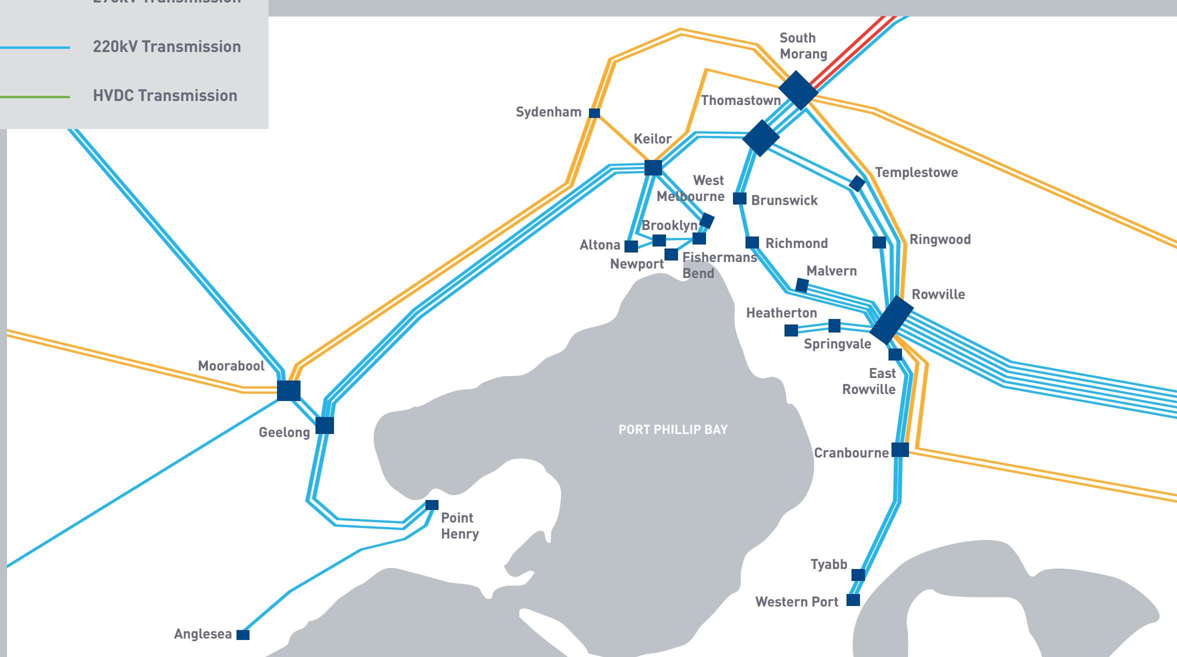
2006

ELECTRICITY ANNUAL PLANNING REPORT

VENCorp

Victorian Energy Networks Corporation

500kV Transmission
330kV Transmission
275kV Transmission
220kV Transmission
HVDC Transmission



2006

DISCLAIMER

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

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

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

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

The document also contains statements about VENCorp's plans. Those plans may change from time to time without notice. Accordingly, written advice on the then current status of those plans must be received from VENCorp before any action is taken based on this document.

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 negligence or negligent misstatement) for any statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or for any omissions from, the information in this document, except in so far as liability under any statute cannot be excluded.

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EXECUTIVE SUMMARY

VENCorp performs a number of crucial roles in Victoria's electricity and gas transmission sectors. These roles are pivotal to the delivery of a safe, secure and reliable supply of electricity and gas for all Victorians.

One of the key roles is to plan and direct expansion of Victoria's electricity transmission network, managing a key link in the supply chain to the State's 2.2 million electricity customers. As such, VENCorp is the Transmission Network Service Provider (TNSP) for the shared transmission network in Victoria.

VENCorp's powers as the TNSP, are set out under the National Electricity Rules (NER). Clause 5.6.2A of the NER requires VENCorp to undertake an annual planning review and publish an Electricity Annual Planning Report (EAPR).

Load forecasts

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

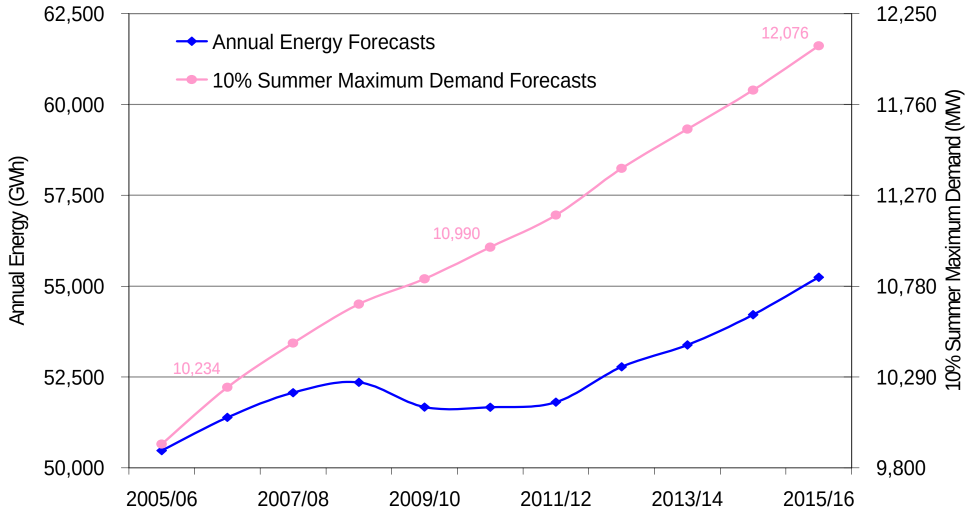
The following table and chart summarise the forecasts for the medium growth scenario. The summer and winter maximum demand forecasts are based on the 10% probability of exceedence (POE) temperature standards, which are not expected to be exceeded more than one year in every ten.

Summary of the forecasts

	2006/07	2010/11	2015/16	Average Growth 2005/06 to 2010/11	Average Growth 2010/11 to 2015/16
Victorian GSP Growth (Medium Growth Scenario)	2.4%	2.7%	3.0%	2.2%	2.8%
Forecast Annual Energy (GWh)	51,387	51,668	55,245	0.5%	1.3%
Forecast 10% POE Summer Maximum Demand (MW)	10,234	10,990	12,076	2.1%	1.9%
Forecast 10% POE Winter Maximum Demand (MW)	7,891	8,222	8,875	1.1%	1.5%

The annual energy is projected to grow at an average rate of 0.5% over the next 5 years to 2010/11, and then 1.3% pa to 2015/16. Summer maximum demand forecasts are projected to grow faster than annual energy, at an average growth rate of 2.1% pa over 2006/07 to 2010/11, and then 1.9% pa over the following 5 years to 2015/16.

Annual energy and 10% POE summer maximum demand forecasts



The updated forecasts are lower than those produced for the 2005 EAPR, reflecting:

- slower economic projections;
- an increase in the projected non-scheduled generation (including wind);
- a revision to the assumption of wind generation capacity available at times of maximum summer and winter demand; and
- a revision to the winter POE temperatures to account for the warming trend in Melbourne temperatures.

Network adequacy

A review of the adequacy of the Victorian electricity transmission network to meet the actual and forecast 2005/06 summer peak demand conditions has been carried out. Highlights of the assessment include:

- The peak electricity demand experienced in Victoria in summer 2005/06 was 8,730 MW, on Friday 24 February 2006. The temperature conditions on this day were consistent with the 61% probability of exceedence level.
- The Victorian shared transmission network has been economically designed to securely supply an aggregate demand of 10,160 MW. The network was operated well within its design capability during the year with the actual peak demand of 8,730 MW being 1,430 MW below the maximum supportable demand.
- The intra / inter-regional transfer levels and Victorian prices during summer 2005/06 were only minimally impacted by planned outages associated with augmentation projects and forced network outages.

Committed augmentations

Following successful consultations on two new large network assets during 2005, the following major projects are now committed to support growth in Melbourne's eastern and western metropolitan areas:

- Rowville 1,000 MVA 500/220 kV A2 Transformer; and
- Moorabool 1,000 MVA 500/220 kV A2 Transformer.

Network developments

The 2006 EAPR is not consulting on any new small network assets. However, in addition to the existing major project associated with the Hazelwood transformer constraint and Latrobe Valley 220 kV switching configuration, the 2006 EAPR concludes VENCorp undertake detailed analysis, as part of justifying a new connection between Malvern and Heatherton Terminal Stations. This connection will increase the security of supply to the south east metropolitan areas of Springvale, Heatherton and Malvern. Further to this, analysis will be undertaken to increase the Victoria to Snowy/NSW transfer capability (export from Victoria), as was identified in the 2005 Annual National Transmission Statement (ANTS) published by NEMMCO.

Ten year outlook

In order to support the full forecast Victorian demand over the next ten years, potential network constraints that may occur in the period up to 2015/16, together with transmission options to remove the constraints, have been investigated.

For this study the network has been modelled with a demand of 12,450 MW. To meet this demand, approximately 2,250 MW of additional generation sources will need to be added by 2015/16, assuming 1,900 MW and 600 MW is available from Snowy/NSW and Tasmania respectively. As the location and size of generation will impact on the transmission needs, a range of supply scenarios, which load different parts of the transmission network, have been examined. This year, an additional scenario has been included to assess the impact of increasing Victoria's export capability to Snowy/NSW. These scenarios were selected as they give reasonable extremes for transmission network development.

The table below provides a summary of the five scenarios examined, and the estimated expenditure in shared transmission network capacity for each scenario.

Summary of supply scenarios

	Scenario	Total Capital Cost ($M)
1	Latrobe Valley generation	482
2	South West generation	367
3	Increase in import from Snowy/NSW	600
4	High metropolitan and State Grid generation	358
5	Increase in export to Snowy/NSW and South Australia	151

A range of other scenarios are possible, and they are likely to result in different transmission requirements. In particular, for import levels above 3,500 MW from Snowy/NSW, significant augmentation may be required, possibly in the form of High Voltage Direct Current links. However, the Latrobe Valley to Melbourne transfer capability designed for scenario 1 will accommodate at least an additional 1,000 MW of generation from the Latrobe Valley.

1. INTRODUCTION

VENCorp performs a number of crucial roles in Victoria's electricity and gas transmission sectors. These roles are pivotal to the delivery of a safe, secure and reliable supply of electricity and gas for all Victorians.

One of the key roles is to plan and direct expansion of Victoria's electricity transmission network, managing a key link in the supply chain to the State's 2.2 million electricity customers.

As the Transmission Network Service Provider (TNSP) for the State, our primary driver is to ensure the long-term reliability of the transmission network that transports electricity between generators and load centres.

VENCorp's Vision Statement is → Victoria will achieve the most reliable and cost effective energy supply through competitive national markets.

VENCorp's Mission Statement is → VENCorp ensures the efficient and effective delivery of energy for the benefit of the Victorian community.

VENCorp's functions specifically relating to electricity are:

- to plan and direct the expansion of the shared transmission network[1] in an economic manner consistent with market reliability requirements and expectations;
- to procure 'bulk' transmission network services from asset owners consistent with the above;
- to advise and liaise with NEMMCO on network constraints, including interconnection transfer limits;
- to provide shared transmission network services to network users for a price in accordance with the National Electricity Rules and AER 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;

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

- to assist in managing an electricity emergency by liaising between the government and NEMMCO, and communicating with the Victorian industry and community both before and during an emergency; and
- to provide information and support to the Victorian Government.

VENCorp is also:

- the independent system operator for the Victorian gas transmission network;
- the manager and developer of the Victorian wholesale gas market;
- the facilitator of gas Full Retail Contestability (FRC) functions; and
- the transmission infrastructure planner for the gas industry.

VENCorp's powers as the TNSP for the Victorian shared transmission network are set out under the National Electricity Rules (NER). Clause 5.6.2A of the NER requires VENCorp to undertake an annual planning review and publish an Annual Planning Report by 30 June each year, setting out:

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

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

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

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

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

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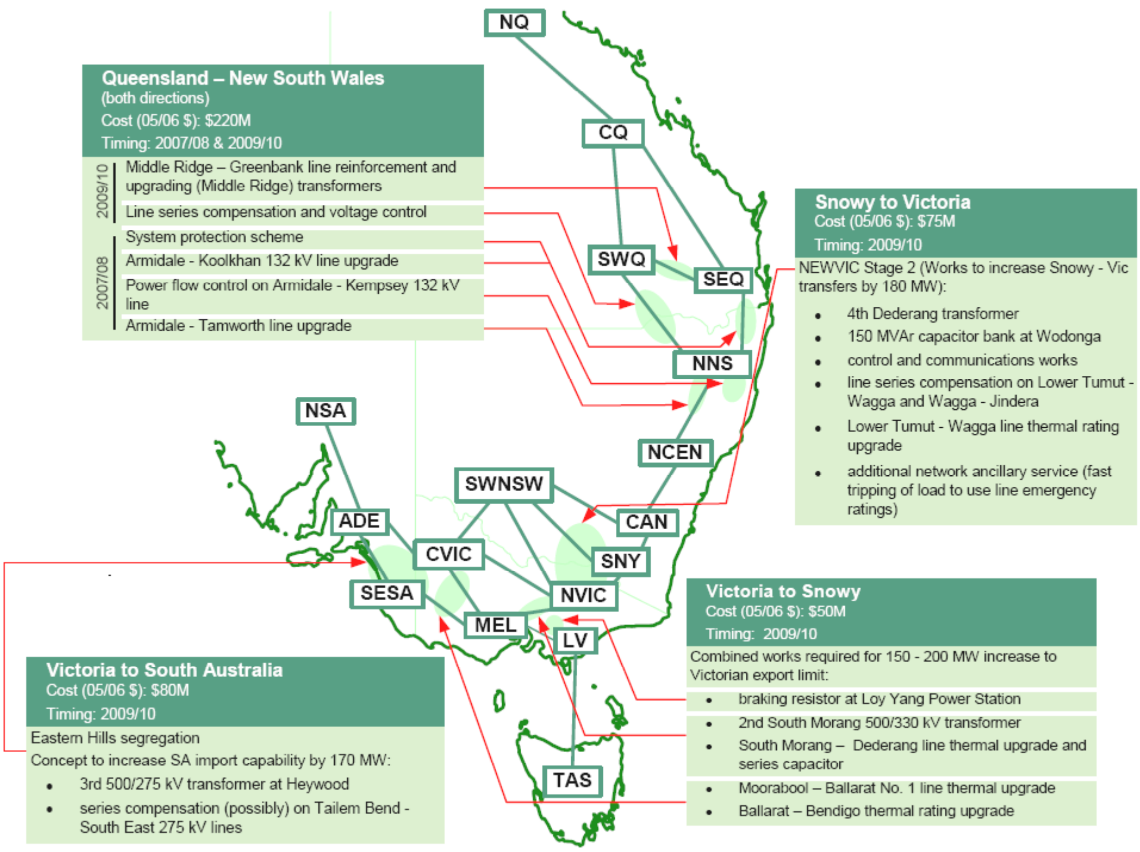
2. NATIONAL TRANSMISSION FLOW PATHS

Clause 5.6.5 of the National Electricity Rules requires NEMMCO to publish an Annual National Transmission Statement (ANTS) report by 31 October each year. The ANTS is the outcome of NEMMCO's annual national transmission review, and provides an overview of the current state and potential future development of national transmission flow paths (NTFPs). A NTFP is defined as "that portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres".

2.1 Outcomes of the 2005 ANTS

NEMMCO's 2005 ANTS prioritised four NTFP augmentation opportunities, specifically focusing on NTFP augmentation opportunities with the potential to deliver positive net market benefits. Figure 2.1 summarises the scope and indicative costs of the conceptual augmentations.

Figure 2.1 – NTFP augmentation opportunities (Source: 2005 ANTS, Figure 2)



Three of these NTFP augmentations opportunities require works on Victoria's electricity shared transmission network, and as such VENCorp would be involved in justifying these individual regulated transmission augmentations.

Following publication of the 2005 ANTS, the Inter-Regional Planning Committee (IRPC) undertook further investigations on the four conceptual augmentations identified. The most important difference between these studies and the ANTS is that the verification studies model each of the four conceptual augmentations explicitly. In contrast, the ANTS considered the effect of relieving all network congestion across the NEM and allocated the benefits across NTFPs most likely to contribute. A summary of the findings of the verification studies is given in Table 2.2.

Table 2.2 – Conceptual augmentations (Source: 2005 ANTS verification studies, Table 2)

Flow Path Augmentation	Ranking	Net Benefit[3]
VIC → SNOWY	2	Marginal to Positive
VIC → SA	3	Insufficient
SNOWY → VIC	4	Insufficient

2.2 VENCorp's interconnector review

Following the findings of the verification studies, VENCorp and TransGrid are undertaking a joint investigation into upgrading Victoria to Snowy capability. The investigation will include the following:

- review of possible alternative options to increase Victoria to Snowy capability;
- technical analysis to finalise the required works and more accurately define the potential increase in capability; and
- economic analysis and, depending on results, the application to the AER Regulatory Test.

Although the verification studies did not find sufficient market benefits for the remaining conceptual augmentations, increasing Victoria's export capability to Snowy is linked to VIC to SA transfer, and therefore both NTFPs will form part of this investigation.

[3] 'Positive' refers to a net present value (NPV) greater than $150M, 'Marginal' refers to an NPV between $50M and $150M, and 'Insufficient' refers to an NPV less than $50M.

3. ENERGY AND MAXIMUM DEMAND FORECASTS

This chapter presents Victorian electricity annual energy, and summer and winter Maximum Demand (MD) forecasts for the next ten years to 2015/16. The load forecasts will be consistent with those included in the 2006 Statement of Opportunities (SOO) prepared by NEMMCO.[4] A review of the year 2005/06, including an assessment of the forecast variance based on last year's forecasts, is also discussed.

Details of the forecast methodologies, assumptions and other supporting load analysis are provided in Appendices A1 to A11. The Appendices are an integral part of the forecast chapter and contain detailed background information that will provide the basis for a good understanding of the load forecasts.

Energy is defined, in this context, as the electricity generated at Victorian generator terminals scheduled under NEMMCO dispatches, plus interstate net imports.[5] Consistent with the above definition, demand is the generated electricity averaged over each half-hourly trading interval. Daily MD is the highest half-hourly average demand for a given day. Summer or winter MD is the highest half-hourly average demand for a given summer or winter.

Historical load data obtained from SP AusNet's Historical Information System (HIS) was used for load forecasts published in previous EAPRs. This data does not match exactly with the operational data published by NEMMCO due to different methods of data calculations.[6] VENCorp conducted a detailed analysis in 2005 to assess the costs and benefits and the impact on the forecasts if NEMMCO's operational data were used instead. The analysis showed that the differences in annual energy and summer and winter MD were immaterial and do not affect the accuracy of the load forecasts.

Historical load data reported in this EAPR and prior to 1 July 2005, is based on SP AusNet's HIS. Data from 1 July 2005 is consistent with NEMMCO's published operational data. Historical energy and demand data have not been corrected for Demand Side Participation (DSP) and non-scheduled generation unless explicitly stated otherwise.

Daily average temperatures are referred to throughout this chapter, and are a key input to the MD forecasts.[7] Temperature data pertains to the Melbourne CBD weather station unless specified otherwise.[8]

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

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

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

7 Daily average temperature is the average of daily maximum temperature from 9:00AM and overnight minimum temperature to 9:00AM of a given day

8 The weather station is located at the corner of Victoria and Latrobe streets in Melbourne

3.1 Summary of the forecasts

This section summarises the key forecast information in this EAPR under the Medium growth scenario.

Table 3.1 presents the Victorian GSP growth, the annual energy, the 10% POE summer MD and the 10% POE winter MD forecasts in this EAPR for 2006/07, 2010/11 and 2015/16.

Table 3.1 – Summary of annual energy, 10% POE summer and winter maximum demand forecasts – EAPR 2006 compared with EAPR 2005 (Medium growth scenario)

	EAPR 2006				EAPR 2005			
	Victorian GSP Growth	Annual Energy (GWh)	10% POE Summer MD (MW)	10% POE Winter MD (MW)	Victorian GSP Growth	Annual Energy (GWh)	10% POE Summer MD (MW)	10% POE Winter MD (MW)
2006/07	2.4%	51,387	10,234	7,891	2.8%	51,343	10,367	8,228
2010/11	2.7%	51,668	10,990	8,222	3.2%	53,768	11,356	8,881
2015/16	3.0%	55,245	12,076	8,875	2.5%	57,076	12,447	9,731
Average Growth 2005/06-2010/11	2.2%	0.5%	2.1%	1.1%	2.5%	1.2%	2.4%	1.7%
Average Growth 2010/11-2015/16	2.8%	1.3%	1.9%	1.5%	2.7%	1.2%	1.9%	1.8%

The forecasts in this EAPR are lower than the forecasts in the EAPR 2005 to reflect:

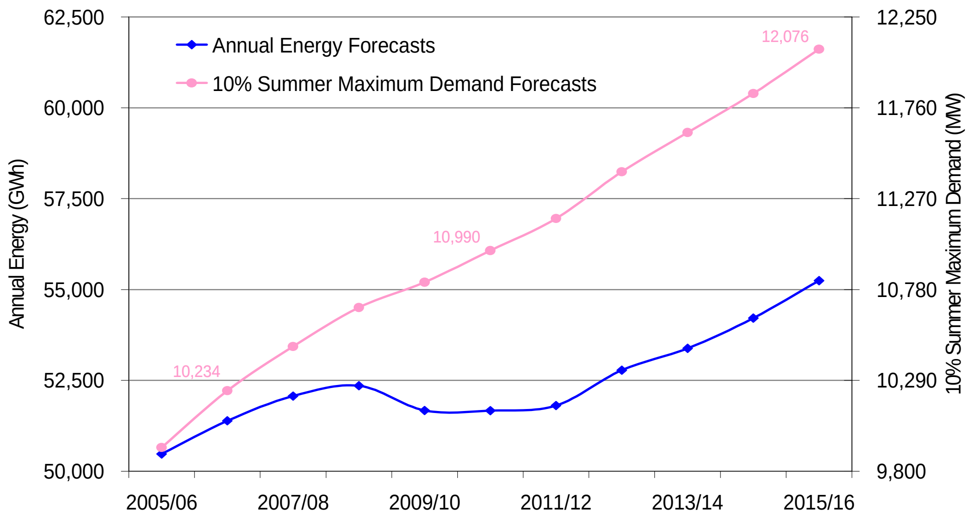
- slower economic growth projections;
- the increased downside risks to the Victorian manufacturing sector;
- the increase in projected non-scheduled and wind generation driven by the Victorian Government's renewable energy strategies which aim to meet 10% of Victorian energy consumption by renewable supply in 2010. Table 3.2 compares the wind and non-scheduled generation forecasts in this EAPR and those included in the EAPR 2005;
- a revision to the assumption of wind generation capacity available on summer and winter MD, which has increased from 8% assumed in the EAPR 2005 to be 24% and 27% used in this EAPR's summer and winter MD forecasts; and
- a revision to the winter POE temperatures to account for the warming trend in Melbourne temperatures. The 10% winter POE temperature has been revised up from 5.4°C to 7.1°C, resulting in 150 MW to 200 MW of reduction in the forecast 10% POE winter MD.

Table 3.2 – Summary of wind and non-scheduled generation forecasts – EAPR 2006 compared with EAPR 2005

	EAPR 2006		EAPR 2005	
	Wind (MW)	Non-Scheduled Generation (MW)	Wind (MW)	Non-Scheduled Generation (MW)
2006/07	238	678	226	672
2010/11	939	1,476	286	788
2015/16	1,056	1,666	286	861

Figure 3.1 shows that annual energy is projected to grow slower than the 10% POE summer MD over the next ten years to 2015/16.

Figure 3.1 – Annual energy and 10% POE summer maximum demand forecasts



3.2 Review of year 2005/06

This section presents the key highlights of the last 12 months up to the end of April 2006. A comparison of the projected annual energy, summer and winter MD for 2005/06 with last year's forecasts is given in Sections 3.4.1, 3.5.1 and 3.6.1 respectively.

The weather in winter 2005 (June 05 to August 05) was warmer than average, although very cold weather was experienced on 10 August and 11 August 2005.

Victoria experienced searing temperatures in late December 2005 and January 2006 resulting in nine days when maximum temperatures soared above 36°C and a heatwave lasting for three days from Friday 20 January to Sunday 22 January.

There was adequate generation to meet both winter and summer demands during the year and there were no supply incidents requiring load shedding. However, up to 198 MW of DSP was observed during summer 2005/06 in response to high electricity prices.[9]

Annual energy to the end of April 2006 was 41,706 GWh and is about 1.4% higher than the energy of 41,133 GWh for the same period a year ago. Smelter load was lower than what was projected in the EAPR 2005.

Table 3.3 shows the top ten days with the highest summer and winter daily energy in 2005/06.

The highest summer daily energy was recorded on Friday 24 February 2006, with 167.0 GWh and daily average temperature of 28.8°C. This is 3.9 GWh (or 2.4%) higher than the highest summer daily energy of 163.1 GWh in 2004/05.

In comparison, the highest winter daily energy of 161.1 GWh occurred on 11 August 2005 with 8.0°C average temperature. This is 4.5 GWh (or 2.9%) higher than the highest winter daily energy of 156.6 GWh in winter 2004.

Due to the increasing penetration of air-conditioners (AC) and warmer weather conditions in recent years, summer daily energy continues to grow faster than winter daily energy.

Table 3.3 – Highest summer and winter daily energy in 2005/06

Season	Date	Day of Week	Daily GWh	Daily Average Temp(°C)
Summer	24-Feb-06	Fri	167.0	28.8
Summer	20-Jan-06	Fri	163.1	30.5
Summer	3-Mar-06	Fri	161.7	27.9
Summer	27-Jan-06	Fri	159.6	30.7
Summer	22-Jan-06	Sun	157.7	34.6
Winter	11-Aug-05	Thu	161.1	8.0
Winter	10-Aug-05	Wed	160.0	7.5
Winter	12-Jul-05	Tue	159.2	8.4
Winter	13-Jul-05	Wed	157.3	9.8
Winter	12-Aug-05	Fri	156.8	9.0

Table 3.4 displays the top ten days in 2005/06 with the highest summer MD. The MD on weekends and public holidays is not normally included in the top 10 days as the demand is lower due to lower commercial and industrial load. However, Saturday 21 January, Sunday 22 January and Australia

[9] This information is based on the results of the annual survey of DSP and embedded generation conducted by NEMMCO as part of the NEMMCO 2006 SOO process

Day are included in Table 3.4 due to the high AC demand on these days driven by very hot temperatures.

The highest summer half-hourly demand of 8,730 MW occurred at 4:00pm on Friday 24 February 2006 with an average temperature of 28.8°C which has a 61% probability of exceedence (POE). This is 195 MW (and 2.3%) higher than the MD of summer 2004/05 at 8,535 MW.

Figure 3.2 compares the half-hourly temperature and demand profiles of the top three summer demand days.

Table 3.4 – Top 10 summer maximum demand days in 2005/06

Date	Day of Week	Demand (MW)	Time of Day (AEST)	Overnight Minimum Temp(°C)	Maximum Temp(°C)	Daily Average Temp(°C)	POE(%)[10]	Comment
24-Feb-06	Fri	8,730	4:00PM	21.0	36.5	28.8	61%	
20-Jan-06	Fri	8,552	3:00PM	24.2	36.7	30.5	31%	First day of the heatwave, reduced load due to DSP
27-Jan-06	Fri	8,460	1:30PM	25.2	36.1	30.7	23%	Reduced load due to an early cool change
03-Mar-06	Fri	8,410	4:00PM	20.3	35.4	27.9	81%	
23-Feb-06	Thu	8,108	4:30PM	15.7	34.0	24.9	>90%	Reduced load due to cool overnight temp and DSP
19-Jan-06	Thu	8,052	5:00PM	15.7	34.1	24.9	>90%	Reduced load due to cool overnight temp and DSP
22-Jan-06	Sun	8,044	3:30PM	26.7	42.4	34.6	NA[11]	Third day of the heatwave
02-Mar-06	Thu	8,022	4:30PM	14.3	34.1	24.2	>90%	Reduced load due to cool overnight temp
26-Jan-06	Thu	8,020	4:00PM	20.8	39.6	30.2	NA	Reduced load due to Australia Day
21-Jan-06	Sat	7,934	4:30PM	20.7	40.7	30.7	NA	Second day of the heatwave

10 Refer to Appendix A1 for discussion on temperature standards for summer and winter MD

11 The POE does not apply to weekends and holidays

Figure 3.2 – Selected summer high demand day profiles in 2005/06

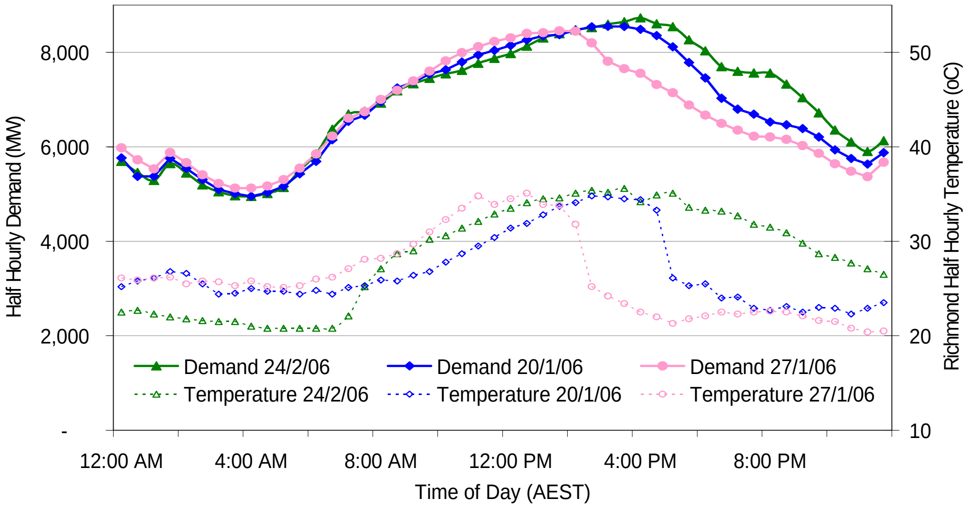


Table 3.5 shows the top five days with the highest MD in winter 2005.[12] The MD on these days occurred between 6:00pm and 6:30pm. Although daily average temperatures on these top five days varied between 7.5°C and 10.9°C, the MD on these days varied within a narrow band between 7,644 MW and 7,764 MW. This illustrates that Victorian winter MD is less responsive to temperature variations than summer MD.

Although very cold minimum temperatures occurred on the top three winter demand days, the POE for these days is greater than 50%. This is because the 2005 winter POE temperatures are too cold.[13] NIEIR reviewed the summer and winter MD POE temperatures in March this year to take account of the warming trend in Melbourne temperatures. The results of this review are explained in detail in Appendix A1.

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12 Winter refers to June to August each year

13 Refer to page 14 of this report

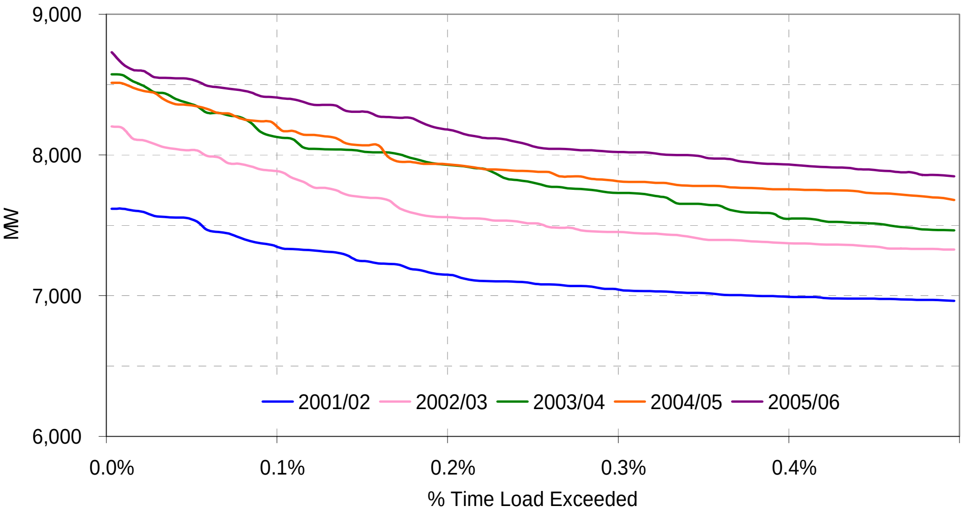
Table 3.5 – Top 5 winter maximum demand days in 2005

Date	Day of Week	Demand (MW)	Time of Day (AEST)	Overnight Minimum Temp(°C)	Maximum Temp(°C)	Daily Average Temp(°C)	POE(%)[14]
10-Aug-05	Wed	7,764	6:30PM	4.6	10.4	7.5	68%
12-Jul-05	Tue	7,758	6:00PM	5.9	10.9	8.4	>90%
11-Aug-05	Thu	7,700	6:30PM	4.5	11.5	8.0	82%
13-Jul-05	Wed	7,662	6:00PM	7.8	11.8	9.8	>90%
11-Jul-05	Mon	7,644	6:00PM	9.3	12.5	10.9	>90%

Figure 3.3 compares the growth in the half-hourly demand in the top 0.5% of the load duration curves (LDC) for 2001/02 to 2005/06. Victorian demand peaks in summer, and hence summer demands are placed in the top part of the LDCs. In a year with a cool summer, winter half-hourly demands can rank within the top 0.1% of the LDC.

There was a rapid growth in demand between 2001/02 and 2003/04. The growth was partly driven by the increased AC penetration and partly by weather conditions. The growth in demand has slowed down since summer 2003/04.

Figure 3.3 – Comparison of load duration curves 2001/02 to 2005/06



14 Refer to Appendix A1 for discussion on temperature standards for summer and winter MD

3.3 Forecast approach

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

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

3.3.1 Economic projections

This section discusses Victorian Gross State Product (GSP) projections from 2005/06 to 2015/16. The basis of the projections and other key economic indicators are presented in Appendix A4.

The economic projections are based on Australian National Accounts and State Accounts data to December 2005 such that the figures for 2005/06 are partly forecast, based on six months of actual data.[15] The State GSP projections were prepared in March-April 2006 prior to the announcements of the 2006/07 State and Commonwealth Budgets.

The Victorian GSP for 2005/06 is projected to grow at 2.2%, and is 0.4% lower than last year's Medium growth projection of 2.6% in the EAPR 2005. The projection reflects the slower than expected growth in private consumption, weaker government investment and a slow down in the residential housing sector.

The Victorian GSP is projected to grow slower than the national average by 0.5% to 0.6% over the next five years as the commodity boom continues to fuel the economic growth in the Northern States. The Victorian GSP is expected to grow by an average of 2.2%, 3.4% and 1.5% pa over the next five years under the Medium, High and Low growth scenarios respectively. A sharp fall in the State GSP is projected for 2009/10 driven by a slow down in both business and government investments in Victoria. The economy is projected to grow stronger over the following five year period at 2.8%, 3.7% and 1.8% pa under the Medium, High and Low growth scenarios respectively. The projected Victorian GSP scenarios are shown in Figure 3.4.

15 ABS data was used for State projections

Figure 3.4 – Victorian GSP projections

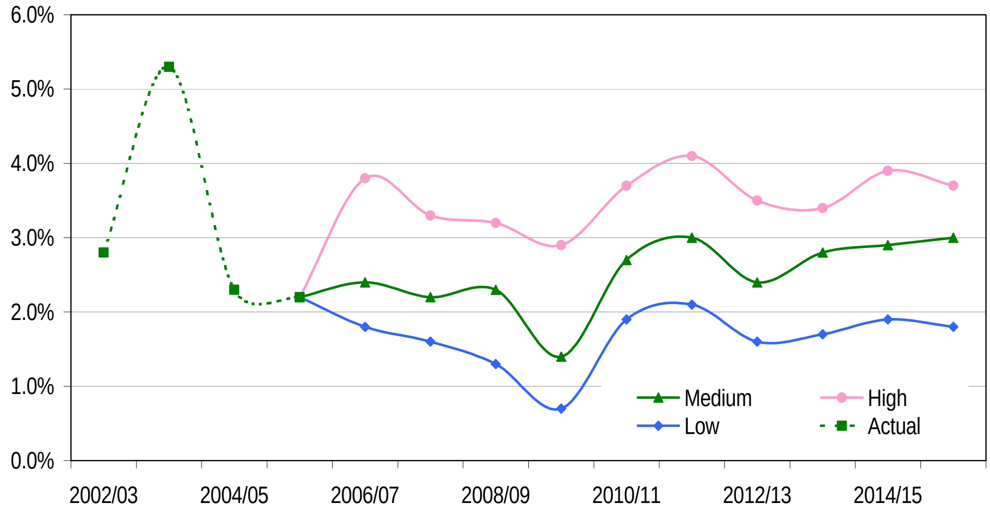


Figure 3.5 compares the Medium growth scenario in this year's forecasts with that included in the 2005 Electricity APR. The projected average GSP growth, over the next five years, is now 0.3% lower than last year's projections averaging 2.5% pa. The longer-term forecast average growth is identical in both forecasts, except a difference in the timing of the business cycle.

