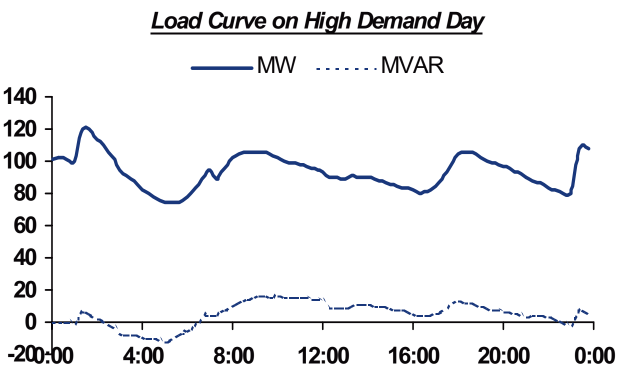


	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	147.2	48.4	140.2	46.1
2004	150.2	49.4	143.2	47.1
2005	153.6	50.5	146.6	48.2
2006	156.8	51.6	149.8	49.3
2007	158.8	52.2	151.8	49.9
2008	161.9	53.3	154.9	51.0
2009	165.1	54.3	158.1	52.0
2010	168.3	55.4	161.3	53.1
2011	171.6	56.5	164.6	54.2
2012	174.7	57.5	167.7	55.2

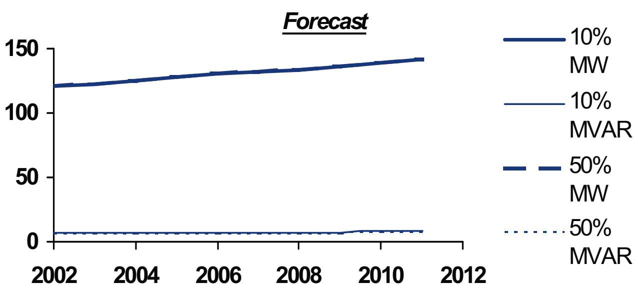


Winter Demand

Previous MD	MW	MVAR
28 Jun 2001 1:30 PM	120.66	6.82



	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	120.3	6.7	120.3	6.7
2003	122.6	6.9	122.6	6.9
2004	125.0	7.0	125.0	7.0
2005	127.5	7.1	127.5	7.1
2006	129.9	7.3	129.9	7.3
2007	131.3	7.4	131.3	7.4
2008	133.8	7.5	133.8	7.5
2009	136.3	7.6	136.3	7.6
2010	138.9	7.8	138.9	7.8
2011	141.5	7.9	141.5	7.9



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts.

Comments:

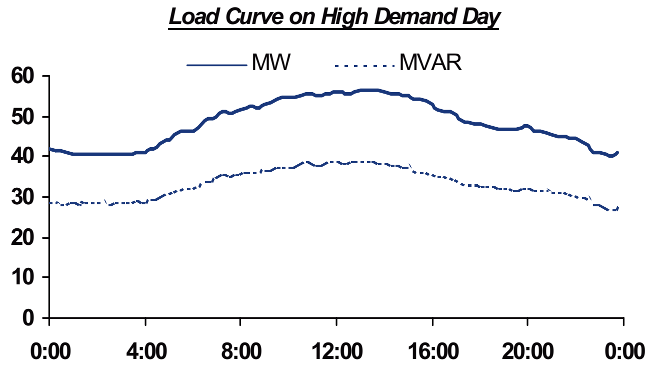
Improvement in power factor due to additional 8MVAr cap banks at CTN,MRO & CMN and 2 MVAr line caps installed at BGO13.

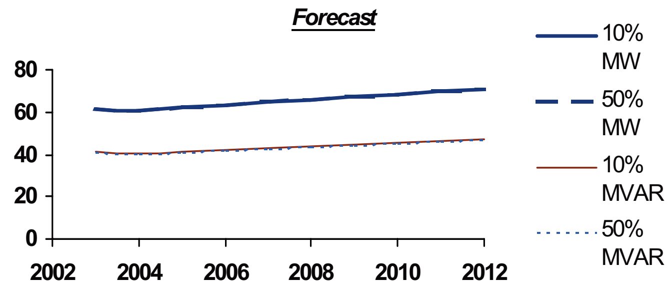
Brooklyn Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:15 PM	56.60	38.90

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	61.6	41.3	61.6	41.3
2004	60.9	40.8	60.9	40.8
2005	62.1	41.5	62.0	41.5
2006	63.3	42.3	63.3	42.3
2007	64.5	43.2	64.5	43.1
2008	65.8	44.1	65.8	44.0
2009	67.1	44.9	67.1	44.9
2010	68.4	45.8	68.4	45.8
2011	69.8	46.6	69.7	46.6
2012	71.1	47.5	71.1	47.5

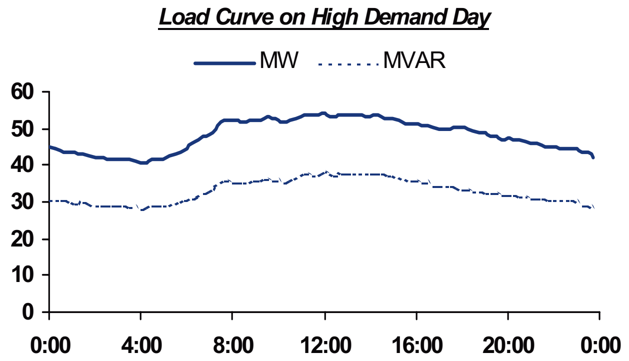


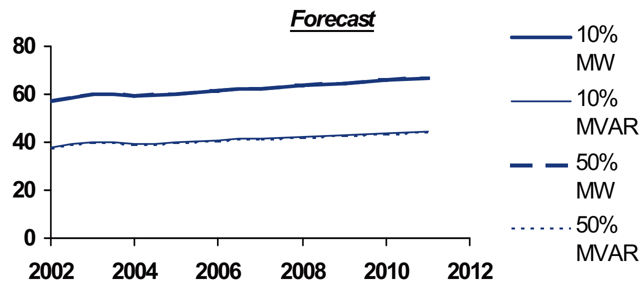


Winter Demand

Previous MD	MW	MVAR
31 May 2001 12:00 PM	54.33	38.39

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	57.0	38.0	56.9	37.9
2003	59.8	39.8	59.8	39.8
2004	59.0	39.3	59.0	39.3
2005	60.0	40.0	60.0	39.9
2006	61.2	40.7	61.1	40.6
2007	62.3	41.4	62.3	41.4
2008	63.4	42.2	63.4	42.1
2009	64.6	42.9	64.5	42.8
2010	65.8	43.7	65.8	43.7
2011	67.0	44.6	67.0	44.5





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

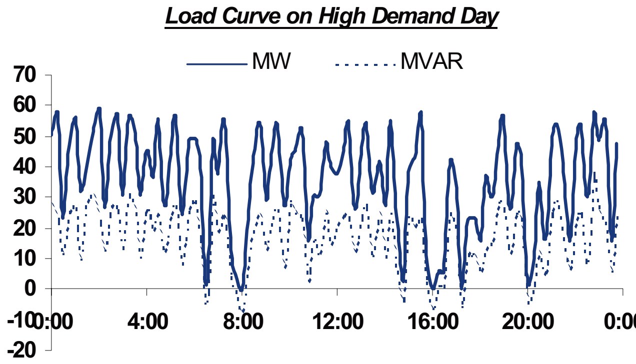
Comments:

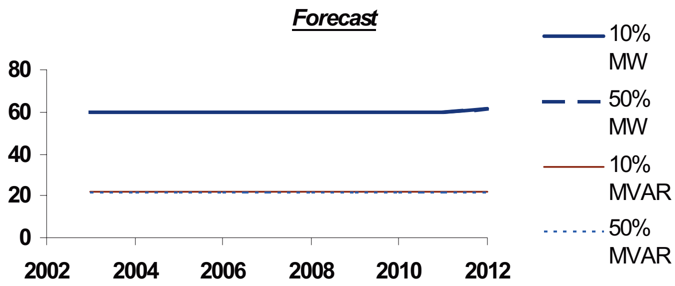
Brooklyn-SCI Terminal Station 66kV Bus

Summer Demand

Previous MD	MW	MVAR
10 Feb 2002 9:45 AM	59.70	21.60

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	60.2	21.8	60.2	21.8
2004	60.2	21.8	60.2	21.8
2005	60.2	21.8	60.2	21.8
2006	60.2	21.8	60.2	21.8
2007	60.2	21.8	60.2	21.8
2008	60.2	21.8	60.2	21.8
2009	60.2	21.8	60.2	21.8
2010	60.2	21.8	60.2	21.8
2011	60.2	21.8	60.2	21.8
2012	61.2	22.2	61.2	22.2

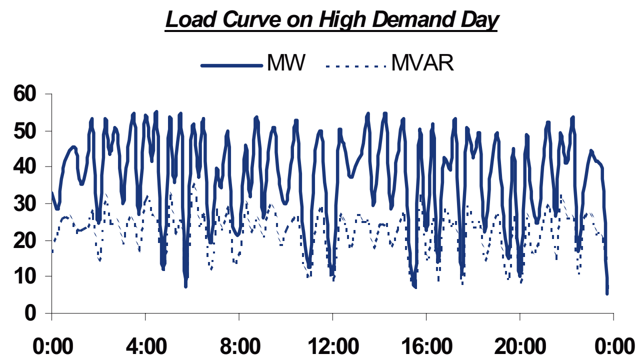


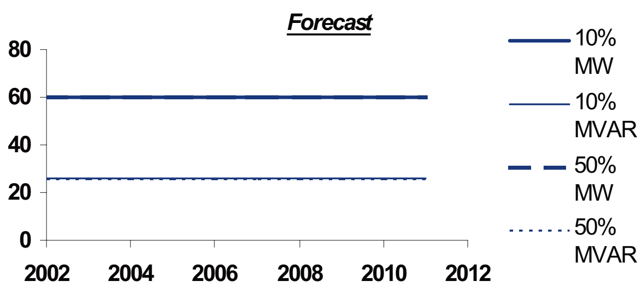


Winter Demand

Previous MD	MW	MVAR
02 Aug 2001 4:30 PM	57.89	29.10

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	60.0	25.9	60.0	25.9
2003	60.0	25.9	60.0	25.9
2004	60.0	25.9	60.0	25.9
2005	60.0	25.9	60.0	25.9
2006	60.0	25.9	60.0	25.9
2007	60.0	25.9	60.0	25.9
2008	60.0	25.9	60.0	25.9
2009	60.0	25.9	60.0	25.9
2010	60.0	25.9	60.0	25.9
2011	60.0	25.9	60.0	25.9





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

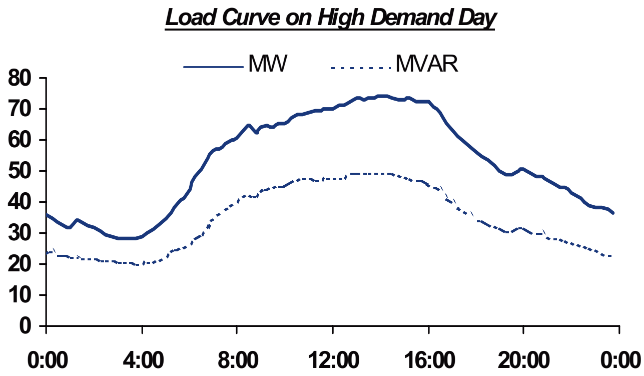
Comments:

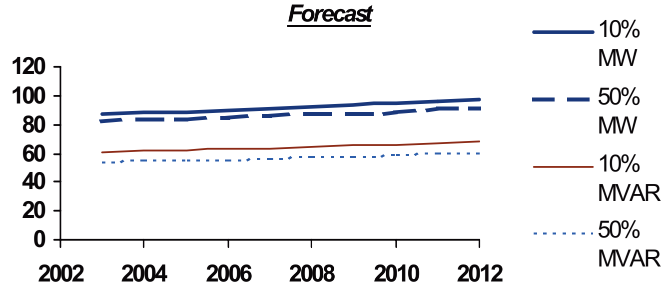
Brunswick Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 2:15 PM	74.20	49.60

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	87.5	60.7	82.0	54.3
2004	88.7	61.5	83.1	55.1
2005	89.0	61.8	83.4	55.3
2006	90.1	62.6	84.4	56.0
2007	91.0	63.3	85.4	56.6
2008	92.4	64.2	86.5	57.5
2009	93.6	65.2	87.7	58.4
2010	95.0	66.3	89.0	59.2
2011	96.4	67.3	90.3	60.1
2012	97.8	68.3	91.6	61.1
2013	99.1	69.4	92.9	62.0

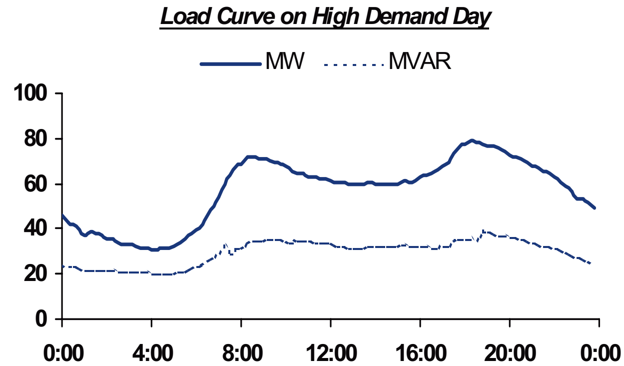


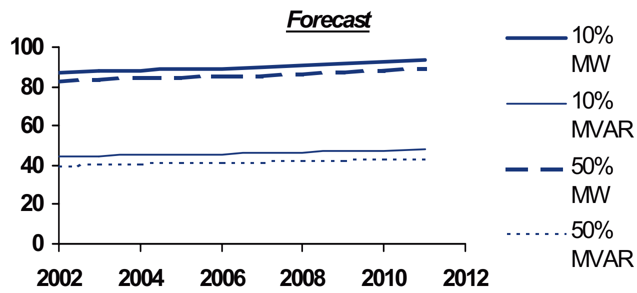


Winter Demand

Previous MD	MW	MVAR
19 Jun 2001 6:15 PM	79.22	35.79

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	86.6	44.0	82.4	40.3
2003	87.5	44.5	83.2	40.7
2004	88.3	45.0	84.1	41.2
2005	88.5	45.1	84.1	41.2
2006	89.2	45.5	84.9	41.6
2007	90.0	45.9	85.6	41.9
2008	91.0	46.4	86.5	42.4
2009	91.8	46.9	87.4	42.9
2010	92.8	47.5	88.3	43.4
2011	93.8	48.0	89.2	43.9
2012	94.8	48.5	90.2	44.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

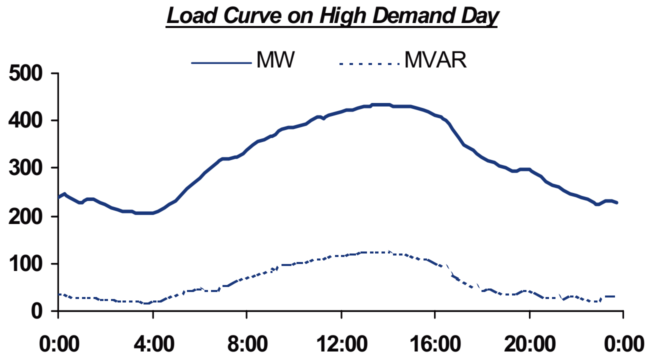
Comments:

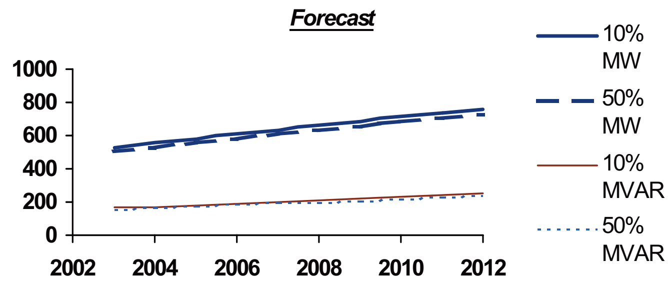
East Rowville/Frankston Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:30 PM	432.40	104.00

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	526.4	163.4	505.3	156.1
2004	552.7	173.5	530.2	165.6
2005	579.9	184.1	555.8	175.5
2006	607.3	194.4	581.5	185.2
2007	634.5	204.8	607.2	195.1
2008	659.6	214.4	630.7	204.2
2009	686.0	224.5	655.6	213.6
2010	712.8	234.4	680.7	223.0
2011	736.9	243.4	703.4	231.4
2012	759.6	251.6	724.8	239.2
2013	783.1	260.1	746.9	247.1

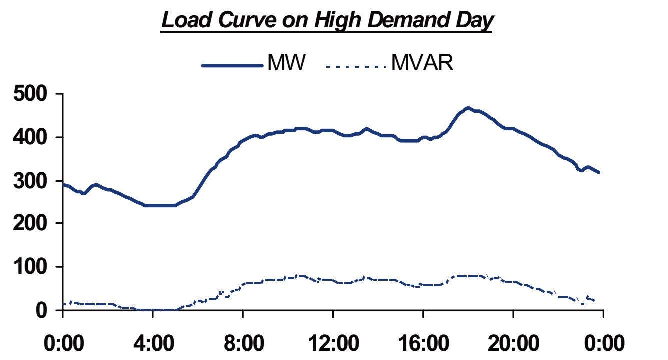


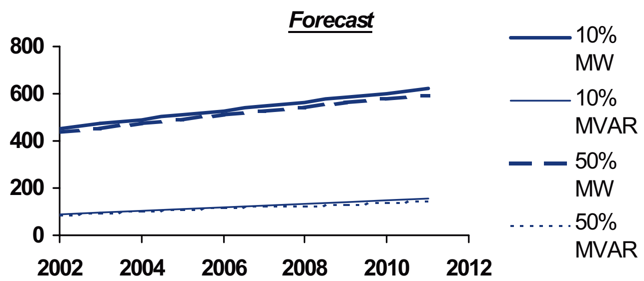


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 6:00 PM	470.95	82.74

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	452.6	90.4	437.0	87.0
2003	471.3	98.7	454.8	95.0
2004	491.3	106.3	473.7	102.1
2005	510.4	113.7	491.8	109.1
2006	528.7	121.0	509.4	116.1
2007	545.2	127.6	525.0	122.4
2008	563.9	134.7	542.6	129.2
2009	581.5	141.5	559.4	135.6
2010	599.9	148.0	576.9	141.8
2011	618.5	154.5	594.7	148.0
2012	637.7	161.2	613.0	154.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

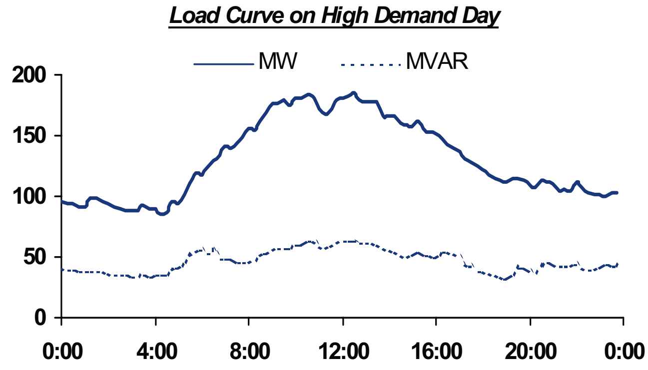
The ERTS/FTS load forecasts incorporates the load from ERTS including the load supplied to FTS. The forecasts include 5MW generation from Dandenong Hospital co-generator.