Figure 3.5 – Victorian Medium growth GSP projections comparison – EAPR 2005 compared with EAPR 2006

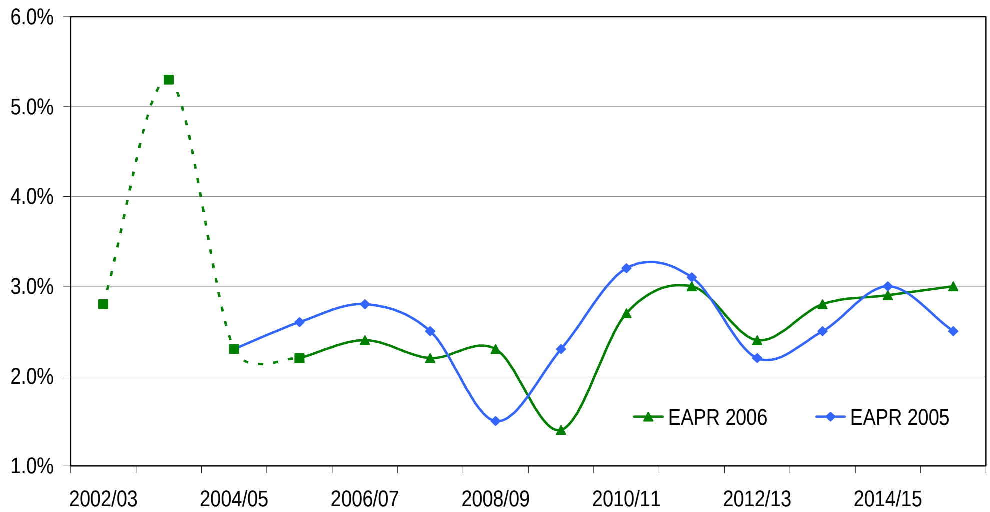
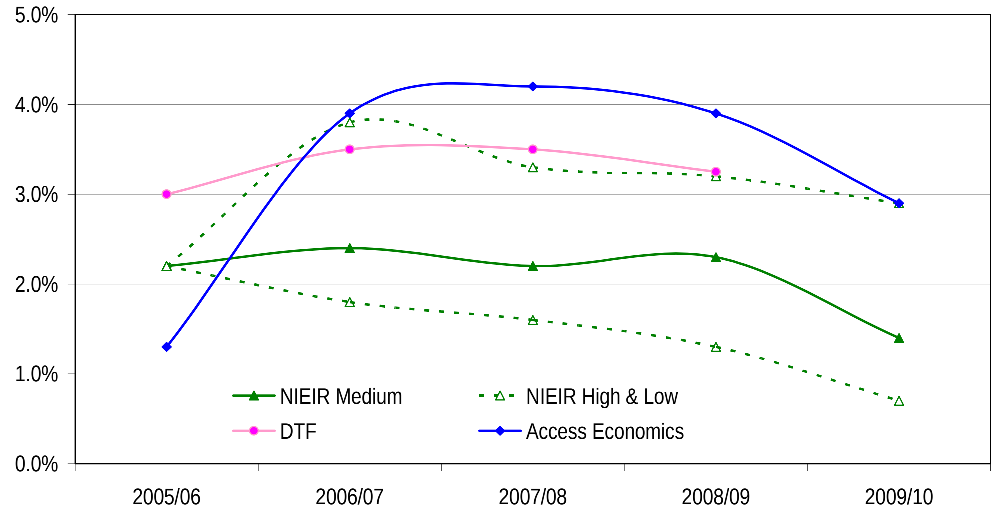


Figure 3.6 compares NIEIR's Victorian GSP projections with those prepared by Access Economics (AE) and those by the Victorian Department of Treasury and Finance (DTF).[16] While NIEIR's Medium growth projections appear to be conservative compared to the forecasts by AE and the DTF, the High growth economic outlook is comparable to the forecasts by the other counterparts.

[16] Data sources: Access Economics Business Outlook March 2005 and State and Territory Budget Monitor No 64 and the 2005/06 Victorian Budget announced on 30 May 2006

Figure 3.6 – Victorian GSP projections comparison – NIEIR, Access Economics and the DTF



3.3.2 *Other forecast inputs*

In addition to economic projections, such as forecasts of investment in Victoria, other key drivers of the electricity energy and demand forecasts include amongst others:

- future population growth impacting on housing demand;
- household disposable income;
- future energy prices;
- major private and government projects;
- energy conservation measures including the use of innovative technologies to drive energy efficiency;
- projected penetration of appliances, in particular AC units and AC unit capacity;
- State and Federal Government energy policies or proposals, discussed in detail in Appendix A5;
- forecast non-scheduled generation, discussed in Appendix A6; and
- weather defined as per the temperature standards for energy and maximum demand forecasts discussed in Appendix A1 and A2.

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

  - *the 10% POE temperature is the non-holiday weekday average temperature not exceeded, on average, more than one in every ten years*

- *the 50% POE temperature is the non-holiday weekday average temperature not exceeded, on average, more than one in every two years*
- *the 90% POE temperature is the non-holiday weekday average temperature not exceeded, on average, more than nine in every ten years*

Table 3.6 shows the POE temperatures used in the EAPR 2005 summer and winter MD forecasts and the revised POE temperatures used in this year's forecasts. While the POE temperature standards for summer MD forecasts remain unchanged those for the winter MD forecasts have been reviewed to take account of the warming trend in Melbourne weather. The review of the POE temperatures is discussed in Appendix A1.

Table 3.6 – Summer and winter MD temperature standards

	POE Temperatures used in EAPR 2006		POE Temperatures used in EAPR 2005	
	Summer MD	Winter MD	Summer MD	Winter MD
10% POE Temperature	32.9°C	7.1°C	32.9°C	5.4°C
50%POE Temperature	29.4°C	8.1°C	29.4°C	7.1°C
90% POE Temperature	27.3°C	9.0°C	27.3°C	8.2°C

3.3.3 *Forecast uncertainties*

A number of factors will affect the accuracy of the forecasts in this EAPR.[17] These factors can be grouped under "demand side impact" or "supply side impact". The impact of these factors is discussed below.

- Demand side impact

  - For forecasting purposes, electricity load is grouped under smelter load and non-smelter load comprised of residential, commercial and non-smelter industrial load.

    Smelter load is a large component of the Victorian electricity load. Future growth in smelter load will depend on domestic demand and global economic conditions (for example sustained economic growth in China). The smelters are also active participants in DSP.

    Residential load, especially demand, has grown rapidly in recent years. The growth has been driven by increased AC penetration which has grown from 46.7% in 2000 to 60.5% in 2005 at 2.8% pa.[18]. NIEIR's database of AC sales in Victoria shows that the capacity of AC units sold has also increased considerably in recent years. AC penetration is expected to slow down in the future.

[17] VENCorp's target forecast accuracy is 2% for weather corrected annual energy forecasts and 3% for 10% POE summer and winter MD forecasts

[18] Refer to *Status of Air-Conditioners in Australia – updated with 2005 data, Energy Efficient Strategies, January 2006*

- A number of Commonwealth and State Governments energy policies/initiatives have been or are going to be implemented with the objective to reduce electricity consumption and greenhouse gas emissions. These policies are explained in more detail in Appendix A5.

  In Victoria, all new homes built from 1 July 2005 are required to have 5 star rating building fabrics and solar hot water heaters or rainwater tanks.

  From 1 May 2006, all new commercial buildings and commercial building refurbishments, alterations and extensions are required to meet the Victorian Government minimum energy standard for commercial buildings.

  In 2002, The National Appliance and Equipment Energy Efficiency Committee (NAEEEC) announced the mandatory increase in the Minimum Energy Performance Standard (MEPS) for single-phase and three-phase ACs. The impact of these policies is highly uncertain. It has been reported that these measures are more effective in reducing energy than demand.[19]

  In July 2004, the Essential Services Commission of Victoria (ESCV) announced a program to progressively rollout interval meters to electricity customers. The program was initially proposed to start in 2006, but has been deferred. Due to the uncertainties surrounding the impact and deployment of interval meters, the forecasts in this EAPR do not take this program into account.

- DSP has been very active in recent times. DSP is negotiated exclusively between customers and their retailers and details of these contractual arrangements are not disclosed to third parties. However, retailers provide the aggregated DSP data to NEMMCO, who then disseminates the information to the relevant Jurisdictions each year as part of the annual NEMMCO SOO planning process. VENCorp does not have information other than that provided by NEMMCO.

  As advised by NEMMCO, over 150 MW of DSP was achieved on a number of occasions in summer 2005/06 as customers volunteered to shut down operations in response to price spikes.

  NEMMCO also advised that a total of 338 MW of DSP can be expected in 2006/07, comprising 179 MW of Committed DSP and 159 MW of Uncommitted DSP. This represents an increase of 135 MW of DSP compared with the amount of DSP included in the NEMMCO SOO 2005 (100 MW of Committed and 103 MW of Uncommitted DSP).

- Supply side impact

On the supply side, the Commonwealth and Victorian Government greenhouse policies will impact future development in renewable energy. These policies are discussed in Appendix A5. The potential impact of these policies on non-scheduled generation is discussed in Appendix A6. The key policy drivers are:

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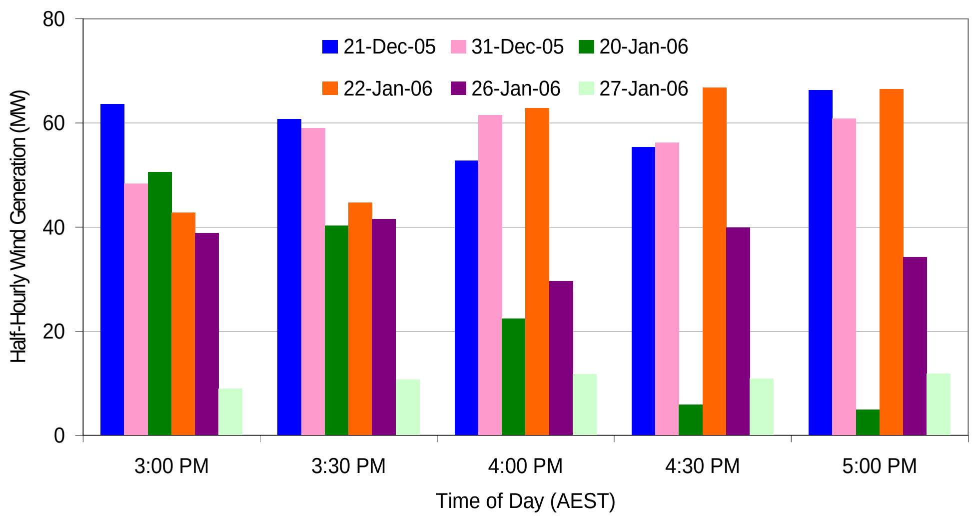
[19] Refer to *A National Demand Management Strategy for Small Air-Conditioners: the role of the National Appliance Equipment Energy Efficiency Program (NAEEEP), George Wilkenfeld and Associates Pty Ltd, November 2004*

- the Mandated Renewable Energy Target (MRET) and the Victorian Renewable Energy Strategy.
- the Victorian Government Renewable Obligation aims to meet 10% of electricity consumption by renewable energy by 2010. This will drive up investments in wind farm generation.

  Wind generation is highly variable due to the intermittent nature of wind. Figure 3.7 depicts the intra-day and inter-day volatility of actual half-hourly wind generation on the six hottest days in summer 2005/06 between 3:00pm and 5:00pm.[20] The actual wind generation varies between 4% and 55% of the installed capacity. The projected increase in wind generation is expected to increase the uncertainty in the MD forecasts.

Figure 3.7 – Actual wind generation



3.4 Annual energy forecasts 2004/05 to 2014/15

This section begins with an assessment of the annual energy forecast for 2005/06 published in the EAPR 2005. Annual energy forecasts for the next ten years to 2015/16 are discussed in Section 3.4.2 focusing on the Medium growth scenario. Forecast methodologies are explained in Appendix A3.1.

3.4.1 Projected annual energy for 2005/06

The projected annual energy for 2005/06 is 50,455 GWh and is calculated from the actual energy for the first ten months of the year to April 2006 and the projected load for May to June 2006.

20 Only Toora, Codrington, Challicum Hills and Yambuk wind farms are included

The weather-corrected annual energy is projected at 50,473 GWh and is 1.0% lower than the Medium growth forecast of 50,976 GWh reported in the EAPR 2005. The-lower-than-projected growth in annual energy this year was due to:

- a weaker growth in the State GSP than what was forecast in the EAPR 2005;
- rising petrol prices, a strong currency and competition from cheap imports adversely affecting the Victorian manufacturing sector; and
- reduced smelter load partly due to a temporary shutdown at BlueScope Steel at Westernport after a fire in August 2005.

This year's projected annual energy has grown by 1.1% over the weather-corrected annual energy of 49,925 GWh for 2004/05.

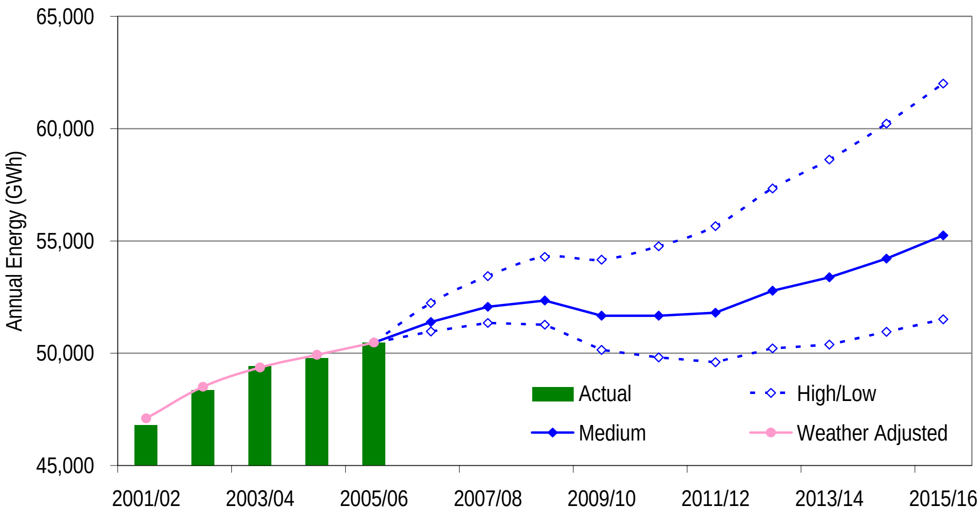
3.4.2 Annual energy forecasts

Three scenarios of energy forecasts are prepared for each year based on Medium, High and Low economic growth projections. The forecasts do not account for potential DSP but take into account the projected energy exported by non-scheduled generators.

The annual energy forecasts assume average weather conditions with 426 Cooling-Degree-Days (CDD) and 1,080 Heating-Degree-Days (HDD) annually. CDD and HDD are temperature indices used to model and estimate annual cooling and heating load. Temperature standards for annual energy forecasts are explained in Appendix A2. Temperature sensitive load is about 5% - 6% of annual energy, but is projected to grow due to the increased penetration of AC. Appendix A7 explains the trend in energy used for space cooling and heating.

Figure 3.8 and Table 3.8 compare the scenario forecasts for the next ten years with the actual and the weather-corrected actual annual energy of the previous five years from 2001/02 to 2005/6. Historical annual energy from 1993/94 is given in Table A10.1 in Appendix 10.

Figure 3.8 – Annual energy forecasts



- Medium growth scenario forecasts

Under the Medium growth scenario, annual energy is forecast to grow by 1.8% from 50,473 GWh (weather corrected) in 2005/06 to 51,387 GWh in 2006/07. Smelter load is expected to return to normal in 2006/07 after a small reduction in 2005/06.

Annual energy is forecast to grow to 51,668 GWh in 2010/11 and 55,245 GWh in 2015/16 at an average rate of 0.9% pa over the next ten years. The projected average growth for the first five years to 2010/11 is 0.5% pa. A stronger growth of 1.3% pa is projected for the following five years to 2015/16.

The projected growth is weaker compared to the growth of 1.5% averaged over the previous five years between 2001/02 and 2005/06 due to:

- the projected slower growth in the State GSP and the increased downside risks to the manufacturing sector in Victoria;
- the Commonwealth and State Government's energy policies to reduce greenhouse gas emissions discussed in detail in Appendix A5. The impact of the key policies is summarised as follows:
    - The Victorian Government's renewable energy strategies will have a major impact on the annual energy forecasts. The Victorian Government has set a target to meet 10% of the Victorian electricity annual consumption by renewable energy in 2010. Investments in renewable energy, in particular wind generation, are projected to grow strongly in the next five years to 2010/11 but slow down thereafter. Table 3.7 summarises the non-scheduled generation forecasts. More details of the non-scheduled generation projections are given in Appendix 6.

Table 3.7 – Summary of non-scheduled generation forecasts

	Capacity (MW)			Annual Output (GWh)	
Year	Wind	Total Renewable	Total	Total Renewable	Total
2005/06	133	359	550	1,313	2,284
2006/07	238	470	678	1,607	2,652
2010/11	939	1,222	1,476	3,802	5,116
2015/16	1,056	1,355	1,666	4,228	5,891

The projected strong growth in non-scheduled generation between 2008/09 and 2011/12 will greatly reduce the annual energy forecasts in these years with the projected growth reduced to -1.3% to 0.3%. A projected sharp fall in the State GSP in 2009/10 combined with a strong growth in non-scheduled generation forecast in this year is expected to reduce the growth in annual energy to -1.3%.

- The Victorian government's 5 star building standard for new homes is expected to reduce the growth in residential load by 10 GWh pa.[21] The proposed MEPS for single-phase and three-phase ACs is assumed to reduce the projected growth in electricity space cooling and heating load by 5.8% in 2018 compared to the Business As Usual (BAU) case;[22]

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21 Refer to "*Comparative Cost Benefit Study of Energy efficiency Measures for Class 1 Buildings and High Risk Apartments in Victoria, Project for the Sustainable Energy Authority of Victoria and the Building Control Commission (Vic)*", Energy Efficiency Strategies June 2002

22 Refer to "*Proposal to increase MEPS for Room Air-Conditioners and harmonise MEPS for single and three-phase units; Regulatory Impact Statement*" by Syneca Consulting for the Australian Greenhouse Office, July 2005

Table 3.8 – Annual energy forecasts

	Annual Energy (GWh)				Annual % Growth		
Year	Actual	Low	Medium[23]	High	Low	Medium	High
2001/02	46,791		47,101			0.7%	
2002/03	48,361		48,505			3.0%	
2003/04	49,435		49,364			1.8%	
2004/05	49,781		49,925			1.1%	
2005/06	50,455		50,473			1.1%	
2006/07		50,970	51,387	52,235	1.0%	1.8%	3.5%
2007/08		51,351	52,069	53,437	0.7%	1.3%	2.3%
2008/09		51,267	52,350	54,293	-0.2%	0.5%	1.6%
2009/10		50,149	51,673	54,167	-2.2%	-1.3%	-0.2%
2010/11		49,812	51,668	54,759	-0.7%	0.0%	1.1%
2011/12		49,601	51,807	55,660	-0.4%	0.3%	1.6%
2012/13		50,215	52,781	57,337	1.2%	1.9%	3.0%
2013/14		50,383	53,383	58,625	0.3%	1.1%	2.2%
2014/15		50,956	54,214	60,223	1.1%	1.6%	2.7%
2015/16		51,514	55,245	62,010	1.1%	1.9%	3.0%
2002-2006						1.5%	
2006-2011					-0.3%	0.5%	1.7%
2011-2016					0.7%	1.3%	2.5%
2006-2016					0.2%	0.9%	2.1%

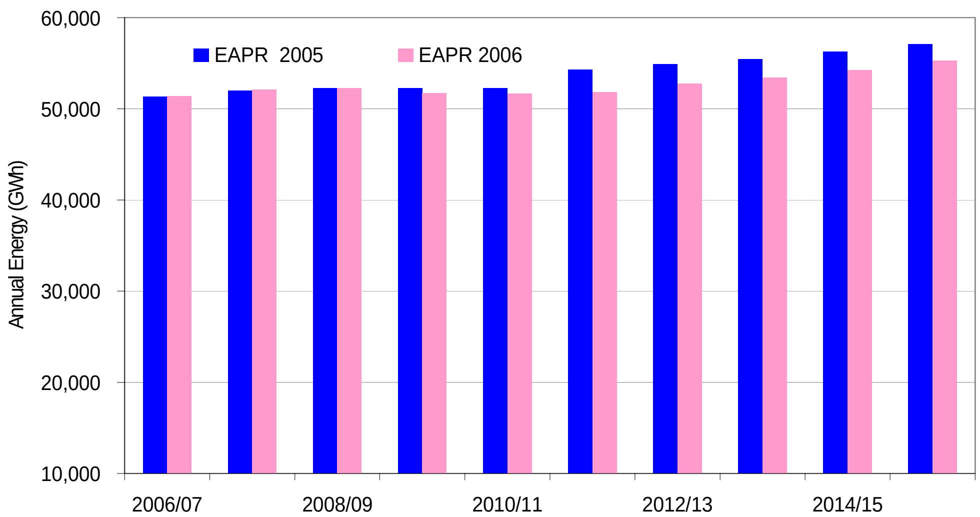
Figure 3.9 compares the current Medium growth scenario annual energy forecasts with those published in the EAPR 2005. This year's annual energy forecasts for 2006/07 to 2008/09 are comparable to those in the EAPR 2005. However, the annual energy forecasts for 2009/10 to 2015/16 are lower than last year's projections with differences between -1,200 GWh and -2,500 GWh (or -2.3% to -4.5%).

23 Historical annual energy shown under the Medium growth scenario forecasts has been corrected to the annual CDD and HDD standards discussed in Appendix A2

The revisions to this year's annual energy forecasts reflect a number of factors including the following:

- estimates of the impact of the Federal and Victorian government's greenhouse and energy policies have been revised resulting in smaller energy savings than what was projected in the EAPR 2005; and
- the increase in projected wind and non-scheduled generation capacity as shown in Table 3.7 and discussed above.

Figure 3.9 – Comparison of annual energy forecasts (Medium economic growth)



- High growth scenario forecasts

Under the High growth scenario, a stronger growth of 1.7% and 2.5% pa is projected for the first five and the last five year periods, respectively.

- Low growth scenario forecasts

Under the Low growth scenario, a weaker economic growth will reduce the projected energy growth to -0.3% and 0.7% pa respectively for each of the five year periods to 2015/16.

3.5 Summer maximum demand forecasts

This section begins with an assessment of the 2005/06 summer MD forecasts published in the EAPR 2005. Summer MD forecasts for the next ten years to 2015/16 are discussed in Section 3.5.2 focusing on the Medium economic growth scenario and the 10% POE summer MD forecasts.

The forecast 10%, 50% and 90% POE summer MD is the forecast maximum half-hourly demand at 4:00pm on a weekday in mid February corresponding to the 10%, 50% and 90% summer POE temperatures respectively.[24] Mid February is the time when commercial and industrial load is expected to return to normal after the extended Christmas holiday break, installed new air-conditioner load is at a maximum, and extreme weather conditions are more likely to happen. The forecast 10% POE MD also includes the thermal effect of a sequence of hot days, likely to be three days, in a heatwave on the MD.

Summer MD forecast methodologies are explained in Appendix A3.2.

Analysis of the correlation between summer MD and temperature is presented in Appendix A8.

Historical summer MDs from 1993/94 are given in Appendix A10.

3.5.1 Summer maximum demand for 2005/06

VENCorp published the results of the assessment of the summer 2005/06 10% POE MD forecast in May 2006. The estimated summer 2005/06 10% POE MD is between 9,704 MW and 9,978 MW. These estimates were derived from the actual MD on Friday 24 February and the MD occurring on the heatwave between Friday 20 January and Sunday 22 January, and account for the following key corrections to the above MDs:

- correction for differences in base load between weekdays and weekends as the base load on Saturday 21 January and Sunday 22 January was lower than the average base load expected of a weekday such as Friday 24 February and Friday 20 January;
- correction for differences in AC demand between weekdays and weekends as the AC demand on Saturday 21 January and Sunday 22 January was lower than that on Friday 24 February and Friday 20 January due to reduced commercial and industrial operations on weekends;
- correction for forecast error in wind generation since the forecast MD assumed 9.8 MW of non-scheduled wind generation which was lower than the actual wind generation on the above days; and
- correction for the thermal impact of the third day of the heatwave on the MD (Sunday 22 January was the third day of the heatwave).

Details of the analysis are reported in the paper "Assessment of the Victorian Summer 2005/06 10% POE Electricity Maximum Demand Forecast" on www.vencorp.com.au.[25]

Figure 3.10 compares the actual MD for 2005/06 summer with the estimated actual, and the forecast 90%, 50% and 10% POE summer MD forecasts published in the EAPR 2005. The actual summer MD includes weekdays (Mondays to Fridays) from 15 November 2005 to 15 March 2006 excluding public holidays, school holidays and the holiday period between 23 December 2005 and 15 January 2006 when industries and businesses operated at a lower capacity. Actual MDs

[24] Refer to Table 3.6 in this report

[25] Refer to http://www.vencorp.com.au/docs/Electricity_Transmission/Transmission_Planning/Assessment_of_Victorian%20Summer_2005_06.pdf

occurring before 3:00pm were also excluded.[26] Figure 3.10 shows that there were only 2 days in summer 2005/06 within the 90% POE and 50% POE temperatures after all of the above mentioned days were excluded. Due to insufficient actual MD data there is a greater uncertainty in the estimated 50% and 90% POE summer MD for 2005/06.

Figure 3.10 – Summer maximum demand compared with the forecasts for 2005/06

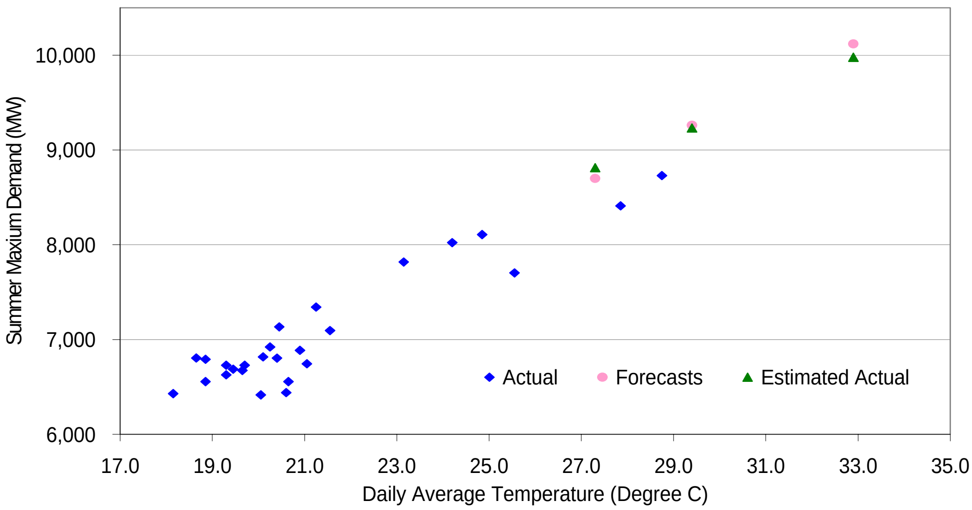


Table 3.9 shows that the estimated 10%, 50% POE MD for summer 2005/06 are 41 MW and 27 MW below the forecasts reported in the EAPR 2005 respectively. However, the estimated 90% POE MD is 113 MW above the forecast in the EAPR 2005.

Table 3.9 – Summer maximum demand forecast variance for 2005/06

	Forecast (MW)	Estimated (MW)	Forecast Variance MW	Forecast Variance %
90% POE	8,700	8,813	113	1.3%
50% POE	9,260	9,233	-27	-0.3%
10% POE	10,119	9,978	-41	-1.4%

The estimated 10% POE summer MD for 2005/06 has grown by 3.2% over the summer 2004/05 estimated 10% POE MD of 9,668 MW.

26 Summer MD occurring before 3:00pm are normally lower due to the arrival of an early cool change

3.5.2 Summer maximum demand forecast

This section focuses on the forecast summer 10%, 50% and 90% MDs corresponding to average (50%) summer and the Medium economic growth scenario.[27] The forecast summer MDs for the High and Low economic growth scenarios are presented in Appendix A9.

The MD forecasts reported in this EAPR do not account for potential reduction in demand due to DSP but incorporate the reduction in the forecast MD due to projected non-scheduled generation. Non-scheduled generation forecasts have been discussed in Section 3.4.2 and summarised in Table 3.7. Details of the forecast non-scheduled generation are provided in Appendix A6.

Table 3.10 and Figure 3.11 present the summer MD forecasts and the estimated actual 10% POE summer MD for 2001/02 to 2005/06 for comparison. It should be noted that the estimated 10% POE MD for summer 2005/06 in Table 3.10 does not include a correction for wind generation and is therefore adjusted down by 50 MW to 9,928 MW. The adjustment for wind generation to the 10% POE summer MD for 2005/06 shown in Table 3.10 was required so that the 10% POE summer MD forecast in the EAPR 2005, which assumed 9.8 MW of wind generation on the 10% POE MD, can be compared on this basis.

The 10% POE summer MD is projected to grow from 9,928 MW in 2005/06 to 10,234 MW in 2006/07, 10,990 MW in 2010/11, and 12,076 MW in 2015/16 at an average rate of 1.9% pa. The projected average growth is 2.0% pa for the first five years to 2010/11 and 1.9% pa for the following five years to 2015/16.

The projected growth in the forecast 10% POE summer MD is weaker compared to the growth of 3.3% pa averaged over the previous five years between 2001/02 and 2005/06. This reflects:

- the projected slower economic growth and the increased downside risks to the manufacturing sector in Victoria;
- a moderate slowdown in AC penetration over the projection period;
- the projected increase in non-scheduled generation driven by the Victorian Government's renewable energy strategies to accelerate investments in wind generation in Victoria;
- an upward revision to wind generation capacity available on the 10% POE MD from 8% assumed in the EPAR 2005 forecasts to 24% assumed in the current forecasts. The revised assumption was based on the analysis of actual half-hourly wind generation on the hottest days in summer 2005/06;[28] and
- the impact of the Victorian government 5 star building standard for new homes and the proposed MEPS for single-phase and three-phase ACs. Most studies on the impact of these policies focus on savings in energy rather than reduction in demand. It is believed that these policies are more effective in reducing electricity energy than demand such that the summer MD forecasts are projected to grow faster than annual energy forecasts.

[27] Summers are defined based on the overall summer average daily temperature

[28] The analysis only included the actual operating capacity at the Toora, Codrington, Challicum Hills and Yambuk wind farms

Table 3.10 – Summer maximum demand forecasts
(average summer, Medium economic growth)

	Summer MD (MW)				Annual % Growth		
Year	Actual	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2001/02	7,621	8,677			2.8%		
2002/03	8,203	9,023			4.0%		
2003/04	8,574	9,350			3.6%		
2004/05	8,535	9,668			3.4%		
2005/06	8,730	9,928			2.7%		
2006/07		10,234	9,421	8,981	3.1%	2.8%	2.6%
2007/08		10,473	9,627	9,170	2.3%	2.2%	2.1%
2008/09		10,683	9,805	9,331	2.0%	1.8%	1.8%
2009/10		10,819	9,914	9,424	1.3%	1.1%	1.0%
2010/11		10,990	10,057	9,553	1.6%	1.4%	1.4%
2011/12		11,163	10,203	9,684	1.6%	1.5%	1.4%
2012/13		11,415	10,428	9,894	2.3%	2.2%	2.2%
2013/14		11,627	10,613	10,065	1.9%	1.8%	1.7%
2014/15		11,837	10,802	10,243	1.8%	1.8%	1.8%
2015/16		12,076	11,020	10,449	2.0%	2.0%	2.0%
2002-2006					3.3%	3.1%	3.0%
2006-2011					2.1%	1.9%	1.8%
2011-2016					1.9%	1.8%	1.8%
2006-2016					2.0%	1.9%	1.8%

Figure 3.11 – Summer maximum demand forecasts
(average summer, Medium economic growth)

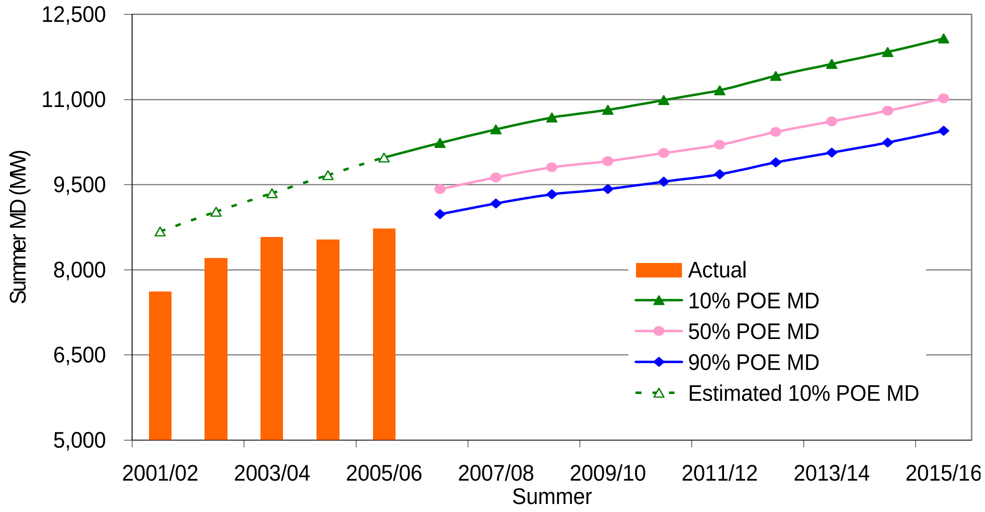
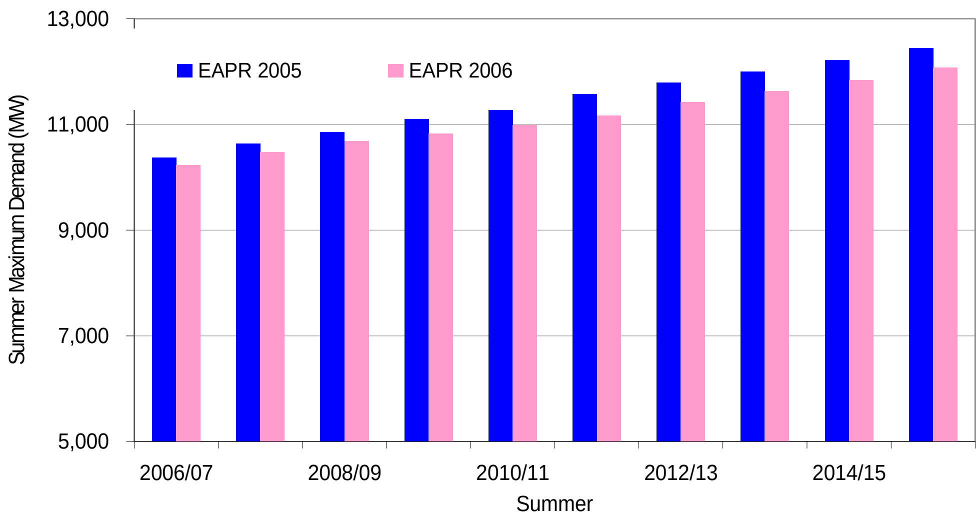


Figure 3.12 shows that the Medium growth 10% POE summer MD forecasts in this EAPR are lower than those in the EAPR 2005. The forecast MD for summer 2006/07 is 133 MW lower than last year's forecast of 10,367 MW. The difference increases to -367 MW (or –3.2%) in 2010/11 and about -371 MW (or -3.0%) in 2015/16.

Figure 3.12 – Comparison of 10% POE summer maximum demand forecasts
(average summer, Medium economic growth)



3.6 Winter maximum demand forecasts

This section begins with an assessment of the 2005 winter MD forecasts published in the EAPR 2005. Winter MD forecasts are discussed in Section 3.6.2 focusing on the Medium economic growth scenario and the 10% POE winter MD forecasts.

Victorian winter MD normally occurs between 6:00pm and 6:30pm on a weekday between June and August each year. The 10%, 50% and 90% POE winter MD forecasts are based on the winter POE temperatures defined in Table 3.6 and discussed in detail in Appendix A1.

Winter MD forecast methodologies are explained in Appendix A3.2.

Historical winter MDs from 1994 are given in Appendix A10.

3.6.1 Winter maximum demand for 2005

Figure 3.13 compares the actual winter 2005 MD with the estimated and the forecast 90%, 50% and 10% POE winter MD forecasts published in the EAPR 2005. The actual MD includes winter weekdays (Mondays to Fridays) between June and August excluding Queen's birthday public holiday.

The actual winter MD shows a high degree of variability not explained by temperature variations. Given similar temperature the winter MD can vary between 300 MW to 500 MW. The diversity in the winter MD reflects the variable residential base load in the evening between 6:00pm and 6:30pm, which is related to lighting, cooking and other household evening activities.

Figure 3.13 – Winter 2005 maximum demand compared with forecasts

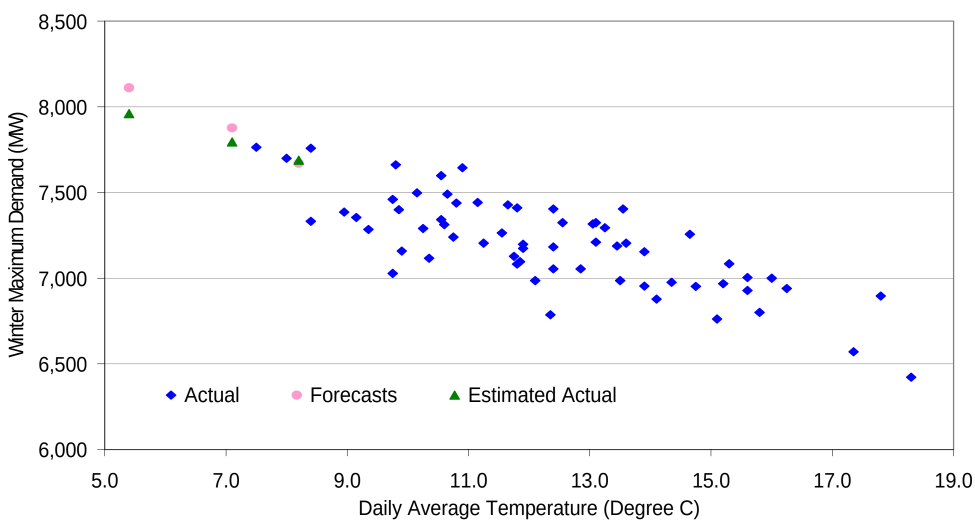


Table 3.11 shows that the estimated winter 2005 10% and 50% POE MD is 151 MW (or 1.9%) and 82 MW (or 1.0%) below the 10% and 50% POE winter MD forecasts in the EAPR 2005 respectively. However, the 90% POE winter MD is 17 MW (0.2%) above the forecast.

Table 3.11 – Winter 2005 maximum demand forecast variance

			Forecast variance	
	Forecast (MW)	Estimated Actual (MW)	MW	%
90% POE	7,671	7,688	17	0.2%
50% POE	7,877	7,795	-82	-1.0%
10% POE	8,111	7,960	-151	-1.9%

3.6.2 Winter maximum demand forecasts

This section focuses on the forecast 10%, 50% and 90% winter MDs corresponding to the Medium economic growth scenario. The forecast winter MDs for the High and Low economic growth scenarios are given in Appendix A9.

<u>The MD forecasts reported in this APR do not account for potential reductions in demand due to DSP but incorporate the reduction in the forecast MD due to projected non-scheduled generation</u>. Details of the forecast non-scheduled generation are in Appendix A6.

The forecasts are based on the revised POE temperatures for winter MD forecasts shown in Table 3.6 in this report. The new 10% winter POE temperature is 7.1°C compared to 5.4°C used in the EAPR 2005. This difference of 1.7°C in temperature standard is equivalent to about 150 MW to 200 MW of reduction in this year's forecast 10% POE winter MD compared to the forecasts in the EAPR 2005.

Winter MD has risen steadily in recent times due to the increased penetration of reverse cycle AC in homes. However, due to the dominance of gas heating in Victoria, winter MD is projected to grow slower than summer MD over the next ten years.

Table 3.12 and Figure 3.14 present the winter MD forecasts and the actual and estimated 10% POE winter MD for 2001 - 2005 for comparison. The forecast 10% POE winter MD is projected to grow from 7,795 MW in 2005 to 8,222 MW in 2010 and 8,875 MW in 2015 at 1.3% pa. The projected average growth rate for the first five years to 2010 is 1.1% pa. Stronger average growth of 1.5% pa is projected for the following five years to 2015.

The key factors affecting this year's winter MD forecasts are:

- the increase in projected non-scheduled generation capacity; and
- the revision to wind generation contribution to the winter MD to 27% from 8% assumed in the EAPR 2005.

Table 3.12 – Winter maximum demand forecasts

	Winter MD (MW)				Annual % Growth		
Year	Actual	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2001	7,054	7,283			0.8%		
2002	7,281	7,349			0.9%		
2003	7,491	7,544			2.7%		
2004	7,435	7,672			1.7%		
2005	7,764	7,795			1.6%		
2006		7,891	7,790	7,680	1.2%	1.2%	1.2%
2007		8,008	7,914	7,800	1.5%	1.6%	1.6%
2008		8,121	8,029	7,911	1.4%	1.5%	1.4%
2009		8,154	8,032	7,911	0.4%	0.0%	0.0%
2010		8,222	8,082	7,957	0.8%	0.6%	0.6%
2011		8,306	8,149	8,020	1.0%	0.8%	0.8%
2012		8,468	8,311	8,179	1.9%	2.0%	2.0%
2013		8,584	8,393	8,257	1.4%	1.0%	1.0%
2014		8,717	8,508	8,368	1.5%	1.4%	1.3%
2015		8,875	8,647	8,504	1.8%	1.6%	1.6%
2001-2005					1.5%		
2005-2010					1.1%	1.0%	1.0%
2010-2015					1.5%	1.4%	1.3%
2005-2015					1.3%	1.2%	1.1%

Figure 3.14 – Winter maximum demand forecasts

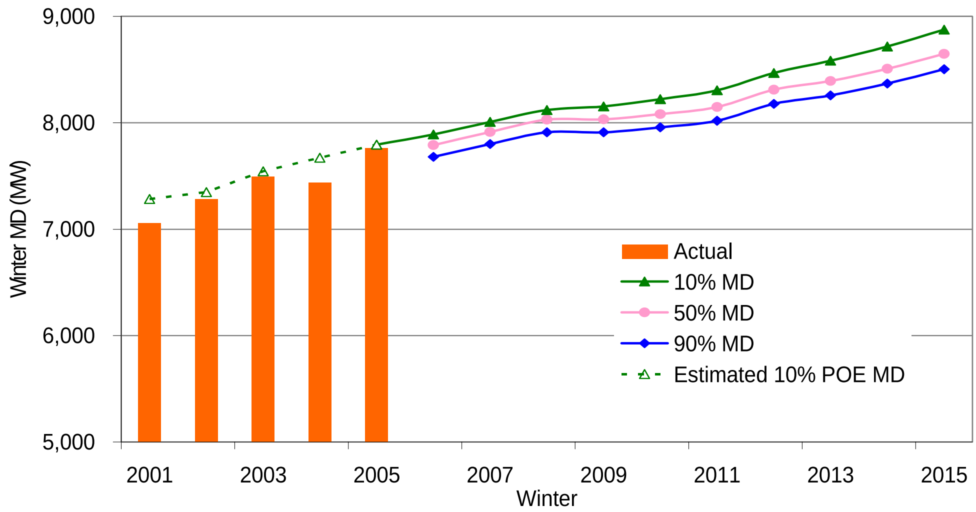
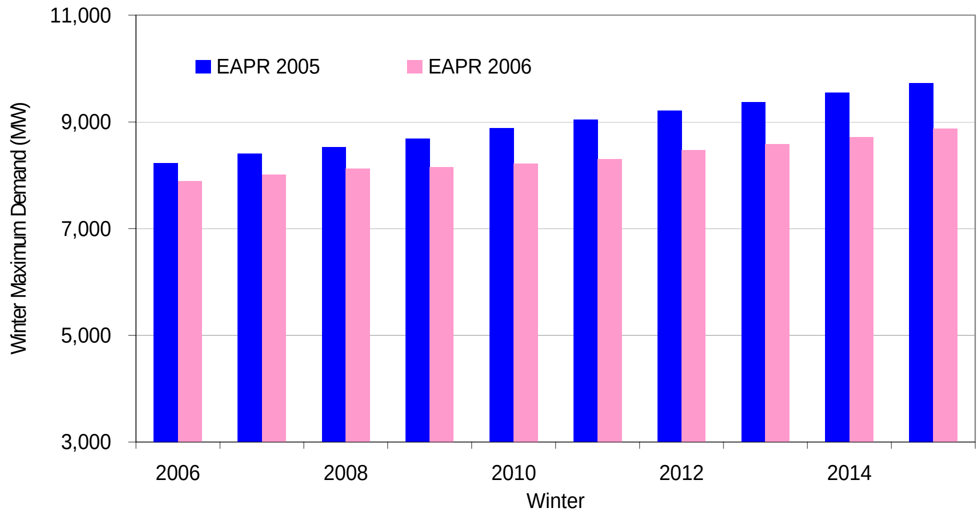


Figure 3.15 compares the winter MD forecasts presented in the 2005 EAPR and the current forecasts. This year's forecasts are lower than last year's projections. The difference is -337 MW (or -4.1%) in 2005, increasing to -660 MW (or -7.4%) in 2010 and -855 MW (-8.8%) in 2015.

Figure 3.15 – Comparison of 10% POE winter maximum demand forecasts



An adjunct to the MD forecasts in this chapter is the Terminal Station Demand Forecasts (TSDF) published by VENCorp on 30 September each year.[29] This document contains the aggregated MD forecasts prepared by distributors, and reconciled with the long-term MD forecasts in VENCorp's EAPR. A summary of the TSDF is included in Appendix B.

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

4. EXISTING NETWORK ADEQUACY

This chapter describes the existing transmission network and its ability to meet the actual and forecast 2005/06 summer peak demand conditions. It includes:

- a review of the shared transmission network conditions during summer 2005/06;
- an overview of the active and reactive supply demand balance at the forecast peak demand; and
- a summary of fault levels and the available headroom on existing circuit breakers at Victorian terminal stations.

It aims to assist existing or potential network users in:

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

4.1 Existing transmission network

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

The 330 kV transmission interconnects with the Snowy region and New South Wales, while transmission at 275 kV provides the interconnection with South Australia. Recent developments have brought two new high voltage DC interconnectors to the Victorian transmission network. One of the DC links forms the second connection with South Australia while the other brings Tasmania into the National Electricity Market by connecting with Victoria.

The electricity transmitted through the extra high voltage transmission is converted to lower voltages at terminal stations, where it then supplies the distribution system. The shared transmission network in Victoria consists of electrical equipment at almost 50 stations across the state with a present day value of about $2 billion. The total circuit distance of transmission lines is approximately 6,000 kilometres and Figure 4.1 provides a map of the existing Victorian transmission network.

Figure 4.1 – Existing Victorian transmission network

4.2 Summer 2005/06 conditions

As discussed in Chapter 3, the peak electricity demand experienced in Victoria in summer 2005/06 was 8,730 MW, on Friday 24 February 2006. The maximum ambient temperature reached was relatively high at 36.5°C, and the average Melbourne temperature was 28.8°C. The temperature conditions on this day were consistent with a 61% Probability of Exceedence (POE).

The Victorian shared transmission network has been economically designed to meet a demand of 10,160 MW. Therefore, the shared transmission network was operated well within its design capability during the year, with the actual peak demand being 1,430 MW below the maximum supportable demand.

The intra / inter-regional transfer levels and Victorian prices during summer 2005/06 were only minimally impacted by planned network outages associated with augmentation projects and forced network outages. No significant system incidents or bushfires occurred to cause price volatility during summer 2005/06.

4.3 System active and reactive power supply demand balance

A detailed assessment of supply and demand is provided in NEMMCO's SOO, but the following summary is provided for information. Table 4.1 shows that the combined Victorian and South Australian forecast reserve at peak demand conditions with all generation available was 261 MW, which is below the reserve requirement of 530 MW. As such, NEMMCO entered into reserve trader agreements for summer 2005/06, to meet this shortfall.

Table 4.1 – Summer 2005/06 supply demand balance forecast (Source: 2005 SOO)

SUPPLY (MW)	Victorian Generation	8,517
	South Australian Generation	3,262
	Import Capability From Snowy/NSW	1,900
	Total Combined Region Supply	**13,679**
DEMAND (MW)	Victorian Forecast Demand (10% POE)	10,119
	South Australian Forecast Demand (10% POE)	3,378
	Expected Demand Side Participation	–191
	Total Combined Region Demand	**13,306**
RESERVE (MW)	Reserve	373
	Combined Reserve Requirement	530
	Reserve Surplus	**–157**

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

Table 4.2 – Summer aggregate generation capacity for Victoria (Source: 2005 SOO)

Generation	Summer 2005/06 Capacity (MW)
Anglesea	158
Bairnsdale	70
Energy Brix Complex	139
Hazelwood	1,580
Hume (VIC)	58
Jeeralang A	200
Jeeralang B	216
Laverton North	312
Loy Yang A	2,020
Loy Yang B	1,000
Newport	475
Somerton GT	128
Southern Hydro	461
Valley Power	280
Yallourn W	1,420
Total	**8,517**

The forecast demand level of 10,119 MW for summer 2005/06 is representative of conditions where:

- transmission losses are approximately 420 MW (4%);
- generator auxiliary load is approximately 540 MW (5%);
- major industrial load is approximately 1,130 MW (11%);
- State Grid regional load is approximately 1,670 MW (17%);
- western metropolitan area load is approximately 1,690 MW (17%);
- eastern metropolitan area load is approximately 4,330 MW (43%); and
- Latrobe Valley area load is approximately 340 MW (3%).

The maximum supportable demand in Victoria is constrained by a voltage control/level limitation. At any time, the system must be operated to be within an acceptable voltage profile and reactive reserve margin, both before and after a critical contingency. Economic analysis used to determine the pre-defined level of maximum supportable demand is conducted in accordance with VENCorp's application of the Regulatory Test. This reflects an optimal trade-off between the benefits of mitigating the risk of loss of load, and the cost of various network or non-network solutions. On a day-to-day basis, the actual system demand will be limited to below the maximum supportable demand to ensure acceptable post contingency voltages and reserve margins. For summer 2005/06, the maximum supportable demand under favourable conditions was 10,160 MW.

The reactive supply/demand balance for the summer 2005/06 system, with the forecast maximum demand of 10,119 MW, is given in Tables 4.3 and 4.4. Table 4.3 shows the system normal conditions with all generators and transmission elements in service. Table 4.4 shows the system reactive supply/demand balance following contingent outage of Newport Power Station (500 MW). For this condition, it was assumed that frequency control was being carried out utilising Snowy/NSW generators. As a result of the generator outage, import from Snowy/NSW increases from 1,900 MW to 2,400 MW, causing an increase in active and reactive transmission power losses. In addition, loss of the generator reduces the amount of reactive supply. The increased net reactive supply is met by the remaining generators, synchronous condensers, static var compensators and series capacitors.

Table 4.3 – Reactive supply and demand balance at 10,119 MW (system normal)

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,300	Loads	3,869
SVC's and Synchronous Condensers	127	Line Reactors	218
Line Charging	2,866	Line Losses	6,065
Shunt Capacitors	4,922	Inter-regional Transfer	230
Series Capacitors	167		
Total	10,382	**Total**	10,382

Table 4.4 – Reactive supply and demand balance at 10,119 MW (following loss of Newport)

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,842	Loads	3,869
SVC's and Synchronous Condensers	418	Line Reactors	204
Line Charging	2,749	Line Losses	7,118
Shunt Capacitors	4,782	Inter-regional Transfer	-95
Series Capacitors	305		
Total	11,096	Total	11,096

4.4 Shared network loading

This section compares the shared network loadings that were experienced during summer 2005/06, with the network loadings that would have occurred if the forecast summer load was achieved. This information is presented in Table 4.6, where loadings of shared transmission network lines and transformers, as a proportion of ratings, are shown for the following three conditions:

- actual 2005/06 MD (8,730 MW);
- forecast 2005/06 10% POE MD (10,119 MW); and
- forecast 2005/06 MD with the worst single contingency outage, producing the highest loading for each network element.

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

Table 4.5 – Actual and forecast 2005/06 MD system loading conditions

	Actual MD	Forecast MD
Victorian Demand	8,730	10,119
Victorian Generation	7,338	8,396
Victoria to Snowy/NSW transfer	-1,060	-1,890
Victoria to TAS transfer	0	-300
Combined Victoria to SA transfer	-332	467

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

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

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

Table 4.6 - Network actual and forecast 2005/06 MD loadings

TRANSMISSION LINK	ACTUAL	FORECAST	CRITICAL OUTAGE using FORECAST	EAPR REFERENCE
	(Percentage of continuous rating)			
Eastern Corridor				
Hazelwood PS-Jeeralang 220 kV	9	32	82	
Hazelwood PS-Morwell 220 kV	14	11	11	
Hazelwood PS-Rowville 220 kV	51	71	91	
Hazelwood PS-Yallourn 220 kV	57	73	95	
Hazelwood TS-Hazelwood PS 220 kV	34	86	86	
Hazelwood TS-Loy Yang PS 500 kV	30	37	56	
Hazelwood TS-Rowville 500 kV	28	35	47	
Hazelwood TS-South Morang 500 kV	38	47	67	
Hazelwood 500/220 kV Transformer	34	86	95	
Rowville-Yallourn 220 kV	90	82	109	Section 5.3.4
South Morang-Rowville 500 kV	23	32	58	
South West Corridor				
APD-Heywood 500 kV	30	30	76	
Heywood-SESS (SA) 275 kV	31	45	53	
Heywood 500/275 kV Transformer	35	54	120	Section 7.5
Moorabool-Heywood/APD 500 kV	12	21	26	
Moorabool-Sydenham 500 kV	20	35	65	
South Morang-Sydenham 500 kV	25	37	63	
Northern Corridor				
Dederang-Murray (SNOWY) 330 kV	40	82	85	
Dederang-South Morang 330 kV	27	64	111	Section 6.4.2
Dederang-Wodonga 330 kV	7	6	26	
Dederang 330/220 kV Transformer	37	79	116	Section 6.4.3
Wodonga-Jindera (SNOWY) 330 kV	13	15	35	

TRANSMISSION LINK	ACTUAL	FORECAST	CRITICAL OUTAGE using FORECAST	EAPR REFERENCE
	(Percentage of continuous rating)			
Greater Melbourne and Geelong				
Altona-Brooklyn 220 kV	3	20	27	
Altona-Keilor 220 kV	23	17	26	
Brooklyn-Fishermans Bend 220 kV	14	21	63	
Brooklyn-Keilor 220 kV	23	18	31	
Brooklyn-Newport 220 kV	19	52	81	
Brunswick-Richmond 220 kV	35	50	87	
Brunswick-Thomastown 220 kV	23	33	49	
Cranbourne-Tyabb 220 kV	29	26	73	
East Rowville-Cranbourne 220 kV	18	31	55	
East Rowville-Rowville 220 kV	19	19	38	
Fishermans Bend-Newport 220 kV	49	26	63	
Fishermans Bend-West Melbourne 220 kV	21	33	63	
Geelong-Keilor 220 kV	18	41	139	Section 5.3.2
Heatherton-Springvale 220 kV	39	44	88	
Keilor-Sydenham 220 kV	16	10	54	
Keilor-Thomastown 220 kV	7	20	43	
Keilor-West Melbourne 220 kV	25	43	77	
Keilor 500/220 kV Transformer	64	68	89	
Moorabool 500/220 kV Transformer	74	74	78	
Ringwood-Thomastown 220 kV	34	26	81	
Rowville-Malvern 220 kV	37	40	80	
Rowville-Richmond 220 kV	69	56	92	
Rowville-Ringwood 220 kV	33	50	72	
Rowville-Springvale 220 kV	60	69	138	Section 6.5.1
Rowville-Templestowe 220 kV	28	19	47	
Rowville-Thomastown 220 kV	9	7	42	
Rowville 500/220 kV Transformer	76	83	107	Section 5.1.1
South Morang-Keilor 220 kV	42	56	74	
South Morang 330/220 kV Transformer	66	76	94	
South Morang 500/330 kV Transformer	19	17	33	
Templestowe-Thomastown 220 kV	12	25	73	
Tyabb-JLA (Western Port) 220 kV	22	26	51	

TRANSMISSION LINK	ACTUAL	FORECAST	CRITICAL OUTAGE using FORECAST	EAPR REFERENCE
	(Percentage of continuous rating)			
Regional Victoria				
Ballarat-Bendigo 220 kV	18	17	105	Section 6.6.3
Ballarat-Horsham 220 kV	32	39	60	
Ballarat-Moorabool 220 kV	45	62	116	Section 6.6.2
Ballarat-Terang 220 kV	18	19	53	
Bendigo-Fosterville 220 kV	47	78	101	Section 6.6.1
Bendigo-Kerang 220 kV	28	42	65	
Dederang-Glenrowan 220 kV	41	56	93	
Dederang-Mount Beauty 220 kV	30	16	92	
Dederang-Shepparton 220 kV	53	68	90	
Eildon-Mount Beauty 220 kV	34	54	78	
Eildon-Thomastown 220 kV	56	83	102	Section 6.4.4
Fosterville-Shepparton 220 kV	47	82	105	Section 6.6.1
Geelong-Moorabool 220 kV	46	38	72	
Geelong-Point Henry/Anglesea 220 kV	46	48	96	
Glenrowan-Shepparton 220 kV	39	45	78	
Horsham-Red Cliffs 220 kV	13	13	34	
Kerang-Red Cliffs 220 kV	9	19	48	
Moorabool-Terang 220 kV	37	44	68	

4.5 Transmission connection asset loading

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

4.6 Fault levels

VENCorp has the responsibility to ensure fault levels in the Victorian transmission network are always maintained within circuit breaker interrupting capability. When VENCorp calculates fault levels, a number of different assumptions are made about the development of generation, transmission, interconnection and system load levels to determine critical fault levels, potentially above circuit breakers capability.

For summer 2005/06, there were no locations within the Victorian transmission network where the interrupting capability of a circuit breaker was inadequate.

Fault levels in 2007 and in the subsequent years will be influenced by the following committed projects in the shared transmission network:

- a new 1,000 MVA 500/220 kV Transformer at Rowville; and
- a new 1,000 MVA 500/220 kV Transformer at Moorabool.

Major changes to generation and interconnection arrangements, which influence the fault levels over the next five years, include new generation at Laverton North planned to be connected at Altona Terminal Station in 2006, and the Basslink interconnector with Tasmania put in service in April 2006.

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

At 220 kV, 66 kV, and 22 kV buses, fault levels are approaching the circuit breaker capability at a number of stations. Table 4.7 summarises the "headroom" available at these voltage levels at stations in the Victorian transmission network, based on the summer 2005/06 fault level review undertaken by VENCorp, published in the Report: "Transmission Network Short Circuit Levels 2006-2010, Victoria".

Table 4.7 – Overview of fault levels at Victorian terminal stations for summer 2005/2006

Summer 2005/06 Maximum Prospective Short Circuit at the Busbars of the Victorian Power System in % of the Circuit Breaker Interrupting Capability

TERMINAL STATION	< 80%	80 – 95 %	> 95%[30]
Altona	220 kV & 66 kV		
Ballarat	66 kV		220 kV
Bendigo	220 kV, 66 kV & 22 kV		
Brooklyn		220 kV	66 kV & 22 kV
Brunswick		22 kV	220 kV
Cranbourne	220 kV & 66 kV		
Dederang	220 kV		
East Rowville		220 kV & 66 kV	
Fishermans Bend	220 kV	66 kV	
Geelong	220 kV	66 kV	
Glenrowan	220 kV & 66 kV		
Hazelwood			220 kV
Heatherton	220 kV	66 kV	
Horsham	220 kV & 66 kV		
Jeeralang		220 kV	
Keilor		66 kV	220 kV
Kerang	220 kV, 66 kV & 22 kV		
Loy Yang	66 kV		
Malvern	220 kV & 22 kV	66 kV	
Moorabool	220 kV		
Morwell			66 kV
Mount Beauty			220 kV & 66 kV
Red Cliffs	220 kV & 66 kV	22 kV	
Richmond	66 kV	220 kV	22 kV
Ringwood	220 kV & 22 kV	66 kV	
Rowville			220 kV
Shepparton	220 kV & 66 kV		
Springvale	66 kV	220 kV	
Templestowe	220 kV	66 kV	
Thomastown			220 kV & 66 kV
Terang	220 kV & 66 kV		
West Melbourne		220 kV	22 kV & 66 kV
Wodonga	66 kV & 22 kV		

The maximum prospective fault levels shown in Table 4.7 are determined with all generation in service and for the most onerous feasible operating conditions.

30 For summer 2005/06, the maximum prospective short circuit current seen by any single circuit breaker is below 100% of the circuit breaker interrupting capability.

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

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

- Hazelwood (HWPS);
- Keilor (KTS);
- Rowville (ROTS); and
- Thomastown (TTS).

At these locations, the bus fault level exceeds the interrupting capability of the lowest rated circuit breaker at the terminal station, or is forecasts to do so in the next five years. However, critical breakers are not exposed to the full bus fault current, so these circuit breakers are not a limiting factor in the operation of the power system.

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

Options to mitigate problems associated with increasing fault levels include:

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

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

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

Operational switching arrangements have been implemented as the most effective and economic way to manage fault levels, and have facilitated the maintenance of fault levels at critical locations within circuit breakers interrupting capabilities for many years. However, the application and increasing complexity of operational arrangements, and the inherent reduction in plant redundancy, means this approach may not always be a technically viable or economic solution.

Table 4.7 shows that the prospective fault levels at seven of the 220 kV terminal stations were above 95% of the lowest circuit breaker interrupting capability in summer 2005/06. This indicates that there is very little "headroom" for fault levels to increase at these terminal stations, and fault level mitigation is becoming an important driver of augmentation.

The ongoing issue of increasing fault levels has raised the need for strategic consideration of this issue in distribution and transmission network planning. VENCorp, SP AusNet and the Distribution Businesses have formed a joint working group to review existing network investment plans, and to develop a strategy for fault level management. Two key considerations of the working group are asset replacement programs, and the need to mitigate fault level issues when network augmentations occur, with additional emphasis on fault level strategy within VENCorp's Vision 2030 outcomes in coming years.

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

SP AusNet's refurbishment strategy over the next 10 years indicates that the switchgear at the majority of stations with critical fault levels, namely HWPS, ROTS, BLTS, WMTS, and TTS is planned to be upgraded during SP AusNet's next regulatory reset period (2008 to 2013).

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

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

5. COMMITTED AUGMENTATIONS

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

- New Large Network Assets (capital cost > $10M);
- New Small Network Assets ($1M < capital cost < $10M);
- Minor Network Augmentations (capital cost < $1M); or
- Future Connection Points.

The following two projects are committed New Large Network Assets:

L1 – Rowville 1,000 MVA 500/220 kV A2 Transformer; and

L2 – Moorabool 1,000 MVA 500/220 kV A2 Transformer.

The following three projects are committed or recently completed New Small Network Assets:

S1 – Rowville to Springvale 220 kV Line Upgrade;

S2 – Rowville to Richmond 220 kV Line Upgrade; and

S3 – Thomastown to Ringwood 220 kV Line Upgrade.

The following five projects are committed or recently completed Minor Network Augmentations:

M1 – Bendigo to Fosterville to Shepparton Wind Monitoring Scheme;

M2 – Keilor to Geelong Wind Monitoring Scheme;

M3 – Moorabool to Ballarat Wind Monitoring Scheme;

M4 – Yallourn and Hazelwood to Rowville 220 kV Wind Monitoring Scheme; and

M5 – Thomastown to Templestowe 220 kV Line Upgrade.

The following project is a planned Future Connection Point:

C1 – South Morang Terminal Station 220/66 kV Development.

5.1 New large network assets

5.1.1 L1 – Rowville 1,000 MVA 500/220 kV transformer

In July 2005 VENCorp published the final report on a proposal to develop a new large transmission network asset to support load growth in the Melbourne metropolitan area. The development involves the installation and switching of a second 500/220 kV, 1,000 MVA transformer at Rowville Terminal Station, and fault level mitigation works at Rowville and East Rowville 220 kV switchyards.

The project primarily improves the reliability of supply to customers in the east and south-east metropolitan area of Melbourne by alleviating constraints on the existing 500/220 kV transformers at Rowville and Cranbourne, and the constraints associated with the outage of these critical transformers.

VENCorp does not consider this augmentation will have a material inter-regional impact, and has entered into agreements to ensure the project is implemented by September 2007.

5.1.2 L2 – Moorabool 1,000 MVA 500/220 kV transformer

In September 2005 VENCorp published the final report on a proposal to develop a new large transmission network asset to support load growth in the western metropolitan Melbourne, Geelong and western Victoria areas. The development involves the supply and installation of a second 500/220 kV, 1,000 MVA transformer at the Moorabool Terminal Station.

The project primarily improves the reliability of supply to customers in the western metropolitan area of Melbourne, Geelong and regional western Victoria.

VENCorp does not consider that this project will have a material inter-regional impact, and has entered into agreements to ensure the project is implemented by September 2008.

5.2 New small network assets

5.2.1 S1 – Rowville to Springvale 220 kV line upgrade

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

The project is forecast for completion by summer 2006/07.

5.2.2 S2 – Rowville to Richmond 220 kV line upgrade

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

The project is forecast for completion by summer 2006/07.

5.2.3 S3 – Thomastown to Ringwood 220 kV line upgrade

This project involves an upgrade of the Thomastown to Ringwood 220 kV line. The scope of works includes the replacement of three 220 kV towers and the conversion of another three from suspension to strain type. The project has increased the line rating by around 40% with the design thermal rating being increased from 65°C operation to 82°C operation. The project secures load in the Ringwood area for outage of either the Rowville to Ringwood 220 kV line or the Rowville 500/220 kV transformer.

This project was completed in April 2006.

5.3 Minor network augmentations

5.3.1 M1 – Bendigo to Fosterville to Shepparton wind monitoring scheme

This project involves the installation of a wind monitoring scheme for the 220 kV line from Bendigo to Fosterville to Shepparton. This scheme will allow the line to be dynamically rated based on the measurement of real time wind speeds, minimising a thermal constraint during critical loading periods.

The project is forecast for completion by summer 2006/07.

5.3.2 M2 – Keilor to Geelong wind monitoring scheme

This project involves the installation of a wind monitoring scheme for the 220 kV lines from Keilor to Geelong. This scheme will allow the line to be dynamically rated based on the measurement of real time wind speeds, minimising a thermal constraint during critical loading periods or an outage of either of these lines or the Moorabool 500/220 kV transformer.

The project is forecast for completion by summer 2006/07.

5.3.3 M3 – Moorabool to Ballarat wind monitoring scheme

This project involves the installation of a wind monitoring scheme for the No 1 220 kV line from Moorabool to Ballarat. This scheme will allow the No 1 line to be dynamically rated based on the measurement of real time wind speeds, minimising a thermal constraint during critical loading periods following the loss of the No 2 Moorabool to Ballarat line.

The project is forecast for completion by summer 2006/07.

5.3.4 M4 – Yallourn and Hazelwood to Rowville 220 kV wind monitoring scheme

This project involves the installation of a wind monitoring scheme for the 220 kV lines from Yallourn and Hazelwood to Rowville. This scheme will allow the lines to be dynamically rated on the measurement of real time wind speeds, minimising a thermal constraint during critical loading periods or following an outage of any of these lines.

The project is forecast for completion by summer 2006/07.

5.3.5 M5 – Thomastown to Templestowe 220 kV line upgrade

This project involves an upgrade of the Thomastown to Templestowe 220 kV line. The scope of works includes the replacement of one 220 kV tower, increasing the design rating of the line from 65°C operation to 82°C operation. The project will increase the rating of the line by around 40%. The project secures load in the Templestowe area following an outage of either the Rowville to Templestowe 220 kV line or the Rowville 500/200 kV transformer.

This project was completed in April 2006.

5.4 Future connection points

5.4.1 C1 – South Morang Terminal Station 220/66 kV development

Victorian distribution businesses SPI Electricity and AGL Electricity are planning for the establishment of a new 66 kV connection point at the existing South Morang Terminal Station. This project includes establishment of a 66 kV switchyard at South Morang, and the installation of two 225 MVA, 220/66 kV transformers.

This project will see the transfer of approximately 230 MW of existing 66 kV load from Thomastown Terminal Station to the new 66 kV connection point at South Morang, and the transfer of the existing 150 MW Somerton Power Station from its existing connection point within the Thomastown 66 kV network to the new 66 kV network supplied from South Morang Terminal Station.

The project assists meeting long-term supply requirements in Melbourne's northern metropolitan region, and at this stage is planned for completion late in 2007.

6. FIVE YEAR PLAN

Victoria's energy transmission infrastructure can be broadly described as a combination of the following elements (see Figure 6.1 below):

- infrastructure in the greater metropolitan area of Melbourne and Geelong to deliver energy to distribution take-off points spread through the various cities and suburbs in this region;
- three major energy transmission corridors (Eastern, Northern and South West) to move bulk energy to the metropolitan demand centre or to other inter-state markets; and
- regional infrastructure to deliver energy to provincial cities and other demand centres in the regional areas of the state.

Figure 6.1 – Victoria's transmission infrastructure topology

There are a number of factors that will tend to preserve this existing broad topology into the long-term future.

These include:

- the location of major long-term fuel sources;
- the long service life of existing assets and relatively low future demand growth; and
- the continuing dominance of the greater metropolitan area as the primary demand centre.

It is most likely that future infrastructure development will utilise existing assets, especially sites and easements, in an evolutionary manner, rather than through unexpected major changes in this broad framework. Accordingly, the associated transmission solutions are most easily understood in terms of this framework, which is the basis of the descriptions in the following sections.

6.1 Network constraints

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

The analysis of constraints presented in this chapter is based on the energy and maximum demand forecasts presented in VENCorp's 2005 Electricity Annual Planning Report. Further, the committed projects listed in Chapter 5 are assumed to be placed in-service, as planned, for this analysis.

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

Table 6.1 – Summary of network constraints

Corridor, Area or Region	EAPR Section	Constraint	Conclusion
Eastern Corridor	6.2.1	Loading of Hazelwood 220/500 kV Tie Transformers	Following the development of a new Latrobe Valley 220 kV configuration, VENCorp will undertake a detailed assessment to determine if this constraint can be economically mitigated.
South West Corridor	NIL		
Northern Corridor	6.4.1	Loading of Murray to Dederang 330 kV Lines	The level of energy at risk does not economically justify any of the works identified. VENCorp will reassess these constraints as part of the planned Interconnector Review discussed in Section 2.2.
	6.4.2	Loading of Dederang to South Morang 330 kV Lines	
	6.4.3	Loading of Dederang 330 kV Tie Transformers	
	6.4.4	Loading of Eildon to Thomastown 220 kV Line	

<table>
<tr><th>Corridor, Area or Region</th><th>EAPR Section</th><th>Constraint</th><th>Conclusion</th></tr>
<tr><td rowspan="5">Greater Melbourne & Geelong</td><td>6.5.1</td><td>Loading of Rowville to Springvale and Heatherton 220 kV Lines</td><td>The small level of energy at risk does not, at present, economically justify any of the works identified to remove this constraint.</td></tr>
<tr><td>6.5.2</td><td>Loading of Rowville to Malvern 220 kV Lines</td><td>At present, the level of the energy at risk does not economically justify any of the works identified. VENCorp will continue to monitor possible load transfers to Malvern Terminal Station.</td></tr>
<tr><td>6.5.3</td><td>Security of Double Circuit 220 kV Lines in South East Metropolitan Area</td><td>The analysis has not identified any option that technically and economically alleviates the constraint at this time. However, given the annualised market benefits and costs of the installation are almost equal, VENCorp will jointly undertake detailed analysis with affected Distribution Businesses, to consider a permanent solution involving a new connection between Malvern and Heatherton Terminal Stations.</td></tr>
<tr><td>6.5.4</td><td>Loading of Keilor to West Melbourne 220 kV Lines</td><td>The small level of energy at risk does not, at present, economically justify any of the works identified to remove this constraint.</td></tr>
<tr><td>6.5.5</td><td>Loading of Fishermans Bend to West Melbourne 220 kV Lines</td><td>The small level of energy at risk does not, at present, economically justify any of the works identified to remove this constraint.</td></tr>
<tr><td rowspan="3">Regional Victoria</td><td>6.6.1</td><td>Loading of Shepparton to Bendigo 220 kV Line</td><td rowspan="3">The level of energy at risk does not economically justify the works identified to mitigate these constraints.</td></tr>
<tr><td>6.6.2</td><td>Loading of Moorabool to Ballarat 220 kV Lines</td></tr>
<tr><td>6.6.3</td><td>Loading of Ballarat to Bendigo 220 kV Line</td></tr>
<tr><td>Reactive Support</td><td>6.7</td><td>Additional Reactive Power Support</td><td>The assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. The maximum Victorian supportable demand, as constrained by voltage stability, exceeds the forecast demand in 2009/10. However, during summer 2010/11 and beyond there may be constraints.</td></tr>
</table>

6.1.1 Planning criteria

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

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

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

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

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

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

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

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

6.1.2 Market modelling basis

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

The assumptions and specifications of VENCorp's NEM modelling for the 2006 Electricity Annual Planning Review include:

- Scenarios / Demand Traces – Only committed changes to the NEM interconnector capabilities and generation were considered for VENCorp's intra-regional transmission planning. Appropriate historical demand traces were scaled for all current NEM regions over the analysis period with 10 and 50 percentile peak demand scenarios being considered based on a medium economic (energy) growth outlook.
- Demand / Energy Forecasts – NEMMCO's 2005 Statement of Opportunity and VENCorp's 2005 EAPR were used as the source of regional energy and demand forecasts.
- Generation – The summer and winter capacities of all dispatched NEM generators were modelled from NEMMCO's 2005 Statement of Opportunity. Forced outage rates and mean repair times were based on aggregated data from NEMMCO. Planned outage programs were based on historical market behaviour and MT PASA forecasts.
- Generation Bidding – Short Run Marginal Costs were sourced from the 2003 ACIL Tasman report (SRMC and LRMC of Generators in the NEM).
- Inter-regional marginal loss factor equations and intra-regional loss factors were based on NEMMCO's marginal loss factors for the 2005/06 financial year, published in 2005.
- Hydro Generation – Forced Outage Rates were modelled for hydro units. Historical energy targets for Snowy and Southern Hydro Generation were enforced.
- New Entry Criteria – New Generators were entered into the market based on the principle of 'Reliability Driven Generation' to reflect an assumption that reserve margins would be maintained in all regions.

6.1.3 Distribution Business planning

VENCorp performs network planning based on load forecasts provided by Distribution Network Service Providers with supply points of connection to the shared transmission network. In doing so VENCorp ensures that shared network augmentation plans take account of Distribution Businesses' plans for development at existing stations and new connection points. Additionally, the impacts of the distribution business augmentation plans on the shared network planning have been individually addressed in VENCorp's assessment of each of the constraints.

The general impact of distribution load growth is addressed through modelling of growth at the connection stations. Generally this accounts for shared network impacts of preferred connection asset constraint network solutions such as installation of additional transformation at existing connection points, which are therefore not addressed explicitly in this report. Table 6.2 shows other planned connection modifications presented in the distribution businesses' 2005 Transmission Connection Planning Report (TCPR), with additional potential shared network impacts. VENCorp's considerations of these augmentations in respect of the shared network are also presented.

Table 6.2 – Distribution Business planning impacts

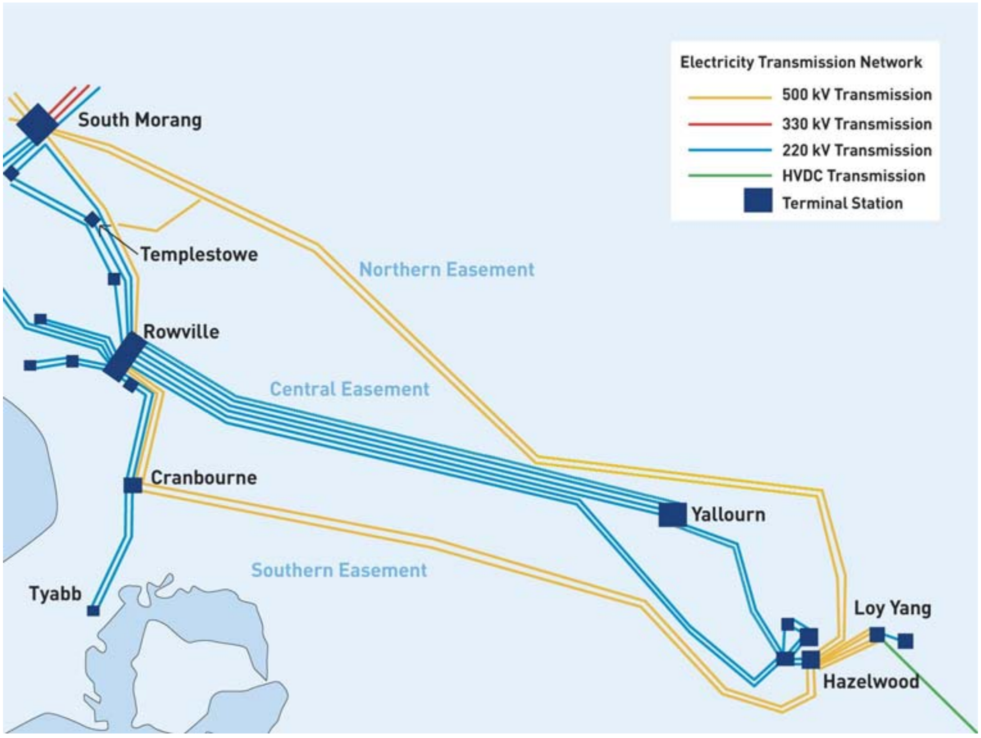
Terminal Station	Preferred Network Solution	VENCorp Consideration
Brunswick 66 kV	A possible new 66 kV supply point to reinforce CBD security of supply, by reducing the reliance on supply from West Melbourne.	Transfer of load from western to eastern metropolitan areas may impact corresponding shared network timings and preferences.
Castlemaine	Establish new 220/66 kV terminal station to off-load Bendigo Terminal Station by 2010.	Establish a short length of 220 kV line to connect the new station, if it is not adjacent to an existing 220 kV line.
East Geelong	Establish new 220/66 kV terminal station to off-load Geelong-terminal Station some time around 2009.	The requirement to support supply into the Geelong area from Moorabool and Keilor will not be changed by this development. However, the relocation of load from Geelong to East Geelong will increase the loading on the Geelong to Point Henry 220 kV lines. VENCorp will review the requirements with Powercor and advise affected parties.
Malvern 66 kV and 22 kV	Redevelopment of Malvern Terminal Station and possible transfer of load from adjacent terminal stations by 2007. Possible transfer of 100 MW from Richmond Terminal Station around 2008/09.	The existing 220 kV circuits from Rowville are adequate to meet supply to Malvern. If the load at Malvern goes beyond 270 MVA the circuits could become a constraint at times of high demand. These circuits can be uprated to increase their capability, when economically justifiable.