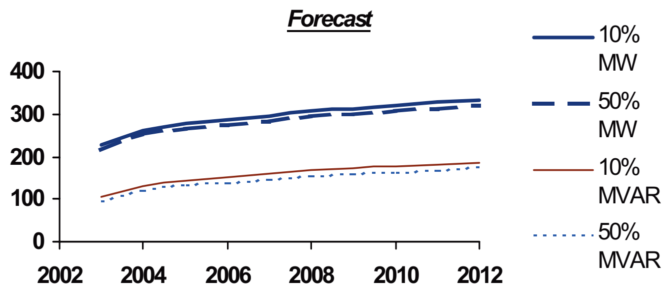
Fishermen's Bend Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 12:30 PM	185.40	63.40

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	226.4	104.4	215.8	95.4
2004	263.1	131.4	251.1	121.3
2005	278.7	144.8	266.1	134.4
2006	286.9	151.7	274.0	141.0
2007	294.8	158.4	281.6	147.4
2008	307.0	166.4	293.6	155.2
2009	313.3	171.3	299.7	160.0
2010	319.8	176.4	306.1	164.9
2011	326.6	181.7	312.7	170.0
2012	333.3	187.0	319.2	175.1

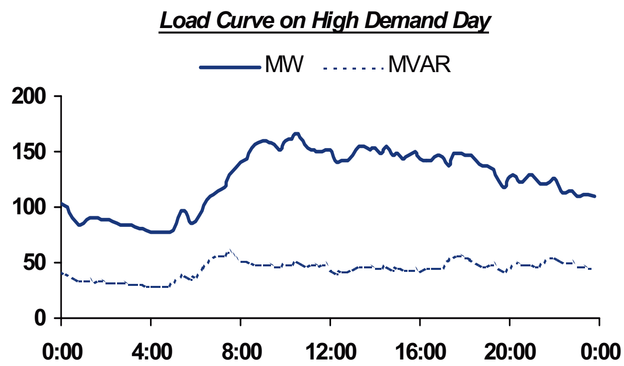


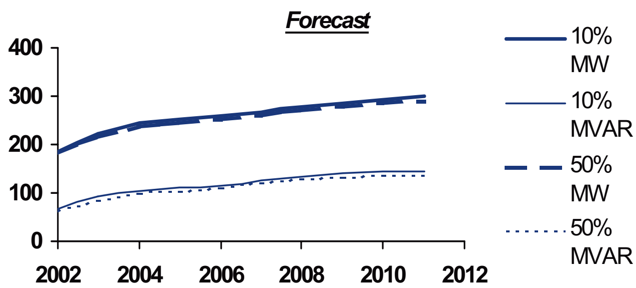


Winter Demand

Previous MD	MW	MVAR
24 Jul 2001 10:30 PM	165.37	51.68

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	187.0	67.3	181.5	63.0
2003	220.6	91.6	214.3	86.7
2004	243.5	103.5	236.8	98.3
2005	253.1	110.6	246.2	105.2
2006	260.4	116.5	253.3	111.0
2007	267.7	127.6	260.5	121.9
2008	279.5	134.9	272.1	129.1
2009	285.5	139.4	278.1	133.5
2010	291.8	144.0	284.2	138.1
2011	298.4	143.6	290.7	137.6





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

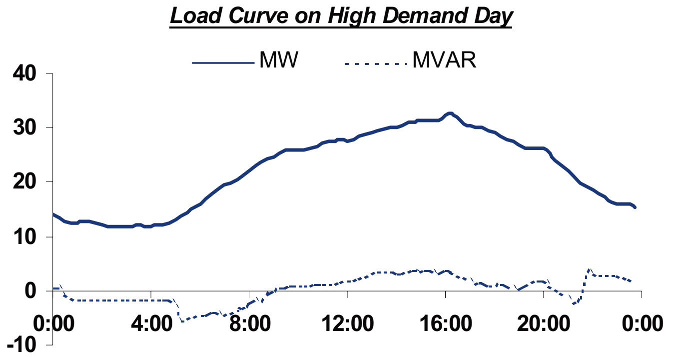
Comments:

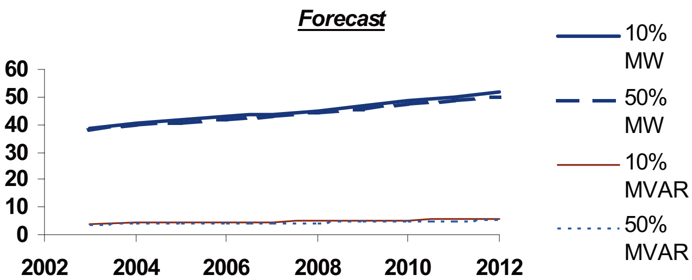
Frankston Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 4:00 PM	32.64	3.49

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	38.4	4.1	37.7	4.0
2004	40.2	4.3	39.5	4.2
2005	41.4	4.4	40.6	4.3
2006	42.7	4.6	41.7	4.5
2007	43.8	4.7	42.9	4.6
2008	45.1	4.8	44.0	4.7
2009	46.9	5.0	45.7	4.9
2010	48.8	5.2	47.6	5.1
2011	50.1	5.4	48.8	5.2
2012	51.5	5.5	50.1	5.4
2013	52.9	5.7	51.4	5.5

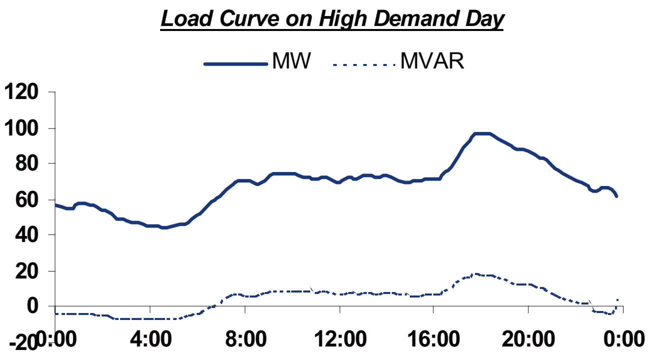


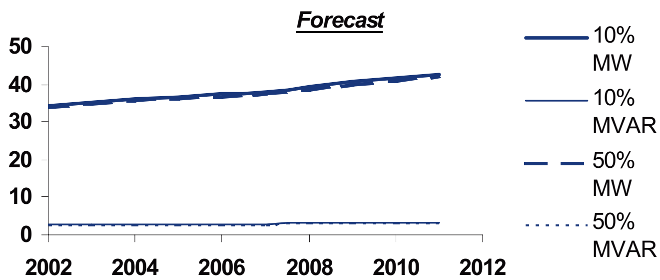


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 6:00 PM	96.66	18.70

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	34.4	2.7	33.9	2.7
2003	35.3	2.8	34.8	2.8
2004	36.2	2.9	35.6	2.8
2005	36.8	2.9	36.2	2.9
2006	37.4	3.0	36.8	2.9
2007	38.1	3.0	37.4	3.0
2008	39.4	3.1	38.6	3.1
2009	40.6	3.2	39.9	3.2
2010	41.7	3.3	40.9	3.3
2011	42.8	3.4	41.9	3.3
2012	43.8	3.5	42.9	3.4





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

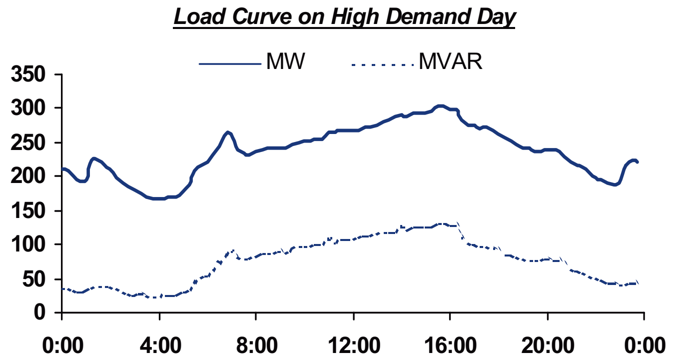
Comments:

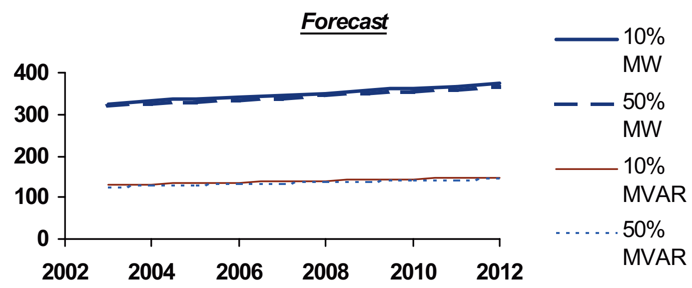
Geelong Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 3:30 PM	304.80	131.10

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	326.0	130.4	318.0	127.2
2004	330.9	132.4	322.9	129.2
2005	335.9	134.4	327.9	131.2
2006	341.0	136.4	333.0	133.2
2007	346.1	138.4	338.1	135.2
2008	351.3	140.5	343.3	137.3
2009	356.6	142.6	348.6	139.4
2010	362.0	144.8	354.0	141.6
2011	367.4	147.0	359.4	143.8
2012	372.9	149.2	364.9	146.0

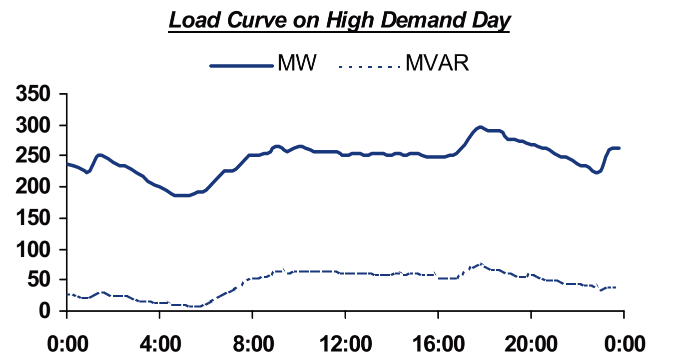


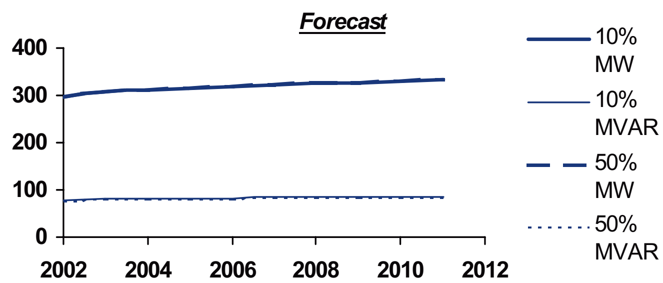


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 5:45 PM	296.62	74.97

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	296.6	77.1	296.6	77.1
2003	308.4	80.2	308.4	80.2
2004	310.4	80.7	310.4	80.7
2005	316.0	82.2	316.0	82.2
2006	319.7	83.1	319.7	83.1
2007	322.1	83.7	322.1	83.7
2008	324.4	84.3	324.4	84.3
2009	326.8	85.0	326.8	85.0
2010	329.2	85.6	329.2	85.6
2011	331.6	86.2	331.6	86.2





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

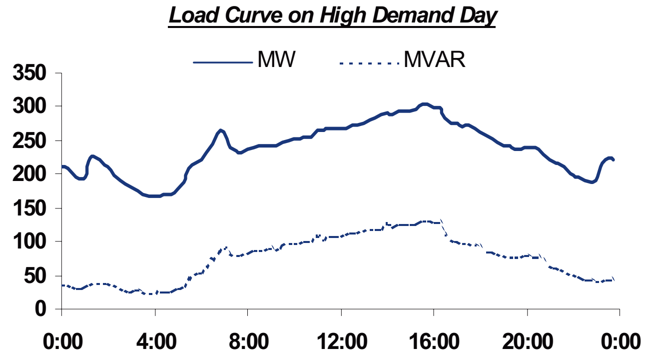
Comments:

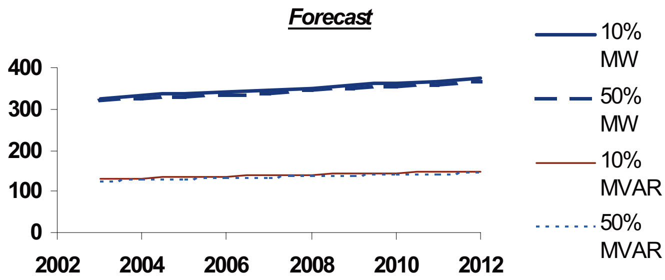
Glenrowan Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 3:30 PM	304.80	131.10

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	81.9	44.2	78.0	42.1
2004	83.6	45.1	79.6	42.9
2005	85.2	45.9	81.1	43.7
2006	86.7	46.6	82.6	44.4
2007	88.3	47.4	84.1	45.1
2008	89.9	48.2	85.6	45.9
2009	91.4	49.0	87.1	46.7
2010	93.0	49.8	88.6	47.4
2011	94.5	50.5	90.0	48.1
2012	96.2	51.4	91.6	48.9
2013	97.3	51.9	92.7	49.5

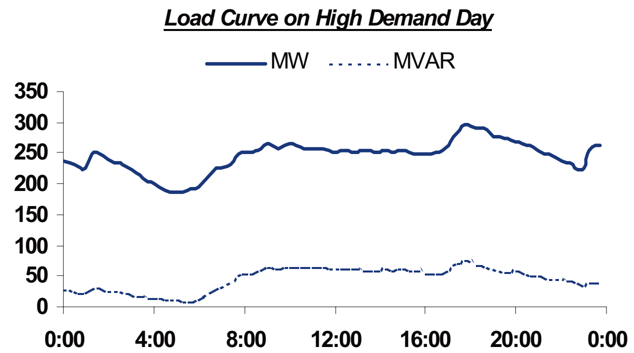


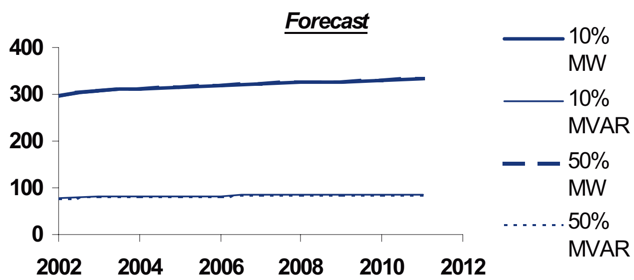


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 5:45 PM	296.62	74.97

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	102.9	33.0	98.0	31.5
2003	104.3	33.8	99.3	32.1
2004	105.7	34.5	100.7	32.8
2005	107.1	35.2	102.0	33.5
2006	108.5	35.9	103.4	34.2
2007	110.0	36.6	104.8	34.9
2008	111.4	37.3	106.1	35.5
2009	112.9	38.0	107.5	36.2
2010	114.3	38.7	108.8	36.9
2011	115.8	39.5	110.3	37.6
2012	117.2	40.2	111.6	38.3
2013	118.2	40.7	112.6	38.8





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

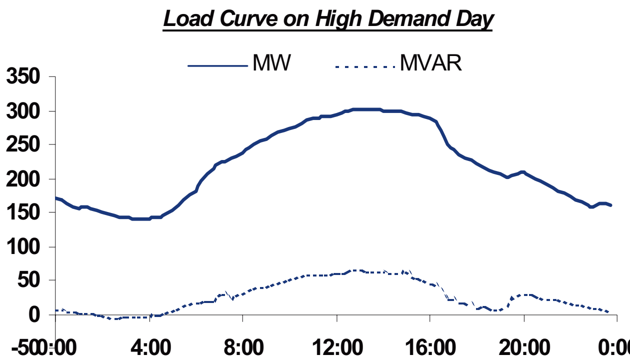
Anticipated new loads (about 7 MW) at WN zone sub station were not connected. Hence the anticipated new loads were removed from the forecasts.