Terminal Station	Preferred Network Solution	VENCorp Consideration
Richmond 66 kV and 22 kV	Establish new terminal station, either by approximately 2010, or later if 100 MW is transferred to Malvern Terminal Station, possibly around 2008/09.	Transfer of 100 MW to Malvern Terminal Station would significantly reduce the loading on the Richmond to Brunswick circuit and the Rowville to Richmond circuits, reducing the risk of the constraints on these circuits. Establishing a new terminal station may further reduce these loadings and risks.
	Upgrade a Southbank area zone substation from 22 kV to 66 kV connection, permanently supplied from Fishermans Bend instead of Richmond Terminal Station, around 2007/08.	This would further reduce Richmond to Brunswick and Rowville to Richmond circuit loadings, while increasing Keilor-West Melbourne-Fishermans Bend loadings and constraint risks.
South Morang 66 kV	Establish new terminal station at South Morang to off-load Thomastown Terminal Station 66 kV bus 12 and bus 34 groups by 2007/08. AGL and SP AusNet have committed to this additional transformation at South Morang.	Providing a 220 kV bus connection at South Morang, as Distribution Businesses propose, impacts a large number of closely inter-related metropolitan area constraints. VENCorp is reviewing the connection proposal, ensuring it is consistent with the long-term development of the South Morang 220 kV switchyard.
Wemen	Establish new 220/66 kV terminal station to off-load Red Cliffs Terminal Station by 2010.	Establish a short length of 220 kV line to connect the new station, if it is not adjacent to an existing 220 kV line. Assess the impact of loading on Kerang to Red Cliffs 220 kV line.

6.2 Eastern Corridor

The Eastern Corridor connects the greater Melbourne load centre to the electricity generators in the Latrobe Valley. Historically, this is one of the oldest energy delivery corridors to Melbourne. It still dominates Melbourne's energy supply, despite electrical connection to hydro-electric schemes to the North and to adjoining states. The physical layout of electricity transmission assets in the Eastern Corridor is shown in Figure 6.2.

Figure 6.2 – Eastern Corridor



With the upgrade of terminating equipment on the 500 kV transmission lines at Hazelwood Terminal Station, there will be considerable headroom in the 500 kV transmission capacity of the Eastern Corridor, compared with the existing installed capacity of generators in the Latrobe Valley. However, with the installation of new generation, a number of constraints local to the Latrobe Valley will emerge.

As noted in Chapter 2, there may be a need to augment the Eastern Corridor following the conclusions of an Interconnector Review. This is likely to be the case if there is a need to increase Victoria's export capability to Snowy/NSW.

The constraints presented in this section include:

- Hazelwood 220/500 kV tie transformers

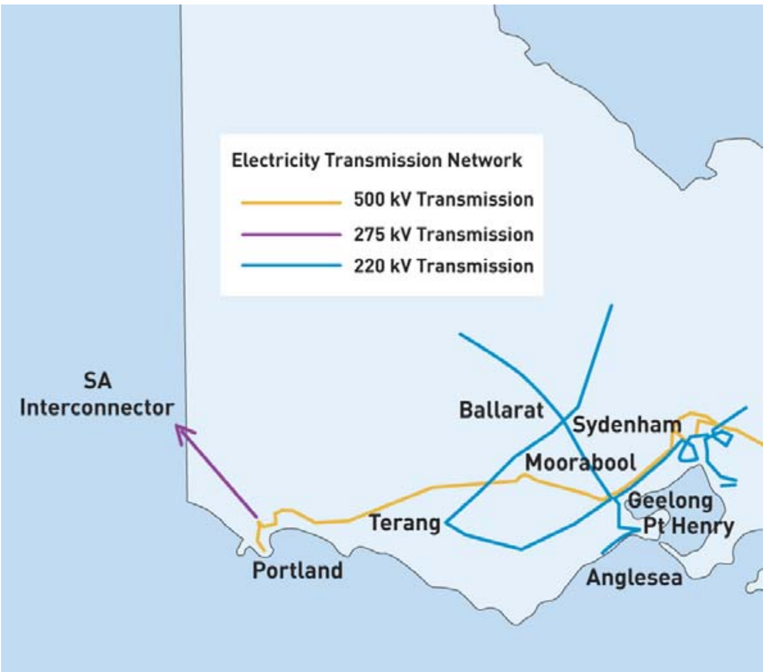
6.2.1 Loading of Hazelwood 220/500 kV tie transformers

Background of the constraint	The four Hazelwood 220/500 kV tie transformers connect a significant portion of the Latrobe Valley 220 kV generation to the high capacity Eastern Corridor transmission assets, being the four 500 kV lines between the Latrobe Valley and Melbourne. Loading of these transformers presents a thermal constraint that can limit the output of all Latrobe Valley generation connecting into the 220 kV buses at Hazelwood Power Station. The constraint typically occurs at times of high demand when all of this generation is likely to be dispatched.
Potential impact of the constraint	The output of generation connected at 220 kV in the Latrobe Valley is constrained such that the Hazelwood 220/500 kV transformers will not become overloaded following loss of any one of the four parallel transformers. Approximately 400 MW of generation can be constrained if the demand at Morwell Terminal Station is low at the same time as all of the generation impacting this constraint is being dispatched.
Network augmentations that impact the constraint	VENCorp is currently working towards developing and implementing a solution to improve the configuration and capacity of the Hazelwood switchyard. Once this configuration is finalised, the Hazelwood transformers constraint can be analysed, and options developed to mitigate this constraint.
Possible options to alleviate the constraint	1. Installation of a fifth 220/500 kV transformer at Hazelwood, at an indicative capital cost of $22M. 2. Installation of a generation tripping scheme to control loading on the Hazelwood transformers.
Conclusion	Following the development of a new Latrobe Valley 220 kV configuration, VENCorp will undertake a detailed regulatory test assessment to determine if this constraint can be economically mitigated.

6.3 South West Corridor

The South West Corridor is relatively recent. It stretches from Melbourne and Geelong to Port Campbell and Portland and West to South Australia. Although 220 kV transmission was established to supply load in South Western Victoria many years ago, the 500 kV transmission was established for electricity supply to the aluminium smelter at Portland. The last 25 years have seen this corridor progressively more clearly defined through electricity connections to South Australia. The physical layout of electricity transmission in the South West Corridor is shown in Figure 6.3.

Figure 6.3 – South West Corridor



There is considerable headroom in the transmission capacity of the South West Corridor compared with the existing supply requirements encompassing the smelter at Portland, Geelong and regional Victoria load, and transfer to South Australia through Heywood.

As noted in Chapter 2, there may be a need to augment the South West Corridor following the conclusions of an Interconnector Review. This is likely to be the case if there is a need to increase Victoria's export capability to South Australia, or new generation connects into this corridor.

There are no constraints presented in this section.

6.4 Northern Corridor

The Northern Corridor includes a range of interstate interconnections including the Snowy Hydro-electric Scheme and NSW power grids in the North East. There is also an electricity interconnection to the South Australian grid in the far North West. This corridor also includes electrical transmission for Victorian Hydro stations in the Kiewa and Eildon schemes. The arrangement of electricity transmission assets in the Northern Corridor is shown in Figure 6.4.

Figure 6.4 – Northern Corridor

At present, the transmission capacity of the Northern Corridor is optimally designed to allow 1,900 MW of import from Snowy/NSW into Victoria with all transmission elements in service, otherwise known as "system normal", and at an ambient temperature of 40°C. Immediately following loss of the largest generator in Victoria, or specific transmission elements, the Northern Corridor could be operating at close to 100% capacity. Operational mechanisms are in place to maintain the loading within rating following an outage.

A number of lines in north western Victoria form parallel paths with the 330 kV transmission lines from greater Melbourne to Snowy/NSW, which results in this corridor connecting to and influencing the regional network.

As noted in Chapter 2, there may be a need to augment the Northern Corridor following the conclusions of an Interconnector Review. This is likely to be the case if there is a need to increase Victoria's import or export capability to Snowy/NSW.

The constraints presented in this section include:

- Murray to Dederang 330 kV lines;
- Dederang to South Morang 330 kV lines;
- Dederang 330/220 kV tie transformers; and
- Eildon to Thomastown 220 kV line.

6.4.1 Loading of Murray to Dederang 330 kV lines

Background of the constraint	The 330 kV transmission lines between Murray and Dederang are key components of the interconnection between the Victorian and Snowy/NSW electricity networks. Loading on these lines defines the existing limit to Victorian import of 1,900 MW. A prior outage of either of these lines significantly reduces this import capability to a level between 600 MW and 900 MW and reduces Victoria's export capability to Snowy/NSW by approximately 130 MW.
Potential impact of the constraint	The limit on Victorian import from Snowy/NSW associated with prior outage of a Murray to Dederang line can potentially increase the market price in Victoria, and results in the need to dispatch higher cost plant in Victoria, South Australia and Tasmania. There is also a possibility of shedding load in Victoria if demand increases above the available generation.
Probability weighted assessment of the constraint	VENCorp estimates the value of this prior outage constraint on Victorian import to be $360k in 2006/07, increasing to approximately $560k in the fifth year of the planning horizon. The impact of the prior outage constraint on Victorian export is expected to be less than $15k pa over the same period.
Possible options to alleviate the constraint	1. Uprating of the Lower Tumut to Wagga and Wagga to Jindera lines and installation of dynamic reactive support at Dederang, at an estimated cost of $27M. 2. Installation of a third Murray to Dederang line at an estimated cost of $64M. This option is subject to confirmation of feasibility as no easement for a third Murray to Dederang line presently exists. 3. Installation of a new 330 kV line from Jindera to Dederang, at an estimated cost of $35M.
Economic evaluation of possible options	At present, the market benefits associated with any of the above projects are insufficient to justify the works identified. VENCorp believes constraints associated with loading on the Murray to Dederang 330 kV lines can be operationally managed until at least 2010/11.
Conclusion	The level of energy at risk does not economically justify any of the works identified. VENCorp will reassess this constraint as part of the planned Interconnector Review and for the 2007 Electricity Annual Planning Report.

6.4.2 Loading of Dederang to South Morang 330 kV lines

Background of the constraint	The 330 kV transmission lines between Dederang and South Morang are key components of the northern Victorian electricity network and of the interconnection between the Victorian and Snowy/NSW regions. With all plant in service, Victorian export is limited to between 1,000 MW and 1,150 MW by a Dederang to South Morang thermal constraint. Loading on the Dederang to South Morang lines does not normally limit Victorian import capability. With prior outage of a South Morang to Dederang line, a number of overlapping constraints on Victorian import apply in association with voltage collapse in the Victorian State Grid and thermal loading on the Dederang 330/220 kV transformers and the Eildon to Thomastown 220 kV line.
Potential impact of the constraint	At present, the Dederang to South Morang constraint is not the dominant system normal constraint for transfer in either direction over the Victoria to Snowy/NSW interconnection and its market impacts are relatively minor.
Probability weighted assessment of the constraint	System normal constraints associated with loading on the Dederang to South Morang 330 kV lines are presently not of significant value. These constraints would need to be addressed as part of any significant upgrade of the interconnection between the Victorian and Snowy/NSW electricity networks.
Possible options to alleviate the constraint	Installation of a third Dederang to South Morang 330 kV line with 50% series compensation to match existing lines at an estimated cost of $120M.
Economic evaluation of possible options	At present, the market benefits associated with the above project are insufficient to justify the works identified. VENCorp believes the system normal constraints associated with loading on the Dederang to South Morang 330 kV lines can be operationally managed until at least 2010/11.
Conclusion	The level of energy at risk does not economically justify the works identified. VENCorp will reassess this constraint as part of the planned Interconnector Review and for the 2007 Electricity Annual Planning Report.

6.4.3 Loading of Dederang 330/220 kV tie transformers

Background of the constraint	The three Dederang 330/220 kV transformers are an important source of supply to northern Victoria and also carry a component of Victorian import from Snowy/NSW. Loading of the three Dederang 330/220 kV tie transformers presents a thermal constraint on Victorian import. With all plant in service and no Kiewa or Eildon area generation, the constraint may reduce Victorian import capability to approximately 1,200 MW. With more than approximately 60% of Kiewa and Eildon area generation dispatched, import capability would be increased to the nominal value of 1,900 MW. With prior outage of a Dederang transformer, the constraint may reduce Victorian import capability to between 100 MW and 1,400 MW depending on Kiewa and Eildon area generation.
Potential impact of the constraint	The limit on Victorian import from Snowy/NSW associated with loading on the Dederang 330/220 kV transformers can potentially increase the market price in Victoria as a result of the need to dispatch higher cost plant in Victoria, South Australia and Tasmania. With prior outage of a Dederang transformer, there is also a possibility of shedding load in Victoria if demand increases above the available generation.
Probability weighted assessment of the constraint	Thermal constraints associated with the Dederang transformers require generation rescheduling with all transmission plant in service and both generation rescheduling and load shedding under prior outage conditions. VENCorp estimates the probability weighted total cost of the constraints to be $187k in 2006/07 and $189k in 2010/11.
Possible options to alleviate the constraint	Installation of a fourth 330/220 kV transformer at Dederang at a cost of $11M.
Economic evaluation of possible options	A fourth 330/220 kV transformer would eliminate the thermal constraints associated with the Dederang transformers. At present, the associated market benefits are insufficient to justify the works. VENCorp believes constraints associated with loading on the Dederang transformers can be operationally managed until at least 2010/11.
Conclusion	The level of energy at risk does not economically justify the works identified. VENCorp will reassess this constraint as part of the planned Interconnector Review and for the 2007 Electricity Annual Planning Report.

6.4.4 Loading of Eildon to Thomastown 220 kV line

Background of the constraint	The Eildon to Thomastown 220 kV line is one of the key components of the northern Victorian electricity network and forms part of the interconnection between the Victorian and Snowy/NSW regions. Loading of the Eildon to Thomastown 220 kV line presents a thermal constraint on Victorian import which can arise during prior outage of a Dederang to South Morang 330 kV line. The constraint restricts Victorian import from Snowy to approximately 1,200 MW in combination with several other constraints.
Potential impact of the constraint	The limit on Victorian import from Snowy/NSW associated with Eildon to Thomastown line loading can potentially increase the market price in Victoria as a result of the need to dispatch higher cost plant in Victoria, South Australia and Tasmania. There is also a possibility of shedding load in Victoria if demand increases above the available generation.
Probability weighted assessment of the constraint	VENCorp estimates the value of the constraint on Victorian import for prior outage of a South Morang to Dederang 330 kV line to be \$315k in 2006/07, increasing to approximately \$480k in the fifth year of the planning horizon. The impact of the prior outage constraint on Victorian export is expected to be \$150k in 2006/07, decreasing to approximately \$120k pa over the next five years. Increasing the capability of the Eildon to Thomastown 220 kV line, will only have a minimal impact on mitigating this prior outage constraint.
Possible options to alleviate the constraint	1. Installation of a wind monitoring scheme on the Eildon to Thomastown line at a cost of \$650k, subject to further investigation on the benefits of such a scheme. 2. Uprating the Eildon to Thomastown line to 73°C operation provides similar benefit at a cost of \$2.4M.
Economic evaluation of possible options	At present, market benefits associated with either of the above projects are insufficient to justify the works identified. VENCorp believes constraints associated with loading on the Eildon to Thomastown 220 kV line can be operationally managed until at least 2010/11.
Conclusion	The level of energy at risk does not economically justify any of the works identified. VENCorp will reassess this constraint as part of the planned Interconnector Review and for the 2007 Electricity Annual Planning Report.

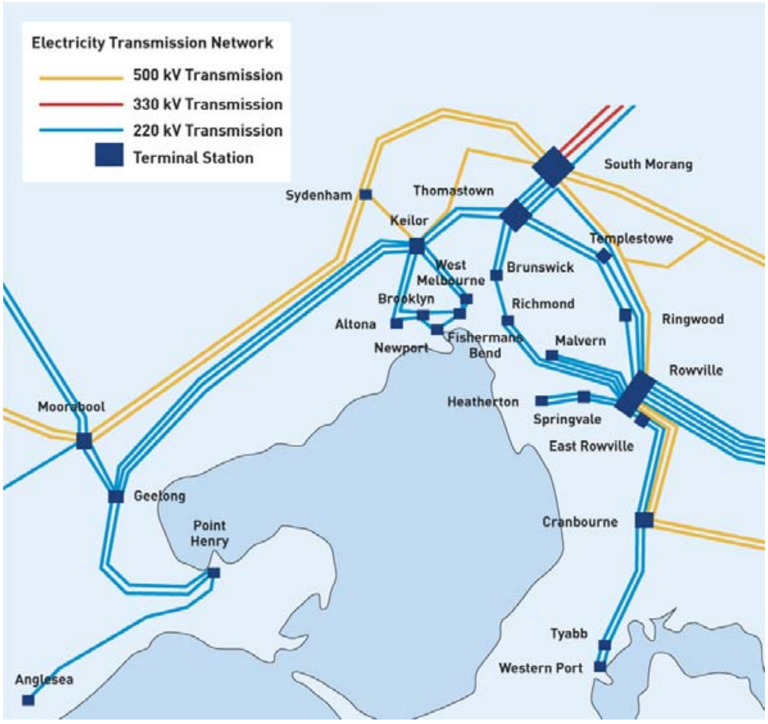
6.5 Greater Melbourne and Geelong

The infrastructure in and around the greater metropolitan area encompassing Melbourne, Geelong and the Mornington peninsula comprises two classes of assets in a classic demand centre configuration:

- an outer 500 kV high capacity ring around most of the territory being supplied; and
- an inner 220 kV ring and radial connections, mainly supplied from the outer ring, to energy delivery points spread throughout the territory.

The arrangement of electricity transmission assets supplying the greater metropolitan areas of Melbourne and Geelong are shown in Figure 6.5.

Figure 6.5 – Greater Melbourne and Geelong



As noted in Chapter 5, a number of augmentation projects are committed to increasing the capacity of supply into this area, namely the two 500/220 kV transformers at Rowville and Moorabool, as well as removing a number of constraints within the area.

The constraints presented in this section include:

- Rowville to Springvale and Heatherton 220 kV lines;
- Rowville to Malvern 220 kV lines;
- Double Circuit 220 kV lines in South East metropolitan area;
- Keilor to West Melbourne 220 kV lines; and
- Fishermans Bend to West Melbourne 220 kV lines.

6.5.1 Loading of Rowville to Springvale and Heatherton 220 kV lines

Background of the constraint	Springvale and Heatherton Terminal Stations are supplied at 220 kV by a radial double circuit line from Rowville Terminal Station. Expected increases in load growth in the areas supplied by Springvale and Heatherton will lead to an increase in loading of these lines over the planning horizon. In recent years the installation of a wind monitoring scheme for these lines, as well as a terminations upgrade, have significantly reduced this constraint.
Potential impact of the constraint	For summer 2010/11, under coincident conditions of peak demand, high ambient temperature and low wind speeds, a single unplanned transmission circuit outage may require up to 300 MW of Springvale and Heatherton load to be shed.
Probability weighted assessment of the constraint	VENCorp estimates that the expected unserved energy over the next five years due to unplanned circuit outages is very low, only reaching approximately \$30k in 2010/11. This is due to the low unplanned outage rates of these circuits, coupled with the low probability of high demand, high ambient temperatures and low wind speeds occurring concurrently.
Possible options to alleviate the constraint	1. Uprating the Rowville to Springvale circuits to 82°C operation at an indicative capital cost of \$1M. 2. New 220 kV circuit between Heatherton and Malvern Terminal Stations, at an indicative capital cost of \$35M. This option will also increase the security of supply to Springvale, Heatherton and Malvern, as described in section 6.5.3.
Economic evaluation of possible options	The market benefits associated with uprating the Rowville to Springvale circuits only represents around one third of the capital cost of this project, for the next five years. As such VENCorp believes this constraint can be operationally managed beyond 2010/11.
Conclusion	The small level of energy at risk does not, at present, economically justify any of the works identified to remove this constraint. VENCorp will reassess the constraint in the 2007 Electricity Annual Planning Report.

6.5.2 Loading of Rowville to Malvern 220 kV lines

Background of the constraint	Malvern Terminal Station is supplied at 220 kV by a radial double circuit line from Rowville. Expected increases in load growth in the areas supplied by Malvern will lead to an increase in loading of these lines over the planning horizon. A permanent load transfer from Richmond to Malvern in 2010 is an option for Distribution Businesses, but this was not a committed project at the time of this publication.
Potential impact of the constraint	Under coincident conditions of peak demand and high ambient temperature, a single unplanned transmission circuit outage may require load to be shed at Malvern.
Probability weighted assessment of the constraint	VENCorp estimates that there is no expected unserved energy over the next five years due to unplanned circuit outages. However, this will change if significant load is transferred to Malvern Terminal Station.
Possible options to alleviate the constraint	1. Uprating the Rowville to Malvern circuits to 82°C operation at an indicative capital cost of \$17M. 2. Installation of a wind monitoring scheme to take advantage of higher wind speeds anticipated on hot summer days, at an indicative capital cost of \$250k. 3. Installation of an automatic load shedding scheme to control circuit loadings, at an estimated cost of \$150k.
Economic evaluation of possible options	With no forecast unserved energy on the Rowville to Malvern lines, no network augmentation is required at this time. Analysis suggests this constraint can be operationally managed beyond 2010/11.
Conclusion	At present, the level of the energy at risk does not economically justify any of the works identified. VENCorp will continue to monitor possible load transfers to Malvern Terminal Station, and reassess this constraint in the 2007 Electricity Annual Planning Report.

6.5.3 Security of double circuit 220 kV lines in South East metropolitan area

Background of the constraint	Springvale, Heatherton, Malvern and Tyabb Terminal Stations and the facility at JLA (Western Port) are supplied by radially configured double circuit 220 kV lines. Subject to the transfer of load away from these areas, failure of one or more of the towers on these radial lines could cause considerable loss of supply to any of these areas.
Potential impact of the constraint	Under peak demand conditions, a single tower outage could result in over 1,000 MW of load shedding for an extended period of time.
Probability weighted assessment of the constraint	Emergency measures that significantly reduce the energy at risk, including distribution transfers, mobile cranes to replace faulted towers, and tie transfers connecting alternative lines, have been established. Though these emergency measures significantly reduce the energy at risk, a new connection between Malvern and Heatherton could secure a further 80 MW of load. The expected (probability weighted) cost of the constraint, is estimated to be: • around \$2.3 million in 2006/07; and • approximately \$2.4 million in 2010/11.
Possible options to alleviate the constraint	Installation of an underground cable connecting Malvern and Heatherton Terminal Stations for approximately \$35M will significantly mitigate this constraint.
Economic evaluation of possible options	The economic evaluation suggests that the gross market benefits associated with installing a Malvern to Heatherton cable are not yet sufficient to make it viable, although the annual market benefits approach 96% of the annualised cost of the augmentation, by the end of the current planning horizon.
Conclusion	The analysis has not identified any option that technically and economically alleviates the constraint at this time. However, given the annualised market benefits and costs of the installation are almost equal, VENCorp will jointly undertake detailed analysis with affected Distribution Businesses, to consider a permanent solution involving a new connection between Malvern and Heatherton Terminal Stations.

BACKGROUND OF THE CONSTRAINT

The Springvale, Heatherton, Malvern and Tyabb Terminal Stations, and the facility at JLA (Western Port), are each supplied by radially configured double circuit 220 kV lines. These stations supply a significant amount of load in the South East Metropolitan Area.

Failure of one or more double circuit towers or both radial lines concurrently, leading to an extended outage of both the circuits on a tower line, can result in loss of supply to a large area. Some causes likely to result in prolonged outages of double circuits, though there are also many other possible causes, are aeroplane and automobile collisions with towers, bushfires near the lines and other natural disasters including cyclones and tornadoes. Such events have a very low probability of occurring, but are considered to be equally likely to occur in any one year.

To minimise the consequences and restore supply after a double circuit failure, Alinta, SP AusNet (Distribution), SP AusNet (Transmission) and VENCorp have put the following emergency plans in place:

- emergency by-pass measures, utilising temporary structures and mobile cranes, developed by SP AusNet (Transmission), allow for restoration of full supply within 12 hours in over half of the possible tower failure cases;
- emergency bridging measures developed by SP AusNet (Transmission), in conjunction with VENCorp, will restore full supply to Malvern from the Rowville to Richmond double circuit line within 6 hours for a Rowville to Malvern double circuit outage; and
- emergency measures developed by Alinta and SP AusNet (Distribution) 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).

POTENTIAL IMPACT OF THE CONSTRAINT

The impact of this constraint, following a double circuit outage, is potentially prolonged outages resulting in significant loss of supply at Malvern, Springvale, Heatherton and Tyabb Terminal Stations as well as at the facility at JLA (Western Port). Table 6.3 outlines the forecast peak loading on each of the double circuit lines both prior to and after distribution transfers.

Table 6.3 – Load at risk for double circuit 220 kV line outages

Double Circuit Line	Length (km)	Peak load at risk for double circuit line outages in summer 2006/07 (MW)		Peak load at risk for double circuit line outages in summer 2010/11 (MW)	
		Prior to transfers	After transfers	Prior to transfers	After transfers
Rowville to Springvale	7	804	624	880	700
Springvale to Heatherton	8	347	247	370	270
Rowville to Malvern	15	183	0	203	0
Cranbourne to Tyabb	23	308	208	343	243
Tyabb to Western Port	2	66	66	66	66

ASSESSMENT OF THE CONSTRAINT

In assessing the value of this constraint, the analysis uses a probabilistic approach by calculating likely double circuit outage duration and frequency. This considers double circuit, tower and other relevant historical outages and the associated outage length as a probability of occurrence.

The study shows that outages caused by tower faults can last as long as a week in duration and the relative outage frequency is generally seen to decrease as the outage duration increases. Table 6.4 shows the outage relative frequency verses outage duration used for the analysis, and Table 6.5 summarises the outage rates for circuit and tower fault outages.

Table 6.4 – Outage duration and relative frequency

Outage duration (hours)	1	3	6	12	24	48	96	168
Relative frequency (%)	35	23	15	10	7	5	3	2

Table 6.5 – Rate of outages

Outages type	Outage rate (per circuit tower per annum)
Circuit outages	0.000368
Tower fault outages	0.000019

It has been assessed that sub-transmission transfers and a number of other emergency operations, such as utilising mobile cranes, can reduce the unserved energy during a double circuit outage. Mobile crane support is only considered for suspension towers because cranes do not have the capability to safely support the additional forces exerted on strain towers. These cranes are also only able to access a fraction of suspension tower sites, depending on location and surrounding terrain. Table 6.6 outlines the number of suspension and strain towers per circuit as well as the percentage of towers that are considered to be accessible by mobile cranes.

Table 6.6 – Circuit towers relieved by mobile crane support

Circuit	Suspension Towers	Strain Towers	Towers accessible by Mobile Cranes (percentage of towers in circuit)
ROTS-SVTS	20	7	50%
SVTS-HTS	18	14	50%
ROTS-MTS	37	14	N/A – Full load secured by tie transfers (6 hours)
CBTS-TBTS	50	12	60%
TBTS-JLA	2	3	60%

Table 6.7 summarises the expected unserved energy at Malvern, Springvale and Heatherton due to double circuit outages on the radial lines connecting Rowville to Malvern and Rowville to Springvale and Heatherton, over the next five years. The value of this constraint is calculated using the Victorian system wide Value of Customer Reliability (VCR) of $29,600 per MW.

No further analysis has been performed on the supply to Tyabb and JLA (Western Port) due to the 2005 EAPR clearly showing the net market benefits associated with a new installation to increase the reliability to these stations, as not economically viable over the current planning horizon.

Table 6.7 – Expected unserved energy

	2006/07	2007/08	2008/09	2009/10	2010/11
Expected Unserved Energy (Pr[x].MWh)	115.4	116.9	117.4	118.7	118.5
Value of Constraint ($k)	3,415	3,459	3,474	3,512	3,507

OPTIONS TO ALLEVIATE THE CONSTRAINT

NETWORK OPTIONS

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

Although the feasibility of other network options is yet to be confirmed, part of the detailed analysis of undertaking a regulatory test for a new large network asset will include seeking alternatives to this underground cable.

VENCorp considers this network option to be a contestable augmentation.

OTHER OPTIONS

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

ECONOMIC EVALUATION

The market benefits have been calculated as a ratio of average load that can be supported by a connection, multiplied by the hours it can be supported at a particular outage duration level by the number of outages per year that are expected to last that duration.

The calculations have also assessed the benefits of emergency transfer measures such as sub-transmission and distribution transfers, mobile crane line reinstatement and tie transfers, which are options that are already in place, independent of any additional augmentations.

Table 6.8 shows the present and annualised value of the constraint, in comparison with the benefits of the Malvern to Heatherton cable installation.

Table 6.8 – Net market benefits of network options

		Present Value ($k)	Annualised Value ($k)					Residual Value ($k)
			2006/07	2007/08	2008/09	2009/10	2010/11	
DO NOTHING		-49,085	-3,415	-3,459	-3,474	-3,512	-3,507	-52,311
OPTION 1	Market Benefits	33,469	2,307	2,343	2,356	2,387	2,396	35,738
MTS-HTS Underground Cable	Costs	-35,000	-2,493	-2,493	-2,493	-2,493	-2,493	-37,185
	Net Market Benefits	-1,531	-186	-150	-137	-106	-97	-1,447

Thermal constraints, which are forecast to occur on some of these lines if a single line outage occurs during peak demand periods, can potentially be reduced from installation of a Malvern to Heatherton connection. If a connection were installed, heavily loaded stations could be subsequently supplied via the cable, resulting in a reduced flow on these lines without having to shed load.

The market benefits associated with alleviating these line outage constraints will be added to the benefits shown in Table 6.8, when undertaking the detailed analysis to justify a new connection between Malvern and Heatherton Terminal Stations.

CONCLUSION

The analysis has not identified any option that technically and economically alleviates the constraint at this time. However, given the annualised market benefits and costs of the installation are almost equal, VENCorp will jointly undertake a detailed analysis with affected Distribution Business, to consider a permanent solution involving a new connection between Malvern and Heatherton Terminal Stations.

6.5.4 Loading of Keilor to West Melbourne 220 kV lines

Background of the constraint	The double circuit lines between Keilor and West Melbourne form part of the 220 kV loop emanating from Keilor, which provide power to commercial, industrial and residential customers in the western metropolitan area. Expected increases in load growth in the area supplied by West Melbourne and Fishermans Bend Terminal Stations will lead to an increase in loading of these lines over the planning horizon.
Potential impact of the constraint	Under coincident conditions of peak demand, high ambient temperatures and low generation in this western metropolitan loop, a single unplanned transmission circuit outage may require West Melbourne/Fishermans Bend load to be shed.
Probability weighted assessment of the constraint	VENCorp estimates that the expected unserved energy over the next five years due to unplanned circuit outages is very low. This is due to the low unplanned outage rates of these circuits, coupled with the low probability of high demand, high ambient temperatures and generation outages occurring in the western metropolitan loop coincidently.
Possible options to alleviate the constraint	1. Uprating the terminations of the Keilor to West Melbourne lines, at an indicative cost of $3M. 2. Installation of an automatic load shedding scheme to control circuit loading at an estimated cost of $300k.
Economic evaluation of possible options	The market benefits associated with either of these options is very small. VENCorp believes this constraint can be operationally managed beyond 2010/11.
Conclusion	The small level of energy at risk does not, at present, economically justify any of the works identified to remove this constraint. VENCorp will reassess this constraint in the 2007 Electricity Annual Planning Report.

6.5.5 Loading of Fishermans Bend to West Melbourne 220 kV lines

Background of the constraint	The double circuit lines between Fishermans Bend and West Melbourne form part of the 220 kV loop emanating from Keilor Terminal Station. Expected increases in load growth in the area supplied by West Melbourne and Fishermans Bend will lead to an increase in loading of these lines over the planning horizon.
Potential impact of the constraint	Under coincident conditions of peak demand, high ambient temperatures and low generation in this western metropolitan loop, a single unplanned transmission circuit outage may require load to be shed at West Melbourne and Fishermans Bend.
Probability weighted assessment of the constraint	VENCorp estimates that the expected unserved energy over the next five years due to unplanned circuit outages is very low. This is due to the low unplanned outage rates of these circuits, coupled with the low probability of high demand, high ambient temperatures and generation outages occurring coincidently.
Possible options to alleviate the constraint	1. Minor termination uprating of the Fishermans Bend to West Melbourne lines, at an indicative cost $350k. 2. Major termination uprating of the Fishermans Bend to West Melbourne lines, at indicative capital cost of $3.1M. 3. Installation of an automatic load shedding scheme to control circuit loading, at an estimated cost of $300k.
Economic evaluation of possible options	At present, the market benefits allocated with the minor termination uprating, or either of the other options, are insufficient to justify augmentation. VENCorp believes this constraint can be operationally managed beyond 2010/11.
Conclusion	The small level of energy at risk does not, at present, economically, justify any of the works identified to remove this constraint. VENCorp will asses this constraint in the 2007 Electricity Annual Planning Report.

6.6 Regional Victoria

In addition to the backbone transmission networks discussed above, regional areas of the state are covered by a lower capacity transmission network to deliver energy to provincial cities and regional load centres. The whole-of-state electricity network is shown in Figure 6.6.

Figure 6.6 – Regional Victoria

As discussed in Section 6.4, a number of transmission lines in regional Victoria form parallel paths with the Northern Corridor, and as such are significantly influenced by levels of import or export from Snowy/NSW. These lines are also influenced by the level of demand at terminal stations in regional Victoria, as well as the amount of transfer across the HVDC interconnector between Berri in South Australia and Red Cliffs in Victoria.

The constraints presented in this section include:

- Shepparton to Bendigo 220 kV line;
- Moorabool to Ballarat 220 kV lines; and
- Ballarat to Bendigo 220 kV line.

6.6.1 Loading of Shepparton to Bendigo 220 kV line

Background of the constraint	The Shepparton to Bendigo line is an important source of supply to north western Victoria and also carries a component of Victorian import from Snowy/NSW. A thermal constraint associated with this line affects Victorian import from Snowy, export to South Australia via Murraylink and supply to the Victorian State Grid. In 2005, VENCorp identified the development of a wind monitoring scheme on the Shepparton to Bendigo 220 kV line as passing the Regulatory Test requirements. These works are now committed and due for completion late 2006 and have reduced the forecast impact of the thermal constraint to an insignificant level over the period 2006/07 to 2010/11.
Potential impact of the constraint	Under extreme loading and temperature conditions, the constraint may increase the market price in Victoria as a result of the need to dispatch higher cost plant in Victoria, South Australia and Tasmania. There is also a possibility of shedding load in Victoria if demand increases above the available generation. These impacts are not forecast to occur over the five year planning horizon.
Probability weighted assessment of the constraint	The Shepparton to Bendigo constraint is presently not significant and its market impacts are forecast to be negligible over the next five years. The constraint would be analysed as part of any future proposal to increase overall capacity of the Victoria to Snowy/NSW interconnection.
Possible options to alleviate the constraint	Uprating the Shepparton to Bendigo line to 90°C at an estimated cost of $5M.
Economic evaluation of possible options	At present, market benefits associated with the above project are insufficient to justify the works identified. VENCorp believes the constraint associated with loading on the Shepparton to Bendigo line 220 kV line can be operationally managed until at least 2010/11.
Conclusion	The level of energy at risk does not economically justify the works identified. VENCorp will reassess this constraint as part of the planned Interconnector Review and for the 2007 Electricity Annual Planning Report.

6.6.2 Loading of Moorabool to Ballarat 220 kV lines

Background of the constraint	One of the main supply points into West Victoria regional areas is via the two Moorabool to Ballarat circuits. These circuits form part of the supply into South Australia via the Murraylink DC interconnector at Red Cliffs, and into south western New South Wales. The justification of a wind monitoring scheme for these lines in 2004 EAPR, will significantly reduce this constraint once implemented. However, load growth in these areas will lead to an increase in loading of these lines over the planning horizon.
Potential impact of the constraint	Under coincident conditions of peak demand in the State Grid, high ambient temperature and export to both South Australia and New South Wales/Snowy a single unplanned transmission circuit outage can result in the export of power to South Australia to be reduced to zero and may require load to be shed at one or more of the stations supplying this West Victoria regional area.
Probability weighted assessment of the constraint	VENCorp estimates that the value of this constraint over the next five years, due to unplanned circuit outages, to be extremely small. This is due to the low unplanned outage rates of these circuits, coupled with low probability of high demand in State Grid, high export to South Australia and Snowy/NSW, high ambient temperature and low wind speed occurring coincidently.
Possible options to alleviate the constraint	1. Uprating the Moorabool to Ballarat No 1 circuit to 75°C operation at an indicative cost of $3M. 2. Uprating the Moorabool to Ballarat No 1 circuit to 82°C operation at an indicative capital cost of $5M. 3. Installation of a third Moorabool to Ballarat circuit at an estimated cost of $8M.
Economic evaluation of possible options	At present, the market benefits associated with any of these projects are substantially smaller than cost. VENCorp believes this constraint can be operationally managed beyond 2010/11.
Conclusion	The level of energy at risk does not economically justify any of the works identified. VENCorp will reassess this constraint in the 2007 Electricity Annual Planning Report.

6.6.3 Loading of Ballarat to Bendigo 220 kV line

Background of the constraint	The 220 KV line between Ballarat and Bendigo forms one of the main supply points into North Western Victoria as well as the supply into South Australia via the Murraylink DC interconnector at Red Cliffs, and into south western New South Wales. Load growth at Bendigo, Kerang and Shepparton will lead to an increase in loading of this line over planning horizon.
Potential impact of the constraint	Under coincident conditions of peak demand, high ambient temperatures and export to Snowy/NSW a single unplanned transmission circuit outage may require load to be shed at Bendigo, Kerang and Shepparton.
Probability weighted assessment of the constraint	VENCorp estimates that the expected unserved energy over the next five years, due to unplanned circuit outages, is almost zero. This is due to the low unplanned outage rates of the circuit, coupled with low probability of high demand in North Western Victoria, high export to Snowy/NSW, and high ambient temperature occurring coincidently.
Possible options to alleviate the constraint	1. Installation of a wind monitoring scheme to take advantage of higher wind speeds anticipated on hot summer days, at an indicative capital cost of $500k. 2. Uprating the Ballarat to Bendigo circuit to 75°C operation at an estimated cost of $3.4M.
Economic evaluation of possible options	At present, there are only extremely small market benefits associated with any of these projects. VENCorp believes this constraint can be operationally managed beyond 2010/11.
Conclusion	The level of energy at risk does not economically justify any of the works identified. VENCorp will reassess this constraint in the 2007 Electricity Annual Planning Report.