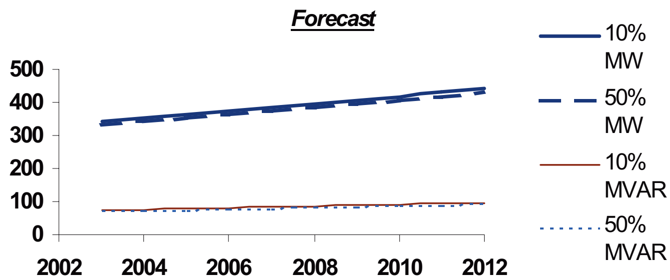
Heatherton Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:00 PM	301.80	64.90

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	339.7	73.1	330.7	71.1
2004	350.9	75.5	341.3	73.4
2005	362.5	78.0	352.2	75.8
2006	375.3	80.7	364.4	78.4
2007	385.5	82.9	374.1	80.5
2008	395.3	85.0	383.2	82.4
2009	406.0	87.3	393.2	84.6
2010	418.3	90.0	404.7	87.0
2011	431.1	92.7	417.0	89.7
2012	444.4	95.6	429.6	92.4
2013	458.1	98.5	442.6	95.2

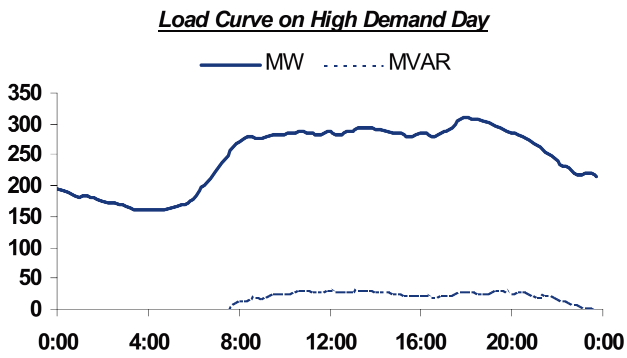


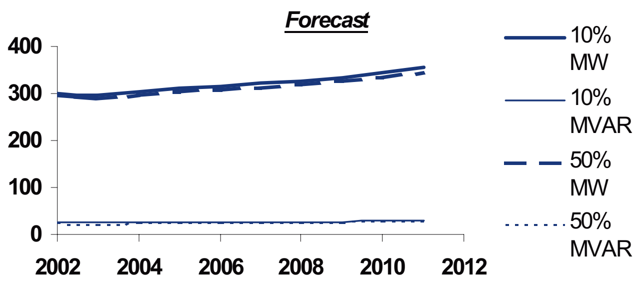


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 6:00 PM	311.80	27.82

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	301.0	25.1	294.9	24.5
2003	295.7	24.6	289.3	24.0
2004	303.8	25.3	296.9	24.7
2005	311.1	25.9	303.8	25.3
2006	316.1	26.3	308.5	25.6
2007	320.7	26.7	312.8	26.0
2008	326.9	27.2	318.6	26.5
2009	333.2	27.7	324.4	27.0
2010	343.4	28.6	334.2	27.8
2011	353.9	29.5	344.3	28.6
2012	364.7	30.4	354.6	29.5





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

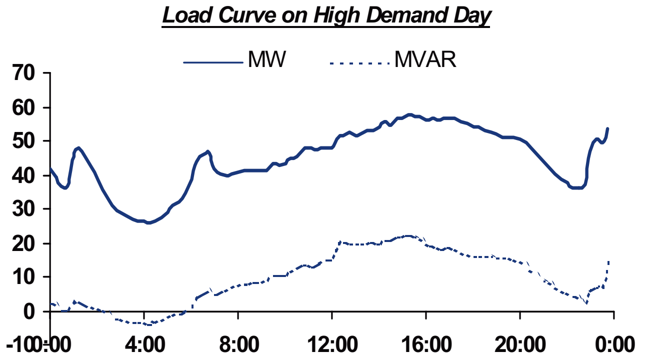
Comments:

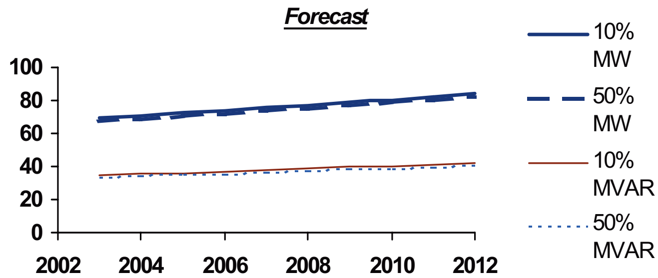
Horsham Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 3:30 PM	57.60	22.20

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	69.4	34.8	67.4	33.8
2004	70.8	35.5	68.8	34.5
2005	72.3	36.3	70.3	35.3
2006	73.8	37.0	71.8	36.0
2007	75.4	37.9	73.4	36.8
2008	77.1	38.7	75.1	37.7
2009	78.8	39.6	76.8	38.6
2010	80.5	40.4	78.5	39.4
2011	82.2	41.3	80.2	40.3
2012	83.9	42.1	81.9	41.1

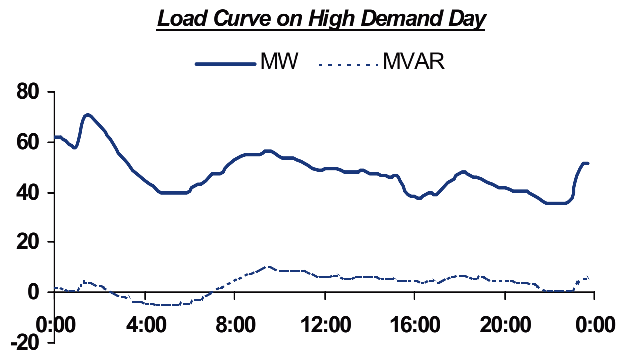


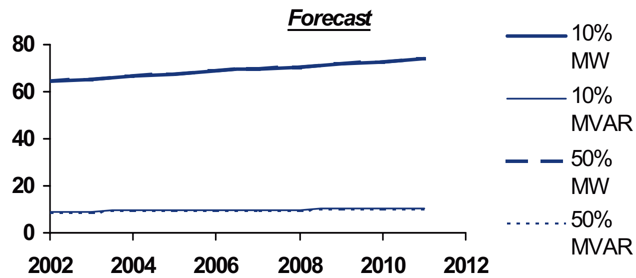


Winter Demand

Previous MD	MW	MVAR
15 May 2001 1:30 PM	275.08	

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	64.5	9.1	64.5	9.1
2003	65.5	9.2	65.5	9.2
2004	66.5	9.4	66.5	9.4
2005	67.5	9.5	67.5	9.5
2006	68.6	9.7	68.6	9.7
2007	69.6	9.8	69.6	9.8
2008	70.7	10.0	70.7	10.0
2009	71.8	10.1	71.8	10.1
2010	72.9	10.3	72.9	10.3
2011	74.0	10.4	74.0	10.4





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts.

Comments:

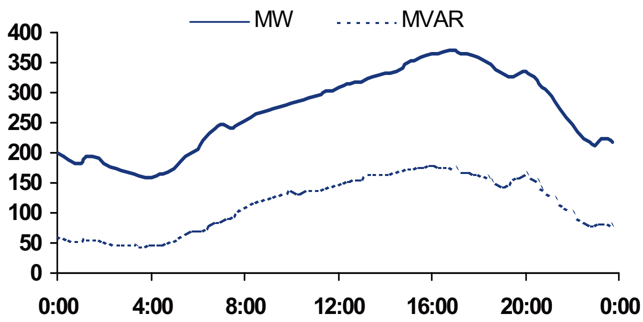
Keilor Terminal Station 66 kV Bus

Summer Demand

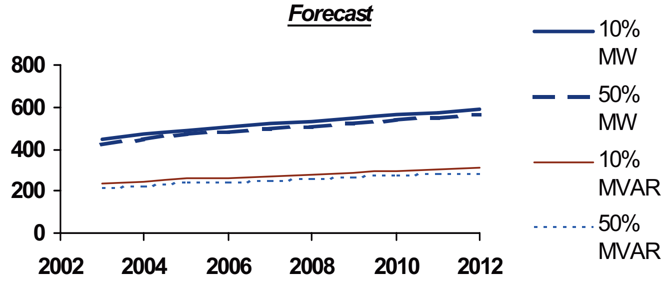
Previous MD	MW	MVAR
14 Feb 2002 4:45 PM	370.50	176.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	446.6	234.6	424.4	218.5
2004	471.9	247.4	449.3	231.0
2005	491.1	258.2	468.0	241.1
2006	504.1	264.8	480.8	247.6
2007	518.5	272.3	495.1	254.8
2008	532.8	279.5	509.1	261.8
2009	547.0	286.7	523.2	268.9
2010	560.8	293.7	536.8	275.6
2011	575.1	301.0	550.9	282.8
2012	589.1	308.2	564.8	289.7

Load Curve on High Demand Day



Forecast

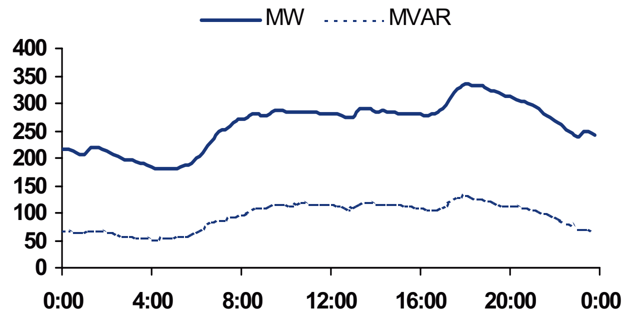


Winter Demand

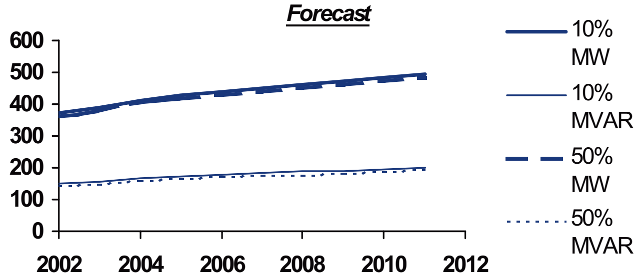
Previous MD	MW	MVAR
14 Jun 2001 6:00 PM	334.14	132.47

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	371.1	150.1	361.3	143.7
2003	389.9	157.6	379.9	151.1
2004	413.5	167.0	403.3	160.3
2005	429.1	173.5	418.5	166.4
2006	440.1	177.9	429.3	170.7
2007	452.4	182.8	441.5	175.6
2008	463.4	187.2	452.3	179.8
2009	473.8	191.4	462.7	183.9
2010	483.8	195.3	472.5	187.8
2011	494.0	199.4	482.7	191.9

Load Curve on High Demand Day



Forecast



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

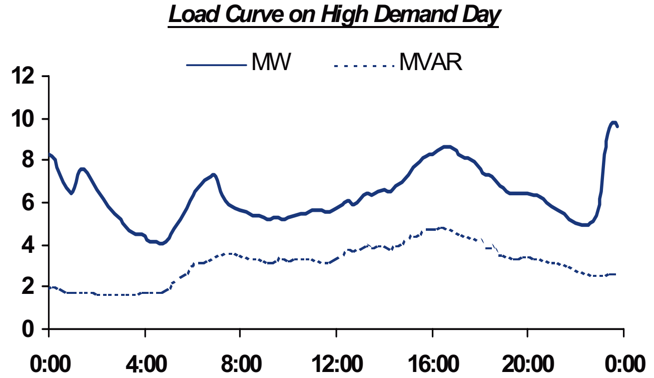
These forecast do not include loads at Powercor's zone substation Woodend (WND). AGL plans to transfer about 8MW of load from BLTS66 to KTS in 2005 (zone substation BY). Forecast includes known additional new load to the system.

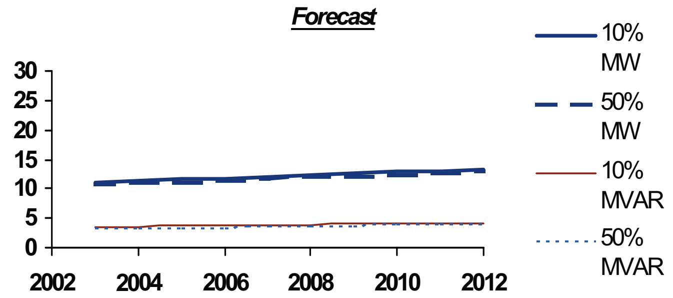
Kerang Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
25 Jan 2002 11:30 PM	9.80	2.70

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	11.1	3.6	10.7	3.4
2004	11.3	3.6	10.9	3.5
2005	11.6	3.7	11.2	3.6
2006	11.8	3.8	11.4	3.6
2007	12.0	3.8	11.6	3.7
2008	12.3	3.9	11.9	3.8
2009	12.5	4.0	12.1	3.9
2010	12.8	4.1	12.4	4.0
2011	13.0	4.2	12.6	4.0
2012	13.3	4.2	12.9	4.1

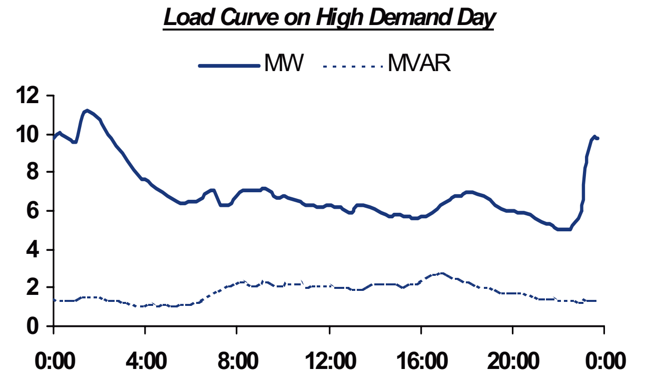


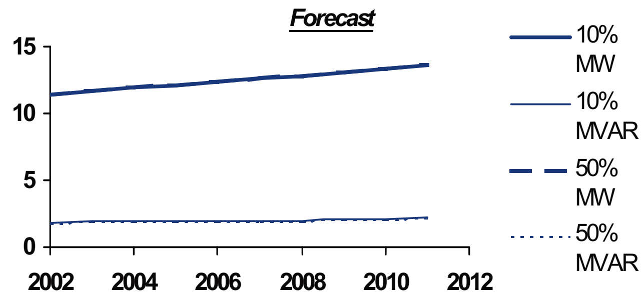


Winter Demand

Previous MD	MW	MVAR
03 Jul 2001 1:30 AM	11.21	1.53

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	11.4	1.8	11.4	1.8
2003	11.6	1.9	11.6	1.9
2004	11.9	1.9	11.9	1.9
2005	12.1	1.9	12.1	1.9
2006	12.3	2.0	12.3	2.0
2007	12.6	2.0	12.6	2.0
2008	12.8	2.0	12.8	2.0
2009	13.1	2.1	13.1	2.1
2010	13.4	2.1	13.4	2.1
2011	13.6	2.2	13.6	2.2





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

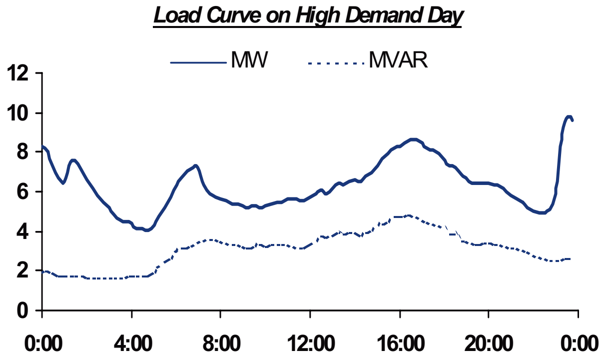
Comments:

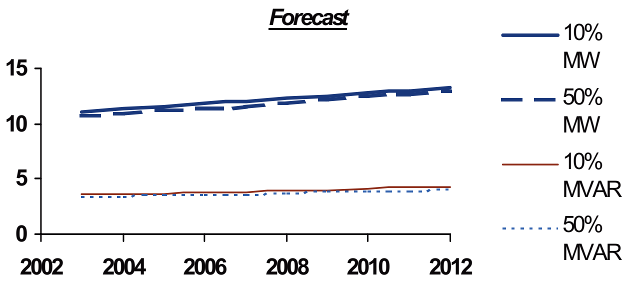
Kerang Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
25 Jan 2002 11:30 PM	9.80	2.70

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	11.1	3.6	10.7	3.4
2004	11.3	3.6	10.9	3.5
2005	11.6	3.7	11.2	3.6
2006	11.8	3.8	11.4	3.6
2007	12.0	3.8	11.6	3.7
2008	12.3	3.9	11.9	3.8
2009	12.5	4.0	12.1	3.9
2010	12.8	4.1	12.4	4.0
2011	13.0	4.2	12.6	4.0
2012	13.3	4.2	12.9	4.1

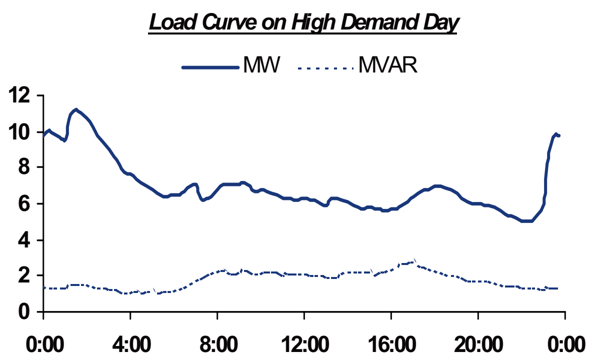


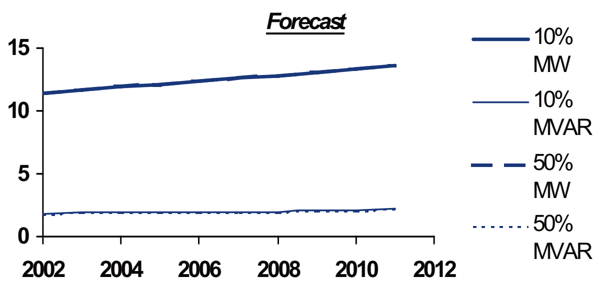


Winter Demand

Previous MD	MW	MVAR
03 Jul 2001 1:30 AM	11.21	1.53

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	11.4	1.8	11.4	1.8
2003	11.6	1.9	11.6	1.9
2004	11.9	1.9	11.9	1.9
2005	12.1	1.9	12.1	1.9
2006	12.3	2.0	12.3	2.0
2007	12.6	2.0	12.6	2.0
2008	12.8	2.0	12.8	2.0
2009	13.1	2.1	13.1	2.1
2010	13.4	2.1	13.4	2.1
2011	13.6	2.2	13.6	2.2





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

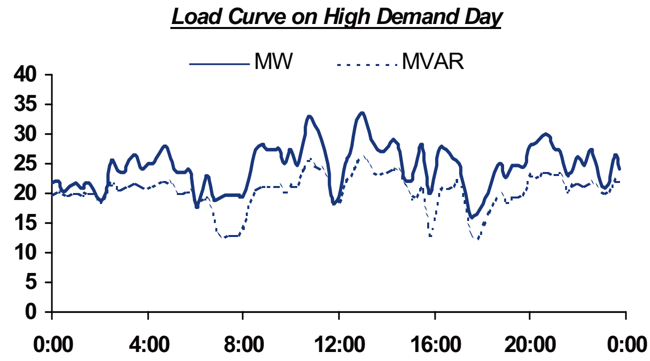
Comments:

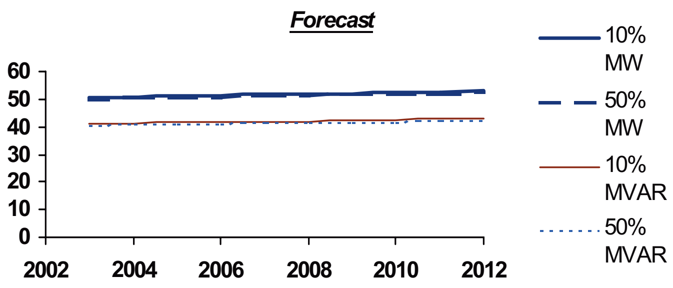
Loy Yang Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
29 Mar 2002 1:00 PM	33.50	25.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	50.5	41.0	50.0	40.6
2004	50.8	41.2	50.3	40.8
2005	51.0	41.4	50.5	41.0
2006	51.3	41.6	50.8	41.2
2007	51.5	41.8	51.0	41.4
2008	51.8	42.0	51.3	41.6
2009	52.1	42.2	51.5	41.8
2010	52.3	42.5	51.8	42.0
2011	52.6	42.7	52.1	42.3
2012	52.9	42.9	52.3	42.5

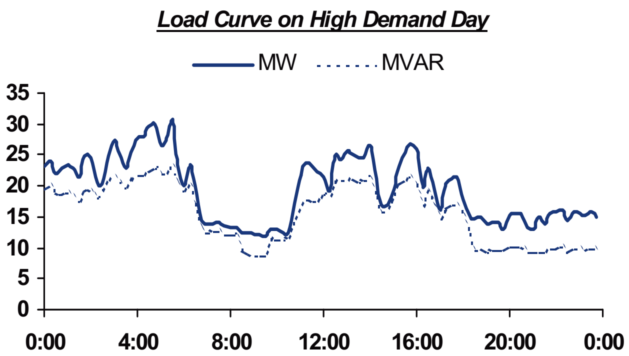


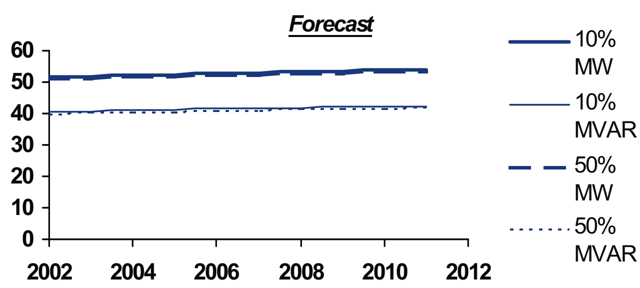


Winter Demand

Previous MD	MW	MVAR
23 Aug 2001 5:30 PM	33.50	25.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	51.5	40.6	51.0	40.2
2003	51.8	40.8	51.3	40.4
2004	52.1	41.0	51.5	40.6
2005	52.3	41.2	51.8	40.8
2006	52.6	41.4	52.1	41.0
2007	52.9	41.6	52.3	41.2
2008	53.2	41.8	52.6	41.4
2009	53.4	42.0	52.9	41.6
2010	53.7	42.3	53.2	41.8
2011	54.0	42.5	53.4	42.0
2012	54.3	42.7	53.7	42.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

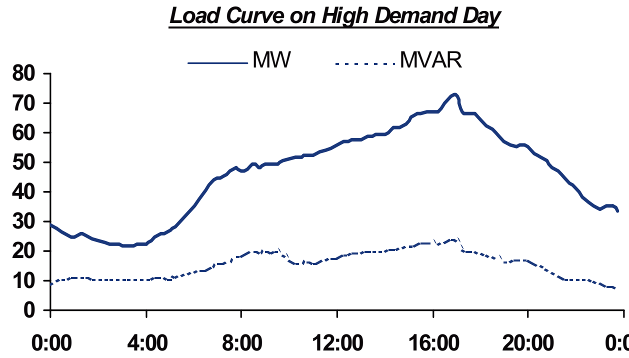
These forecasts allow for a continuous Loy Yang power station load of 25 MW. For an outage of a unit transformer the load could increase by up to 50MW.

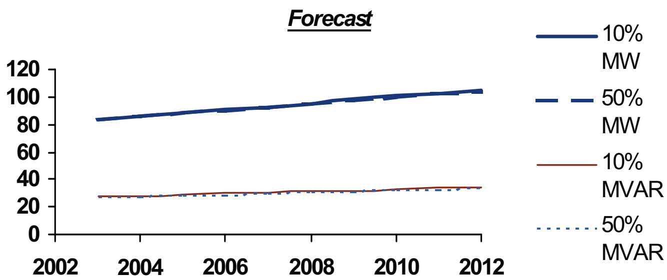
Malvern Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 4:45 PM	72.60	23.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	83.2	27.3	83.0	27.2
2004	86.4	28.4	86.0	28.3
2005	88.6	29.1	88.1	28.9
2006	90.7	29.8	90.2	29.6
2007	92.8	30.5	92.2	30.3
2008	95.3	31.3	94.6	31.1
2009	98.2	32.2	97.3	32.0
2010	100.7	33.1	99.7	32.8
2011	102.9	33.8	101.8	33.4
2012	105.1	34.5	103.9	34.1
2013	107.3	35.2	106.1	34.8

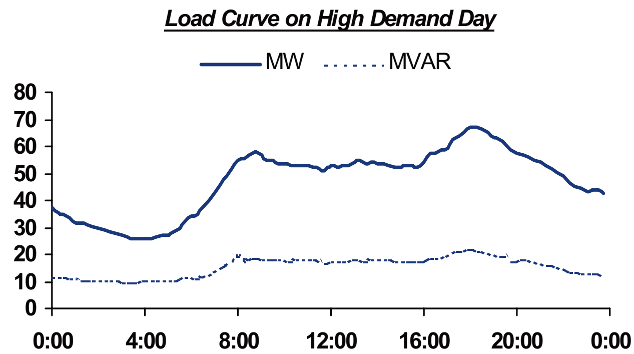


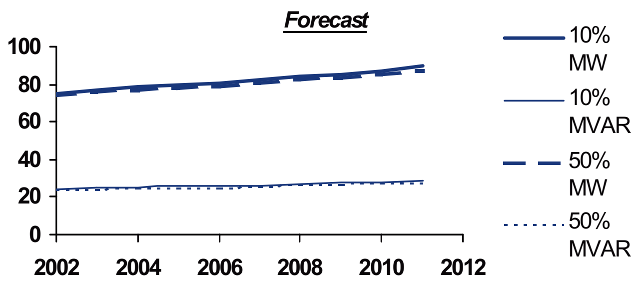


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 6:15 PM	66.99	21.45

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	75.4	24.1	74.1	23.7
2003	76.9	24.6	75.5	24.2
2004	78.5	25.1	77.0	24.7
2005	79.6	25.5	78.0	25.0
2006	80.6	25.8	79.0	25.3
2007	82.2	26.3	80.5	25.8
2008	84.2	27.0	82.4	26.4
2009	85.6	27.4	83.7	26.8
2010	87.5	28.0	85.5	27.4
2011	89.4	28.6	87.3	28.0
2012	91.4	29.3	89.2	28.6





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

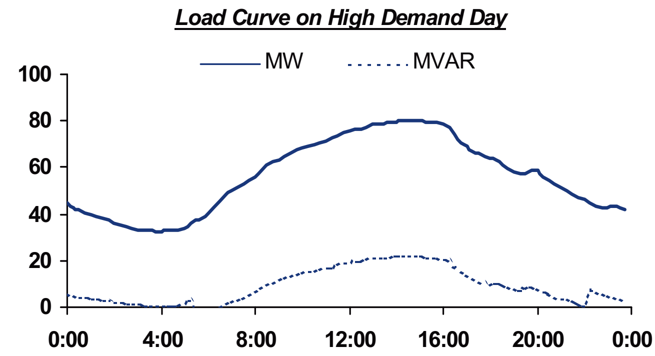
Comments:

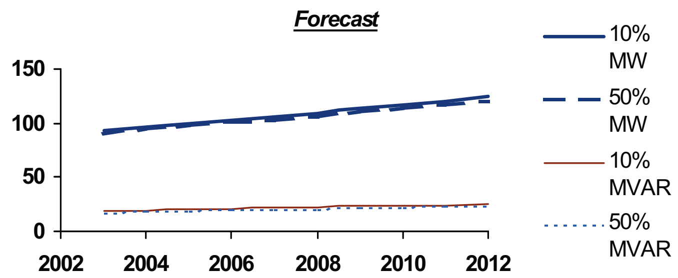
Malvern Terminal Station 66 kV Bus

Summer Demand

Previous MD	**MW**	**MVAR**
15 Feb 2002 3:00 PM	80.10	22.40

	10%		**50%**	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	93.0	18.7	90.5	18.1
2004	96.8	19.5	94.2	18.8
2005	100.1	20.2	97.3	19.4
2006	103.3	20.8	100.3	20.0
2007	106.1	21.4	103.0	20.5
2008	109.6	22.1	106.3	21.2
2009	113.4	22.9	109.9	21.9
2010	117.1	23.6	113.4	22.6
2011	120.5	24.3	116.6	23.2
2012	124.0	25.0	119.8	23.9
2013	127.5	25.7	123.2	24.6

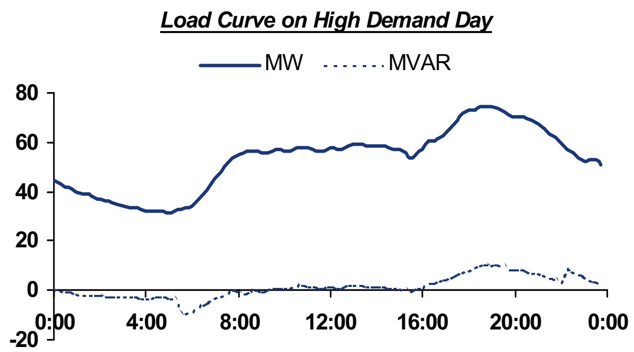


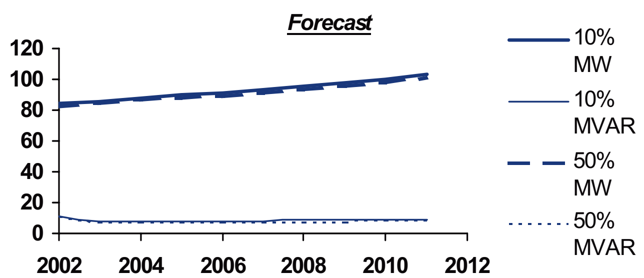


Winter Demand

Previous MD	**MW**	**MVAR**
14 Jun 2001 6:30 PM	74.75	9.70

	10%		**50%**	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	84.0	10.9	82.6	10.7
2003	85.8	7.5	84.2	7.3
2004	88.1	7.7	86.4	7.5
2005	89.8	7.9	88.0	7.7
2006	91.2	8.0	89.3	7.8
2007	93.2	8.2	91.3	7.9
2008	95.7	8.4	93.6	8.1
2009	97.8	8.6	95.6	8.3
2010	100.4	8.8	98.1	8.5
2011	103.1	9.1	100.7	8.8
2012	105.9	9.3	103.3	9.0





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

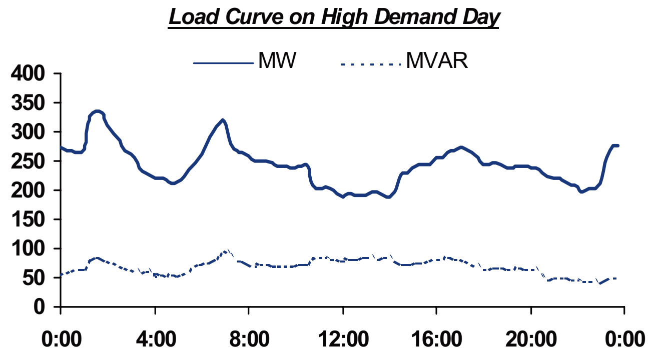
Demand figures are based on 15 minute energy forecasts

Comments:

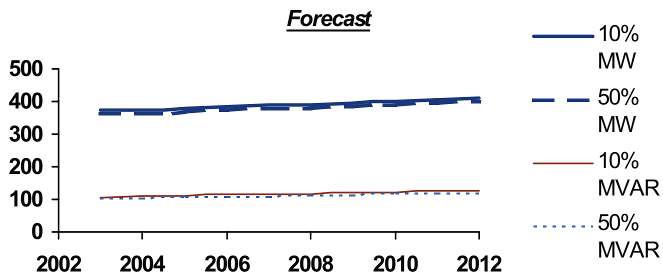
Morwell/Loy Yang Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
07 Dec 2001 1:30 AM	337.90	86.10

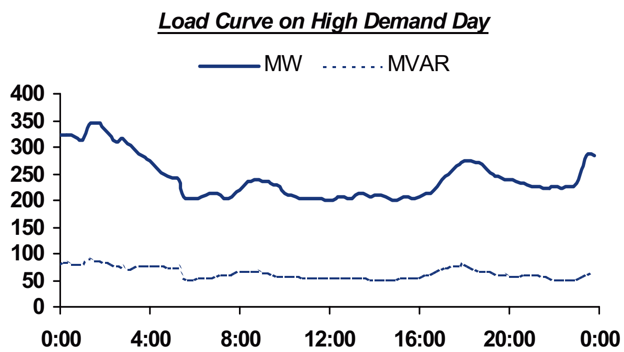


	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	372.1	107.8	362.0	105.3
2004	374.5	109.0	364.3	106.4
2005	378.8	111.1	368.5	108.5
2006	383.1	113.3	372.7	110.6
2007	387.4	115.4	376.9	112.7
2008	391.7	117.6	381.0	114.8
2009	396.1	119.8	385.3	116.9
2010	400.5	122.0	389.6	119.0
2011	404.9	124.2	393.8	121.2
2012	409.3	126.4	398.1	123.3

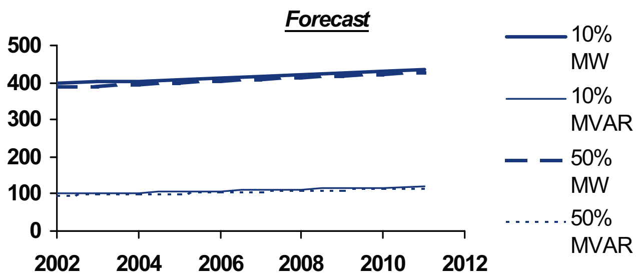


Winter Demand

Previous MD	MW	MVAR
11 Aug 2001 1:30 AM	356.25	90.68



	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	397.9	100.0	387.0	97.7
2003	402.0	102.1	391.0	99.8
2004	404.7	103.4	393.6	101.0
2005	409.2	105.7	398.0	103.3
2006	413.8	108.0	402.5	105.5
2007	418.4	110.3	406.9	107.7
2008	423.0	112.6	411.4	109.9
2009	427.5	114.9	415.8	112.2
2010	432.1	117.2	420.3	114.4
2011	436.8	119.5	424.8	116.6
2012	441.2	121.7	429.1	118.8



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

These forecasts allow for a continuous Loy Yang power station load of 25 MW. For an outage of a unit transformer the load could increase by up to 50MW.

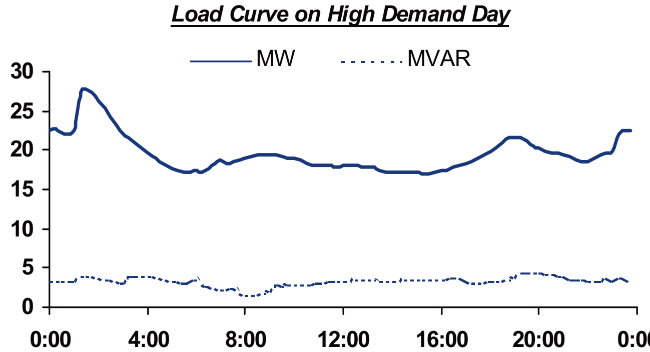
Forecasts include load supplied from Morwell Power Station G1, G2 and G3 units. Forecasts also includes load supplied from Bairnsdale power station generation, which is required to generate at least 20 MW at the (overnight) load peak.

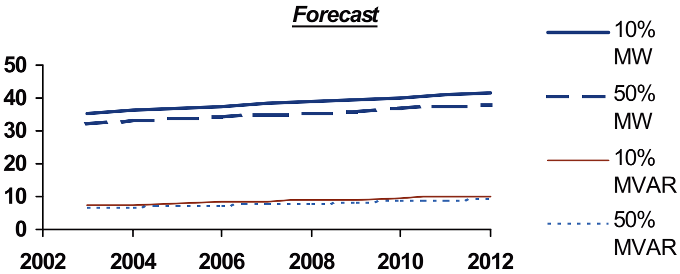
Mount Beauty Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
31 Mar 2002 1:30 AM	27.90	4.00

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	35.5	7.2	32.3	6.6
2004	36.2	7.5	32.9	6.9
2005	36.8	7.9	33.5	7.2
2006	37.5	8.2	34.1	7.5
2007	38.2	8.5	34.7	7.8
2008	38.9	8.9	35.4	8.1
2009	39.6	9.2	36.0	8.4
2010	40.2	9.6	36.6	8.7
2011	40.9	9.9	37.2	9.0
2012	41.6	10.2	37.8	9.3
2012	42.2	10.6	38.4	9.6

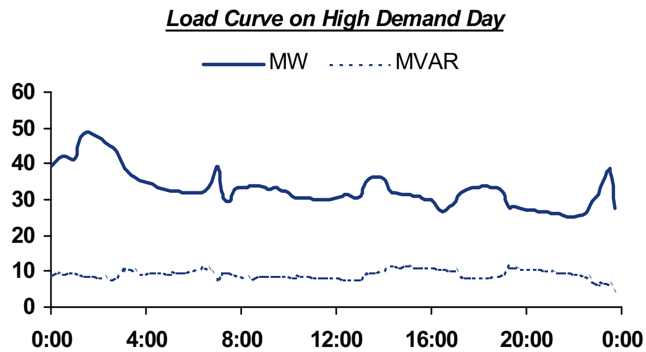


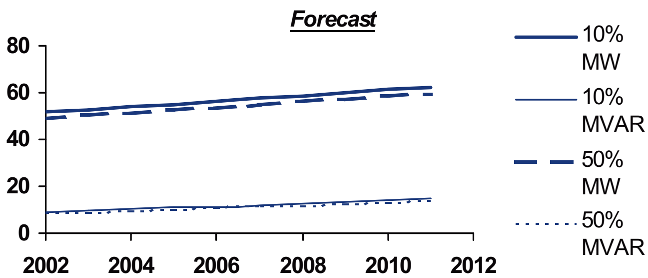


Winter Demand

Previous MD	MW	MVAR
04 Aug 2001 1:30 AM	43.27	5.16

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	51.5	9.0	49.0	8.6
2003	52.7	9.6	50.2	9.2
2004	53.9	10.2	51.3	9.7
2005	55.1	10.8	52.5	10.3
2006	56.3	11.4	53.6	10.9
2007	57.6	12.1	54.9	11.5
2008	58.8	12.7	56.0	12.1
2009	60.1	13.3	57.2	12.7
2010	61.3	13.9	58.3	13.2
2011	62.5	14.5	59.5	13.8
2012	63.8	15.2	60.8	14.5
2013	64.9	15.7	61.8	15.0





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

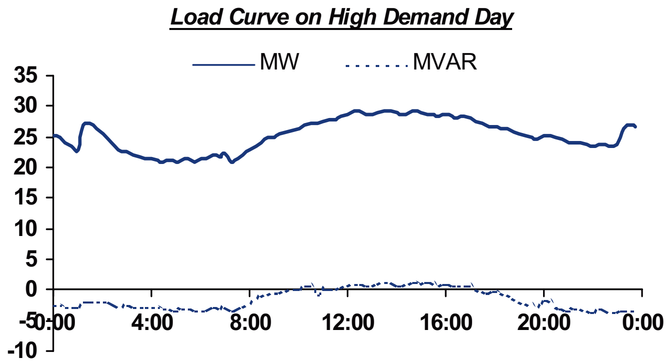
Forecast excludes generation from Clover Power Station.