6.7 Reactive support

Background of the constraint	Reactive power supply and demand needs to be balanced to maintain system voltage stability and to meet target voltage levels. In addition, adequate reactive power reserve is required, in order to maintain system security following outages. During summer peak demand periods, reactive power load increases as a result of increased use of air conditioners, and reactive power losses increase as a result of increased system loading. To meet the increased reactive power demand, adequate reactive power support at appropriate locations in the Victorian transmission network is required.
Potential impact of the constraint	Following the worst credible contingency, system voltage stability needs to be maintained and voltage levels should remain within the acceptable levels. To achieve this, one or more of the following actions can be taken to reduce the impacts of this constraint prior to a contingency (i.e. under system normal operating conditions): • rescheduling of generation • load reduction in Victoria (other than in Latrobe Valley area)
Probability weighted assessment of the constraint	System normal constraints associated with additional reactive support are presently not of significant value. These constraints would need to be addressed as part of any new generation connection, or an upgrade to any of Victoria's interconnectors.
Possible options to alleviate the constraint	1. Request connected parties to improve power factor at the point of connection. 2. Installation of shunt capacitor banks at transmission level. 3. Reduction of reactive losses by installation of new transmission lines and/or transformers.
Economic evaluation of possible options	Market modelling has identified a generation shortfall occurring from summer 2009/10 to meet the forecast 10% POE maximum demand. If new generation is added to the Latrobe Valley or import is increased from Snowy/NSW, additional reactive support may be required. If new generation is added in the metropolitan Melbourne or State Grid areas, reactive support may be deferred. The required level of reactive support and location need to be assessed as part of all new generation proposals.

Conclusion	The assessment has identified no network options that technically and economically alleviate the forecast constraint at this time. This year's assessment has identified that the maximum Victorian supportable demand, as constrained by voltage stability, exceeds the forecast demand in 2009/10. However, during summer 2010/11 and beyond there may be constraints. VENCorp will continue to monitor this constraint and the timing and identification of feasible options will be subject to further assessment in the 2007 Electricity Annual Planning Report.

7. TEN YEAR OUTLOOK

This chapter provides an indication of potential network constraints that may occur in the ten year period up to 2015/16, together with transmission options to remove the constraints, in order to support the full forecast Victorian demand. Transmission development options are categorised in the following groups (Figure 7.1):

- Eastern Corridor;
- South West Corridor;
- Northern Corridor;
- Greater metropolitan area of Melbourne and Geelong; and
- Regional areas of the state.

Figure 7.1 – Victoria's energy transmission corridors

For the ten year development study, the transmission network has been modelled with a demand of 12,450 MW. To meet this demand and to allow for up to 500 MW export to South Australia, approximately 2,250 MW of additional new generation will be required in Victoria by 2015/16. Table 7.1 provides the supply-demand balance used for the ten year outlook, which sets out the level of existing and committed generation, import and export levels, Victorian demand and the reserve levels used to determine the requirement for additional new generation.

Table 7.1 – Supply and demand balance for 2015/16

Demand	Victorian maximum demand (10% POE) [31]	12,450
	Export to South Australia	500
	Victorian Reserve level	265
	Total demand plus reserve level	13,215
Supply[32]	Anglesea	156
	Bairnsdale	70
	Energy Brix Complex	139
	Hazelwood	1,580
	Hume (Vic)	58
	Jeeralang	416
	Laverton North GT	312
	Loy Yang A	2,060
	Loy Yang B	1,000
	Newport	475
	Somerton GT	120
	Southern Hydro	483
	Valley Power	280
	Yallourn	1,420
	Import from Snowy/NSW	1,800
	Import from Tasmania	600
	Total Supply	10,969
Amount of additional new generation needed		2,246 (~2,250)

As the location and size of generation will impact on the augmentations required on the transmission network, a range of supply scenarios, which load different parts of the transmission network, have been examined. At present, export from Victoria is limited at 1,100 MW to Snowy/NSW, 500 MW to Tasmania, and 680 MW to South Australia. An additional scenario has been included to assess the effect on the Victorian transmission network, for an increase in export level to Snowy/NSW and South Australia. These scenarios are as shown in Table 7.2.

31 This demand is based on the forecasts presented in the Electricity Annual Planning Report 2005.

32 Generation capacities are based on the summer 2014/15 figures from NEMMCO's 2005 SOO.

Table 7.2 – Supply scenarios for the ten year outlook

	Description	Increased Latrobe Valley Generation (MW)	Increased South Western Victoria Generation (MW)	Increased Import from Snowy/NSW (MW)	Metro/State Grid Generation/DSM (MW)	Total Additional Supply (MW)
Scenario 1	Latrobe Valley generation	1,950	0	0	300	2,250
Scenario 2	South West generation	1,150 650	500 1,000	0	600	2,250
Scenario 3	Increase in import from Snowy/NSW	1,770 1,350 350	0	180 600 1,600	300	2,250
Scenario 4	High metropolitan and State Grid generation	1,050	0	0	1,200	2,250
Scenario 5	Increase in export to Snowy/NSW and South Australia	Increased export of 200 MW to Snowy/NSW and 300 MW to South Australia during low to moderate demand periods				

The scenarios selected are consistent with VISION 2030 published by VENCorp in October 2005. They provide a representation of the many plausible scenarios for the development of the transmission network. However, a range of other scenarios are possible, and they may result in different transmission requirements. In particular, for import levels from Snowy/NSW beyond 3,500 MW[33], significant additional augmentation may be required, possibly in the form of High Voltage Direct Current (HVDC) links.

In considering this ten year period, the network constraints and solutions outlined for the five year period up to 2010/11, as described in Chapter 6, are included. For the constraints in the second half of the ten year period, a probabilistic analysis of the amount of energy at risk due to these network constraints has not been undertaken so the timing of any possible augmentation works is only indicative and would be confirmed by full economic assessment at an appropriate time in the future.

7.1 Increased Latrobe Valley generation

Latrobe Valley generation increases by 350 MW to 1,950 MW depending on the scenario, in addition to the 600 MW from Basslink. If Basslink becomes unavailable, it is assumed that 600 MW of alternative generation is available from the Latrobe Valley.

33 Scenario 3 has a total import capability of 3,500 MW from Snowy/NSW (i.e. 1,900 MW existing plus 1,600 MW additional)

7.2 Increased South Western Victoria generation

The effect on the transmission network due to generation in South Western Victoria is modelled by including new generation connected to the existing 500 kV transmission lines between Moorabool and Heywood. It is assumed all the new generators are concentrated around the Mortlake district. The scenarios include a range of options from 0 to 1,000 MW.

7.3 Increased import from Snowy/NSW

The import level considered is in addition to the import level of 1,800 MW from Snowy/NSW. Joint planning between VENCorp and TransGrid has identified an initial outline of works required to increase the import capability into the Victorian/SA region by 180 MW, 600 MW and 1,600 MW. The scenarios include these increases to import levels.

7.4 Metropolitan/State Grid generation and/or demand side management

The effect of generation or significant demand side management within the Greater metropolitan area of Melbourne and Geelong and State Grid areas is modelled by including new generation on the 220 kV network. In the metropolitan area, new generation is modelled at Moorabool, Keilor, and Rowville areas. For the State Grid area, new generation is modelled at Kerang and Horsham. The actual timing and location of any new embedded generation or large scale demand side management may have a significant impact on the timing and nature of any transmission augmentations. The locations selected are representative of possible locations, and should provide an indication of the effects of this new generation. The scenarios include a range of options from 300 MW to 1,200 MW.

7.5 Increased export to South Australia and Snowy/NSW

In the base case model, it is assumed up to 500 MW export to South Australia, and no export to Snowy/NSW and Tasmania, at the time of 10% POE demand in Victoria. The system is designed to export to South Australia a maximum of 680 MW (460 MW and 220 MW via Heywood and Murraylink interconnectors respectively). At low to moderate demand period nominally 1,100 MW can be exported to Snowy/NSW.

The effect on Victoria's transmission network due to additional export to SA and Snowy/NSW during the moderate demand period was assessed. Scenarios included are 300 MW additional export to South Australia via Heywood interconnector (i.e. up to 760 MW via Heywood) and 200 MW additional export to Snowy/NSW.

7.6 Transmission development

Transmission constraints for the different supply scenarios and possible shared transmission network projects to remove these transmission constraints over the next ten years are presented in this section. These shared transmission network projects would proceed if they pass the Regulatory Test as specified by the AER or are funded by the interested parties.

7.6.1 Eastern Corridor

The Eastern Corridor connects the greater Melbourne load centre to the electricity generators in the Latrobe Valley. The physical layout of electricity transmission assets in the Eastern Corridor is shown in Figure 6.2 of Chapter 6.

In scenarios with high levels of new generation added in the Latrobe Valley, the existing 500 kV lines may not provide sufficient power transfer capability into the Melbourne metropolitan area. The existing limitations of the terminating plant at the Hazelwood terminal station need to be upgraded when the amount of new generation in the Latrobe Valley connected at 500 kV exceeds about 500 MW beyond existing levels, including Basslink. With increased generation in the Latrobe Valley, the upgraded capacity may not be sufficient towards the end of the ten year period. For scenario 1, where 1,950 MW of generation is added in the Latrobe Valley, a new 500 kV transmission line is required from the Latrobe Valley to Melbourne.

If significant additional generation is connected at Loy Yang 500 kV switchyard, the existing capacity between Loy Yang and Hazelwood would become a constraint, and an additional 500 kV circuit between Loy Yang and Hazelwood may be required. The existing easements do not have space to accommodate another circuit, hence widening of the existing easement or a new easement would be required.

If new generation is connected to the 220 kV network in the Latrobe Valley, additional 500/220 kV transformation at Hazelwood terminal station would be required to bring power into the 500 kV system for transportation to Melbourne.

7.6.2 South West Corridor

The South West Corridor is predominantly a 500 kV transmission network from Moorabool to Heywood to Portland and 275 kV transmission network from Heywood to South East in South Australia. The connection arrangement of electricity transmission network in the South West Corridor is shown in Figure 6.3 of Chapter 6.

If large new generation were developed in the South West Corridor, a new 500 kV terminal station in the South West Corridor would be required to connect this generation into the 500 kV network. For the scenario with increased export to South Australia via Heywood, the transmission network between Heywood and South East would need to be augmented.

7.6.3 Northern Corridor

The Northern Corridor consists of a range of interstate connections with New South Wales and South Australia, and 330 kV transmission lines between Dederang and South Morang. This corridor includes:

- 330 kV interconnection between Dederang and Murray (NSW) and between Wodonga and Jindera (NSW);
- 220 kV interconnection between Red Cliffs and Buronga (NSW);
- HVDC interconnection between Red Cliffs and Monash in South Australia;
- 330 kV transmission lines between Dederang and South Morang; and
- 220 kV transmission lines to connect Victorian Hydro stations in the Kiewa and Eildon schemes.

This corridor also connects to and influences the Victorian regional network. The arrangement of the electrical transmission network in the Northern Corridor is shown in Figure 6.4 of Chapter 6.

In the scenarios where additional capacity is obtained from Snowy/NSW, enhancement of the existing interconnection would be required. All the scenarios considered here assume either no increase at all in the Snowy to Victoria interconnection capability beyond the existing committed level of 1,900 MW, or an upgrade, which would provide 180 MW, 600 MW or 1,600 MW of additional interconnection capability. The scenario to increase the import by 180 MW involves less capital works in Victoria, but is subject to availability of additional Network Control Ancillary Services (NCAS) of about 180 MW post-contingency load shedding.

The 1,600 MW upgrade would require significant capital works, including augmentation of the transformation tying the 330 kV lines from Snowy/NSW with the Victorian 500 kV and 220 kV networks, additional 330 kV lines between Dederang and South Morang, and Dederang and Wagga, series compensation of several existing lines, additional shunt reactive plant, and line upgrading works and additional new lines in New South Wales. Any works required in NSW have not been costed or included in the summary of works.

7.6.4 Greater metropolitan area of Melbourne and Geelong

The infrastructure in and around the greater metropolitan area encompassing Melbourne, Geelong and the Mornington Peninsula comprises of the outer 500 kV electricity ring and the inner 220 kV ring and radial connections as shown in Figure 6.5 of Chapter 6.

The capacity of the existing 500/220 kV and 330/220 kV transformation in the Melbourne metropolitan area will become a constraint on delivery of increased power from the Latrobe Valley, South West or increased import from Snowy/NSW. An additional metropolitan 500/220 kV transformer would be required around 2012. 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.

For scenarios with increased import from or increased export to Snowy/NSW, additional 330/220 kV transformation would be required at South Morang.

Some uprating and/or re-configuration of the 220 kV transmission circuits within the Melbourne metropolitan area is likely to be required, particularly affecting lines between and around Thomastown and Rowville, both to provide for increased power transfer capacity across the metropolitan area, and to manage the loading of critical radial systems such as Springvale and Heatherton.

AGL, SP AusNet (Distribution) and Powercor have identified new 220/66 kV terminal station at South Morang and East Geelong to meet the continued load growth in these areas.

7.6.5 Regional areas of the state

Regional areas of the state are mainly covered by 220 kV transmission network to deliver energy to provincial cities and regional load centres as shown in Figure 6.6 of Chapter 6. Some reinforcement of the supply to the State Grid will be required during this period.

Powercor has identified new 220/66 kV terminal stations at Castlemaine and Wemen in north western Victorian to meet the continued load growth in these areas.

7.6.6 Management of fault levels

New generation developments and transmission network augmentations will generally result in higher fault levels across the transmission system. Management of fault levels is already a critical issue at a number of locations within the Melbourne metropolitan area, and a combination of circuit breaker replacement (to permit operation at higher fault levels), installation of series reactors and operational measures such as segregation of the transmission network to limit fault current infeed, are likely to continue over the next ten years. The appropriate balance between containing the fault level and allowing the fault level to increase will require ongoing investigation, this work will consider SP AusNet's plans for circuit breaker replacement, and the impact on distribution networks. The issue of fault levels will be particularly impacted by higher levels of generation connected at 220 kV and lower voltage levels, and a higher cost is assigned for the higher embedded generation scenarios. To address the long-term fault level issues, a strategic fault level review is underway.

7.6.7 Reactive support

Increased reactive support is required due to load growth, to compensate for increased reactive losses and to maintain system voltage stability. Additional new transmission lines and transformers would reduce reactive losses. The required level of reactive support and location needs to be assessed as part of generation and network developments.

7.7 Summary of results

The different balance between embedded generation, Latrobe Valley generation, South West generation and increased import from Snowy/NSW under the different scenarios would have a significant impact on the level of energy at risk if a particular augmentation were not to proceed, and hence the timing for many of these projects would be different between the scenarios.

Table 7.4, provides a summary of the works required to remove transmission constraints emerging over the next ten year period for each of the five supply scenarios. Table 7.5 indicates the estimated capital cost for network solutions over the 1-5 year and 6-10 year periods. The capital cost in the first five years is similar because there is little difference in the augmentation requirements across the five scenarios in this time period. This is because there is more certainty on the generation scenarios in this period.

The capital cost for network solutions in the 6-10 year period varies more significantly across the scenarios. The scenarios that rely on transporting the bulk of the additional generation from a specific location such as the Latrobe Valley (scenario 1) or Snowy/NSW (scenario 3) require more investment in transmission capacity and therefore involve higher capital costs. Those scenarios that have a high level of embedded generation (scenario 4) or with significant new generation in the South West (scenario 2), reduce the amount of new transmission needed or utilises the spare capacity on the existing 500 kV lines in that corridor, hence have a lower capital cost.

Augmentation of the transmission network needed to increase the export capability to Snowy/NSW and SA are covered under scenario 5.

Table 7.3 – Summary of committed projects

Constraint	Network Solution	Project Cost ($M)	Estimated Timing	Comments
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformers	Second 500/220 kV 1,000 MVA transformer at Rowville; and Replacement of circuit breakers and associated plant with higher fault level capability at Rowville and East Rowville	68	September 2007	Project in progress
Outage of the Moorabool transformer overloads Keilor 500/220 kV transformers and Keilor-Geelong 220 kV lines	Second 500/220 kV 1,000 MVA transformer at Moorabool		September 2008	Project in progress
Bendigo-Fosterville-Shepparton circuit overload at high Victorian demand and import from Snowy/NSW	Wind monitoring scheme on the Bendigo-Fosterville-Shepparton circuit		December 2006	Project in progress

Table 7.4 – Summary of network constraints over the next 10 years

Eastern Corridor

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Inadequate thermal capacity on Latrobe Valley (LV) to Melbourne 500 kV lines	Upgrade terminations and circuit breaker thermal ratings at Hazelwood	6	At the time of about 500 MW new generation at LV 500 kV	Timing depends on generation development behind the constraint
	Fifth 500 kV line from LV to Melbourne	125	At the time of about 1,800 MW new generation at LV 500 kV	
Inadequate thermal capacity of Loy Yang to Hazelwood 500 kV lines	Fourth 500 kV line from Loy Yang to Hazelwood	30	At the time of about 500 MW new generation connected at Loy Yang	Timing depends on generation development behind the constraint and subject to availability of easement.
Outage of a Hazelwood 500/220 kV transformer overload the parallel transformers	Additional 220/500 kV transformation at Hazelwood and fault level mitigation	22	At the time of additional new generation connected at Hazelwood or Jeeralang 220 kV	Timing depends on generation development behind the constraint
Transient stability limit for a fault on Hazelwood-South Morang 500 kV line	A 500 MW, 500 kV braking resistor at Loy Yang	7	At the time of 150-200 MW increase in export to Snowy/NSW or 300 MW increase in export to SA (Scenario 5)	

South Western Corridor

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
No suitable connection point for possible large generators around Mortlake	Establishment of a 500 kV terminal station near Mortlake to connect to the existing Moorabool-Heywood 500 kV lines	20	At the time of additional new generation connection to 500 kV in the South West corridor	Location of new terminal station depends on the area of generation development
Outage of a Heywood 500/275 kV transformer overloads the parallel transformer	Third 370 MVA 500/275 kV Heywood transformer and 500 kV bus-tie at Heywood	18	At the time of 300 MW additional export to SA via Heywood	
Outage of a Heywood-South East 275 kV circuit overloads the parallel circuit	Third Heywood-South East 275 kV circuit	55	At the time of 300 MW additional export to SA via Heywood	
Reactive support and voltage control in the Heywood area	One SVC at Heywood (+200/-200 MVAr)	22	At the time of 300 MW additional export to SA via Heywood	Timing with increased export to SA or increased load at Portland

Northern Corridor

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Dederang 330/220 kV transformers overload for an outage of a parallel transformer	Fourth Dederang 330/220 kV transformer	11	At time of Interconnection Upgrade by 180 MW	
Reactive support at Wodonga and Dederang	Installation of a 150 MVAr capacitor bank at Wodonga and control & communications	4	At time of Interconnection Upgrade by 180 MW	
South Morang to Dederang 330 kV line and series capacitors overload for outage of parallel circuit	Uprate of South Morang to Dederang 330 kV lines and increase in rating of South Morang to Dederang series compensation to match line uprate	7.4	At time of Interconnection Upgrade by 600 MW	Subject to further investigation of increased operating voltage limits.
	Third South Morang to Dederang 330 kV circuit and series compensation	120	At time of Interconnection Upgrade by 1,600 MW	
Murray to Dederang 330 kV line overload for outage of parallel circuit	60-65% series compensation on Wodonga to Dederang and/or Wodonga-Jindera 330 kV lines & 150 MVAr shunt cap bank at Wodonga/Dederang	12	At time of Interconnection Upgrade by 600 MW	
	Second Jindera-Dederang 330 kV line (bypass at Wodonga)	35	At time of Interconnection Upgrade by 1,600 MW	Subject to availability of easement
Eildon-Thomastown line for outage of South Morang to Dederang line	Wind monitoring scheme on Eildon-Thomastown 220 kV line	0.65	Around 2012	
	Upgrade of Eildon to Thomastown 220 kV line	2.4	At time of Interconnection Upgrade by 600 MW or around 2013	
	25% series compensation on the Eildon to Thomastown 220 kV line	7	At time of Interconnection Upgrade by 600 MW	

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Voltage collapse at Dederang and South Morang	Controlled series compensation of South Morang to Dederang lines	15	At time of Interconnection Upgrade to 1,600 MW	

Greater metropolitan area of Melbourne and Geelong

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Rowville-Springvale circuit overload for outage of a parallel circuit.	Uprate Rowville-Springvale line to 82°C	1	Around 2012	
Springvale-Heatherton circuit overload for outage of a parallel circuit.	Wind monitoring scheme on the Springvale-Heatherton lines	0.4	Around 2012	
Rowville to Malvern circuit overload for outage of a parallel circuit	Wind monitoring scheme on the Rowville-Malvern lines	0.4	Around 2012	CitiPower plans to transfer about 100 MW load from Richmond to Malvern, following refurbishment of Malvern by SP AusNet
	Rowville to Malvern 220 kV line upgrade to 82°C	17	At the time of significant load transfer from Richmond to Malvern	
Security of supply to radially connected Springvale, Heatherton and Malvern terminal stations	Malvern-Heatherton 220 kV underground cable (or a overhead line - if feasible at a lower cost)	35	Around 2012	Timing subjected to alternative contingency arrangement by Distribution businesses and feasibility of network options
Rowville to Richmond circuit overload for outage of parallel circuit	Wind monitoring scheme on the Rowville-Richmond line	0.5	Around 2012	Level of overload reduced if CitiPower transfer part of Richmond load to Malvern, following refurbishment of Malvern by SP AusNet
Keilor to West Melbourne-circuit overload for outage of a parallel circuit	Replacement of circuit breakers and inter-plant connections at Keilor and West Melbourne of the Keilor to West Melbourne 220 kV lines	3	Around 2012	SP AusNet scheduled to replace the limiting plants by 2008/09 as part of asset refurbishment program

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Fishermans Bend to West Melbourne circuit overload for outage of a parallel circuit	Replacement of inter-plant connections and primary plant of Fishermans Bend to West Melbourne line	3	Around 2012	
Geelong to Moorabool 220 kV circuit overload for outage of a parallel circuit	Upgrade terminal station plants at Moorabool and Geelong	1	Around 2012	
Outage of an eastern metropolitan 500/220 kV transformer overloads the remaining eastern metropolitan transformer, Thomastown-Ringwood 220 kV circuit and Thomastown-Templestowe 220 kV circuit	One 1,000 MVA 500/220 kV transformer at Templestowe, Ringwood or South Morang	35	Around 2012	Timing and location subjected to further assessment
Outage of Rowville-Ringwood 220 kV circuit overloads Thomastown-Ringwood 220 kV circuit				
South Morang–Thomastown 220 kV circuit for outage of a parallel circuit	Establishment of South Morang 220 kV terminal station and cutting of existing Rowville to Thomastown 220 kV circuit into South Morang 220 kV bus to form the third South Morang to Thomastown 220 kV circuit	15	At time of Interconnection Upgrade by 600 MW or around 2012	
	Cutting of existing Eildon to Thomastown 220 kV circuit onto South Morang 220 V bus to form fourth South Morang to Thomastown 220 kV circuit	4	At time of Interconnection Upgrade by 1,600 MW	
South Morang 330/220 kV transformer overload for a outage of a parallel transformer	Third 700 MVA 330/220kV South Morang transformer	20	At time of Interconnection Upgrade by 600 MW	
	Fourth 700 MVA 330/220 kV transformer at South Morang	20	At time of Interconnection Upgrade by 1,600 MW	

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
South Morang 500/330 kV transformer overload with increased export to Snowy/NSW	Second 1,000 MVA 500/330 kV transformer at South Morang	35	At the time of increase in export to Snowy/NSW	
Inadequate 220/66 kV transformation capacity at Thomastown	Establishment of a new 220/66 kV terminal station at South Morang	Shared network configuration, location of 66 kV switchgear within South Morang Terminal Station and timing is under review		Project identified by Distribution Company
Inadequate 220/66 kV transformation capacity at Geelong	Establishment of a new 220/66 kV terminal station at East Geelong	Timing and shared network configuration under review		Project identified by Distribution Company
Network reactive support in the metropolitan area	500 to 2,000 MVAr Reactive Support	10-40	Ongoing as required	Location and amount of capacitor banks depend on development of the network
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the metropolitan area	10-25	Ongoing as required	
Line terminations, secondary equipment and dynamic system and supply of quality monitoring equipment.	Miscellaneous Works	20	Ongoing as required	

Regional areas of the state

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Bendigo-Fosterville-Shepparton circuit overload for outage of a Ballarat to Bendigo circuit	Bendigo-Fosterville-Shepparton 220 kV line upgrade to 90°C	5	At time of Interconnection Upgrade by 600 MW	
Ballarat to Moorabool circuit overload for outage of parallel Ballarat to Moorabool circuit at high load.	Uprate the Ballarat to Moorabool No 1 circuit to 75°C conductor temperature	3	Around 2010	
Ballarat to Bendigo circuit overload for outage of the Bendigo to Shepparton line	Wind monitoring scheme on the Ballarat to Bendigo circuit	0.5	Around 2010	
	Ballarat to Bendigo 220 kV line upgrade to 75°C conductor temperature	3.4	Around 2013	
Dederang-Glenrowan circuit overload for outage of a parallel circuit	Installation of a phase angle transformer on the Bendigo-Shepparton 220 kV line	5	At the time of Interconnection Upgrade by 600 MW or around 2013	
Inadequate 220/66 kV transformation capacity at Bendigo	Establishment of a new 220/66 kV terminal station at Castlemaine (near Bendigo)	Timing and shared network configuration under review		Project identified by Distribution Company
Inadequate 220/66 kV transformation capacity at Red Cliffs	Establishment of a new 220/66 kV terminal station at Wemen (near Red Cliffs)	Timing and shared network configuration under review		Project identified by Distribution Company
Network reactive support in the State Grid area	200 to 600 MVAr	4-12	Ongoing as required	Location and amount of capacitor banks depend on development of the network
Fault level issues	Fault limiting devices, series reactors and upgrade selected 220 kV switchgear in the regional areas of the State Grid	5-10	Ongoing as required	

Constraint	Possible Network Solution	Estimated Capital Cost ($M)	Estimated Timing	Comments
Line terminations, secondary equipment and dynamic system and supply of quality monitoring equipment.	Miscellaneous Works	10	Ongoing	Ongoing

Table 7.5 – Estimated total capital cost for network solutions

Scenario	Estimated Total Capital Cost ($M)		
	Years 1 –5	Years 6-10	Total
1. Latrobe Valley generation	149	333	482
2. South West generation	149	218	367
3. Increase import from Snowy/NSW	149	451	600
4. High metropolitan / State Grid area generation	149	209	358
5. Increase in export to Snowy/NSW and SA[34]		151	151

[34] Increase in export level at low to moderate Victorian demand periods.

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ELECTRICITY ANNUAL PLANNING REPORT

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APPENDICES

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A FORECAST METHODOLOGIES AND ASSUMPTIONS

A1 TEMPERATURE STANDARDS FOR SUMMER AND WINTER MAXIMUM DEMAND FORECASTS

Electricity demand is highly dependent on ambient temperature. Summer and winter MD forecasts reported in the EAPR 2004 and EAPR 2005 were based on temperature standards developed by NIEIR and reviewed in 2004.[35]

The 10%, 50% and 90% POE temperatures were defined based on the probability distributions of the hottest summer and coldest winter weekday daily average temperatures of each year included in the analysis. Summer POE temperatures were based on weekday data (December to February) from 1954/55 to 2003/04 excluding 20 December to 20 January in each year. Winter POE temperatures were based on weekdays (June to August) in each year from 1970 to 2003.

The review in 2004 did not take account of the long-term warming trend in Melbourne CBD temperatures. It was noted that the winter POE temperatures were too cold and the winter MD forecasts were too high.

A review of the summer and winter POE temperatures was conducted in 2006 to assess the impact of the weather warming trend on the POE temperatures. Temperature data from the last two summers (2004/05 and 2005/06) and the last two winters (2004 and 2005) were added to the original data set.

Figure A1.1 shows that the warming trend in historical hottest summer weekday daily average temperatures is not as strong as the warming trend in historical coldest winter weekday daily average temperatures. Figure A1.2 shows that the warming trend in winter coldest day temperatures is about 0.0597°C/year.

35 Refer to Section 3.3.2 for definition of % POE temperatures

Figure A1.1 – Warming trend in hottest summer weekday daily average temperature

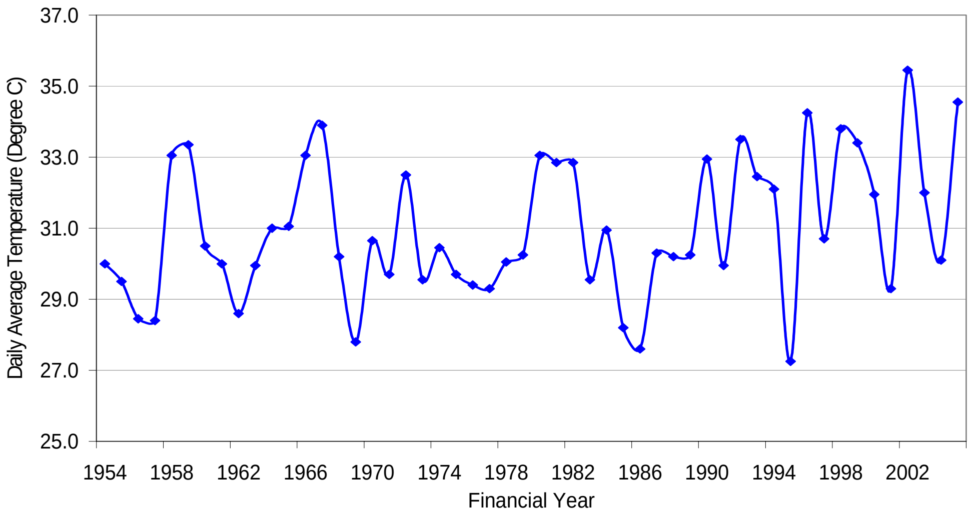
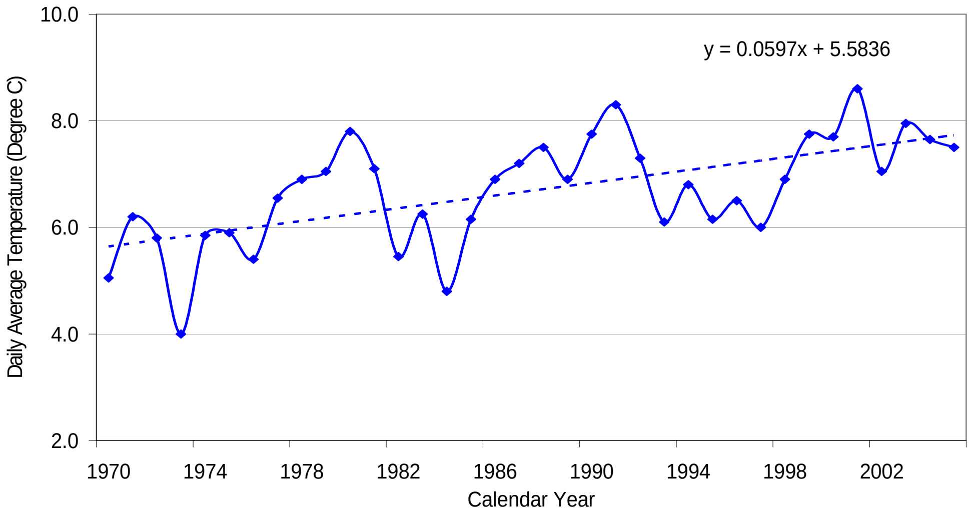


Figure A1.2 – Warming trend in coldest winter weekday daily average temperature



The study recommends that:

- no correction for warming trend for the summer POE temperatures be required;
- the current summer POE temperatures be retained;
- the new winter POE temperatures which incorporate the projected warming trend to 2011 (i.e. the mid point of the projection period 2006/07 – 2015/16) be used in the EAPR 2006; and
- the POE temperatures be reviewed in the future, possibly every five years or as required.

Figure A1.3 and A1.4 show the probability distributions of the hottest summer and the coldest winter weekday daily average temperatures of each year, which were used to derive the summer and winter POE temperatures for summer and winter MD forecasts.[36] [37]

Figure A1.3 – Hottest summer weekday daily average temperature distribution

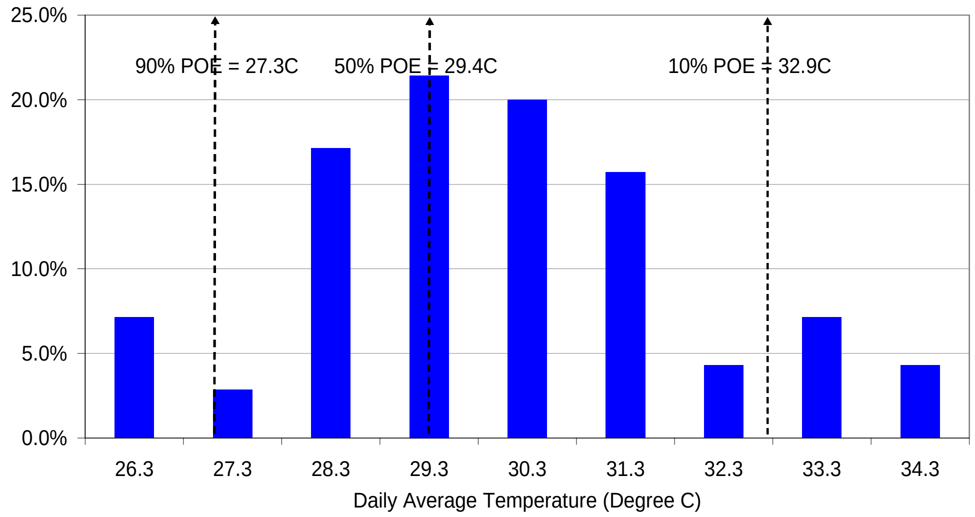
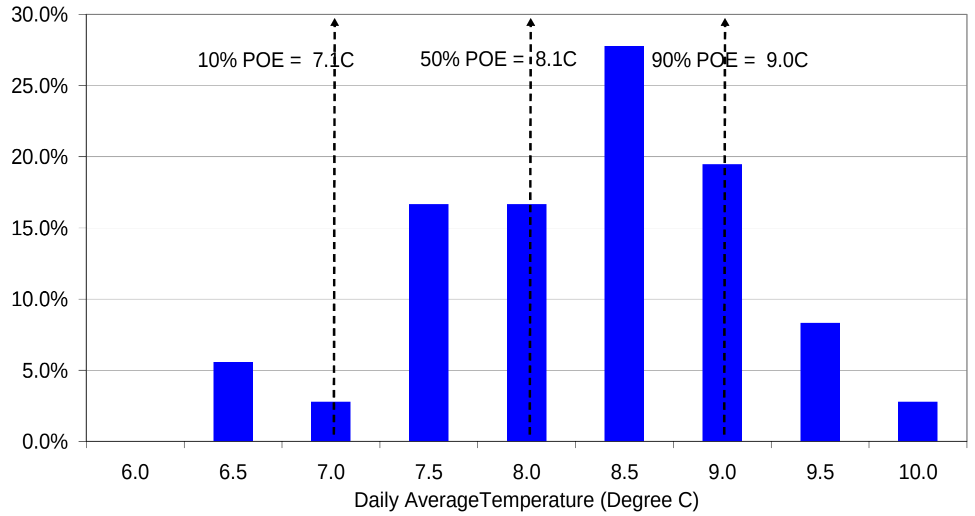


Figure A1.4 –Coldest winter weekday daily average temperature distribution



36 Some selected hot weekends were also included in the calculations of the summer MD POE temperatures

37 Historical coldest weekday temperatures have been de-trended

A2 TEMPERATURE STANDARDS FOR ANNUAL ENERGY FORECASTS (COOLING AND HEATING-DEGREE-DAYS)

Daily energy has shown increased variations in recent years, due to increased heating and cooling load. It is therefore important to estimate the effect of weather on the temperature sensitive component of energy so that the underlying growth in energy can be assessed more accurately. Weather standards, defined by Heating-Degree-Day (HDD) and Cooling-Degree-Day (CDD), are used in annual energy forecasts.

HDD and CDD are used by energy utilities to measure the coldness (or hotness) in outdoor ambient temperatures affecting energy usage for space heating and cooling respectively. It has been shown that space heating occurs when daily average temperature is below a certain threshold. Similarly, cooling appliances are switched on when daily average temperature is above the defined threshold. VENCorp uses a threshold temperature of 18°C (65°F), which is most commonly used in the energy industry. The definitions of CDD and HDD are given below.

HDD = 18°C – daily average temperature

= 0 (if daily average temperature > 18°C)

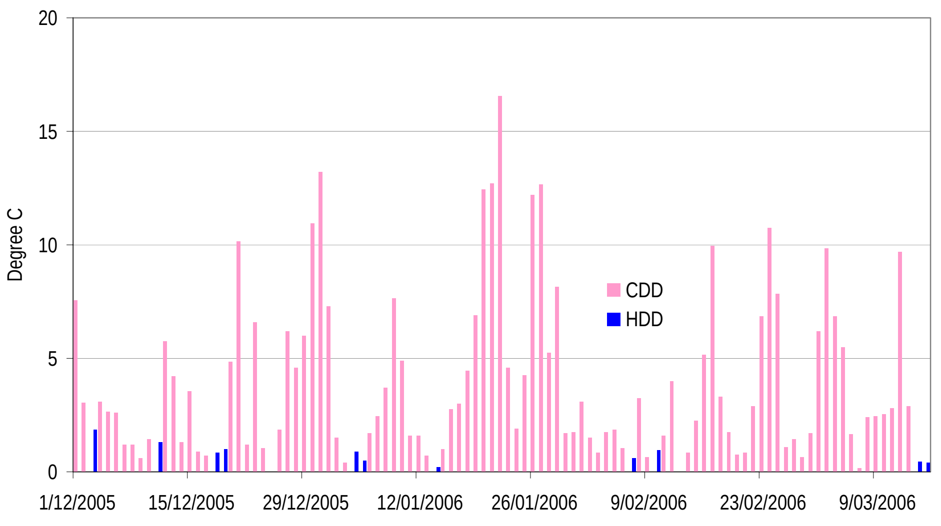
CDD = daily average temperature - 18°C

= 0 (if daily average temperature < 18°C)

Daily average temperature is the average of the daily maximum temperature (from 9:00am) and the overnight minimum daily temperature (to 9:00am) of the day in consideration. For forecasting purposes, daily maximum and minimum temperatures at the Melbourne CBD weather station are used.

HDD is normally zero in summer months and similarly CDD is zero in winter months. However, Melbourne weather is known to be highly variable such that very warm days can end with a drastic cool change lasting for a couple of days, as shown in Figure A2.1 for summer 2005/06.

Figure A2.1 – Summer 2005/06 daily CDD and HDD



HDD and CDD can be summed by month and year. The colder the winter the greater is the annual HDD, similarly the hotter the summer, the greater the CDD. Normally, shoulder months, March to April and October to November, have a mixture of warm and cold days. Figure A2.2 shows that, for the last 12 months to end of March 2006, the coldest month was July with over 180 HDD and the warmest month was January with about 150 CDD.[38]

Figure A2.2 – 2005/06 monthly CDD and HDD

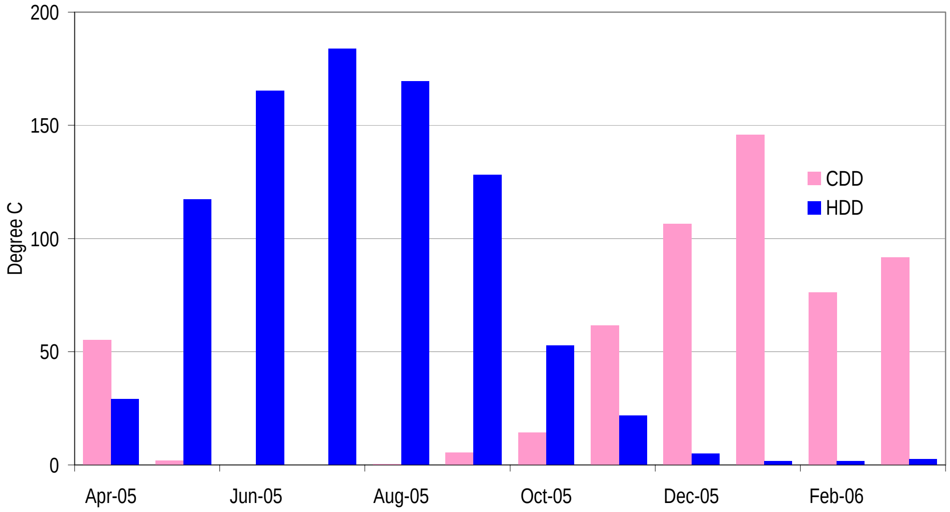
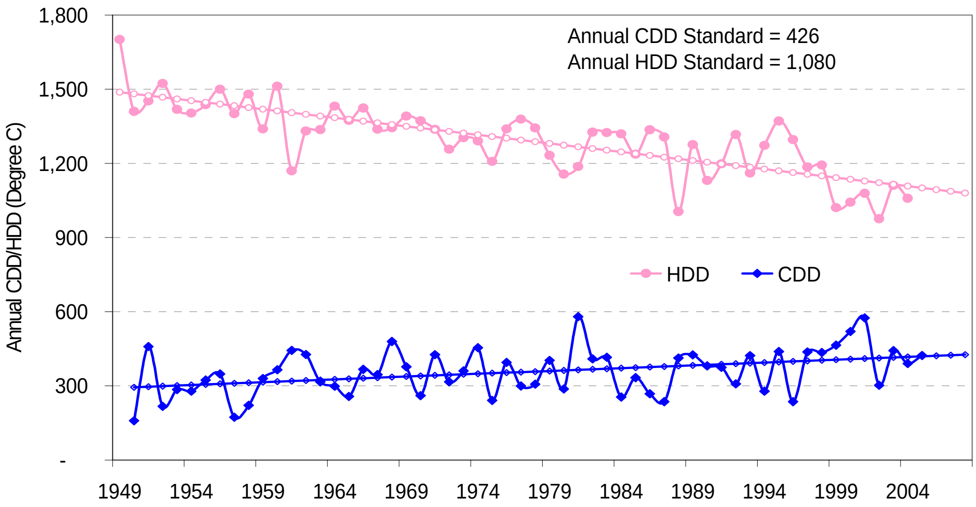


Figure A2.3 displays the annual HDD and CDD for the last thirty five years, and depicts a warming trend in Melbourne CBD temperatures since 1949.[39] The warming trend is stronger in annual HDD than in annual CDD. Melbourne annual CDD has increased by about 2.5°C pa while annual HDD has fallen by about 7°C per year.

[38] This is the sum of daily HDD values

[39] HDD and CDD are calculated on a calendar and fiscal year basis respectively

Figure A2.3 – Annual HDD and CDD warming trend



The annual temperature standards for annual energy forecasts are 426 CDD and 1,080 HDD respectively, being the projected warming trend to year 2008/09. The annual standards will be reviewed periodically, possibly every five years, or as required.

A3 FORECAST METHODOLOGY AND ASSUMPTIONS

VENCorp engaged NIEIR to produce independent long-term Victorian electricity energy and demand forecasts for Medium (most likely), High (optimistic) and Low (pessimistic) economic growth scenarios. The State economic projections are documented in Appendix A4.

Electricity energy and demand are defined in Chapter 3 of this report.

A3.1 Energy forecast methodology

NIEIR has developed an integrated multi-purpose econometric model linking the economic forecast module with the energy forecast module. Energy forecasts are prepared by industrial, commercial and residential sectors.[40] Large industrial load, namely the smelter load managed by VicPower Trading, is forecast separately. The aggregated end-use forecasts, adjusted up for transmission and distribution losses, and less non-scheduled generators net outputs, are reconciled with the forecast scheduled generators' sent-out energy.[41] Forecast non-scheduled generation is discussed in more detail in Appendix A6.

Key economic inputs to the econometric model include:

- Victorian GSP;
- State industry output projections; and
- forecasts of State population, dwelling stocks, Real Household Disposable Income, electricity and gas prices.

The forecasts also take into account impact on load growth of the factors discussed in Section 3.2.2 of the report.

A3.2 Forecast methodology for summer and winter maximum demands

Victorian summer MD usually occurs around 4:00pm (EST) on a weekday in late January or February. NIEIR's forecast MDs refer to the half-hourly demand on a weekday at 4:00pm in mid February. The 10% POE forecast MD also includes the thermal impact of the third day of a heatwave on the MD.

Summer MDs consist of 3 components, which are forecast separately:

- smelter demand which is not sensitive to weather;
- non-smelter base load demand; and
- non-smelter temperature sensitive demand.

The smelter load forecasts are provided to VENCorp by VicPower Trading and incorporated into NIEIR's aggregate forecasts.

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40 NIEIR collated historical sales data from individual retailers/distributors

41 This is equal to energy generated at the scheduled generators less their own-use

Forecast growth in non-smelter base load demand is consistent with the forecast growth in annual energy.

Forecasting summer MD temperature sensitive load requires detailed analysis of historical temperature sensitive demand. The latter is directly linked to AC sales. The process involves the following steps:

1) Estimate temperature sensitive demand from stock and sales of AC from ABS import data and input capacity of the equipment. The estimated temperature sensitive demand also includes an estimate of the stock of refrigerators and fans. These estimates are then reconciled with the estimated temperature sensitive demand at 4:00pm (AEST) from two or three years of actual 10% (or close to) POE MDs.

2) For each summer, estimate the actual daily temperature sensitive demand from a "switching" regression model using historical summer MD data and the corresponding daily average temperatures. Daily average temperatures of the MD day and the previous day are included in the analysis. The modelled temperature sensitive demand, when compared with the maximum temperature sensitive load derived in the first step, determines the AC utilisation rates for the three POE temperatures and the 10%, 50% and 90% summers.

3) Forecast growth in temperature sensitive demand from an econometric model including such drivers as projected building activities, projected real household income, assumed space cooling replacement rates and summer weather conditions. The projections of temperature sensitive demand take into account energy savings from new technologies and government greenhouse initiatives (for example the MEPS).

4) Apply the relevant space cooling utilisation rates from the switching regression model to the forecast temperature sensitive load to generate the 90%, 50% and 10% POE summer MD cooling demand.

The final summer MD forecasts take into account forecast available non-scheduled generation capacity on hot summer days. Forecast non-scheduled generation is presented in Appendix A6.

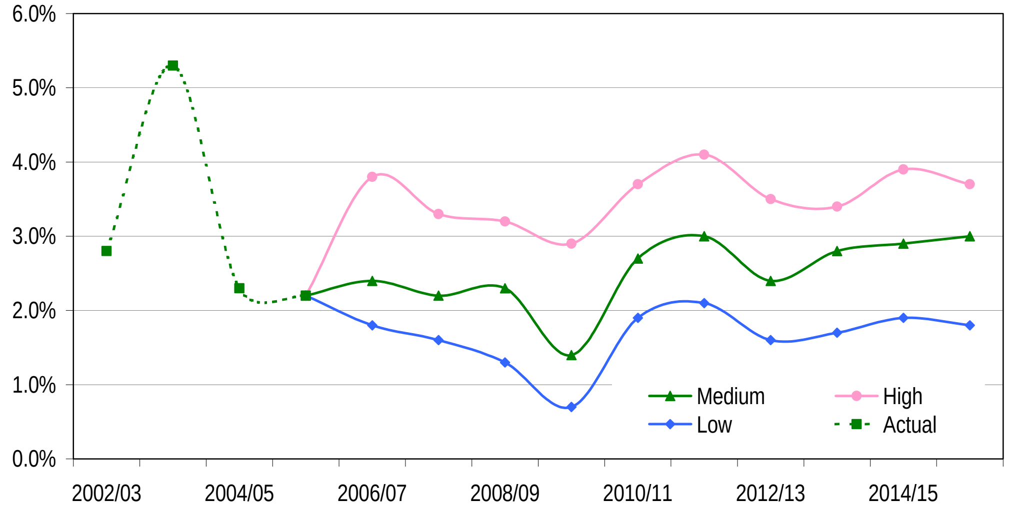
NIEIR's back-casts of historical summer MD are presented in Appendix A11.

Forecasting winter daily MD follows a similar process. NIEIR prepares three sets of winter MDs for each economic scenario based on 90%, 50% and 10% winter POE temperatures. The forecast methodology uses a combination of regression methods, and estimated reverse cycle AC stocks and sales to model the winter MD temperature sensitive load.

A4 VICTORIAN ECONOMIC PROJECTIONS

NIEIR provides three scenario forecasts based on Medium, High and Low economic growth assumptions summarised in Figure A4.1 and Table A4.1. The State economic outlook is discussed below, focussing on the Medium growth scenario over the medium term to 2010/11.

Figure A4.1 – Victorian GSP projections



A4.1 Medium growth scenario

The projected Victorian GSP growth for 2005/06 is 2.2% and similar to the growth in 2004/05.[42] A stable growth of 2.2% to 2.4% pa is projected for the next three years to 2008/09 before a sharp contraction in 2009/10 with the growth falling to 1.4%. Stronger growth above 2.5% returns thereafter.

The Victorian GSP projections for the medium term to 2010/11 are underpinned by:

- a moderate growth in private spending;
- a marked slowdown in business investment following a period of accelerated growth in recent years;
- further contraction in Victorian dwelling investments before a rebound in 2007/08. A slowdown in population growth to between 0.9% and 1.0% from a high of 1.2% in 2004/05 will have a direct impact on dwelling investments;
- projected increased Government consumption and investment in infrastructure projects, for example the Eastlink, rail tunnel under the Westgate Bridge; and

42 Based on actual to December 2004

- increased risks to the Victorian manufacturing sector from overseas imports and a strong Australian currency.

Table A4.1 – Victorian GSP projections

Year	Medium	High	Low
2002/03	2.8%		
2003/04	5.3%		
2004/05	2.3%		
2005/06	2.2%		
2006/07	2.4%	3.8%	1.8%
2007/08	2.2%	3.3%	1.6%
2008/09	2.3%	3.2%	1.3%
2009/10	1.4%	2.9%	0.7%
2010/11	2.7%	3.7%	1.9%
2011/12	3.0%	4.1%	2.1%
2012/13	2.4%	3.5%	1.6%
2013/14	2.8%	3.4%	1.7%
2014/15	2.9%	3.9%	1.9%
2015/16	3.0%	3.7%	1.8%
2006-2011	2.2%	3.4%	1.5%
2011-2016	2.8%	3.7%	1.8%

A4.2 High and low growth scenarios

The high economic growth scenario is based on assumptions of stronger growth globally across Asia, USA and Europe. International terrorism will be settled. The Australian economy is projected to grow stronger, driven by new major resource projects. Under this scenario, the Victorian GSP is projected to grow at an average rate of 3.4% and 3.7% pa, over the medium and longer term respectively.

The Low economic scenario is for continued political turmoil in the Middle East, a US economy struggling to recover, oil prices rising to US$100/barrel, global interest rate rises affecting consumer and investor confidence and global economic growth. Under this scenario, the average Victorian GSP growth rate is 1.5% and 1.8% pa over the medium-term (five years) and longer term (ten years) respectively.

A5 GOVERNMENT ENERGY POLICIES AND INITIATIVES

A number of government energy policies and initiatives, at both the national and state level, have been proposed or implemented in recent years to reduce greenhouse gas emissions. Some of these policies aim to reduce growth in future energy consumption while others aim to drive up future investments in clean energy production. The impact of these polices on future growth in Victorian electricity energy and demand is highly uncertain. These policies are explained below.

A5.1 Commonwealth Government energy policies

- Mandated Renewable Energy Target (MRET)

The MRET was first set under the Renewable Energy (Electricity) Act 2000, requiring the purchase of additional renewable energy by Australian electricity retailers from 2001 to 2020, of up to 9,500 GWh pa in 2010, and beyond. The MRET is implemented via the creation of tradeable Renewable Energy Certificates (RECs) which are earned for each MWh of renewable energy created by generators or through installation of solar hot water units.

A review of MRET in 2004, conducted by an independent panel (Tambling Committee), recommended that the MRET be increased from 9,500 MW in 2010 to 20,000 MW in 2020. However, the Federal government has decided to maintain the current MRET target to 2020.[43]

- The Greenhouse Gas Abatement Program (GGAP)

The Commonwealth Government has allocated $400 million to sponsor projects capable of delivering reduction in greenhouse gas of 250,000 tonnes of carbon dioxide or more per year.

- Green Power

The Green Power scheme requires that electricity retailers offer Green Power products to customers and purchase an amount of electricity from nominated renewable sources matching or exceeding that purchased by customers.

- Low Emission Technology Development Fund

The Commonwealth government has allocated $500 million for the research and development of new technologies for reducing greenhouse gas emissions.

- The National Framework for Energy Efficiency (NFEE) and the Minimum Energy Performance Standard (MEPS) for appliances

In November 2003, the Ministerial Council for Energy (MCE) endorsed a proposal for the development of a National Framework for Energy Efficiency (NFEE) to define future directions for energy efficiency policy and programs in Australia.

[43] Refer to the Commonwealth Government White Paper on Energy, “Securing Australia’s Energy Future” in June 2004

The MCE has committed to implement a package of policy measures as Stage 1 of the NFEE. This consists of nine integrated and inter-linked packages including the following key proposals:

- more stringent residential building energy efficiency regulation;
- introducing commercial building energy efficiency regulation;
- consumer awareness programs;
- the Energy Efficiency Opportunity Act 2006 which mandates large energy users (consuming 0.5 PJ of energy or more pa) to assess and report on their energy usage and future plans for improving energy efficiency;
- 'Solar Cities' demonstration projects to trial innovative energy technologies and techniques such as solar heaters, photovoltaics, smart meter technologies, energy efficiency improvements and load management, and effective energy pricing; and
- extending labelling and MEPS for electrical appliances and applying the same approach to gas appliances. MEPS for single phase AC were introduced in October 2004.[44] The second stage of MEPS took effect in April 2006 and applied to cooling equipments less than 7.5 MW input capacity. More stringent MEPS will be introduced in October 2007 and October 2008 for all single phase AC to align the local MEPS level with that of Korea, which has the highest standard in the world.

A5.2 Victorian Government Energy Policies

- **Victorian 5 star building regulations**

From 1 July 2005 all Victorian new homes are required to have 5 star rating for building fabrics, a rainwater tank for toilet flushing or a solar hot water heater. A recent survey of residents living in 5 star homes for over 12 months, commissioned by the Sustainability Victoria shows that about 71% of residents reported lower energy bills. The Victorian Government plans to conduct more studies to quantify the savings in energy from the 5 star new home policy in late 2006.

- **Energy Technology and Innovation Strategy (ETIS)**

The Victorian Government's 2005-06 State Budget allocated funding over five years to the Energy Technology and Innovation Strategy (ETIS) to; ensure a secure energy supply, maximise industry competitiveness and job opportunities, and reduce greenhouse gases. Part of the ETIS includes exploring the development of large pre-commercial demonstration plants trialling new clean brown coal technology in the Latrobe Valley.

- **Minimum energy efficiency for commercial buildings**

The energy efficiency measures for the commercial building sector took effect on 1 May 2006. These measures were introduced through the Building Code of Australia (BCA) 2006 and apply to all new commercial and public buildings, and also commercial building refurbishments, alterations and extensions. These measures are designed to reduce the use of artificial heating and cooling,

[44] These are common in the residential market

improve the energy performance of lighting, conditioning and ventilation, and reduce energy loss through air leakage.

- Victorian Renewable Obligation

In its Position Paper released in December 2004, the Victorian Government had set a target to meet 10% of Victorian electricity consumption from renewable sources by 2010 and to facilitate the development of 1,000 MW of wind energy by 2006.[45]

In December 2005, the Department of Infrastructure (DOI) in Victoria published an Issues Paper, seeking submissions from stakeholders for the development and implementation of a market based renewable energy policy in Victoria. Submissions closed in February 2006.[46] Details of the decision will be announced soon. The likely outcomes are summarised below:

- the start date for the trading scheme for Victorian Renewable Obligation Certificates (VROCS) could be as early as 1 January 2007;
- the duration of the certificates is expected to be fifteen years after the renewable project commission date;
- all renewable electricity plants commissioned after mid 2006 would be eligible. Solar hot water heaters would not be included; and
- the likely target level of additional renewable energy would be 2,500 GWh to be phased in from 2007 to 2010. The target is likely to grow after 2010.

- Interval Meter Roll Out (IMRO)

In July 2004, the Essential Services Commission of Victoria (ESCV) issued the final decision mandating the rollout of interval meters to Victorian electricity customers starting in 2006.[47] The decision did not require installation of communication equipments as part of the rollout program and there was no target date for all customers to have interval meters.

In May 2005, the DOI engaged CRA International to investigate whether it would be cost-effective to add communication equipment to interval meters. The CRA study concludes that there are significant net benefits if two-way communications are added to the IMRO meters.[48] The study also recommends that the planned IMRO program be deferred, possibly to 1 January 2008, to allow more time for the Victorian Government to investigate the options.

A5.3 Emission Trading Scheme (ETS)

As a result of the Commonwealth Government's decision not to ratify the Kyoto Protocol, the State and Territory Governments will take the initiative to design a national ETS independently of the Commonwealth Government. Details of the scheme are yet to be announced.

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45 Refer to "The Greenhouse Challenge for Energy: Driving Investment, Creating Jobs"

46 Refer *to Driving Investment in Renewable Energy in Victoria: Options for a Victorian Market-Based Measure*

47 Refer to *Mandatory Rollout of Interval Meters for Electricity Customers, Final Decision, July 2004*

48 Refer to *Advanced Interval Meter Communications Study, CRA International, 23 December 2005*

A6 FORECAST NON-SCHEDULED GENERATION

Non-scheduled generation refers to smaller grid-connected generators, either exempted from NEM registration or registered with NEMMCO as embedded generation. Most of these generators are embedded within the distribution networks. However, some are connected to the transmission grid, such as large scale wind farms. The information presented here excludes remote area and non-grid connected generators, emergency or standby generation.

Non-scheduled generators can be classified under Cogeneration and Non-Cogeneration, and further grouped into Renewable and Non-Renewable. Non-scheduled renewable generation includes foremost, hydro and wind, and others such as biomass (for example sawdust, bagasse or animal waste). Solar power generators, hot rock or tidal experimental or demonstration projects are not included in these projections.

NIEIR's projections of non-scheduled generation, including capacity and annual outputs (broken down by Buyback and Own-use), are given in Table A6.1.[49] The projections include existing and planned generators, and are based on market information collected by NIEIR, and are cross-checked against the survey results of non-scheduled generation, organised by NEMMCO as part of the NEMMCO 2006 SOO planning process.

There is about 550 MW of non-scheduled generation capacity in 2005/06, consisting of 191 MW of non-renewable capacity and 359 MW from renewable sources, including 133 MW of installed wind capacity. Table A6.1 shows the 5 major wind farms commissioned since 2001.

Table A6.1 – Installed wind generation capacity

Wind Farm	Capacity (MW)	Commission Year
Codrington	18.2	2001
Toora	21	2002
Challicum Hills	52.5	2003
Yambuk	30	2005
Wonthaggi	12	2005

Future growth in non-scheduled generation remains uncertain. The Victorian Renewable Energy Strategy will be the main driver of future investments in renewable energy in Victoria, in particular wind generation. Renewable energy investments are projected to accelerate over the medium-term to 2010/11. The key features of the projections are summarised below:

- Total non-scheduled generation capacity is projected to increase by 270% over the next ten years from 550 MW in 2005/06 to 1,476 MW in 2010/11 and 1,666 MW in 2015/16. Annual generated energy is projected to increase by 260% from about 2,284 GWh in 2005/06 to 5,116 GWh and 5,891 GWh over the next five and ten years respectively. The estimated

49 Buyback refers to the amount exported to the grid

buyback component of the total generated energy is 950 GWh in 2005/06 and is projected to grow by over 420% at the end of the projection period, totalling 3,460 GWh in 2010/11 and 3,961 GWh in 2015/16.

- The projected growth in non-scheduled generation capacity and annual energy is predominantly in the renewable sector. The projections assume that renewable generation capacity is expected to grow to 1,222 MW (with 939 MW of wind) and 1,355 MW (with 1,056 MW of wind) by 2010/11 and 2015/16 respectively, from a base of 359 MW (with 133 MW of wind) in 2005/06. The growth will be driven by the Victorian Government initiative to increase Victorian Renewable Obligation explained in Appendix A5. Figure A6.1 shows the projected growth in wind generation capacity and compares the projected growth in non-scheduled renewable and non-renewable capacity over the planning period.

- The projections also assume that renewable generated energy will increase to 3,802 GWh by 2010/11 and 4,228 GWh by 2015/16 from a base of 1,313 GWh in 2005/06.

Table A6.2 – Non-scheduled generation forecasts

	Capacity (MW)					Annual Output (GWh)				
Year	Wind	Other Renew-able	Total Renew-able	Total Non-Renew-able	Total	Total Renew-able	Total Non-Renew-able	Total	Buyback -Export	Own Use
2003/04	91	195	286	204	490	1,105	1,006	2,111	803	1,308
2004/05	91	200	291	204	495	1,140	971	2,111	820	1,291
2005/06	133	226	359	191	550	1,313	971	2,284	950	1,334
2006/07	238	232	470	208	678	1,607	1,045	2,652	1,240	1,412
2007/08	298	272	570	214	784	1,867	1,082	2,949	1,488	1,461
2008/09	407	280	687	244	931	2,213	1,253	3,466	1,867	1,599
2009/10	739	283	1,022	254	1,276	3,242	1,314	4,556	2,905	1,651
2010/11	939	283	1,222	254	1,476	3,802	1,314	5,116	3,460	1,656
2011/12	1,044	287	1,331	269	1,600	4,134	1,406	5,540	3,798	1,742
2012/13	1,044	287	1,331	269	1,600	4,134	1,406	5,540	3,798	1,742
2013/14	1,056	293	1,349	278	1,627	4,199	1,461	5,660	3,875	1,785
2014/15	1,056	295	1,351	293	1,644	4,217	1,553	5,770	3,917	1,853
2015/16	1,056	299	1,355	311	1,666	4,228	1,663	5,891	3,961	1,930

Figure A6.1 – Non-scheduled generation forecasts

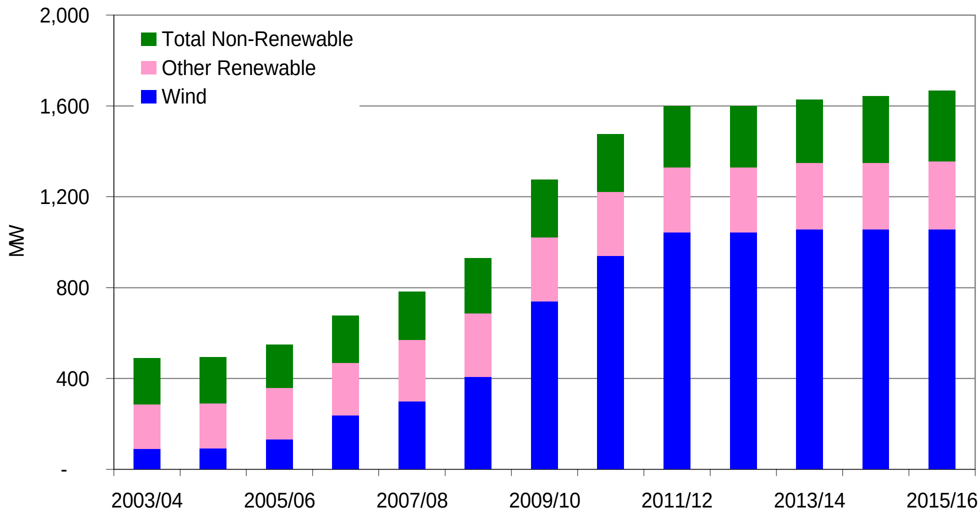


Table A6.3 summarises the changes in non-scheduled generation forecasts in this EAPR from those included in the EAPR 2005. This year's projections of non-scheduled generation capacity are between 6 MW and 805 MW higher than last year's forecasts. Total projected annual outputs are between 56 GWh and 2,418 GWh higher than last year's projections. Energy exported to the grid is projected to be 2,303 GWh higher than last year's forecasts by 2015/16.

Table A6.3 – Changes in non-scheduled generation forecasts from EAPR2005

	Capacity (MW)					Annual Output (GWh)				
Year	Wind	Other Renew-able	Total Renew-able	Total Non-Renew-able	Total	Total Renew-able	Total Non-Renew-able	Total	Buyback - Export	Own Use
2006/07	12	5	17	-10	6	7	49	56	- 22	77
2007/08	12	42	53	-10	43	98	49	147	54	90
2008/09	121	46	167	-10	156	433	50	483	385	96
2009/10	453	46	498	-10	488	1,451	49	1,500	1,394	106
2010/11	653	46	698	-10	688	2,011	49	2,060	1,949	111
2011/12	758	46	804	-10	793	2,332	49	2,382	2,267	115
2012/13	758	46	804	-10	793	2,332	49	2,382	2,267	115
2013/14	770	46	816	-10	805	2,369	49	2,418	2,303	114
2014/15	770	46	815	-10	805	2,369	49	2,418	2,303	114
2015/16	770	46	816	-10	805	2,370	49	2,418	2,303	114

Table A6.4 summarises the assumptions on the available non-scheduled generation capacity, which was used in the summer and winter POE MD forecasts. The available wind generation capacity has been revised up from 8% used in the EAPR 2005, to 24% and 27% used in this year's summer MD and winter MD forecasts respectively.

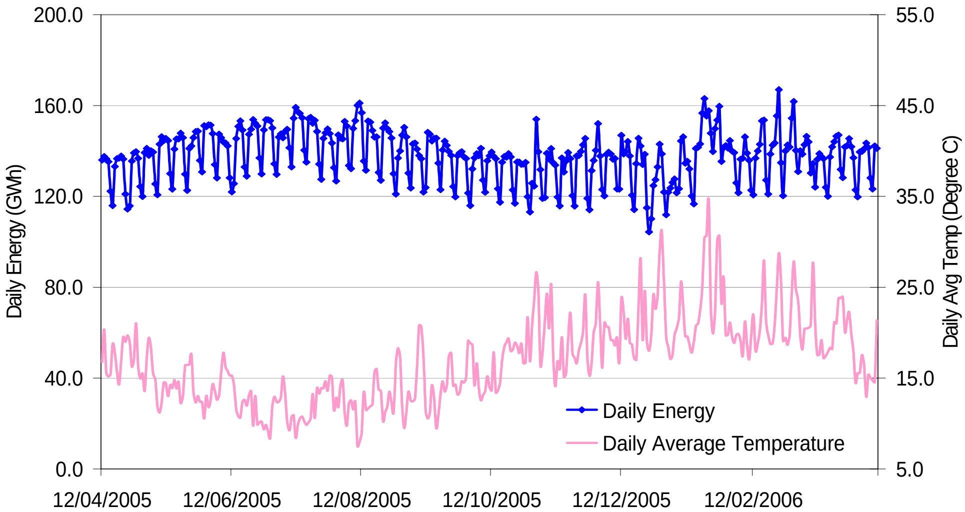
Table A6.4 – Assumed available generation capacity by type of non-scheduled generation

Type of Non-Scheduled Generation	Assumed % of Installed Capacity Available
Non-scheduled Cogeneration	20%
Biomass and Biogas	60%
Wind	24% for summer MD 27% for winter MD
Mini Hydro	30%
Other Non-Renewable	50%

A7 CORRELATION BETWEEN DAILY AVERAGE TEMPERATURE AND DAILY ENERGY

Victorian daily energy peaks in summer and winter due to the increased cooling and heating load, as shown in Figure A7.1. Given similar daily average temperatures, weekday (Mondays to Fridays) daily energy is relatively stable.[50] Given similar daily average temperatures, Saturday and Sunday daily energy is lower, by about 10% and 15% respectively, than weekday daily energy. Daily energy is lower on public holidays and lowest on Christmas day at about 105 GWh.

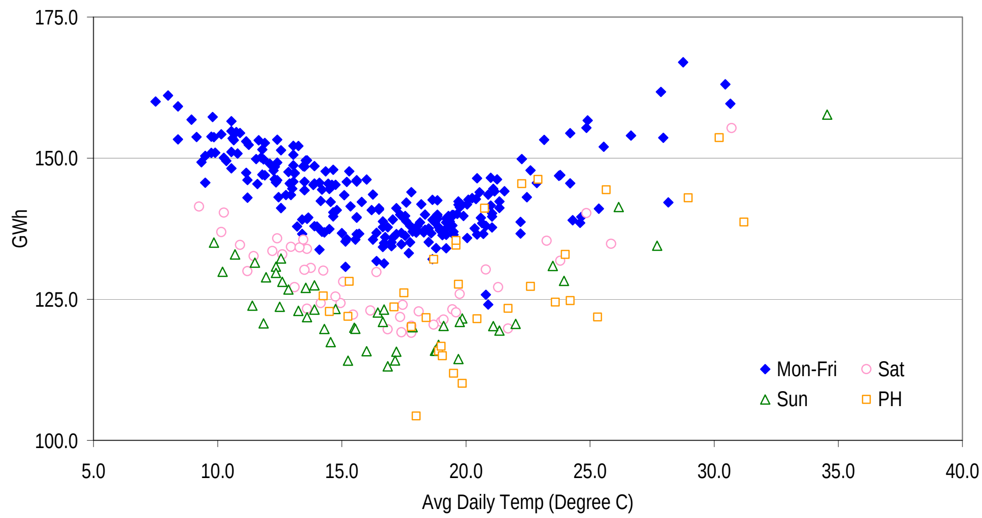
Figure A7.1 – Daily energy and daily average temperature (April 2005 to March 2006)



Another graphical method to summarise the characteristics of Victorian daily electricity energy is to plot the load by day type against daily average temperatures as shown in Figure A7.2 below.

50 Friday load can be lower sometimes

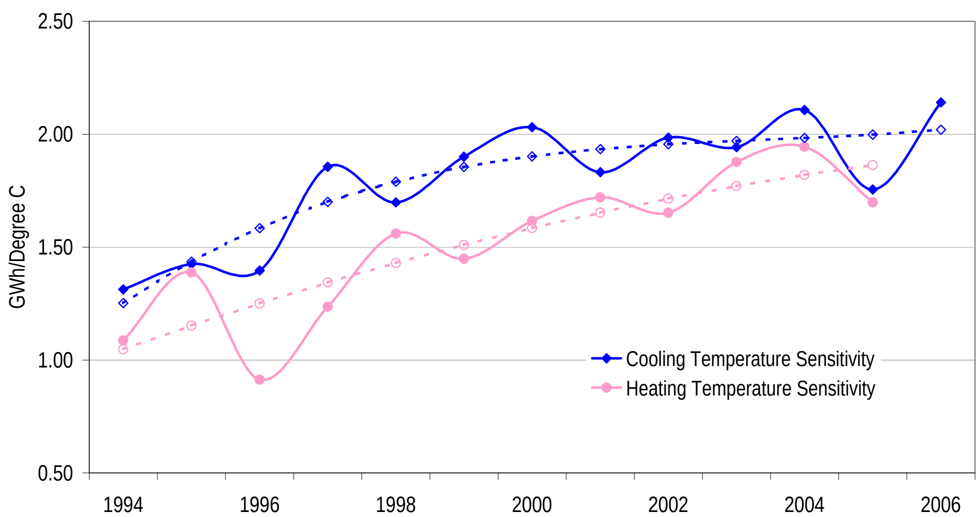
Figure A7.2 – Daily energy and daily average temperature



Energy used for space cooling and heating was a small component of daily energy in the past. However, the increased penetration of AC, in particular reverse cycle AC, in homes in recent years, has driven up the temperature sensitive load.

Figure A7.3 compares the trend in Victorian energy cooling and heating sensitivities from 1993/94 to 2005/06. Cooling temperature sensitivities increase from about 1.2 GWh/CDD in 1993/94 to about 2.0 GWh/CDD in 2005/06. Moderate growth has been observed in recent years following a rapid rise in the early 1990s. Victorian energy heating sensitivities were smaller in the previous decade due to the dominance of cheaper gas heating in Victoria. Recent years have seen a rapid increase in energy heating sensitivities to 1.9 GWh/HDD due to the increased penetration of reverse cycle AC in the residential market.

Figure A7.3 – Trend in daily energy cooling and heating sensitivities



Total annual temperature sensitive load has increased to about 5.7% in recent years, with 1.4% to 1.7% cooling and 2.7% to 4.0% heating load respectively.

A8 CORRELATION BETWEEN DAILY SUMMER AND WINTER MAXIMUM DEMAND AND DAILY AVERAGE TEMPERATURE

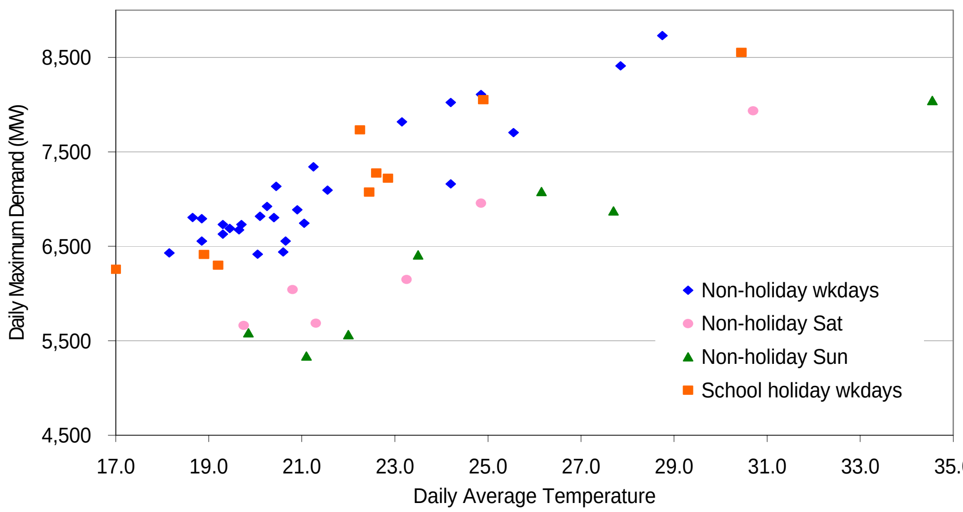
A8.1 Correlation between summer daily maximum demand and daily average temperature

Victorian summer half-hourly demand normally peaks around 4:00pm (AEST) on most summer weekdays. However, an early cool change on a hot day will see the demand falling sharply within a short space of time. This happened on 27 January 2006, the third highest MD last summer when demand fell after 2:00pm following the cool change (see Table 3.2 and Figure 3.1).

Although daily average temperature has been identified as the key driver of summer MD, other influential factors include:

- Day type. For the purpose of analysing summer MD, the period 20 December to 20 January of each year, is normally treated as the extended Christmas to New Year holiday when industries operate below their maximum capacity.[51] Given similar weather conditions, the MD for non-holiday weekdays, Mondays-Fridays, is similar. The MD for non-holiday Saturdays and Sundays can be 15% to 20% lower than that for non-holiday weekdays. The MD for public holidays (PH) and days prior to the PH is also lower. The MD for school holidays can be 235 MW lower. Figure A8.1 displays summer 2005/06 daily MD by day type excluding PH and the extended Christmas to New Year holidays;

Figure A8.1 – 2005/06 summer MD by day type

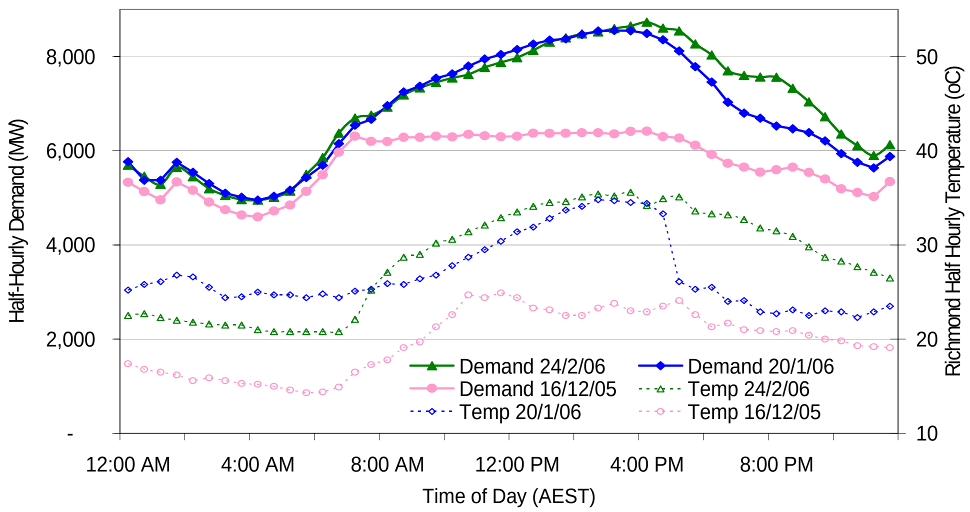


51 The dates vary from year to year.

- temperatures of previous days;
- maximum temperature of the day, when the maximum temperature of the day occurs and how long it lasts. As discussed earlier, a cool change in temperature in the early afternoon will result in a lower MD than what would have normally been expected;
- the overall summer weather conditions;
- time of season (this impacts on cooling appliance sales); and
- non-scheduled generation.

Figure A8.2 compares the half-hourly demand and temperature profiles for three selected days in summer 2005/06. Friday 16 December 2005 was a day with an average temperature of 19°C. The demand profile for this day is representative of the base load profile for a summer day with minimum cooling and heating demand. The demand was stable at about 6,410 MW between 10:00am and 4:00pm. The demand on Friday 20 January 2006 and Friday 24 February 2006 at 4:00pm was some 2,100 MW to 2,300 MW higher than that for Friday 16 December 2005 due to the additional cooling demand.