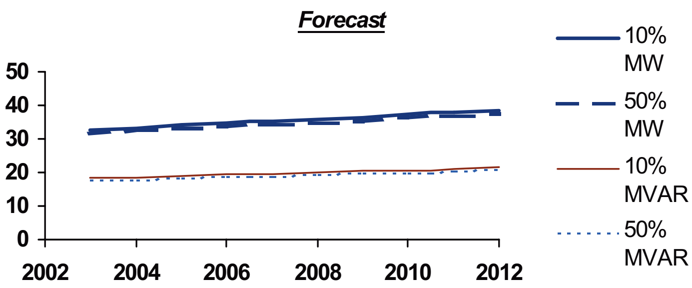
Red Cliffs Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
31 Mar 2002 1:30 AM	27.90	4.00

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	35.5	7.2	32.3	6.6
2004	36.2	7.5	32.9	6.9
2005	36.8	7.9	33.5	7.2
2006	37.5	8.2	34.1	7.5
2007	38.2	8.5	34.7	7.8
2008	38.9	8.9	35.4	8.1
2009	39.6	9.2	36.0	8.4
2010	40.2	9.6	36.6	8.7
2011	40.9	9.9	37.2	9.0
2012	41.6	10.2	37.8	9.3
2012	42.2	10.6	38.4	9.6

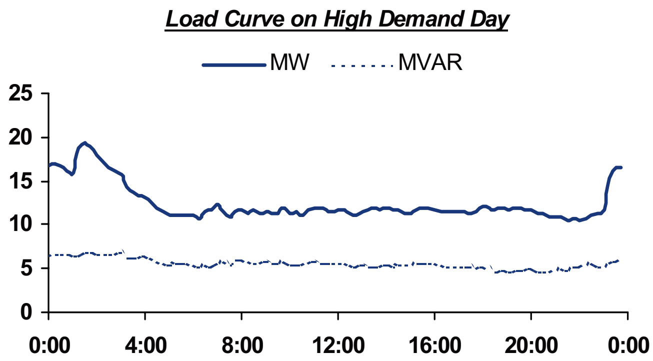


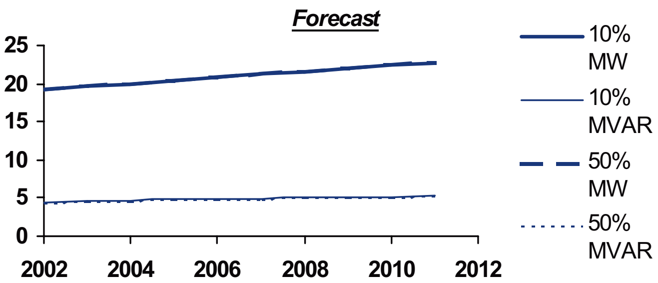


Winter Demand

Previous MD	MW	MVAR
04 Aug 2001 1:30 AM	43.27	5.16

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	51.5	9.0	49.0	8.6
2003	52.7	9.6	50.2	9.2
2004	53.9	10.2	51.3	9.7
2005	55.1	10.8	52.5	10.3
2006	56.3	11.4	53.6	10.9
2007	57.6	12.1	54.9	11.5
2008	58.8	12.7	56.0	12.1
2009	60.1	13.3	57.2	12.7
2010	61.3	13.9	58.3	13.2
2011	62.5	14.5	59.5	13.8
2012	63.8	15.2	60.8	14.5
2013	64.9	15.7	61.8	15.0





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

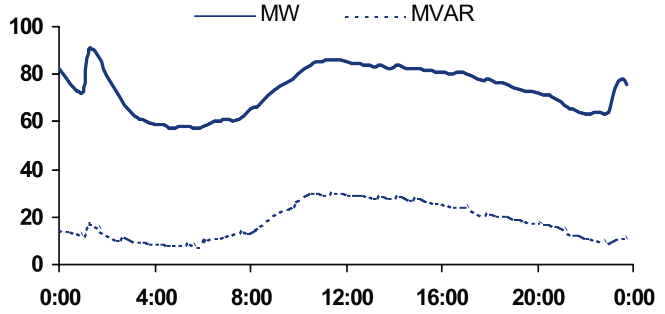
Red Cliffs Terminal Station 66 kV Bus

Summer Demand

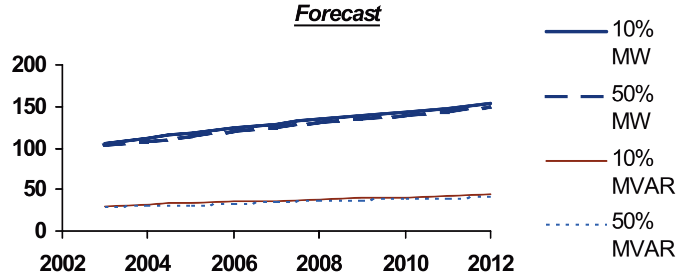
Previous MD	MW	MVAR
20 Jan 2002 1:15 AM	90.20	16.60

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	106.2	30.3	102.2	29.1
2004	111.8	31.9	107.8	30.7
2005	118.4	33.7	114.4	32.6
2006	123.9	35.3	119.9	34.2
2007	128.7	36.7	124.7	35.5
2008	133.9	38.2	129.9	37.0
2009	138.3	39.4	134.3	38.3
2010	143.3	40.8	139.3	39.7
2011	147.9	42.2	143.9	41.0
2012	152.8	43.5	148.8	42.4

Load Curve on High Demand Day



Forecast

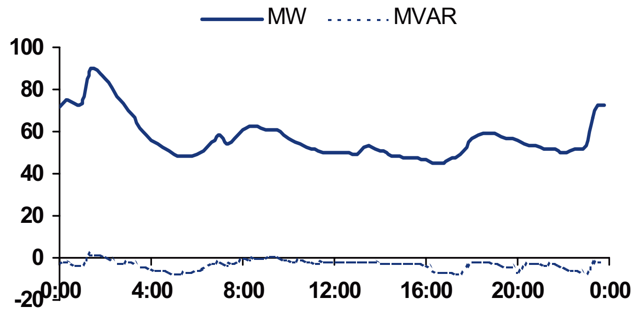


Winter Demand

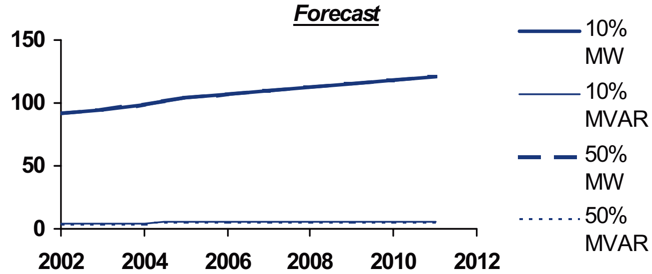
Previous MD	MW	MVAR
29 Jun 2001 1:30 AM	89.63	2.03

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	91.7	4.3	91.7	4.3
2003	94.7	4.5	94.7	4.5
2004	98.8	4.6	98.8	4.6
2005	104.2	4.9	104.2	4.9
2006	107.2	5.0	107.2	5.0
2007	109.6	5.2	109.6	5.2
2008	112.4	5.3	112.4	5.3
2009	115.3	5.4	115.3	5.4
2010	118.2	5.6	118.2	5.6
2011	121.1	5.7	121.1	5.7

Load Curve on High Demand Day



Forecast



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

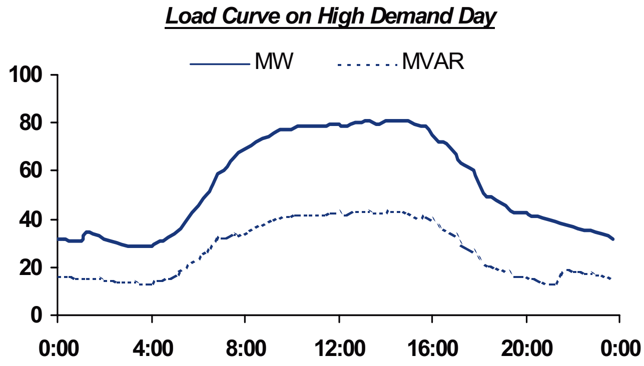
Comments:

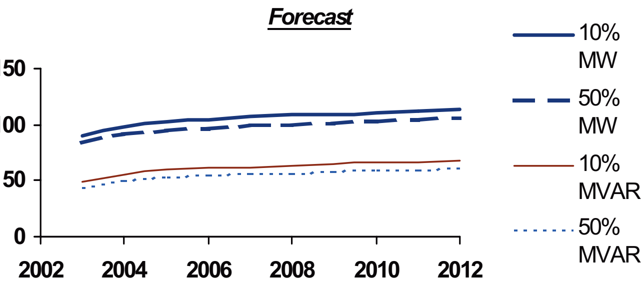
Richmond Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 2:45 PM	81.20	43.20

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	89.5	48.9	82.9	44.1
2004	98.4	55.7	91.1	50.4
2005	103.0	59.3	95.4	53.8
2006	104.9	60.8	97.1	55.1
2007	106.8	62.3	98.9	56.5
2008	108.2	63.4	100.2	57.6
2009	109.6	64.5	101.5	58.6
2010	111.0	65.6	102.8	59.6
2011	112.5	66.8	104.1	60.7
2012	113.9	67.9	105.5	61.7
2013	115.4	69	106.8	62.8

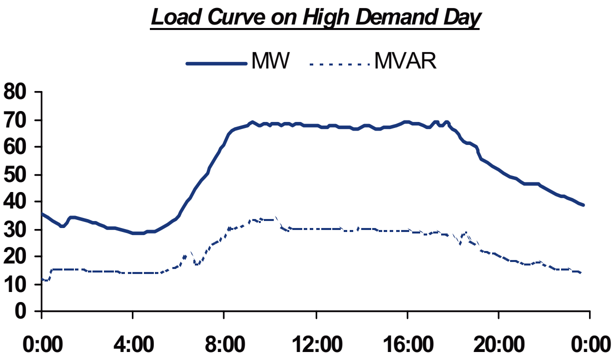


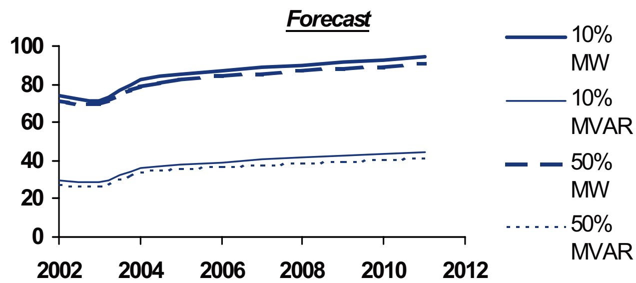


Winter Demand

Previous MD	MW	MVAR
26 Jul 2001 9:15 AM	69.03	33.23

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	73.8	29.8	70.9	28.0
2003	71.7	28.3	69.0	26.6
2004	82.3	35.8	79.1	33.9
2005	85.4	38.1	82.2	36.0
2006	87.2	39.3	83.8	37.2
2007	88.9	40.5	85.5	38.3
2008	90.1	41.4	86.7	39.2
2009	91.4	42.2	87.9	40.0
2010	92.7	43.1	89.1	40.9
2011	94.0	44.0	90.3	41.7
2012	95.2	44.9	91.6	42.6





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

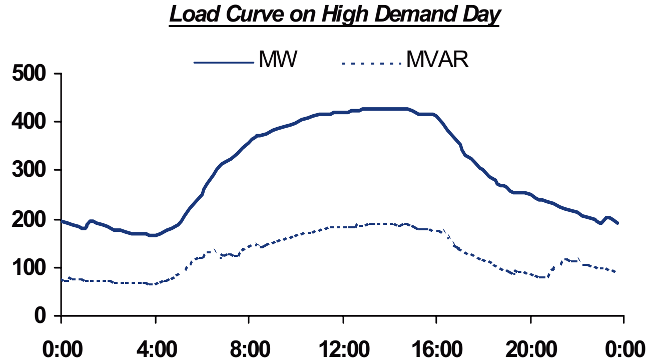
Comments:

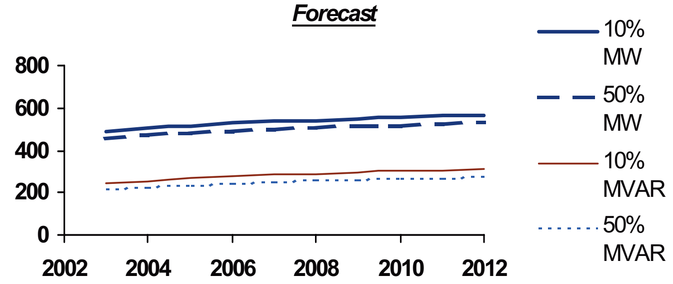
Richmond Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:15 PM	427.70	190.50

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	487.6	241.8	454.5	214.8
2004	502.9	255.0	468.6	227.2
2005	517.7	268.2	482.5	239.3
2006	527.7	276.9	491.7	247.3
2007	535.3	283.4	498.8	253.4
2008	541.6	288.5	504.6	258.2
2009	548.0	293.8	510.6	263.0
2010	554.6	299.2	516.7	268.1
2011	561.0	304.4	522.7	272.9
2012	567.5	309.7	528.6	277.9
2013	574	315.2	534.7	282.9

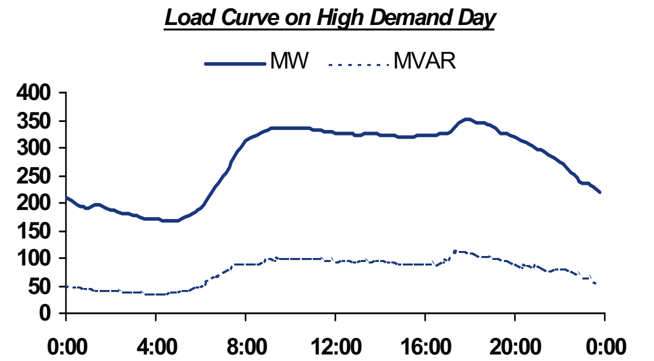


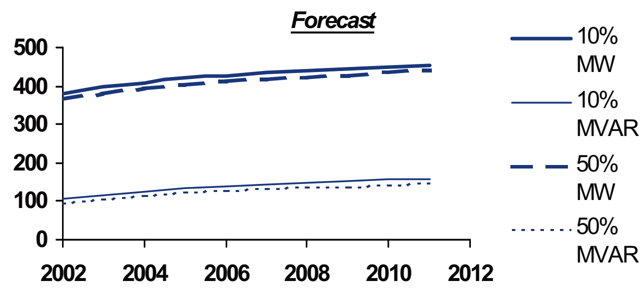


Winter Demand

Previous MD	MW	MVAR
19 Jun 2001 6:00 PM	351.98	109.44

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	379.8	106.7	366.4	97.5
2003	395.9	116.8	381.8	107.3
2004	409.0	126.5	394.3	116.6
2005	419.3	134.1	404.3	123.9
2006	426.0	138.9	410.8	128.5
2007	432.9	143.7	417.3	133.1
2008	438.6	147.5	422.8	136.7
2009	444.4	151.3	428.2	140.4
2010	450.0	155.2	433.7	144.0
2011	455.8	158.9	439.2	147.7
2012	461.4	162.8	444.6	151.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

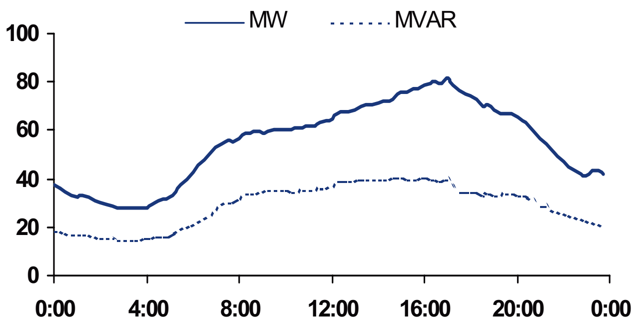
Ringwood Terminal Station 22 kV Bus

Summer Demand

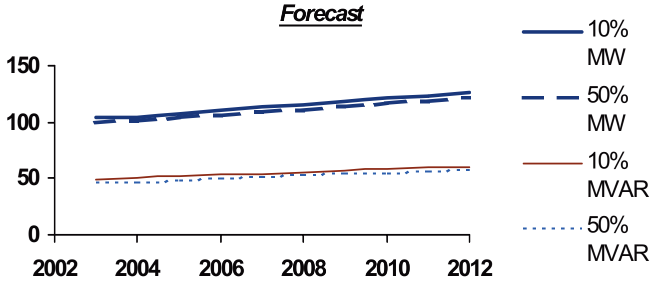
Previous MD	MW	MVAR
14 Feb 2002 5:00 PM	81.30	39.40

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	103.5	49.5	99.9	47.7
2004	104.5	50.0	100.8	48.1
2005	107.4	51.4	103.5	49.5
2006	110.3	52.9	106.3	50.8
2007	113.0	54.1	108.8	52.1
2008	115.7	55.4	111.3	53.3
2009	118.4	56.7	113.9	54.6
2010	121.3	58.3	116.7	56.0
2011	123.8	59.4	119.1	57.1
2012	126.2	60.6	121.3	58.3
2013	128.8	61.9	123.8	59.4

Load Curve on High Demand Day



Forecast

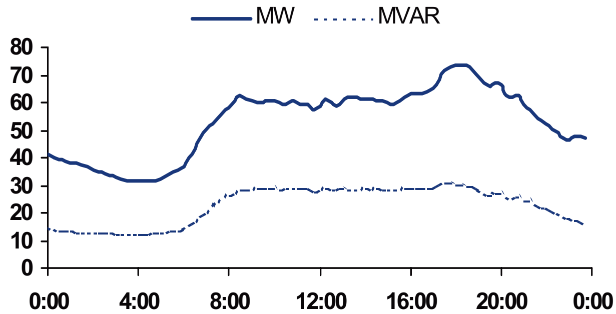


Winter Demand

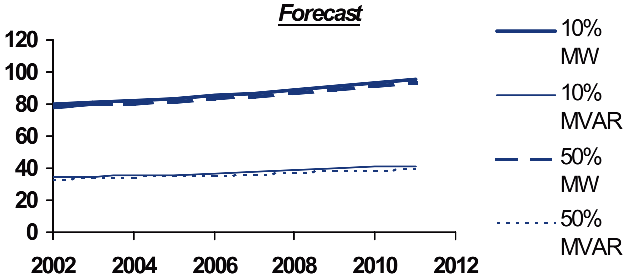
Previous MD	MW	MVAR
14 Jun 2001 6:00 PM	73.86	30.44

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	80.1	34.3	78.1	33.5
2003	81.6	35.0	79.6	34.2
2004	81.8	35.4	79.7	34.4
2005	83.6	36.1	81.4	35.2
2006	85.3	36.9	83.1	35.9
2007	87.1	37.8	84.8	36.8
2008	89.1	38.7	86.7	37.6
2009	91.1	39.6	88.7	38.5
2010	93.3	40.6	90.7	39.4
2011	95.6	41.6	92.9	40.4
2012	97.8	42.7	95.1	41.5

Load Curve on High Demand Day



Forecast



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

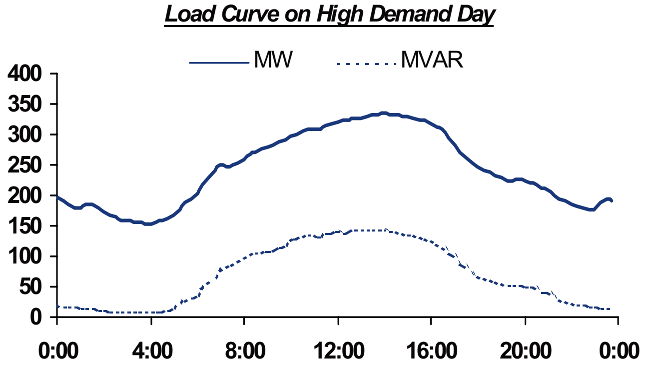
Comments:

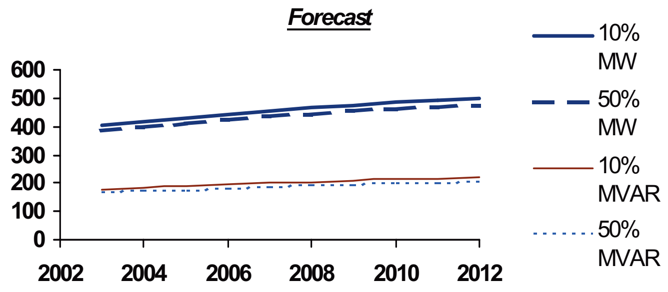
Ringwood Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 2:00 PM	334.30	144.90

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	404.8	176.6	385.4	167.6
2004	420.0	183.2	400.1	173.8
2005	432.2	188.8	411.5	179.2
2006	443.9	194.1	422.6	184.2
2007	455.4	199.4	433.3	189.1
2008	465.6	204.0	443.0	193.4
2009	474.9	208.2	451.8	197.3
2010	484.3	212.3	460.6	201.3
2011	493.0	216.0	468.7	204.8
2012	501.4	219.8	476.7	208.3
2013	509.9	223.6	484.7	211.9

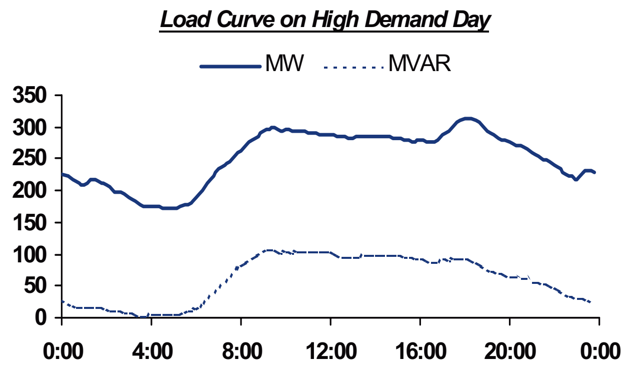


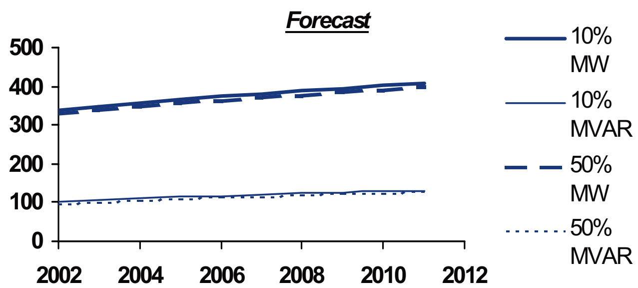


Winter Demand

Previous MD	MW	MVAR
03 Jul 2001 6:00 PM	313.32	92.08

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	336.5	101.3	327.7	98.6
2003	346.0	105.8	336.8	102.8
2004	356.8	110.0	347.4	107.0
2005	365.1	113.7	355.3	110.5
2006	372.8	117.2	362.8	113.9
2007	380.2	120.4	369.9	117.1
2008	387.3	123.6	376.7	120.0
2009	394.2	126.5	383.4	122.9
2010	401.0	129.2	390.0	125.6
2011	407.8	131.9	396.4	128.1
2012	414.7	134.6	403.1	130.8





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

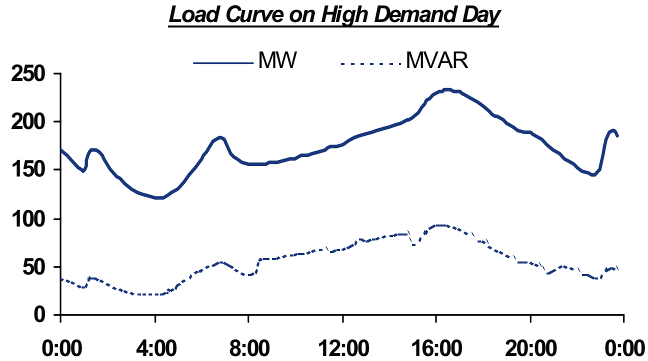
Comments:

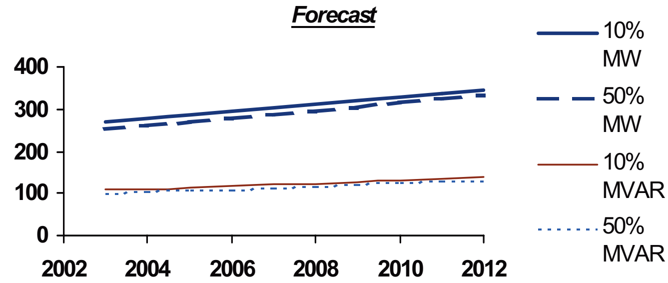
Shepparton Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
01 Feb 2002 4:30 PM	233.10	94.50

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	269.7	107.6	254.7	101.6
2004	277.1	110.6	262.1	104.6
2005	284.9	113.7	269.9	107.7
2006	292.8	116.8	277.8	110.8
2007	302.1	120.5	287.1	114.6
2008	310.7	124.0	295.7	118.0
2009	319.4	127.4	304.4	121.5
2010	328.8	131.2	313.8	125.2
2011	338.0	134.9	323.0	128.9
2012	347.1	138.5	332.1	132.5

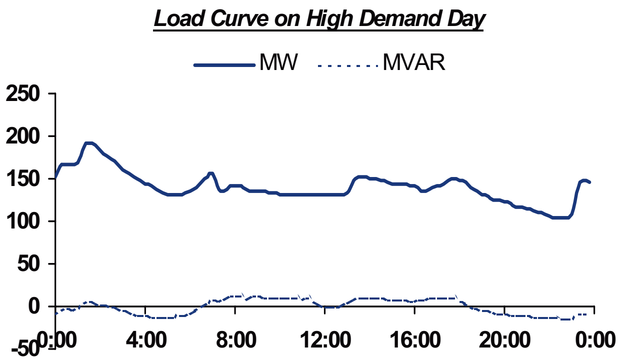


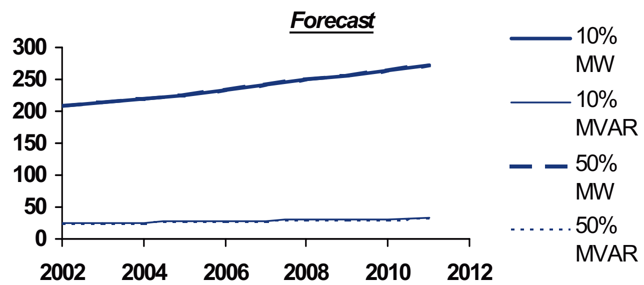


Winter Demand

Previous MD	MW	MVAR
20 Jun 2001 1:30 AM	190.79	6.64

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	207.4	24.5	207.4	24.5
2003	213.5	25.2	213.5	25.2
2004	219.8	25.9	219.8	25.9
2005	226.2	26.7	226.2	26.7
2006	232.9	27.5	232.9	27.5
2007	241.7	28.5	241.7	28.5
2008	249.0	29.4	249.0	29.4
2009	256.4	30.3	256.4	30.3
2010	264.0	31.2	264.0	31.2
2011	271.9	32.1	271.9	32.1





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

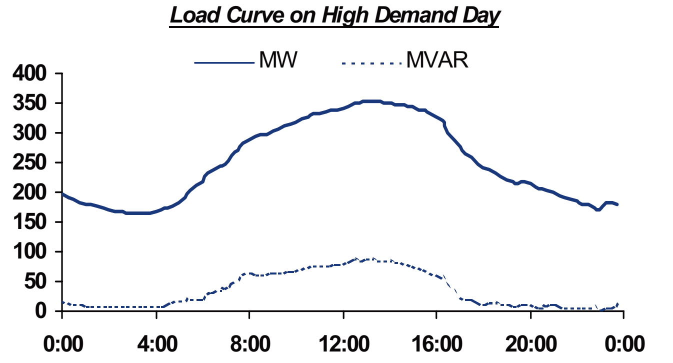
Comments:

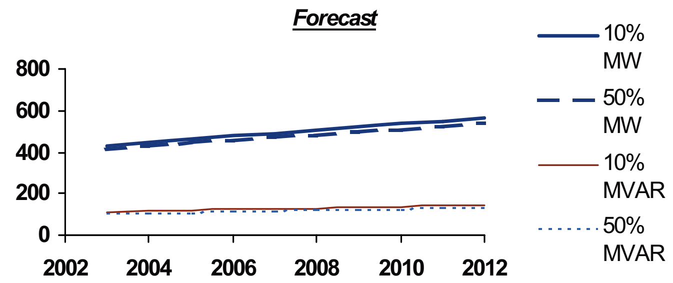
Springvale Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 1:15 PM	353.10	70.80

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	433.4	111.5	414.3	105.8
2004	448.4	115.3	428.4	109.4
2005	463.8	119.4	442.7	113.0
2006	477.5	122.8	455.2	116.2
2007	491.3	126.3	468.2	119.5
2008	504.6	129.7	480.5	122.6
2009	519.3	133.4	494.1	126.1
2010	535.0	137.5	508.6	129.9
2011	549.3	141.1	521.9	133.2
2012	563.9	144.8	535.4	136.7
2013	579.0	148.7	549.5	140.3

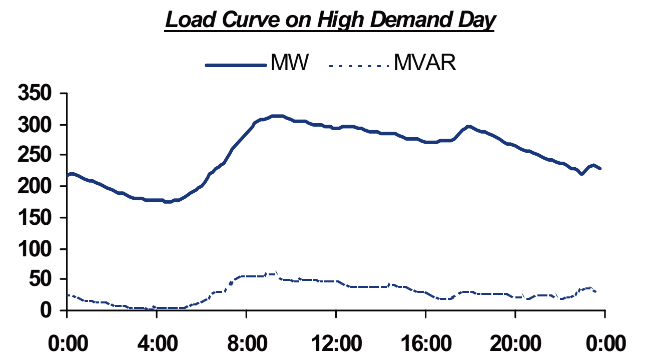


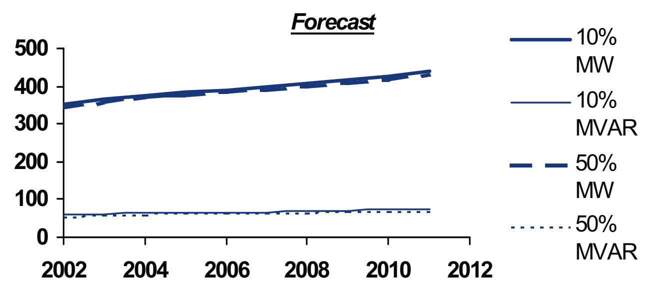


Winter Demand

Previous MD	MW	MVAR
04 Jul 2001 9:15 AM	317.48	63.59

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	350.3	59.1	343.5	57.4
2003	365.2	61.6	357.9	59.8
2004	376.5	63.4	368.8	61.6
2005	383.7	64.6	375.5	62.8
2006	391.2	65.8	382.6	63.9
2007	398.6	67.1	389.7	65.1
2008	407.8	68.6	398.4	66.5
2009	416.5	70.0	406.6	67.8
2010	427.8	71.9	417.5	69.6
2011	439.4	73.9	428.5	71.5
2012	451.3	75.8	439.9	73.4





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

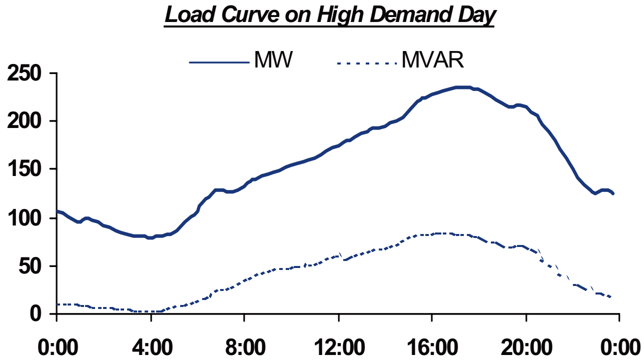
Forecasts include generation (18MW) from Clayton and Springvale landfill gas co-generators.

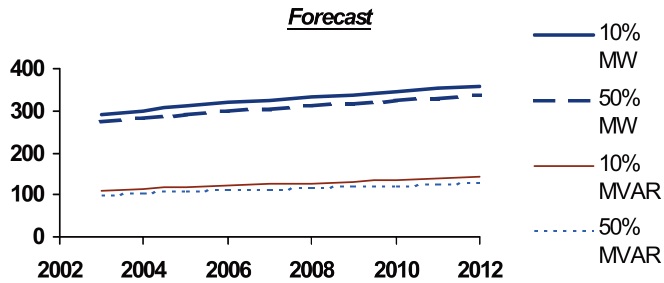
Templestowe Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
14 Feb 2002 5:30 PM	235.20	82.30

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	291.2	110.0	273.2	100.2
2004	300.4	114.2	281.7	104.1
2005	310.3	118.7	291.0	108.2
2006	317.9	122.2	298.2	111.7
2007	324.4	125.4	304.2	114.4
2008	330.7	128.2	309.9	117.2
2009	338.4	131.7	317.0	120.2
2010	346.4	135.3	324.6	123.6
2011	352.7	138.1	330.4	126.2
2012	359.2	141.1	336.2	128.9
2013	365.7	144.1	342.2	131.7

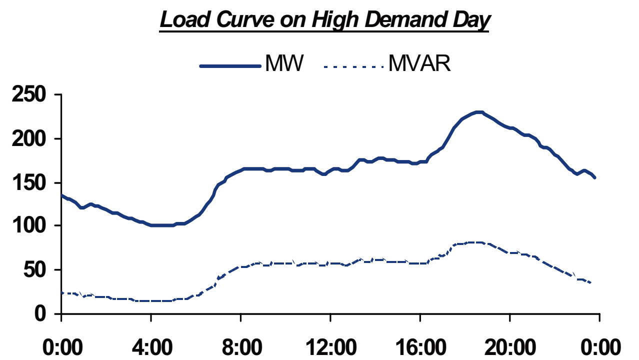


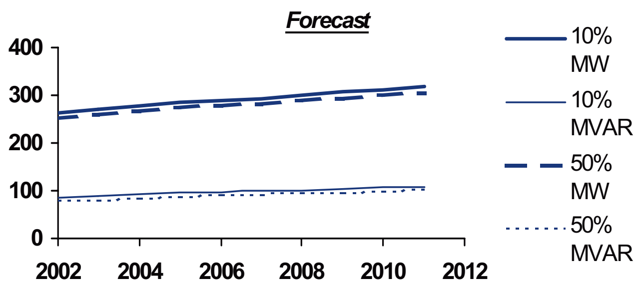


Winter Demand

Previous MD	MW	MVAR
14 Jun 2001 6:30 PM	230.00	83.38

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	268.7	88.5	257.8	82.9
2003	277.5	92.0	266.2	86.2
2004	284.0	94.8	272.3	88.8
2005	288.7	97.0	276.8	91.0
2006	293.3	99.1	281.1	93.0
2007	299.9	101.6	287.2	95.3
2008	306.0	104.1	293.2	97.7
2009	311.8	106.4	298.6	99.8
2010	317.7	108.8	304.3	102.2
2011	324.0	111.2	310.0	104.4





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

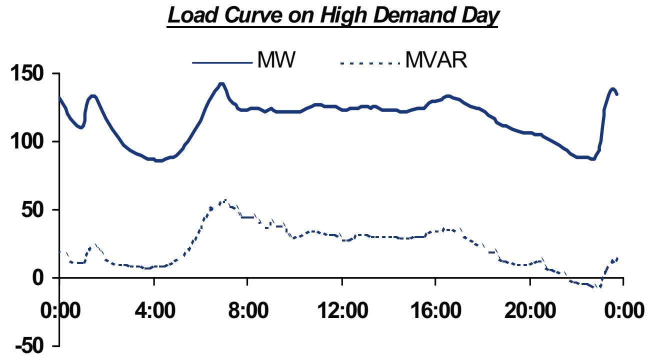
June 02: This forecast assumes an increased load at SLF based on last winter actual (I.e it recorded 15.5MW).

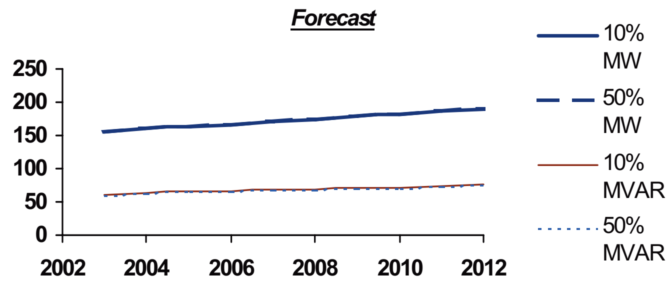
Terang Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
08 Feb 2001 7:00 AM	142.50	101.00

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	152.3	60.3	152.3	60.3
2003	158.1	62.6	158.1	62.6
2004	163.0	64.5	163.0	64.5
2005	174.0	68.9	174.0	68.9
2006	178.8	70.8	178.8	70.8
2007	183.8	72.8	183.8	72.8
2008	188.7	74.7	188.7	74.7
2009	193.6	76.7	193.6	76.7
2010	198.4	78.6	198.4	78.6
2011	203.2	80.5	203.2	80.5

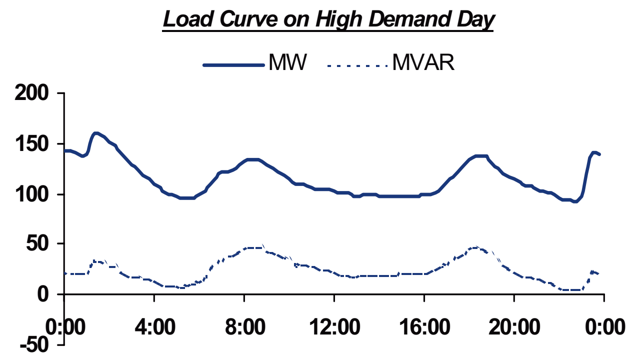


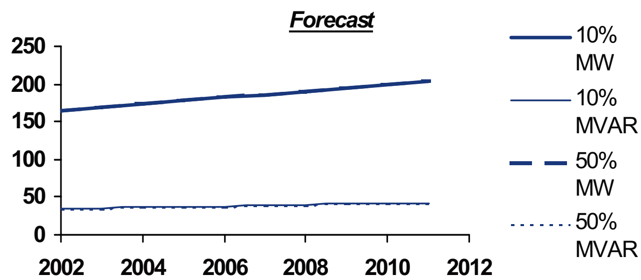


Winter Demand

Previous MD	MW	MVAR
06 Jul 2001 1:30 AM	158.26	25.30

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2001	170.0	35.5	170.0	35.5
2002	175.5	36.7	175.5	36.7
2003	180.0	37.6	180.0	37.6
2004	184.6	38.6	184.6	38.6
2005	195.1	40.8	195.1	40.8
2006	199.7	41.7	199.7	41.7
2007	204.3	42.7	204.3	42.7
2008	208.9	43.7	208.9	43.7
2009	213.6	44.6	213.6	44.6
2010	218.1	45.6	218.1	45.6





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

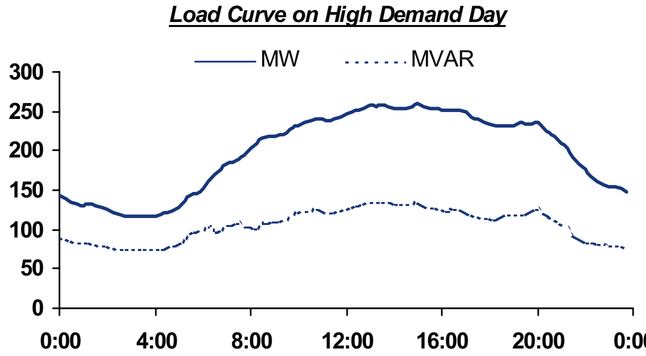
The highest Terang Terminal Station summer MD under normal system conditions has been used. This occurred in 2000/01.