Figure A8.2 – Selected summer MD and temperature profiles



A significant amount of work has been devoted to investigate how demands respond to temperatures, in particular very warm temperatures at the 10% POE temperature. The issue is whether summer MD increases linearly with temperature increases or non-linearly in an "S" shape. Conceptually, it is expected that the AC demand reaches saturation when all available AC capacity is utilised. Historically there were very few hot days as shown in Table A8.1, which can be used for this analysis. However, most of these days either fell on holidays (including the extended Christmas to New Year period between 20 December and 20 January), weekends or when load shedding occurred (for example 1992/93).

Table A8.1 – Warmest day average temperatures by year

Year	Date	Day of Week	Average Temperature (°C)	Comments
1992/93	3-Feb-93	Wed	33.3	Load Shedding
1993/94	26-Jan-94	Wed	30.5	Australia Day, reduced load
1994/95	6-Dec-94	Tue	30.7	
1995/96	14-Jan-96	Sun	27.3	Xmas-NY holiday, reduced load
1996/97	21-Jan-97	Tue	34.3	Load peaked at 12:30pm
1997/98	26-Feb-98	Thu	30.3	
1998/99	12-Dec-98	Sat	33.8	Saturday, reduced load
1999/00	3-Feb-00	Thu	33.4	Load shedding
2000/01	11-Jan-01	Thu	32.0	Xmas-NY holiday, reduced load
2001/02	15-Feb-02	Fri	29.3	Friday, reduced load
2002/03	25-Jan-03	Sat	35.5	Saturday, reduced load
2003/04	30-Dec-03	Tue	32.0	Xmas-NY holiday, reduced load
2004/05	26-Jan-05	Wed	30.1	Australia Day, reduced load
2005/06	22-Jan-06	Sun	34.6	Sunday, reduced load

A three-day heatwave occurred between Friday 20 January 2006 and Sunday 22 January 2006. The maximum temperature on Sunday 22 January reached 42.4°C and was the second hottest day since 1992/93 based on the daily average temperature of 34.6°C. The demand on this day provides useful information for an insight into the impact of extreme temperatures on electricity demand. Figure A8.3 depicts the half-hourly AC demand profile for total Victoria on Sunday 22 January 2006 and the aggregated half-hourly AC demand for the same day measured at 10 selected meters supplying predominantly residential loads.[52] [53] Both of these load profiles suggest that the half-hourly AC demands taper off at temperatures above 41°C.

[52] This was derived by subtracting the estimated base load profile from the actual load profile

[53] Templestowe 66 kV, Ringwood 22 kV, Ringwood 66 kV and Keilor 66 kV terminal stations

Figure A8.3 – Air-conditioner demand saturation

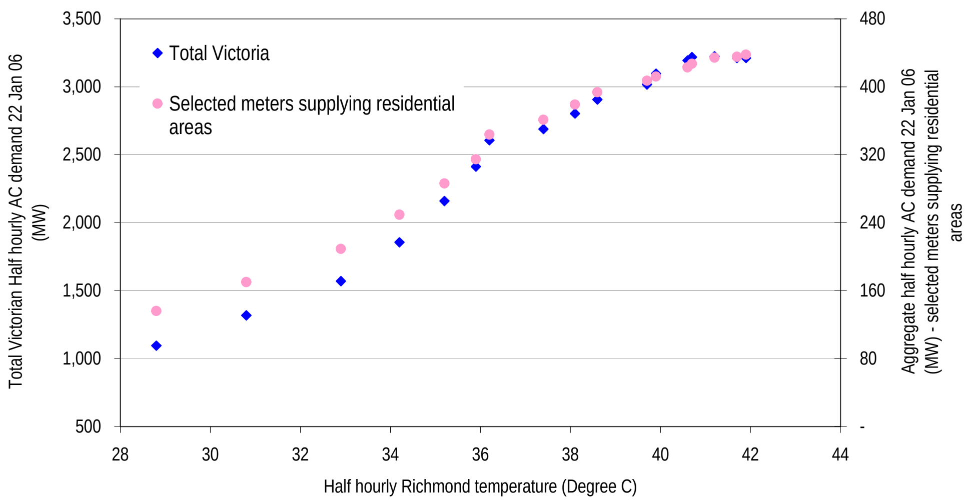
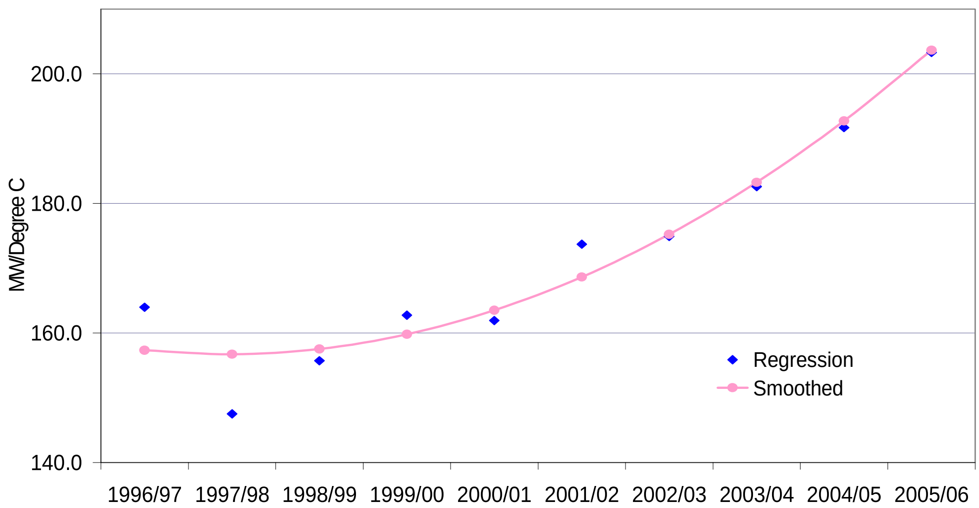


Figure A8.4 shows that summer weekday AC demand has increased steadily, by almost 30% since 1996/97, from below 160 MW/°C in 1996/97 to about 205 MW/°C in 2005/06. It should be noted that these values represent the summer MD average temperature sensitivities corresponding to daily average temperatures between 90% POE and 10% POE. The temperature sensitivities for specific temperatures may vary slightly from these average values.

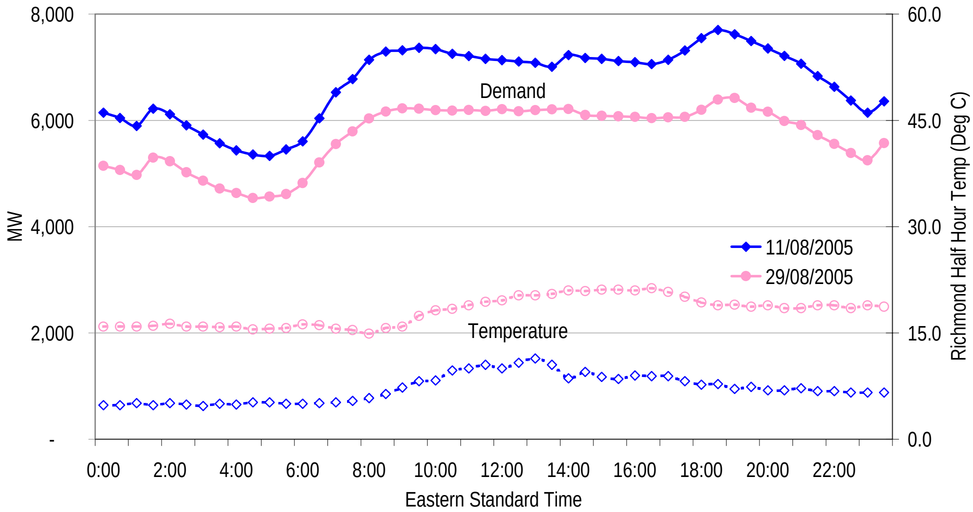
Figure A8.4 – Summer MD average temperature sensitivities



A8.2 Correlation between winter daily maximum demand and daily average temperature

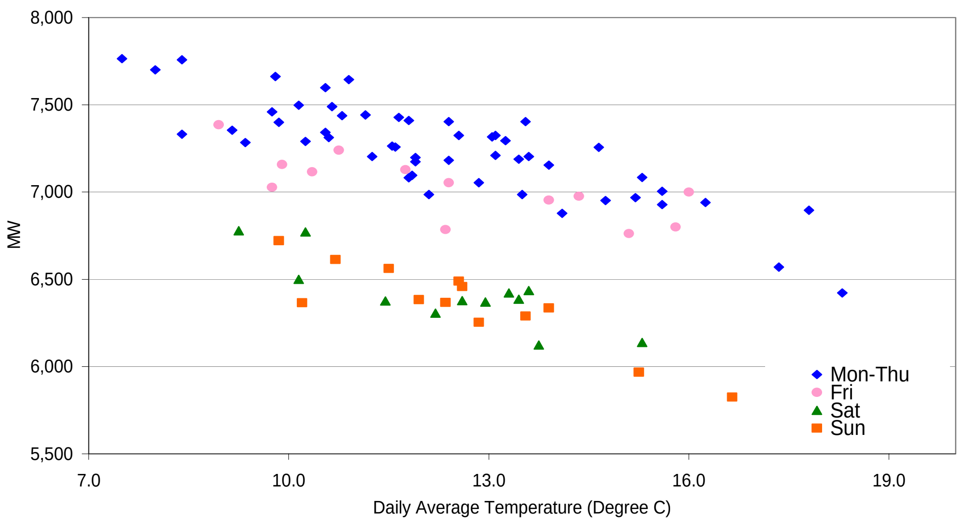
Winter weekday MDs peak between 6:00pm and 6:30pm (AEST) as shown in Figure A8.5. The link between winter MD and daily average temperature is weaker due to a smaller temperature sensitive component.

Figure A8.5 – Selected winter MD and temperature profiles



Winter 2005 daily MDs, excluding public holidays, is shown by day type in Figure A8.6. There is a greater diversity in winter demands, which is not explained by weather.[54] Given similar weather conditions, the MD on Fridays are about 3% lower than the MDs on weekdays whereas the MDs on Saturdays and Sundays are some 11% to 12% lower. Heating demand is about 95 to 100 MW/°C.

Figure A8.6 – Winter 2005 maximum demand by day type



[54] Between 15 May 2005 and 15 September 2005

A9 FORECAST SUMMER AND WINTER MAXIMUM DEMAND FOR HIGH AND LOW ECONOMIC GROWTH SCENARIOS

Table A9.1 shows that, under the High growth scenario, the forecast 10% POE summer MDs are projected to grow at an average rate of 2.7% pa for the first five year period to 2010/11, and 2.9% pa for the next five years. Under the Low growth scenario, slower growth of 1.3% pa is projected for each of five year period.

Table A9.1 – Summer maximum demand forecasts
(average summer, High and Low economic growth)

		Summer MD (MW)			Annual % Growth		
	Year	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
High	2006/07	10,279	9,461	9,019	3.0%	3.3%	3.2%
	2007/08	10,588	9,737	9,276	3.0%	2.9%	2.9%
	2008/09	10,879	9,994	9,515	2.8%	2.6%	2.6%
Economic	2009/10	11,104	10,186	9,690	2.1%	1.9%	1.8%
	2010/11	11,376	10,426	9,913	2.5%	2.4%	2.3%
	2011/12	11,680	10,697	10,166	2.7%	2.6%	2.6%
Growth	2012/13	12,051	11,034	10,485	3.2%	3.1%	3.1%
	2013/14	12,386	11,335	10,767	2.8%	2.7%	2.7%
	2014/15	12,735	11,654	11,069	2.8%	2.8%	2.8%
	2015/16	13,114	12,002	11,401	3.0%	3.0%	3.0%
	2006-2011				2.7%	2.6%	2.6%
	2011-2016				2.9%	2.9%	2.8%
Low	2006/07	10,163	9,356	8,920	1.9%	2.0%	1.9%
	2007/08	10,344	9,509	9,058	1.8%	1.6%	1.5%
	2008/09	10,484	9,622	9,156	1.4%	1.2%	1.1%
Economic	2009/10	10,536	9,649	9,170	0.5%	0.3%	0.2%
	2010/11	10,644	9,734	9,242	1.0%	0.9%	0.8%
	2011/12	10,750	9,817	9,313	1.0%	0.9%	0.8%
Growth	2012/13	10,933	9,978	9,462	1.7%	1.6%	1.6%
	2013/14	11,064	10,088	9,561	1.2%	1.1%	1.0%
	2014/15	11,215	10,223	9,686	1.4%	1.3%	1.3%
	2015/16	11,363	10,354	9,808	1.3%	1.3%	1.3%
	2006-2011				1.3%	1.2%	1.1%
	2011-2016				1.3%	1.2%	1.2%

Forecast winter MDs for High and Low growth scenarios are shown in Table A9.2. Under the High growth scenario, the forecast 10% winter MD is projected to grow at an average rate of 2.2% pa for the first five year period to 2010/11, and at a higher rate of 2.7% pa for the next five years. The projected growth is reduced to 0.2% pa and 0.8% pa under the Low growth scenario.

Table A9.2 – Winter maximum demand forecasts (High and Low economic growth)

		Winter MD (MW)			Annual % Growth		
	Year	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
High	2006	7,994	7,888	7,777	2.6%	2.5%	2.5%
	2007	8,199	8,095	7,978	2.6%	2.6%	2.6%
	2008	8,399	8,293	8,171	2.4%	2.5%	2.4%
Economic	2009	8,512	8,370	8,243	1.3%	0.9%	0.9%
	2010	8,673	8,508	8,376	1.9%	1.7%	1.6%
	2011	8,875	8,688	8,550	2.3%	2.1%	2.1%
Growth	2012	9,144	8,951	8,807	3.0%	3.0%	3.0%
	2013	9,370	9,139	8,990	2.5%	2.1%	2.1%
	2014	9,620	9,364	9,209	2.7%	2.5%	2.4%
	2015	9,897	9,616	9,454	2.9%	2.7%	2.7%
	2005-2010				2.2%	2.0%	2.0%
	2010-2015				2.7%	2.5%	2.5%
Low	2006	7,792	7,693	7,585	0.0%	-0.1%	-0.1%
	2007	7,862	7,772	7,660	0.9%	1.0%	1.0%
	2008	7,910	7,827	7,712	0.6%	0.7%	0.7%
Economic	2009	7,866	7,755	7,639	-0.6%	-0.9%	-1.0%
	2010	7,877	7,752	7,633	0.1%	0.0%	-0.1%
	2011	7,900	7,762	7,640	0.3%	0.1%	0.1%
Growth	2012	8,001	7,868	7,743	1.3%	1.4%	1.4%
	2013	8,049	7,886	7,760	0.6%	0.2%	0.2%
	2014	8,132	7,956	7,828	1.0%	0.9%	0.9%
	2015	8,216	8,028	7,896	1.0%	0.9%	0.9%
	2005-2010				0.2%	0.1%	0.1%
	2010-2015				0.8%	0.7%	0.7%

A10 HISTORICAL ANNUAL ENERGY AND SUMMER AND WINTER MAXIMUM DEMAND

Table A10.1 displays actual annual energy, actual summer and winter MD from 1993/94. Data prior to 1 July 2005 was obtained from SP AusNet Historical Information System. Data from 1 July 2005 is based on the operational data published by NEMMCO.

Table A10.1 – Historical annual energy and summer and winter maximum demand

Financial Year	Annual Energy (GWh)	Summer MD (MW)	Calendar Year	Winter MD (MW)
1993/94	38,566	6,134	1993	5,885
1994/95	39,306	6,509	1994	5,890
1995/96	39,804	5,922	1995	6,018
1996/97	41,430	7,115	1996	6,059
1997/98	43,275	7,213	1997	6,404
1998/99	44,861	7,576	1998	6,662
1999/00	46,053	7,815	1999	6,682
2000/01	46,972	8,179	2000	7,091
2001/02	46,791	7,621	2001	7,054
2002/03	48,361	8,203	2002	7,281
2003/04	49,435	8,574	2003	7,491
2004/05	49,781	8,535	2004	7,435
2005/06	50,455	8,730	2005	7,764

A11 BACK-CASTING OF HISTORICAL SUMMER MAXIMUM DEMANDS

NIEIR has undertaken a preliminary back-casting exercise of historical summer MDs from 1989/90 to 2005/06. The objective of the exercise is to validate the current method of forecasting the summer POE MD explained in detail in Section A3.2. Details of the analysis are explained below.

For each year, nine estimated % POE MDs are calculated (corresponding to three % POE summers and three % POE temperature standards). These estimated MDs form the % POE bands as shown in Figure A11.1 below. The estimated % POE MDs are derived from temperature sensitive load and cooling appliance utilisation rates.

NIEIR undertook a review of the AC utilisation rates based on the reconciliation of actual AC sales and the actual MD in summer 2005/06. The AC utilisation rates have been revised downward and are shown in Table A11.1. The AC utilisation rates at the 10% POE temperature vary within a narrow band between 91% and 95%. This demonstrates that, most of the cooling capacity is utilised on hot summer days. However, the utilisation rates at the 50% and 90% POE temperatures display a greater degree of diversity.

Table A11.1 – Cooling appliance utilisation rates

	10% POE MD	50% POE MD	90% POE MD
10% POE Summer	93.0%	76.0%	66.0%
50% POE Summer	90.0%	71.5%	61.5%
90% POE Summer	89.0%	67.5%	53.0%

The actual MDs are adjusted so that historical data is consistent with the summer MD forecasts, which assume summer MDs occur in mid February and on a weekday around 4:00pm (AEST). Table A11.2 displays the actual and adjusted actual summer MDs, and the POE temperatures for each year from 1989/90. The adjustments include:

- a correction for time of season which applies to summer MDs occurring before late January when demand is lower due to school closures;
- a correction for time of MD which applies to cases where a cool change in mid-afternoon leads to a sharp fall in load. The actual peak in these cases typically falls between 1:00pm and 2:30pm such as in 1989/90 and 2000/01;
- a correction for AC sales. This applies to cases where actual MDs occur in early December (for eg 2003/04) when not all of the ACs are installed; and
- a correction for large industrial load (for example smelter demand).

It should be noted that the effects of the State economic activities and other factors (previous days' temperatures) have not been taken into account in these corrections. For comparison purposes and for simplicity, the MDs are separated into 3 groups, according to the MD % POE temperatures. These groups are as shown below:

- group 1 includes adjusted actual MDs (1991/92, 1995/96, 2001/02 and 2004/05) with average temperatures closest to the 90% POE (this group is shaded in green in the table);
- group 2 includes adjusted actual MDs (1989/90, 1990/91, 1993/94, 1997/98, 1998/99, 1999/00, 2000/01, 2002/03, 2003/04 and 2005/06) with average temperatures closest to the 50% POE (this group is shaded in pink in the table); and
- group 3 includes adjusted actual MDs (1992/93, 1994/95 and 1996/97) with average temperatures closest to the 10% POE (this group is shaded in blue in the table).

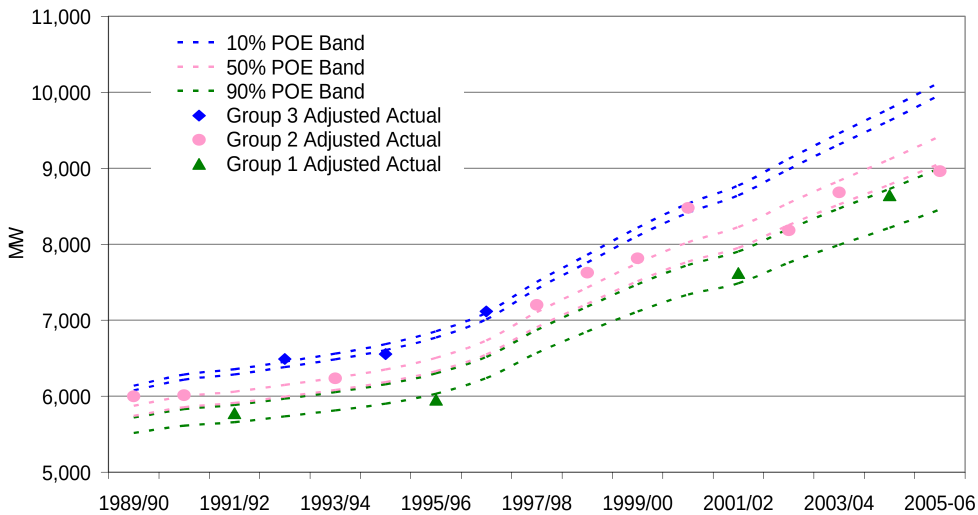
Table A11.2 – Historical summer MDs and % POE temperatures

Year	Date	Time (AEST)	Actual (MW)	Adjusted Actual (MW)	Average Temp (^{0}C)	% POE Temp	Group	Comment
1989/90	24-Jan-90	1.30pm	5,754	5,999	28.6	67%	2	Adjusted actual MD within the 50% POE band
1990/91	25-Feb-91	5.00pm	6,019	6,014	28.4	73%	2	Adjusted actual MD within the 50% POE band
1991/92	17-Feb-92	5.00pm	5,775	5,775	26.0	94%	1	Adjusted actual MD within the 90% POE band
1992/93	3-Feb-93	4.00pm	6,489	6,489	33.3	4%	3	Adjusted actual MD within the 10% POE band
1993/94	25-Jan-94	5.00pm	6,134	6,234	28.2	74%	2	Adjusted actual MD within the 50% POE band
1994/95	6-Dec-94	4.30 pm	6,509	6,554	30.7	23%	3	Adjusted actual MD below the 10% POE band as expected as it was a 23% POE day
1995/96	26-Feb-96	3.00pm	5,922	5,954	25.1	99%	1	Adjusted actual MD below the 90% POE band as expected as it was a 99% POE day
1996/97	19-Feb-97	4.00pm	7,115	7,115	31.5	15%	3	Adjusted actual MD within the 10% POE band
1997/98	26-Feb-98	4.00pm	7,213	7,201	30.3	35%	2	Adjusted actual MD slightly above the 50% POE band as it was a 35% POE day
1998/99	4-Feb-99	3.30pm	7,576	7,626	29.7	45%	2	Adjusted actual MD slightly above the 50% POE band as it was a 45% POE day
1999/00	2-Mar-00	4.00pm	7,815	7,815	29.7	45%	2	Adjusted actual MD slightly above the 50% POE band as it was a 45% POE day

Year	Date	Time (AEST)	Actual (MW)	Adjusted Actual (MW)	Average Temp (⁰C)	% POE Temp	Group	Comment
2000/01	8-Feb-01	1.30pm	8,179	8,479	30.3	35%	2	Adjusted actual MD within the 10% POE band
2001/02	14-Feb-02	4.30pm	7,621	7,621	27.7	82%	1	Adjusted actual MD within the 90% POE band
2002/03	24-Feb-03	4.30pm	8,203	8,183	30.1	41%	2	Adjusted actual MD outside the 50% POE band
2003/04	17-Dec-04	4.00pm	8,574	8,684	30.1	41%	2	Adjusted actual MD slightly below the 50% POE band
2004/05	25-Jan-05	4.30pm	8,535	8,645	27.3	90%	1	Adjusted actual MD within the 90% POE band
2005/06	24-Feb-05	4.00pm	8,730	8,963	28.8	60%	2	Adjusted actual MD slightly below the 50% POE band as it was a 60% POE day

Figure A11.1 compares the adjusted actual MDs, identified by the assigned grouping, with the estimated 90%, 50% and 10% POE MD bands. The upper and the lower bounds of each band correspond to the estimated MDs for 10% and the 90% summers respectively.[55]

Figure A11.1 – Adjusted actual summer MDs and the %POE bands



[55] The estimated MDs corresponding to 50% summers are not shown in the chart

All of the adjusted actual MDs are within or outside the % POE bands, as expected, except 2000/01 and 2002/03. The average temperature for the 2000/01 actual MD was 30.3°C, close to the 50% POE temperature. However, the MD was higher than expected and falls within the 10% POE band. The average temperature for the 2002/03 actual MD was 30.1°C, which places this MD close to the 50% POE level. However, the load on the day was significantly lower and falls within the 90% POE band. Table A11.2 summarises the back-casting results.

In conclusion, NIEIR has proved the robustness of the summer MD forecast system through the back-casting exercise. There is a greater uncertainty surrounding the 10% POE band, as there is little historical data to support the analysis. As this is the first back-casting exercise undertaken by NIEIR, some refinements to this work are expected in the future.

B TERMINAL STATION DEMAND FORECASTS (2005/06 – 2014/15)

VENCorp has prepared and makes available load forecasts for points of connection within the shared electricity transmission network in Victoria, as required by the Victorian Electricity System Code (section 6.260.1.3) and the National Electricity Code (clause 5.6.2a section b.1).

The forecasts for each terminal station in Victoria are provided in the following tables, and the detailed report *"Terminal Station Demand Forecasts 2005/06 - 2014/15",* is available online on VENCorp's website (www.vencorp.com.au).

Alinta Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Heatherton 66 kV [56]	10	321.2	91.4	331.6	94.4	340.8	97.0	349.6	99.5	359.0	102.2	370.0	105.3	380.5	108.3	389.8	110.9	399.4	113.7	409.1	116.4
	50	312.9	89.1	323.0	91.9	331.9	94.4	340.4	96.9	349.4	99.4	360.0	102.5	370.2	105.3	379.1	107.9	388.3	110.5	397.7	113.2
Malvern 22 kV [57]	10	57.0	19.9	58.5	20.5	60.0	21.0	61.2	21.4	62.5	21.9	64.0	22.4	65.4	22.9	66.7	23.3	68.0	23.8	69.3	24.2
	50	56.1	19.6	57.6	20.1	59.0	20.6	60.2	21.0	61.5	21.5	62.9	22.0	64.3	22.5	65.5	22.9	66.7	23.3	68.0	23.8
Malvern 66 kV [57]	10	120.6	31.0	124.6	32.0	128.2	33.0	131.7	33.9	135.3	34.8	139.4	35.8	143.4	36.9	147.2	37.8	151.0	38.8	154.9	39.8
	50	116.2	29.8	120.0	30.8	123.4	31.7	126.7	32.5	130.1	33.4	134.1	34.4	137.9	35.4	141.4	36.3	145.1	37.2	148.8	38.2
Tyabb 66 kV	10	232.0	85.2	241.5	88.7	250.7	92.0	259.3	95.2	267.7	98.3	277.3	101.8	286.9	105.3	295.6	108.5	304.4	111.7	313.5	115.1
	50	223.2	81.9	232.2	85.2	241.0	88.5	249.1	91.5	257.1	94.4	266.4	97.8	275.6	101.2	283.9	104.2	292.2	107.3	300.9	110.5

Alinta Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Heatherton 66 kV [56]	10	295.3	45.1	253.9	38.8	257.5	39.3	260.5	39.8	266.0	40.6	271.4	41.5	279.1	42.6	286.2	43.7	293.1	44.8	300.2	45.9
	50	290.3	44.4	250.6	38.3	254.0	38.8	256.8	39.2	262.0	40.0	267.1	40.8	274.6	41.9	281.6	43.0	288.2	44.0	295.0	45.1
Malvern 22 kV [57]	10	57.2	17.3	53.9	16.3	54.6	16.5	55.5	16.7	56.9	17.2	57.9	17.5	59.0	17.8	60.2	18.2	61.6	18.6	62.9	19.0
	50	56.7	17.1	53.7	16.2	54.3	16.4	55.2	16.6	56.6	17.1	57.5	17.3	58.6	17.7	59.7	18.0	61.0	18.4	62.3	18.8
Malvern 66 kV [57]	10	94.3	18.8	101.5	20.2	103.0	20.5	105.0	20.9	108.0	21.5	110.4	22.0	113.2	22.5	116.1	23.1	119.2	23.7	122.3	24.4
	50	91.9	18.3	98.7	19.7	100.1	19.9	102.0	20.3	104.9	20.9	107.2	21.3	109.7	21.9	112.6	22.4	115.5	23.0	118.5	23.6
Tyabb 66 kV	10	202.3	40.3	208.4	41.5	212.8	42.4	217.4	43.3	224.8	44.8	231.1	46.1	237.7	47.4	244.2	48.7	251.5	50.1	258.9	51.6
	50	196.7	39.2	202.5	40.4	206.7	41.2	211.0	42.1	218.1	43.5	224.1	44.7	230.4	45.9	236.7	47.2	243.6	48.5	250.7	50.0

[56] Forecasts include load transfers from HTS to CBTS after winter 2005.

[57] Forecasts include load transfers from MTS22kV to MTS66kV prior to summer 2005/06.

Citipower Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	96.8	45.4	100.1	47.2	108.1	52.1	113.1	55.3	117.7	58.2	121.5	60.7	123.5	62.1	126.3	63.9	129.2	65.9	132.0	67.8
	50	89.6	40.9	92.7	42.5	100.1	47.1	104.7	50.0	109.0	52.8	112.5	55.0	114.3	56.3	117.0	58.1	119.6	59.8	122.2	61.6
West Melbourne 22 kV	10	101.6	64.4	106.6	68.9	112.3	74.2	115.8	77.3	119.2	80.6	122.7	83.9	126.2	87.2	129.8	90.6	133.4	94.0	137.0	97.5
	50	95.9	59.8	100.6	64.0	106.0	69.0	109.2	72.0	112.5	75.1	115.8	78.2	119.1	81.3	122.5	84.5	125.8	87.8	129.3	91.1

Citipower Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	75.0	30.4	81.1	33.5	85.0	34.8	90.9	37.7	94.8	39.7	98.9	41.9	101.4	43.3	103.9	44.8	106.4	46.3	109.6	47.9
	50	72.1	28.6	77.9	31.6	81.7	32.8	87.4	35.6	91.2	37.6	95.1	39.6	97.5	41.1	99.9	42.5	102.3	43.9	105.4	45.5
West Melbourne 22 kV	10	83.8	44.3	87.9	48.0	92.3	51.8	97.5	56.4	100.6	59.1	103.8	61.9	107.0	64.7	110.2	67.6	113.4	70.6	116.7	73.5
	50	80.5	42.0	84.5	45.5	88.8	49.2	93.8	53.5	96.8	56.2	99.8	58.9	102.8	61.6	105.9	64.4	109.0	67.2	112.2	70.1

Powercor Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV [58]	10	153.5	80.4	156.5	82.0	159.5	83.6	162.6	72.2	165.8	67.0	169.9	55.7	173.2	56.8	176.6	57.9	180.2	59.1	183.8	60.3
	50	153.5	80.4	156.5	82.0	159.5	83.6	162.6	72.2	165.8	67.0	169.9	55.7	173.2	56.8	176.6	57.9	180.2	59.1	183.8	60.3
Bendigo 22 kV	10	35.3	11.5	38.0	12.4	42.8	14.0	43.7	14.3	44.6	14.6	47.7	15.6	48.8	15.9	49.4	16.1	50.5	16.5	51.6	16.8
	50	34.3	11.2	37.0	12.1	41.8	13.6	42.7	14.0	43.6	14.3	46.7	15.3	47.8	15.6	48.4	15.8	49.5	16.2	50.6	16.5
Bendigo 66 kV	10	152.7	45.1	156.4	46.2	155.3	45.8	157.0	46.3	160.0	47.2	160.8	47.5	163.9	48.4	167.4	49.4	170.6	50.3	173.8	51.3
	50	145.7	43.0	149.4	44.1	148.3	43.8	150.0	44.3	153.0	45.1	153.8	45.4	156.9	46.3	160.4	47.3	163.6	48.3	166.8	49.2
Brooklyn-SCI 66 kV	10	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
	50	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV [58]	10	160.7	53.8	163.4	54.7	166.9	55.8	170.5	57.0	174.2	45.3	177.9	42.2	182.6	30.4	186.5	31.0	190.4	31.7	194.4	32.3
	50	160.7	53.8	163.4	54.7	166.9	55.8	170.5	57.0	174.2	45.3	177.9	42.2	182.6	30.4	186.5	31.0	190.4	31.7	194.4	32.3
Bendigo 22 kV	10	24.7	8.0	28.3	9.1	30.6	9.9	34.8	11.2	35.6	11.5	36.4	11.7	39.2	12.6	40.0	12.9	40.4	13.0	41.4	13.3
	50	24.7	8.0	28.3	9.1	30.6	9.9	34.8	11.2	35.6	11.5	36.4	11.7	39.2	12.6	40.0	12.9	40.4	13.0	41.4	13.3
Bendigo 66 kV	10	125.7	6.8	126.9	6.9	131.2	7.1	131.0	7.1	132.4	7.2	134.8	7.3	135.7	7.4	138.2	7.5	141.2	7.7	143.8	7.8
	50	125.7	6.8	126.9	6.9	131.2	7.1	131.0	7.1	132.4	7.2	134.8	7.3	135.7	7.4	138.2	7.5	141.2	7.7	143.8	7.8
Brooklyn-SCI 66 kV	10	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1
	50	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1	62.4	27.1

58 Forecasts are on the basis that Challicum Hills windfarm is not operating.

Powercor Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Geelong 66 kV [59]	10	346.9	102.9	367.7	109.1	383.0	113.7	391.6	116.2	396.9	117.8	402.1	119.3	410.0	121.7	413.7	122.8	417.5	123.9	421.3	125.0
	50	338.9	100.6	359.7	106.8	375.0	111.3	383.6	113.8	388.9	115.4	394.1	117.0	402.0	119.3	405.7	120.4	409.5	121.5	413.3	122.7
Horsham 66 kV [60]	10	79.0	28.0	80.4	28.5	81.4	28.9	82.3	29.2	83.3	29.5	84.2	29.9	85.2	30.2	86.2	30.5	87.2	30.9	88.2	31.2
	50	77.0	27.3	78.4	27.8	79.4	28.1	80.3	28.5	81.3	28.8	82.2	29.1	83.2	29.5	84.2	29.8	85.2	30.2	86.2	30.5
Kerang 22 kV	10	11.7	3.1	11.9	3.1	12.0	3.2	12.1	3.2	12.3	3.2	12.4	3.3	12.6	3.3	12.7	3.3	12.8	3.4	13.0	3.4
	50	11.3	3.0	11.5	3.0	11.6	3.1	11.7	3.1	11.9	3.1	12.0	3.2	12.2	3.2	12.3	3.2	12.4	3.3	12.6	3.3
Kerang 66 kV	10	53.1	8.6	56.1	9.1	58.9	9.6	60.6	9.9	62.4	10.2	64.1	10.4	65.7	10.7	67.4	11.0	69.2	11.3	71.0	11.6
	50	52.1	8.5	55.1	9.0	57.9	9.4	59.6	9.7	61.4	10.0	63.1	10.3	64.7	10.5	66.4	10.8	68.2	11.1	70.0	11.4

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Geelong 66 kV [59]	10	322.2	58.4	328.6	59.5	349.2	63.3	364.4	66.0	372.8	67.6	378.0	68.5	383.0	69.4	390.1	70.7	393.7	71.3	397.3	72.0
	50	322.2	58.4	328.6	59.5	349.2	63.3	364.4	66.0	372.8	67.6	378.0	68.5	383.0	69.4	390.1	70.7	393.7	71.3	397.3	72.0
Horsham 66 kV [60]	10	73.7	0.9	76.0	0.9	76.8	1.0	77.6	1.0	78.4	1.0	79.2	1.0	80.1	1.0	81.0	1.0	81.9	1.0	82.8	1.0
	50	73.7	0.9	76.0	0.9	76.8	1.0	77.6	1.0	78.4	1.0	79.2	1.0	80.1	1.0	81.0	1.0	81.9	1.0	82.8	1.0
Kerang 22 kV	10	11.2	1.8	11.3	1.8	11.5	1.8	11.6	1.9	11.7	1.9	11.8	1.9	12.0	1.9	12.1	1.9	12.2	2.0	12.3	2.0
	50	11.2	1.8	11.3	1.8	11.5	1.8	11.6	1.9	11.7	1.9	11.8	1.9	12.0	1.9	12.1	1.9	12.2	2.0	12.3	2.0
Kerang 66 kV	10	48.0	-0.6	49.6	-0.1	52.0	0.7	54.4	1.4	55.8	1.9	57.4	2.4	58.8	2.9	60.3	3.3	61.8	3.8	63.3	4.3
	50	48.0	-0.6	49.6	-0.1	52.0	0.7	54.4	1.4	55.8	1.9	57.4	2.4	58.8	2.9	60.3	3.3	61.8	3.8	63.3	4.3

59 8 MW of embedded generation is considered as negative load.

60 Forecasts are on the basis that Challicum Hills windfarm is not operating.

Powercor Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	41.2	22.9	42.6	23.7	44.1	24.6	45.4	25.3	46.6	25.9	47.5	26.5	48.5	27.0	49.5	27.6	50.5	28.2	51.6	28.7
	50	40.2	22.4	41.6	23.1	43.1	24.0	44.4	24.7	45.6	25.4	46.5	25.9	47.5	26.5	48.5	27.0	49.5	27.6	50.6	28.2
Red Cliffs 66 kV	10	129.5	36.9	136.5	38.9	146.5	41.7	152.1	43.4	157.5	44.9	162.6	46.3	167.8	47.8	172.9	49.3	178.1	50.8	183.3	52.2
	50	125.5	35.8	132.5	37.8	142.5	40.6	148.1	42.2	153.5	43.8	158.6	45.2	163.8	46.7	168.9	48.1	174.1	49.6	179.3	51.1
Shepparton 66 kV	10	279.5	111.5	282.7	112.8	287.5	114.7	290.8	116.0	294.1	117.4	297.6	118.7	301.1	120.1	304.7	121.6	308.3	123.0	311.9	124.4
	50	264.5	105.5	267.7	106.8	272.5	108.7	275.8	110.0	279.1	111.4	282.6	112.7	286.1	114.2	289.7	115.6	293.3	117.0	296.9	118.4
Tyabb 220 kV	10	65.9	37.5	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7
	50	65.9	37.5	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7	66.3	37.7
Terang 66 kV [61]	10	166.5	52.7	171.6	54.4	175.8	55.7	182.2	57.7	185.6	58.8	188.9	59.8	192.2	60.9	195.6	62.0	199.0	63.0	202.6	64.2
	50	166.5	52.7	171.6	54.4	175.8	55.7	182.2	57.7	185.6	58.8	188.9	59.8	192.2	60.9	195.6	62.0	199.0	63.0	202.6	64.2

Powercor Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	22.9	5.3	23.4	5.5	23.9	5.6	24.3	5.7	24.7	5.8	25.1	5.8	25.5	5.9	25.9	6.0	26.3	6.1	26.7	6.2
	50	22.9	5.3	23.4	5.5	23.9	5.6	24.3	5.7	24.7	5.8	25.1	5.8	25.5	5.9	25.9	6.0	26.3	6.1	26.7	6.2
Red Cliffs 66 kV	10	99.8	4.7	99.6	4.7	102.4	4.8	108.2	5.1	111.0	5.2	114.0	5.4	117.4	5.5	120.6	5.7	123.8	5.8	127.2	6.0
	50	99.8	4.7	99.6	4.7	102.4	4.8	108.2	5.1	111.0	5.2	114.0	5.4	117.4	5.5	120.6	5.7	123.8	5.8	127.2	6.0
Shepparton 66 kV	10	206.0	24.3	208.3	24.6	210.8	24.9	214.5	25.3	217.1	25.6	219.7	25.9	222.4	26.2	225.1	26.6	227.8	26.9	230.6	27.2
	50	206.0	24.3	208.3	24.6	210.8	24.9	214.5	25.3	217.1	25.6	219.7	25.9	222.4	26.2	225.1	26.6	227.8	26.9	230.6	27.2
Tyabb 220 kV	10	66.9	40.8	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0
	50	66.9	40.8	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0	67.3	41.0
Terang 66 kV [61]	10	181.6	36.9	185.6	37.7	191.5	38.9	196.6	40.0	203.8	41.4	207.5	42.2	211.2	42.9	215.1	43.7	219.0	44.5	223.0	45.3
	50	181.6	36.9	185.6	37.7	191.5	38.9	196.6	40.0	203.8	41.4	207.5	42.2	211.2	42.9	215.1	43.7	219.0	44.5	223.0	45.3

[61] Effect of Codrington windfarm generation has been excluded.

SP AusNet (Distribution) Summer Peak Forecasts by Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [62]	10	89.9	44.8	92.6	46.2	95.4	47.6	98.1	49.0	101.0	50.4	103.8	51.8	106.7	53.3	109.6	54.7	112.6	56.2	115.5	57.6
	50	85.6	42.7	88.2	44.0	90.8	45.3	93.5	46.6	96.2	48.0	98.9	49.3	101.6	50.7	104.4	52.1	107.2	53.5	110.0	54.9
Mount Beauty 66 kV	10	37.4	5.3	38.0	5.6	38.5	5.9	39.1	6.2	39.7	6.5	40.3	6.8	40.9	7.1	41.5	7.4	42.1	7.7	42.8	8.0
	50	34.0	4.8	34.5	5.1	35.0	5.4	35.6	5.6	36.1	5.9	36.6	6.2	37.2	6.4	37.7	6.7	38.3	7.0	38.9	7.3
Wodonga 22 kV	10	26.5	2.6	27.1	3.1	27.7	3.3	28.4	3.5	29.0	3.7	29.7	3.9	30.3	4.2	31.0	4.4	31.7	4.6	32.4	4.8
	50	26.0	2.6	26.6	3.1	27.2	3.3	27.8	3.5	28.4	3.7	29.1	3.9	29.7	4.1	30.4	4.3	31.1	4.5	31.8	4.7
Wodonga 66 kV	10	61.9	21.0	63.5	21.8	65.2	22.6	66.8	23.4	68.5	24.2	70.1	25.1	71.8	25.9	73.5	26.7	75.2	27.6	76.8	28.4
	50	60.7	20.5	62.3	21.3	63.9	22.1	65.5	22.9	67.1	23.8	68.8	24.6	70.4	25.4	72.0	26.2	73.7	27.0	75.3	27.8
Yallourn 11 kV [63]	10	3.6	2.2	3.6	2.2	3.7	2.3	3.7	2.3	3.8	2.3	3.8	2.4	3.9	2.4	4.0	2.5	4.0	2.5	4.1	2.5
	50	3.5	2.2	3.6	2.2	3.6	2.2	3.7	2.3	3.7	2.3	3.8	2.3	3.8	2.4	3.9	2.4	3.9	2.4	4.0	2.5

SP AusNet (Distribution) Winter Peak Forecasts by Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [62]	10	116.0	44.5	118.9	45.4	121.9	46.3	124.8	47.2	127.8	48.1	130.7	49.1	133.6	50.1	136.4	51.1	139.1	52.1	141.8	53.1
	50	110.5	42.4	113.2	43.2	116.1	44.1	118.9	45.0	121.7	45.9	124.5	46.8	127.2	47.7	129.9	48.7	132.5	49.6	135.0	50.5
Mount Beauty 66 kV	10	49.4	6.9	50.3	7.4	51.3	7.9	52.4	8.4	53.4	8.9	54.5	9.5	55.6	10.0	56.7	10.6	57.8	11.1	59.0	11.7
	50	47.0	6.6	47.9	7.1	48.9	7.5	49.9	8.0	50.9	8.5	51.9	9.0	52.9	9.5	54.0	10.1	55.1	10.6	56.2	11.2
Wodonga 22 kV	10	28.7	-0.8	29.1	-0.6	29.6	-0.6	30.0	-0.5	30.5	-0.4	30.9	-0.4	31.4	-0.3	31.9	-0.3	32.4	-0.2	32.9	-0.2
	50	28.1	-0.8	28.5	-0.6	29.0	-0.6	29.4	-0.5	29.9	-0.4	30.3	-0.4	30.8	-0.3	31.3	-0.3	31.7	-0.2	32.2	-0.1
Wodonga 66 kV	10	48.1	7.5	49.6	8.3	51.0	9.0	52.6	9.8	54.2	10.6	55.8	11.4	57.5	12.2	59.2	13.1	61.0	14.0	62.8	14.9
	50	47.2	7.4	48.6	8.1	50.0	8.8	51.5	9.6	53.1	10.3	54.7	11.1	56.3	12.0	58.0	12.8	59.8	13.7	61.5	14.6
Yallourn 11 kV [63]	10	4.1	2.0	4.2	2.0	4.3	2.1	4.5	2.2	4.6	2.2	4.7	2.3	4.8	2.3	4.9	2.4	5.0	2.4	5.1	2.5
	50	4.0	1.9	4.1	2.0	4.2	2.1	4.4	2.1	4.5	2.2	4.6	2.2	4.7	2.3	4.8	2.3	4.9	2.4	5.0	2.4

62 Lake William Hovell generator is considered as negative load.

63 3 MW of embedded generation is considered as negative load.

Peak Summer Forecasts by Shared Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [64]	10	453.0	170.5	457.5	171.8	451.8	169.1	460.2	172.2	468.8	175.3	479.0	179.1	489.1	182.7	499.6	186.6	510.5	190.6	521.5	194.6
	50	429.3	161.7	434.1	163.1	429.1	160.7	437.4	163.7	445.9	166.8	456.0	170.5	465.9	174.1	476.3	177.9	487.1	181.9	497.9	185.8
Brooklyn 22 kV	10	54.1	36.0	55.4	36.9	56.2	37.5	57.1	38.1	58.0	38.7	58.9	39.3	59.9	39.9	60.9	40.6	61.8	41.2	62.8	41.9
	50	54.0	36.0	55.3	36.9	56.2	37.5	57.1	38.1	58.0	38.7	58.9	39.3	59.9	39.9	60.8	40.5	61.8	41.2	62.8	41.9
Brunswick 22 kV	10	88.0	53.1	88.2	53.6	89.8	54.6	91.3	55.6	92.8	56.6	94.6	57.8	96.4	59.0	98.3	60.2	100.1	61.5	102.0	62.7
	50	82.0	49.5	82.2	50.0	83.7	50.9	85.1	51.9	86.5	52.8	88.2	53.9	89.9	55.0	91.6	56.2	93.3	57.3	95.1	58.5
Cranbourne 66 kV [65]	10	222.1	87.6	228.7	90.5	238.0	94.6	247.5	98.9	257.4	103.3	268.0	108.0	278.8	112.9	290.0	117.9	301.6	123.2	313.8	128.7
	50	212.0	83.4	218.3	86.2	227.1	90.1	236.1	94.1	245.4	98.2	255.4	102.7	265.7	107.3	276.2	112.1	287.3	117.0	298.8	122.3
East Rowville 66 kV [66]	10	470.8	181.6	488.6	188.8	505.8	195.8	522.6	202.7	539.8	209.8	559.0	217.7	577.7	225.4	595.0	232.7	613.0	240.3	631.5	248.1
	50	454.0	174.8	470.8	181.6	487.3	188.3	503.2	194.8	519.7	201.6	537.9	209.1	555.8	216.4	572.3	223.4	589.4	230.6	607.0	238.0

Peak Winter Forecasts by Shared Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [64]	10	375.5	126.2	401.0	134.3	405.7	135.7	401.8	134.1	409.1	136.4	416.6	138.8	425.0	141.5	433.6	144.3	442.7	147.2	452.1	150.2
	50	370.0	124.4	395.4	132.5	400.2	133.8	396.5	132.3	403.8	134.7	411.3	137.1	419.6	139.7	428.2	142.5	437.3	145.4	446.7	148.4
Brooklyn 22 kV	10	52.9	34.9	51.0	33.7	52.3	34.5	53.1	35.1	53.9	35.6	54.7	36.2	55.6	36.7	56.5	37.3	57.4	37.9	58.3	38.5
	50	52.8	34.9	51.0	33.7	52.2	34.5	53.0	35.0	53.9	35.6	54.7	36.1	55.6	36.7	56.5	37.3	57.4	37.9	58.3	38.5
Brunswick 22 kV	10	84.5	37.7	86.2	38.6	86.1	38.6	87.4	39.2	88.5	39.7	89.6	40.3	91.0	40.9	92.3	41.6	93.7	42.2	95.1	42.9
	50	81.2	36.3	82.8	37.0	82.8	37.0	83.9	37.6	85.0	38.2	86.1	38.7	87.4	39.3	88.7	39.9	90.1	40.6	91.4	41.2
Cranbourne 66 kV [65]	10	142.1	59.3	198.8	73.2	205.4	76.3	212.2	79.5	220.4	83.1	228.9	86.8	237.5	90.7	246.5	94.7	256.0	99.0	266.0	103.4
	50	136.2	56.7	190.5	70.0	196.8	72.9	203.2	75.9	211.0	79.4	219.1	82.9	227.2	86.6	235.8	90.4	244.9	94.5	254.3	98.7
East Rowville 66 kV [66]	10	374.1	131.2	385.6	135.6	395.5	139.6	404.7	143.4	416.6	148.1	428.3	152.7	440.7	157.6	453.4	162.6	467.7	168.1	482.6	173.8
	50	363.7	126.9	374.6	131.1	384.1	134.9	392.8	138.6	404.2	143.0	415.4	147.4	427.3	152.0	439.4	156.8	453.2	162.1	467.5	167.6

64 Forecasts include load demand from Citipower's zone substation Tavistock Place (TP). Brooklyn Landfill embedded generator in Brooklyn is assumed to be running at about 2 MW in the forecast. AGL plans to transfer approximately 8.0 MW of load from BLTS66 to KTS in 2007 (zone substation BY). AGL plans to transfer approximately 14.1 MW of load from BLTS66 to WMTS in 2008.

65 Reported Station MD forecasts were based on individual forecasts of the following zone subs: PHM, BWN, NRN, CLN. Berwick Tip (5.15 MW) generator is considered as negative load.

66 ERTS and CBTS forecast loads reflect the resulting (estimated) MDs after load transfers. Cardinia and Dandenong hospital generation are considered as negative load.

Peak Summer Forecasts by Shared Terminal Station

Terminal Station	POE	2005/06 MW	2005/06 MVAr	2006/07 MW	2006/07 MVAr	2007/08 MW	2007/08 MVAr	2008/09 MW	2008/09 MVAr	2009/10 MW	2009/10 MVAr	2010/11 MW	2010/11 MVAr	2011/12 MW	2011/12 MVAr	2012/13 MW	2012/13 MVAr	2013/14 MW	2013/14 MVAr	2014/15 MW	2014/15 MVAr
Fishermans Bend 66 kV[67]	10	257.2	112.8	265.2	119.7	279.4	131.4	288.9	139.6	298.3	147.9	307.7	156.3	317.1	164.8	326.5	173.4	335.9	182.1	345.3	190.9
	50	245.1	103.9	252.8	110.5	266.3	121.6	275.4	129.5	284.4	137.4	293.3	145.4	302.3	153.5	311.2	161.6	320.2	169.9	329.2	178.4
Keilor 66 kV [68]	10	490.5	230.0	515.9	242.2	533.7	250.4	549.3	257.5	566.2	265.3	581.5	272.2	596.7	279.1	612.4	286.3	628.7	293.7	645.2	301.2
	50	462.8	217.0	487.2	228.7	504.6	236.7	519.9	243.7	536.4	251.2	551.5	258.0	566.4	264.8	581.7	271.8	597.8	279.0	614.0	286.4
Loy Yang 66 kV [69]	10	37.0	32.2	37.3	32.4	37.5	32.7	37.8	32.9	38.1	33.1	38.3	33.4	38.6	33.6	38.9	33.9	39.1	34.1	39.4	34.4
	50	36.5	31.7	36.8	32.0	37.0	32.2	37.3	32.4	37.5	32.7	37.8	32.9	38.0	33.1	38.3	33.4	38.6	33.6	38.8	33.8
Morwell/Loy Yang 66 kV [70]	10	360.2	99.1	370.8	104.4	381.3	109.6	392.2	115.0	403.4	120.6	415.0	126.5	427.1	132.5	439.6	138.8	452.6	145.2	466.0	152.0
	50	350.0	96.4	360.3	101.6	370.5	106.6	381.0	111.9	391.9	117.4	403.2	123.0	415.0	128.9	427.1	134.9	439.7	141.2	452.7	147.8

Peak Winter Forecasts by Shared Terminal Station

Terminal Station	POE	2005 MW	2005 MVAr	2006 MW	2006 MVAr	2007 MW	2007 MVAr	2008 MW	2008 MVAr	2009 MW	2009 MVAr	2010 MW	2010 MVAr	2011 MW	2011 MVAr	2012 MW	2012 MVAr	2013 MW	2013 MVAr	2014 MW	2014 MVAr
Fishermans Bend 66 kV [67]	10	207.6	68.5	224.6	81.8	238.6	92.4	250.6	101.9	259.6	109.4	268.5	117.0	277.5	124.7	286.4	132.5	295.4	140.4	304.3	148.4
	50	201.6	64.3	218.2	77.3	231.7	87.6	243.5	96.8	252.2	104.1	260.9	111.5	269.6	119.0	278.3	126.5	286.9	134.2	295.7	141.9
Keilor 66 kV [68]	10	405.1	156.5	420.1	162.5	442.1	171.4	456.0	176.7	469.5	181.6	483.1	186.7	496.1	191.3	508.8	195.9	522.1	200.7	535.9	205.6
	50	397.6	153.6	412.4	159.5	434.1	168.3	447.9	173.5	461.4	178.4	474.8	183.4	487.8	188.0	500.5	192.6	513.7	197.4	527.4	202.3
Loy Yang 66 kV [69]	10	39.2	33.8	39.5	34.0	39.7	34.2	40.0	34.5	40.3	34.7	40.6	35.0	40.9	35.2	41.2	35.5	41.5	35.8	41.8	36.0
	50	38.6	33.2	38.9	33.5	39.2	33.7	39.4	34.0	39.7	34.2	40.0	34.5	40.3	34.7	40.6	35.0	40.9	35.2	41.1	35.5
Morwell/Loy Yang 66 kV [70]	10	401.7	90.3	409.6	94.2	417.2	98.0	425.0	101.9	433.1	106.0	441.4	110.1	450.0	114.4	458.9	118.9	468.0	123.4	477.4	128.1
	50	390.3	87.9	397.9	91.7	405.3	95.4	412.9	99.2	420.8	103.1	428.9	107.2	437.2	111.3	445.8	115.6	454.7	120.1	463.8	124.6

67 8 MW of embedded generation is considered as negative load.

68 AGL's forecast does not include loads at Powercor's zone substation Woodend (WND). AGL plans to transfer about 8.0 MW of load from BLTS66 to KTS in 2007 (zone substation BY).

69 Forecasts allow for continuous Loy Yang power station load of 10 MW and 15 MW of open-cut load.

70 Forecast excludes generation from Alinta generator (up to 86 MW) and Toora (up to 21 MW) in both summer and winter. However 20 MW is available from Duke during SP AusNet's peak load as per the Network Support Agreement. Esso generates about 15 MW most of the year. Hence it is considered as a negative load along with other embedded generators, i.e. Blue Rock Dam (2.8MW), Thomson Dam (7.6MW), Lake Glenmaggi (3.8 MW). All other new renewables under consideration are excluded in the forecast.

Peak Summer Forecasts by Shared Terminal Station

		2005/06		2006/07		2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 66 kV	10	534.1	258.7	553.7	275.5	563.1	283.2	573.4	291.8	583.8	300.5	594.3	309.3	605.0	318.2	615.5	327.1	626.1	336.1	636.8	345.2
	50	496.8	230.1	515.1	245.7	523.9	252.8	533.5	260.8	543.1	268.9	552.9	277.1	562.8	285.3	572.6	293.6	582.5	302.0	592.4	310.4
Ringwood 22 kV	10	96.9	44.6	99.6	46.0	102.4	47.3	105.1	48.5	107.5	49.7	110.1	50.9	112.8	52.2	115.3	53.4	117.4	54.4	119.6	55.4
	50	93.4	43.0	96.1	44.3	98.7	45.5	101.3	46.7	103.6	47.8	106.2	49.0	108.8	50.3	111.1	51.4	113.3	52.4	115.4	53.4
Ringwood 66 kV	10	422.7	162.5	439.9	169.5	458.8	176.9	474.1	183.9	490.1	191.1	506.7	198.7	523.8	206.5	541.2	214.6	559.3	222.9	578.0	231.6
	50	401.5	153.8	417.9	160.4	436.0	167.4	450.5	174.0	465.6	180.8	481.3	188.0	497.4	195.3	513.8	202.9	530.9	210.8	548.6	219.0
Springvale 66 kV [71]	10	441.8	103.2	456.5	107.2	472.2	110.9	484.0	113.7	496.4	116.6	510.5	120.0	523.8	123.1	535.4	126.0	547.0	128.8	559.7	131.8
	50	428.9	99.1	442.9	102.8	458.1	106.4	469.4	109.1	481.2	111.9	494.8	115.1	507.6	118.1	518.8	120.8	530.3	123.5	542.0	126.3

Peak Winter Forecasts by Shared Terminal Station

		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 66 kV	10	421.9	124.3	449.6	145.5	461.4	154.6	469.7	161.0	478.4	167.6	487.2	174.3	496.2	181.0	505.2	187.8	514.4	194.7	523.6	201.7
	50	406.7	114.4	433.3	134.9	444.6	143.6	452.6	149.8	461.0	156.1	469.4	162.5	478.1	168.9	486.8	175.5	495.6	182.1	504.5	188.8
Ringwood 22 kV	10	85.3	36.5	88.3	37.5	90.5	38.2	92.6	38.9	95.3	39.8	98.0	40.7	101.0	41.7	104.1	42.7	107.5	43.8	110.9	45.0
	50	82.2	35.2	85.0	36.2	87.1	36.8	89.1	37.5	91.6	38.3	94.1	39.2	96.9	40.1	99.9	41.1	103.1	42.1	106.3	43.2
Ringwood 66 kV	10	358.9	82.1	370.1	85.5	381.2	88.9	392.3	92.3	404.3	96.0	417.0	99.8	430.1	103.7	443.7	107.8	457.6	112.0	472.0	116.4
	50	349.5	79.9	360.2	83.1	371.0	86.4	381.7	89.7	393.4	93.3	405.6	97.0	418.4	100.8	431.5	104.8	445.0	108.9	459.0	113.1
Springvale 66 kV [71]	10	355.1	37.1	362.6	37.8	369.9	38.5	376.8	39.3	387.2	40.4	396.8	41.4	407.6	42.5	418.0	43.6	429.1	44.8	440.4	45.9
	50	344.2	35.7	351.1	36.3	357.9	37.0	364.5	37.7	374.3	38.8	383.3	39.7	393.5	40.8	403.4	41.8	413.9	42.9	424.5	44.1

71 Clayton and Springvale landfill embedded generations (16 MW) are considered as negative load.

Peak Summer Forecasts by Shared Terminal Station

Terminal Station	POE	2005/06 MW	2005/06 MVAr	2006/07 MW	2006/07 MVAr	2007/08 MW	2007/08 MVAr	2008/09 MW	2008/09 MVAr	2009/10 MW	2009/10 MVAr	2010/11 MW	2010/11 MVAr	2011/12 MW	2011/12 MVAr	2012/13 MW	2012/13 MVAr	2013/14 MW	2013/14 MVAr	2014/15 MW	2014/15 MVAr
Templestowe 66 kV	10	308.9	118.7	326.4	125.9	334.7	130.0	343.0	134.2	351.0	138.0	359.4	142.0	367.8	146.0	376.1	150.1	384.6	154.2	393.4	158.4
	50	291.7	109.1	308.6	116.0	316.4	119.9	324.1	123.8	331.6	127.3	339.5	131.1	347.4	134.8	355.2	138.6	363.2	142.5	371.4	146.4
Thomastown Bus 1&2 66 kV [72]	10	334.6	175.8	336.3	176.4	259.3	134.2	266.6	138.0	274.2	141.9	281.7	145.8	289.4	149.7	297.4	153.7	305.7	157.9	314.3	162.2
	50	316.9	166.5	318.6	167.1	245.9	127.3	252.8	130.8	260.1	134.6	267.2	138.2	274.6	142.0	282.2	145.8	290.0	149.8	298.2	153.9
Thomastown Bus 3&4 66 kV [73]	10	336.6	182.1	361.5	195.8	236.3	132.0	241.4	134.9	247.0	138.0	251.4	140.5	255.9	143.0	260.5	145.6	265.2	148.2	270.0	150.9
	50	318.7	172.4	342.2	185.3	222.9	124.6	227.7	127.2	233.0	130.2	237.2	132.5	241.5	134.9	245.8	137.3	250.2	139.8	254.7	142.3
West Melbourne 66 kV [74]	10	418.8	190.2	445.6	215.5	478.0	235.8	490.5	247.5	502.2	258.7	514.2	270.1	526.3	281.7	538.6	293.6	551.0	305.8	563.6	318.2
	50	394.9	172.7	420.2	196.5	450.7	215.7	462.5	226.8	473.5	237.3	484.8	248.0	496.3	259.0	507.8	270.2	519.6	281.7	531.4	293.4

Peak Winter Forecasts by Shared Terminal Station

Terminal Station	POE	2005 MW	2005 MVAr	2006 MW	2006 MVAr	2007 MW	2007 MVAr	2008 MW	2008 MVAr	2009 MW	2009 MVAr	2010 MW	2010 MVAr	2011 MW	2011 MVAr	2012 MW	2012 MVAr	2013 MW	2013 MVAr	2014 MW	2014 MVAr
Templestowe 66 kV	10	267.4	74.9	275.7	78.4	282.6	82.1	287.8	84.5	294.9	87.7	301.6	90.5	307.1	92.8	312.9	95.2	319.0	97.6	325.1	100.1
	50	257.0	70.5	264.8	73.8	271.4	77.3	276.3	79.6	283.0	82.6	289.4	85.2	294.6	87.4	300.1	89.7	305.9	92.0	311.7	94.4
Thomastown Bus 1&2 66 kV [72]	10	278.7	138.0	295.9	146.4	297.7	147.4	215.2	103.9	219.7	106.2	224.3	108.5	228.2	110.4	232.3	112.3	236.4	114.3	240.5	116.3
	50	267.8	132.6	284.3	140.7	285.9	141.5	206.4	99.7	210.6	101.8	215.1	104.0	218.8	105.9	222.7	107.7	226.6	109.6	230.6	111.4
Thomastown Bus 3&4 66 kV [73]	10	260.3	101.2	268.9	105.1	287.9	113.6	178.4	77.4	181.7	78.8	185.4	80.4	187.9	81.5	190.5	82.6	193.2	83.8	195.9	84.9
	50	250.0	97.3	258.3	101.1	276.6	109.2	172.3	74.7	175.5	76.1	179.1	77.7	181.6	78.7	184.1	79.8	186.7	80.9	189.2	82.1
West Melbourne 66 kV [74]	10	341.2	123.6	361.0	128.4	377.6	142.7	404.7	157.1	414.9	166.0	425.0	175.1	435.3	184.4	445.8	194.0	456.4	203.7	467.0	213.6
	50	328.5	114.8	347.6	118.9	363.5	132.7	389.7	146.6	399.5	155.2	409.3	163.9	419.2	172.9	429.3	182.0	439.4	191.4	449.7	200.9

[72] Somerton Power Station is not included in the forecast. AGL plans to transfer about 2.3 MW of load from TTS B3-B4 to TTS B1-B2 in 2006. AGL plans to transfer about 13.2 MW of load from TTS B1-B2 to TTS B3-B4 in 2007. AGL plans to transfer about 78.8 MW of load from TTS B1-B2 to the new SMTS in 2008.

[73] Bolinda Landfill embedded generator in Broadmeadows is assumed to be running at about 5 MW in the forecast. AGL plans to transfer approximately 2.3 MW of load from TTS B3-B4 to TTS B1-B2 in 2006, and 13.2 MW of load from TTS B1-B2 to TTS B3-B4 in 2007. Latrobe Unit (about 3-4 MW output & AGL customer) co-generator is considered as negative load.

[74] AGL plans to transfer about 14.1 MW of load from BLTS66 to WMTS in 2008.

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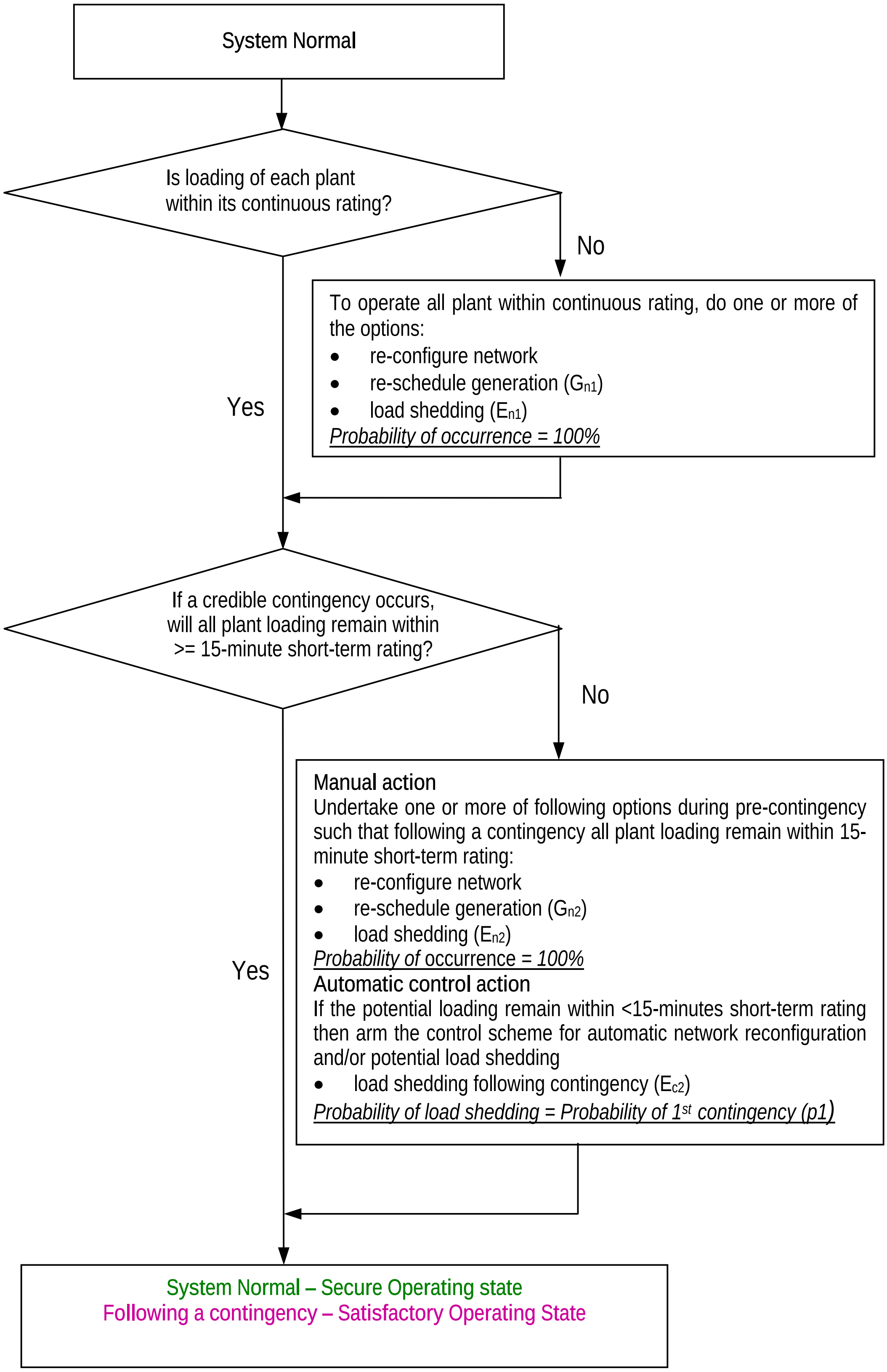
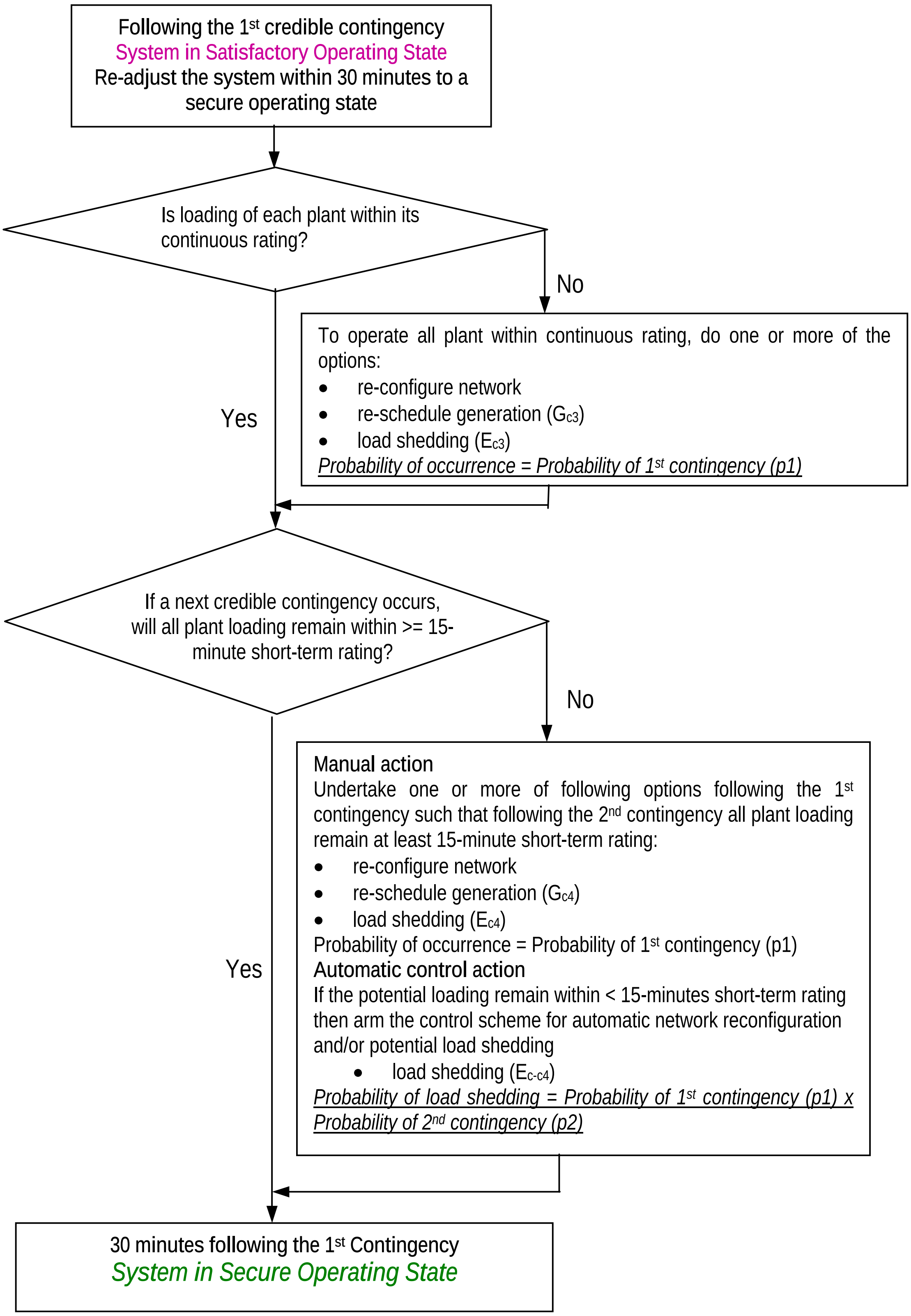
C PLANNING FLOWCHART

ASSESSMENT OF SECURE OPERATING STATE

System Normal



Within 30 minutes following the 1st Credible Contingency



Definitions of secure operating state and satisfactory operating state are as referred in the National Electricity Code.

Probabilistic assessment

Expected rescheduled generation $= G_{n1} + G_{n2} + G_{c3} \times p1 + G_{c4} \times p1$

Expected unserved energy $= E_{n1} + E_{n2} + E_{c2} \times p1 + E_{c3} \times p1 + E_{c4} \times p1 + E_{c\text{-}c4} \times p1 \times p2 +$ expected unserved energy due to inadvertent operation of the control scheme + expected unserved energy due to failure of the control scheme + risk due to failure of the control scheme.

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D GLOSSARY

ABBREVIATIONS	
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
BOM	Bureau of Meteorology
CPI	Consumer Price Index
DB	Distribution Business
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
EAPR	Electricity Annual Planning Report
EHV	Extra High Voltage
ESC	Essential Services Commission
FCAS	Frequency Control Ancillary Service
GSP	Gross State Product
GWh	Giga Watt hours
HVDC	High Voltage Direct Current
k	Thousand
km	Kilometers
kV	Kilovolts
LOR	Lack of Reserve
LRA	Long Run Average
M	Million
MD	Maximum Demand
MVA	Mega Volt Amperes
MVAr	Mega Volt Amperes Reactive
MW	Mega Watts
MWh	Mega Watt hours
NCAS	Network Control Ancillary Service
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
POE	Probability of Exceedence
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
SVC	Static Var Compensator
TNSP	Transmission Network Service Provider
TOC	Transmission Operations Centre (formally VNSC)
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Networks Corporation

DEFINITIONS	
Contestable Augmentation	An augmentation for which the capital cost is reasonably expected to exceed $10M and can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable).
Contingency	Either a forced or planned outage.
Credible Contingency	Any planned or forced outage that is reasonably likely to occur. Examples, outage of a single transmission line, transformer, generating unit, reactive plant, etc through one or two phase faults.
Critical Contingency	The specific forced or planned outage that has the greatest potential to impact on the network at any given time.
Eastern Metropolitan Load	Load supplied out of Thomastown, Brunswick, Richmond, Malvern, Templestowe, Ringwood, Springvale, Heatherton, East Rowville, Cranbourne and Tyabb Terminal Stations.
Flow Path	Those elements of the transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
Forced Outage	An outage of a transmission element (transmission line, transformer, generator, reactive plant, etc) caused by failure of primary or secondary equipment or operating error for which there is less than 24 hours notice or due to lightning and storms.
Generator Auxiliary Load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as "used in station load").
Latrobe Valley Area Load	Load supplied out of Yallourn and Morwell.
Load Shedding	Disconnection of customer load.
Non-Contestable Augmentation	Augmentations which would not be considered to be economically or practically classified as contestable augmentations.
Non-Credible Contingency	Any planned or forced outage for which the probability of occurrence is considered very low. Examples, outage of a single transmission line, transformer, generating unit, reactive plant, etc through three phase faults, multiple generating unit failures, double circuit tower failures, busbar faults, etc.
Planned Outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours notice.
Post-Contingent	The timeframe after a contingency occurs.
Pre-Contingent	The timeframe before a contingency occurs.
Prior Outage Conditions	A weakened transmission state where a transmission element is unavailable for service due to either a forced or planned outage.
Satisfactory Operating State	Operation of the network such that all plant is operating at or below either its continuous rating or its applicable short term rating.
Secure Operating State	Operation of the network such that should a credible contingency occur, the network will remain in a 'satisfactory' state.

State Grid	The regional transmission network in the northwest area of Victoria, including Moorabool, Ballarat, Terang, Horsham, Red Cliffs, Kerang, Bendigo, Shepparton, Glenrowan, Dederang, Mt Beauty and Eildon Terminal Stations and all 220 kV transmission lines connecting these sites.
State Grid Regional Load	Load supplied out of Geelong, Terang, Ballarat, Bendigo, Shepparton, Glenrowan, Mt Beauty, Wodonga, Kerang, Red Cliffs and Horsham Terminal Stations.
System Normal Constraint	A constraint that arises even when all plant is available for service.
Western Metropolitan Load	Load supplied out of Keilor, West Melbourne, Fisherman's Bend, Brooklyn and Altona Terminal Stations.

TERMINAL STATION NAMES	
APD	Portland Aluminium (customer owned station)
APS	Anglesea Power Station
ATS	Altona Terminal Station
BATS	Ballarat Terminal Station
BETS	Bendigo Terminal Station
BLTS	Brooklyn Terminal Station
BTS	Brunswick Terminal Station
CBTS	Cranbourne Terminal Station
DDTS	Dederang Terminal Station
DPS	Dartmouth Power Station
EPS	Eildon Power Station
ERTS	East Rowville Terminal Station
FBTS	Fishermans Bend Terminal Station
FVTS	Fosterville Terminal Station (customer owned station)
GNTS	Glenrowan Terminal Station
GTS	Geelong-terminal Station
HYTS	Heywood Terminal Station
HOTS	Horsham Terminal Station
HTS	Heatherton Terminal Station
HWPS	Hazelwood Power Station
HWTS	Hazelwood Terminal Station
HYTS	Heywood Terminal Station
JLA	Western Port (customer owned station)

TERMINAL STATION NAMES	
JLTS	Jeeralang Terminal Station
KGTS	Kerang Terminal Station
KTS	Keilor Terminal Station
LY	Loy Yang Substation (customer owned substation)
LYPS	Loy Yang Power Station
MBTS	Mount Beauty Terminal Station
MKPS	McKay Creek Power Station
MLTS	Moorabool Terminal Station
MPS	Morwell Power Station
MTS	Malvern Terminal Station
MWTS	Morwell Terminal Station
NPSD	Newport Power Station
PTH	Point Henry (customer owned station)
RCTS	Red Cliffs Terminal Station
ROTS	Rowville Terminal Station
RTS	Richmond Terminal Station
RWTS	Ringwood Terminal Station
SHTS	Shepparton Terminal Station
SMTS	South Morang Terminal Station
SVTS	Springvale Terminal Station
SYTS	Sydenham Terminal Station
TBTS	Tyabb Terminal Station
TGTS	Terang Terminal Station
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
VPGS	Valley Power Gas Station
WKPS	West Kiewa Power Station
WMTS	West Melbourne Terminal Station
WOTS	Wodonga Terminal Station
YPS	Yallourn Power Station

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