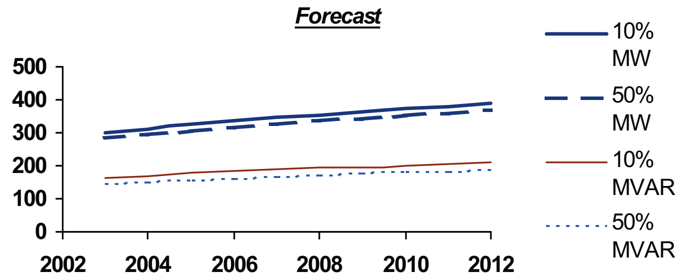
Thomastown Bus 1&2 Terminal Station 66 kV Bus

Summer Demand

Previous MD	**MW**	**MVAR**
14 Feb 2002 4:15 PM	242.40	114.50

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	301.0	164.0	283.8	148.5
2004	312.8	170.3	294.9	154.3
2005	324.6	176.5	306.2	160.0
2006	334.8	182.0	315.8	165.0
2007	345.2	187.4	325.6	170.1
2008	354.4	192.2	334.3	174.4
2009	363.4	197.0	342.7	178.8
2010	371.8	201.5	350.7	182.9
2011	379.7	205.7	358.2	186.7
2012	387.8	210.0	365.9	190.6
2013	395.0	213.9	372.7	194.3

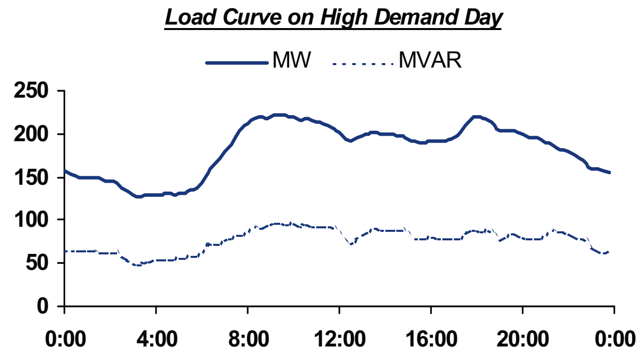


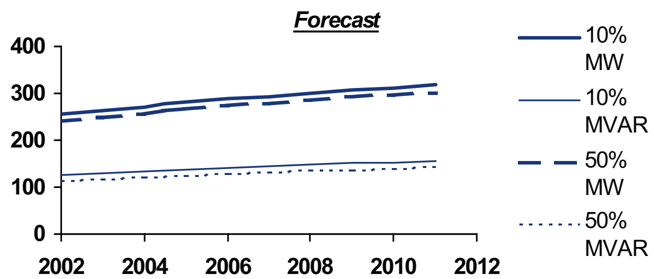


Winter Demand

Previous MD	**MW**	**MVAR**
14 Jun 2001 6:00 PM	225.01	92.04

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	254.4	124.7	241.4	114.5
2003	262.2	128.6	248.8	118.1
2004	271.1	133.1	257.4	122.1
2005	279.7	137.3	265.4	126.1
2006	287.1	141.0	272.6	129.5
2007	294.0	144.5	279.1	132.8
2008	300.1	147.5	284.8	135.6
2009	306.4	150.7	290.9	138.5
2010	312.1	153.5	296.3	141.2
2011	317.9	156.4	301.8	143.9
2012	323.9	159.4	307.5	146.6





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

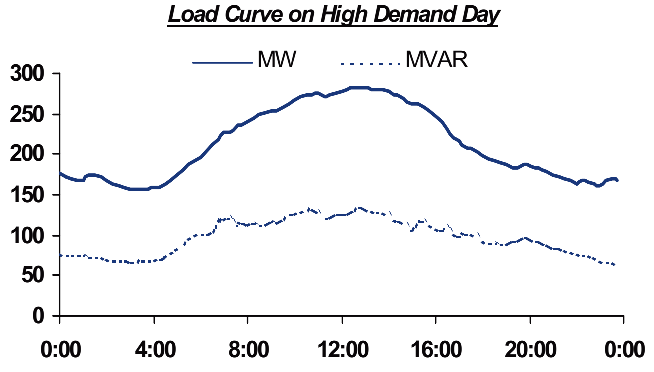
Somerton Power Station is not included in the forecast. Austin Hospital embedded generator in Heidelberg is included in the forecast. Australian Paper Fairfield embedded generator is included in the forecast.

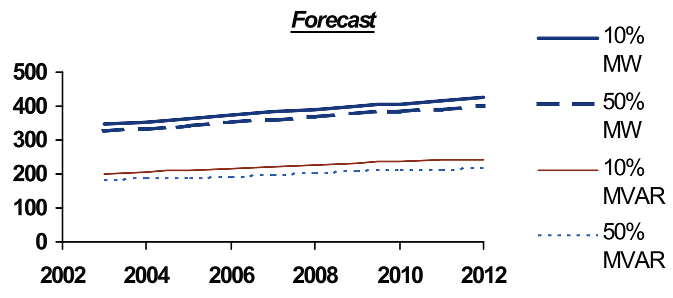
Thomastown Bus 3&4 Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
15 Feb 2002 12:45 PM	283.30	133.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	345.1	201.4	325.2	182.2
2004	354.5	206.5	334.2	186.9
2005	363.8	211.5	342.9	191.5
2006	372.4	216.1	351.1	195.7
2007	381.7	221.2	359.7	200.3
2008	390.8	226.1	368.4	204.9
2009	399.1	230.7	376.4	209.0
2010	407.7	235.4	384.4	213.3
2011	415.8	239.9	392.1	217.3
2012	424.0	244.4	399.8	221.5
2013	431.7	248.6	407.0	225.3

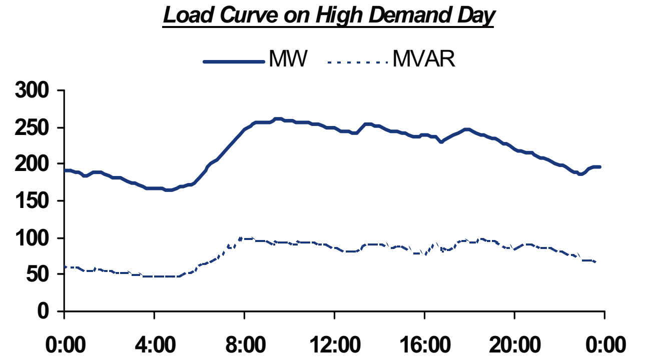


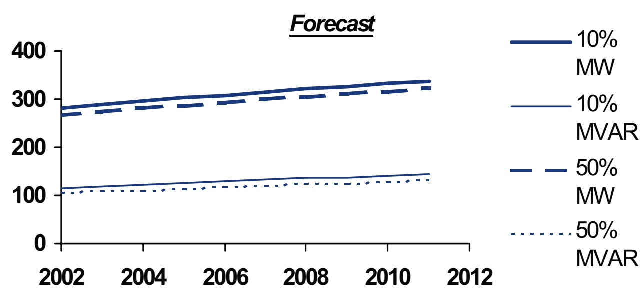


Winter Demand

Previous MD	MW	MVAR
20 Jun 2001 9:30 AM	260.50	93.61

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	281.2	116.0	266.8	105.8
2003	289.0	119.9	274.2	109.4
2004	296.2	123.4	281.1	112.6
2005	302.4	126.5	287.0	115.5
2006	308.8	129.7	293.1	118.5
2007	315.7	133.1	299.7	121.6
2008	321.4	135.9	305.1	124.2
2009	327.2	138.8	310.6	126.9
2010	333.2	141.7	316.2	129.6
2011	338.3	144.2	321.1	132.0
2012	343.6	146.8	326.1	134.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

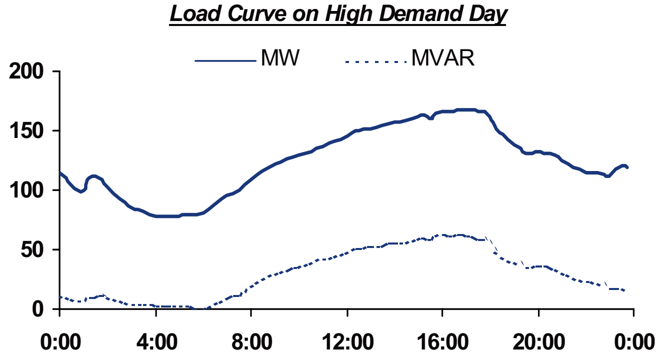
Bolinda Landfill embedded generator in Broadmeadows is included in the forecast.

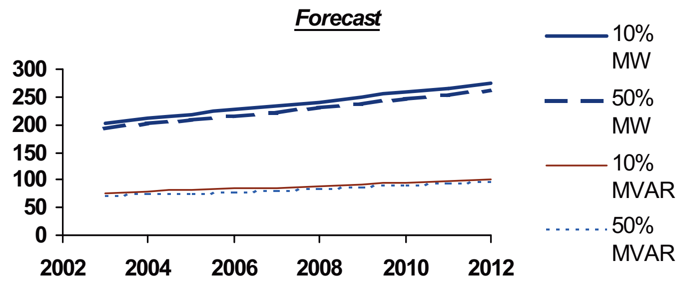
Tyabb Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
26 Jan 2002 5:00 PM	283.30	133.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	201.6	74.6	192.3	71.2
2004	210.9	78.1	201.1	74.4
2005	218.7	80.9	208.3	77.1
2006	226.1	83.7	215.3	79.7
2007	232.8	86.2	221.6	82.0
2008	240.8	89.1	229.1	84.8
2009	249.9	92.5	237.7	88.0
2010	259.0	95.8	246.1	91.1
2011	266.6	98.7	253.3	93.7
2012	274.6	101.6	260.7	96.5
2013	282.7	104.6	268.4	99.3

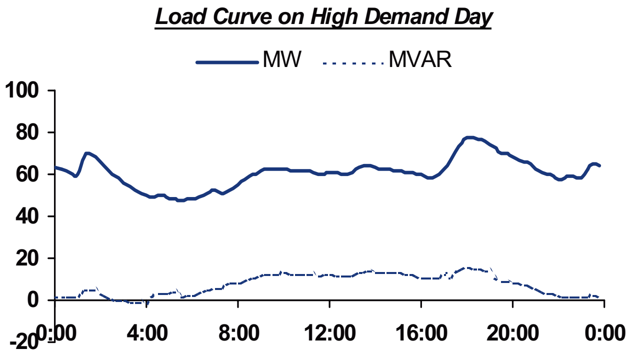


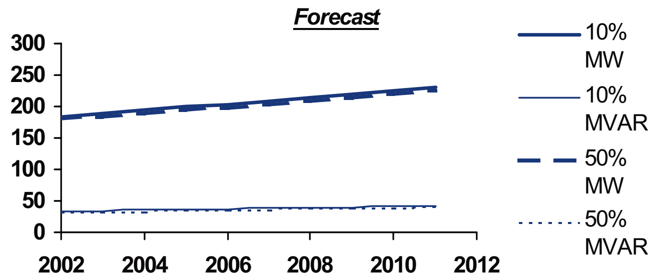


Winter Demand

Previous MD	MW	MVAR
20 Jun 2001 9:30 AM	260.50	93.61

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	183.9	33.7	179.5	32.9
2003	188.6	34.6	184.0	33.7
2004	194.4	35.6	189.5	34.7
2005	198.7	36.4	193.5	35.5
2006	202.4	37.1	197.0	36.1
2007	207.2	38.0	201.6	36.9
2008	213.6	39.1	207.7	38.1
2009	219.1	40.1	212.9	39.0
2010	225.4	41.3	218.9	40.1
2011	231.9	42.5	225.1	41.2
2012	238.6	43.7	231.5	42.4





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

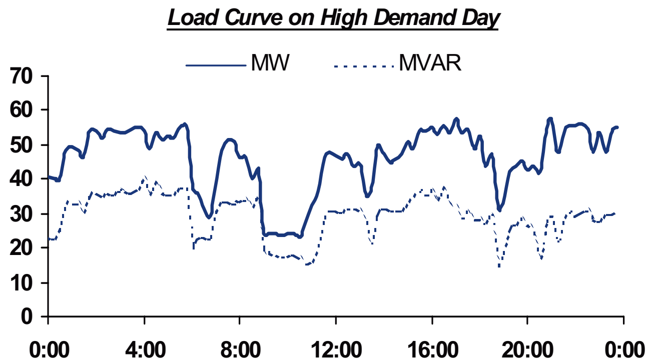
Comments:

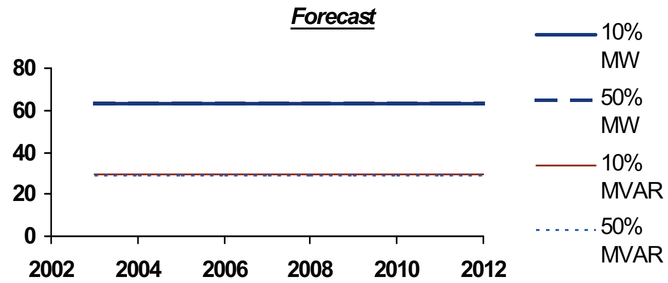
Tyabb Terminal Station 220 kV Bus

Summer Demand

Previous MD	MW	MVAR
29 Mar 2002 7:30 AM	64.31	37.99

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	63.5	29.9	63.5	29.9
2004	63.5	29.9	63.5	29.9
2005	63.5	29.9	63.5	29.9
2006	63.5	29.9	63.5	29.9
2007	63.5	29.9	63.5	29.9
2008	63.5	29.9	63.5	29.9
2009	63.5	29.9	63.5	29.9
2010	63.5	29.9	63.5	29.9
2011	63.5	29.9	63.5	29.9
2012	63.5	29.9	63.5	29.9
2013	63.5	29.9	63.5	29.9

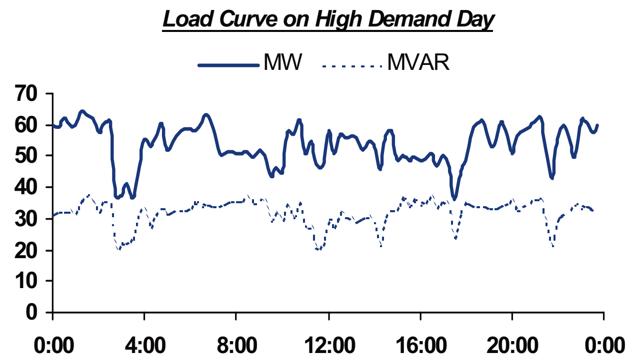


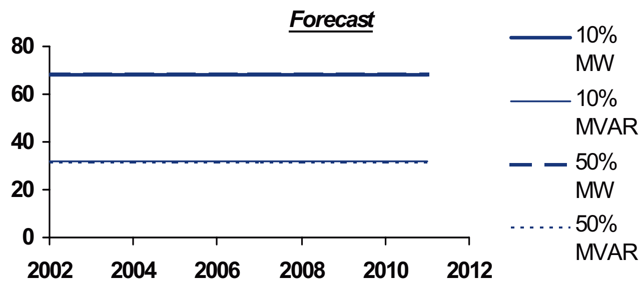


Winter Demand

Previous MD	MW	MVAR
19 Jul 2001 8:15 PM	67.11	39.13

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	67.8	31.9	67.8	31.9
2003	67.8	31.9	67.8	31.9
2004	67.8	31.9	67.8	31.9
2005	67.8	31.9	67.8	31.9
2006	67.8	31.9	67.8	31.9
2007	67.8	31.9	67.8	31.9
2008	67.8	31.9	67.8	31.9
2009	67.8	31.9	67.8	31.9
2010	67.8	31.9	67.8	31.9
2011	67.8	31.9	67.8	31.9
2012	67.8	31.9	63.5	31.9





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

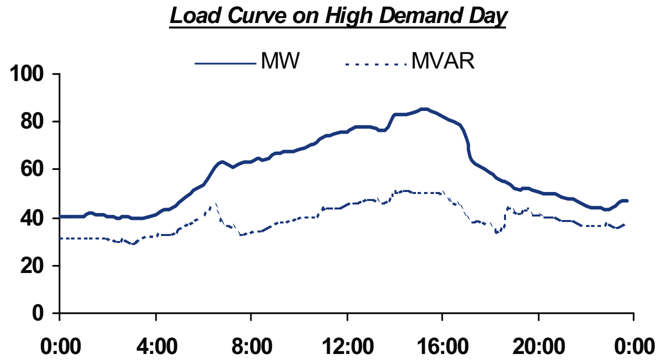
Comments:

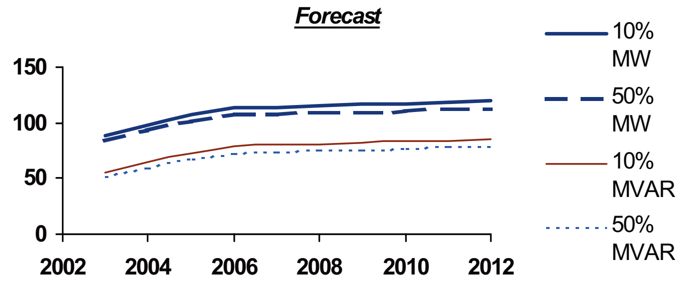
West Melbourne Terminal Station 22 kV Bus

Summer Demand

Previous MD	**MW**	**MVAR**
25 Feb 2002 3:15 PM	85.10	51.10

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	88.6	55.7	83.6	51.6
2004	98.6	65.0	93.0	60.4
2005	107.3	73.3	101.2	68.2
2006	113.0	78.8	106.6	73.4
2007	114.0	79.8	107.6	74.3
2008	115.1	80.8	108.6	75.3
2009	116.1	81.8	109.5	76.2
2010	117.2	82.9	110.5	77.2
2011	118.2	83.9	111.5	78.2
2012	119.3	84.9	112.5	79.2
2013	120.4	86.0	113.6	80.2

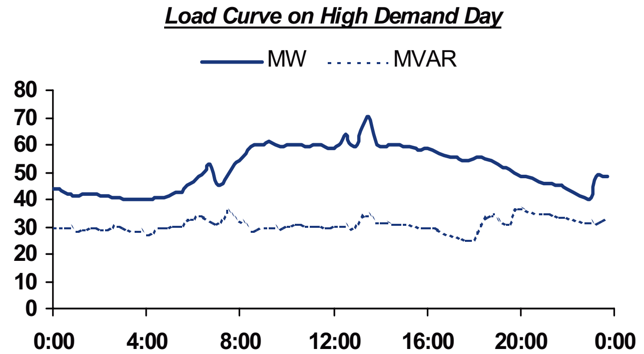


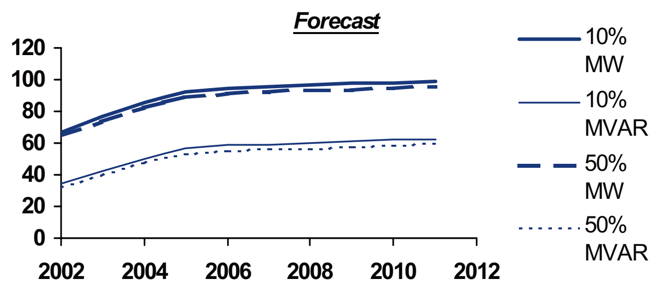


Winter Demand

Previous MD	**MW**	**MVAR**
20 Aug 2001 1:30 PM	70.18	34.29

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	67.2	33.9	64.6	32.0
2003	76.2	41.9	73.3	39.6
2004	85.3	50.0	82.0	47.4
2005	92.2	56.3	88.7	53.5
2006	94.7	58.5	91.1	55.6
2007	95.6	59.3	91.9	56.4
2008	96.5	60.1	92.8	57.1
2009	97.4	60.9	93.6	57.9
2010	98.3	61.7	94.5	58.7
2011	99.2	62.5	95.4	59.5
2012	100.1	63.3	96.2	60.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

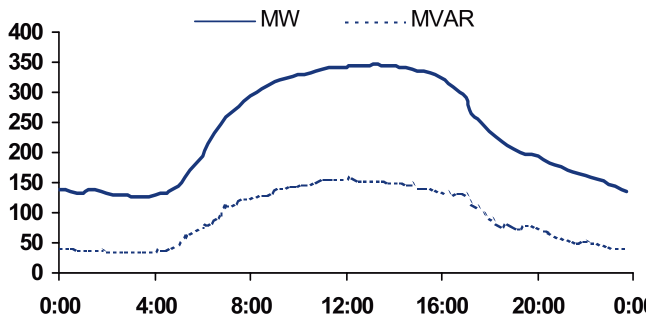
West Melbourne Terminal Station 66 kV Bus

Summer Demand

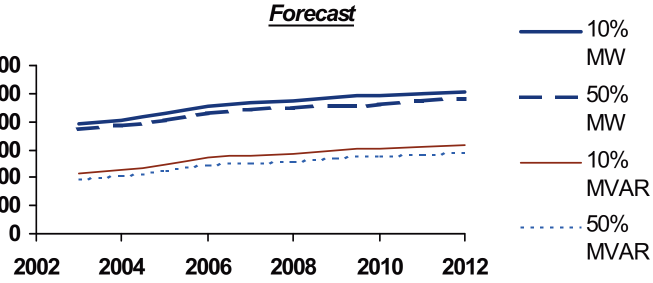
Previous MD	MW	MVAR
15 Feb 2002 1:15 PM	345.70	152.90

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	392.1	213.4	369.6	194.0
2004	406.5	228.4	383.3	208.2
2005	426.5	248.5	402.1	227.1
2006	457.9	269.1	431.7	246.1
2007	467.5	278.6	440.7	255.0
2008	475.4	286.1	448.2	262.0
2009	483.4	293.7	455.8	269.2
2010	491.6	301.5	463.4	276.4
2011	499.7	309.4	471.2	283.9
2012	508.0	317.4	479.0	291.4
2013	516.5	325.5	487.0	299.0

Load Curve on High Demand Day



Forecast

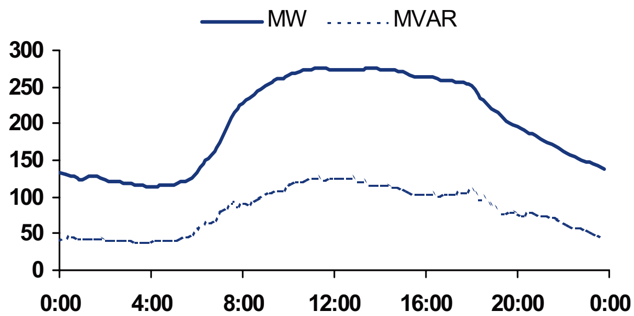


Winter Demand

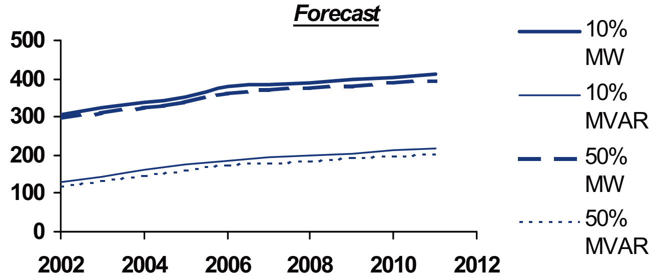
Previous MD	MW	MVAR
15 May 2001 1:30 PM	275.08	

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	307.8	130.4	295.7	121.0
2003	321.9	143.9	309.2	133.9
2004	337.1	159.8	323.9	149.3
2005	352.3	175.0	338.4	163.8
2006	377.7	187.3	362.8	175.6
2007	383.9	193.3	368.7	181.3
2008	390.5	199.3	375.0	187.0
2009	397.1	205.4	381.3	192.9
2010	403.8	211.6	387.7	198.8
2011	410.5	217.9	394.2	204.9
2012	417.3	224.3	400.7	211.1

Load Curve on High Demand Day



Forecast



Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

Comments:

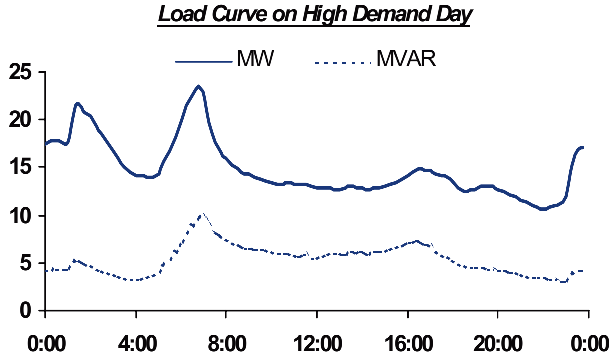
AGL plans to transfer about 17MW of load from BLTS66 to WMTS in 2006.

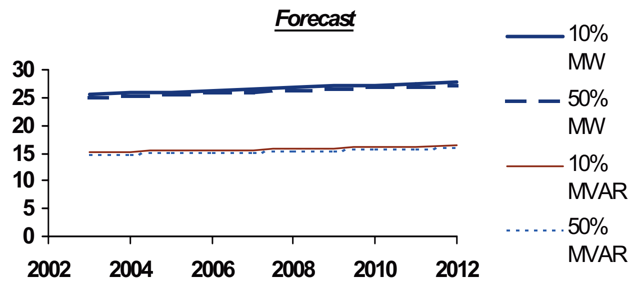
Wodonga Terminal Station 22 kV Bus

Summer Demand

Previous MD	MW	MVAR
01 Nov 2001 6:45 AM	23.50	9.80

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	25.5	15.1	25.0	14.8
2004	25.8	15.3	25.3	15.0
2005	26.0	15.4	25.5	15.1
2006	26.3	15.5	25.8	15.2
2007	26.5	15.6	26.0	15.3
2008	26.8	15.8	26.3	15.5
2009	27.1	15.9	26.5	15.6
2010	27.3	16.0	26.8	15.7
2011	27.6	16.2	27.0	15.8
2012	27.8	16.3	27.3	16.0
2013	28.0	16.4	27.5	16.1

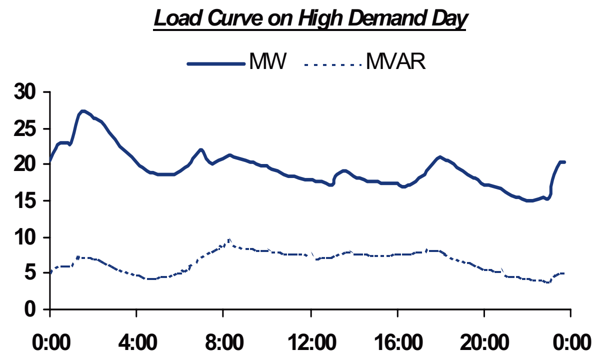


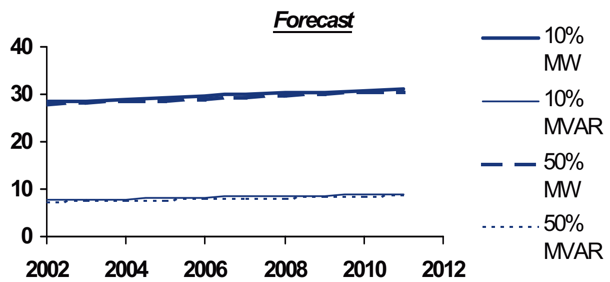


Winter Demand

Previous MD	MW	MVAR
03 Jul 2001 1:30 AM	27.24	7.33

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	28.4	7.6	27.8	7.5
2003	28.7	7.8	28.1	7.6
2004	29.0	7.9	28.4	7.8
2005	29.3	8.1	28.7	7.9
2006	29.6	8.2	29.0	8.1
2007	29.9	8.4	29.3	8.2
2008	30.2	8.5	29.6	8.3
2009	30.5	8.7	29.9	8.5
2010	30.8	8.8	30.2	8.6
2011	31.1	9.0	30.5	8.8
2012	31.4	9.1	30.8	8.9
2013	31.7	9.3	31.0	9.1





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts

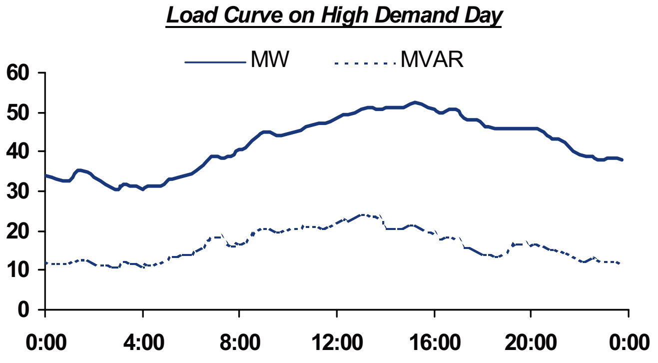
Comments:

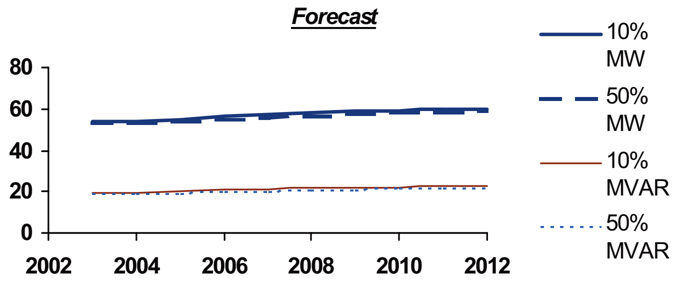
Wodonga Terminal Station 66 kV Bus

Summer Demand

Previous MD	MW	MVAR
31 Jan 2002 4:00 PM	48.40	16.40

	10%		50%	
Year	MW	MVAR	MW	MVAR
2003	54.1	19.6	53.0	19.2
2004	54.0	19.6	53.0	19.2
2005	55.1	20.1	54.0	19.7
2006	56.1	20.7	55.0	20.2
2007	56.9	21.1	55.8	20.6
2008	57.7	21.5	56.6	21.0
2009	58.6	21.9	57.4	21.4
2010	59.1	22.1	58.0	21.7
2011	59.7	22.4	58.5	22.0
2012	60.2	22.7	59.1	22.3
2013	60.6	22.9	59.5	22.5

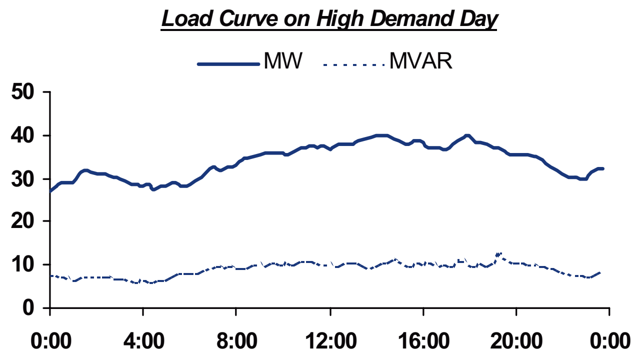


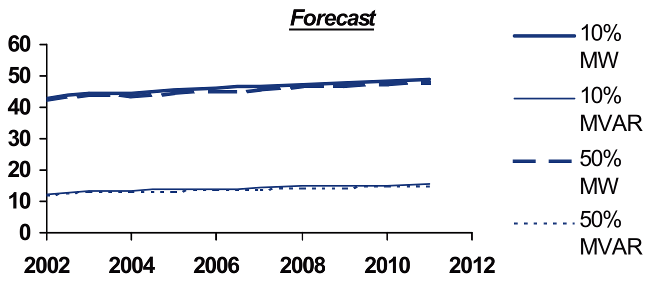


Winter Demand

Previous MD	MW	MVAR
15 May 2001 1:30 PM	275.08	

	10%		50%	
Year	MW	MVAR	MW	MVAR
2002	42.8	12.5	42.0	12.3
2003	44.7	13.4	43.8	13.2
2004	44.5	13.3	43.6	13.1
2005	45.4	13.8	44.5	13.5
2006	46.0	14.1	45.1	13.8
2007	46.7	14.4	45.8	14.1
2008	47.4	14.8	46.4	14.5
2009	47.8	15.0	46.9	14.7
2010	48.3	15.2	47.3	14.9
2011	48.7	15.5	47.8	15.2
2012	48.7	15.5	47.8	15.2
2013	49.1	15.6	48.1	15.3





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts.

Comments:

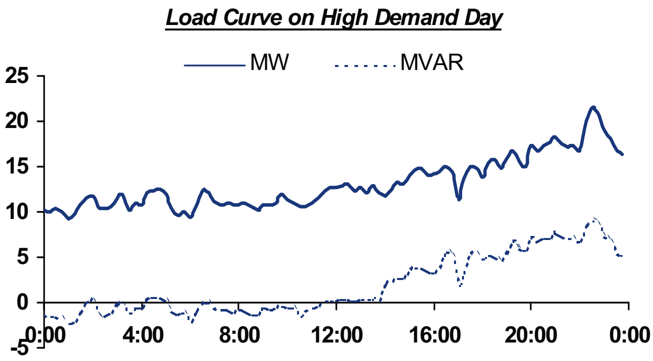
Forecast excludes generation from Hume Power Station.

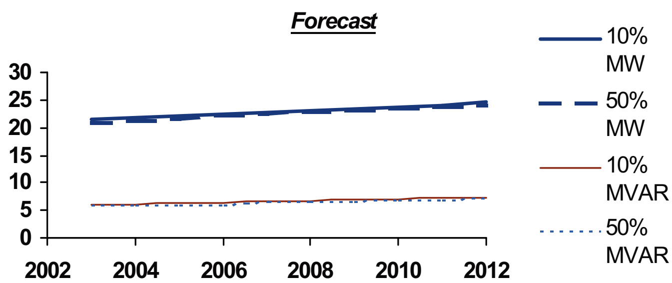
Yallourn Terminal Station 11 kV Bus

Summer Demand

Previous MD	MW	MVAR
02 Feb 2002 10:30 PM	21.50	9.10

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2003	21.4	6.0	21.0	5.9
2004	21.7	6.1	21.3	6.0
2005	22.1	6.2	21.6	6.1
2006	22.4	6.3	22.0	6.1
2007	22.7	6.6	22.3	6.5
2008	23.1	6.7	22.6	6.6
2009	23.4	6.8	23.0	6.7
2010	23.8	6.9	23.3	6.8
2011	24.1	7.2	23.7	7.1
2012	24.5	7.3	24.0	7.2
2013	24.9	7.5	24.4	7.3

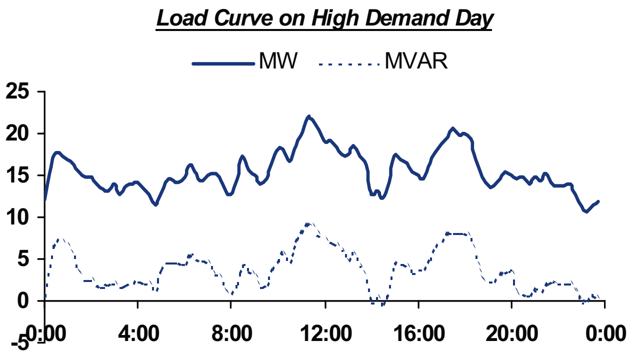


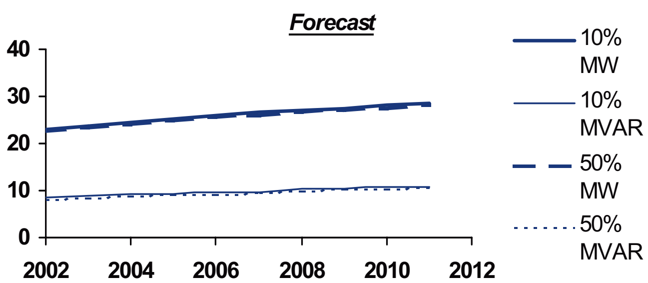


Winter Demand

Previous MD	MW	MVAR
15 May 2001 1:30 PM	275.08	

	10%		50%	
Year	**MW**	**MVAR**	**MW**	**MVAR**
2002	23.0	8.5	22.5	8.3
2003	23.8	8.8	23.3	8.6
2004	24.5	9.1	24.0	8.9
2005	25.2	9.3	24.7	9.1
2006	26.0	9.6	25.4	9.4
2007	26.5	9.8	26.0	9.6
2008	27.0	10.3	26.5	10.1
2009	27.5	10.5	27.0	10.3
2010	28.1	10.7	27.5	10.5
2011	28.7	10.9	28.1	10.7
2012	29.2	11.1	28.7	10.9
2013	29.8	11.3	29.2	11.1





Notes:

Summer 2002 refers to the period of November 2001 to March 2002.

Demand figures are based on 15 minute energy forecasts.

Comments: