VICTORIAN ANNUAL PLANNING REPORT

Victoria's Electricity and Gas Transmission Network Planning Document

2010

AUSTRALIAN ENERGY MARKET OPERATOR

VICTORIAN ELECTRICITY AND GAS TRANSMISSION NETWORKS

ELECTRICITY	
500kV Transmission	
330kV Transmission	
275kV Transmission	
220kV Transmission	
HVDV Transmission	

GAS	
Declared Transmission System	
Other Transmission System	

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Contents

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Executive Summary

The Victorian Annual Planning Report (VAPR) is prepared by AEMO in accordance with Section 5.6.2A of the National Electricity Rules (Rules) and Rule 323 of the National Gas Rules (NGR). This is the first VAPR produced by AEMO.

The VAPR provides forecasts for energy demand and supply, and identifies future development needs for both the electricity Declared Shared Network (electricity DSN) and the gas Declared Transmission System (gas DTS) for the forecast period 2010-2020. The VAPR covers the stationary energy sector (reticulated natural gas and electricity), and reflects various electricity and gas market synergies by combining information historically published separately in AEMO's annual planning reports for electricity and gas. In the electricity market, AEMO is responsible for planning and directing augmentations to Victoria's electricity DSN. In the gas market, AEMO provides planning information to the gas industry, but it is not AEMO's role to act on that information.

The VAPR was prepared prior to Australian Government announcements regarding the Henry Review of Taxation and the Resource Rent Tax in May 2010, and issues relating to these policies have not been considered.

Energy corridors and regions examined

The VAPR examines a number of important energy corridors and zones that are used to transmit electrical energy or gas, as well as the two main demand regions. This examination takes the form of an analysis of energy demand and network constraints over a 5-year and a 10-year outlook.

Table 1 lists the corridors and zones considered, as well as identifying the colour coding used to differentiate between the two throughout the VAPR. Findings are reported against these corridors and zones.

Table 1 – Electricity and gas regions

Electricity region	Gas region
The Eastern Corridor	Gippsland Zone
The South-West Corridor	Western Zone
The Northern Corridor	Northern Zone
Greater Melbourne and Geelong	Melbourne and Geelong Zone
Regional Victoria	Ballarat Zone

The VAPR enables industry and government to understand and plan for demand increases, and to develop safe, secure, reliable, and economically viable transmission networks by providing information that:

- identifies and advances options to relieve existing or potential gas and electricity transmission constraints
- assesses future requirements for gas supplies and gas DTS augmentation, as well as the availability of spare capacity for new connections, and
- includes electricity DSN asset refurbishment plans provided by SP AusNet for the next 10 years.

Table 2 summarises the key findings from the 2010 Victorian Annual Planning Report (VAPR).

Table 2 – Key messages for 2010

	Key messages
New initiatives	Several changes have been made to the VAPR this year: Scenario planning has been linked to the scenario planning to be used in other planning documents, such as the National Transmission Network Development Plan (NTNDP), which were developed for the NTNDP in consultation with energy industry stakeholders There are two new chapters: 'Fuel outlook', which provides a fuel outlook for Victoria; and 'Emerging issues and trends for 2010', which discusses a number of issues that will influence future transmission investment planning in Victoria See Chapter 1 for more detail
Electricity investment	In the 5-year outlook for electricity, the VAPR identifies a number of projects to alleviate constraints that warrant further economic assessment under the Regulatory Investment Test for Transmission (RIT-T) including: Eastern Corridor Braking resistor installation at Hazelwood terminal station, and Regional Victoria Uprating of the Ballarat-Moorabool, Ballarat-Bendigo, and Geelong-Moorabool 220 kV lines The range of augmentation project costs to address these constraints is between $190 million and $625 million. Individual projects, however, may not prove economic under the RIT-T The 2009 Transmission Connection Planning Report (produced jointly by the Victorian electricity distribution businesses who are responsible for planning and directing the augmentation of the facilities that connect their distribution systems to the electricity DSN)[1] has highlighted a further $232 million of capital projects for the next 10 years on distribution/transmission connection works SP AusNet is also carrying out a significant capital replacement program totalling $573 million over the next 10 years See Chapter 9 for more information
Gas investment	In the 5-year outlook for gas, the VAPR identifies a number of projects to alleviate constraints caused by system demand growth, greater export and/or new gas powered generation (GPG) including: Gippsland Zone Warragul-Pakenham branch pipeline duplication Northern Zone Compressor upgrades to increase gas export through Culcairn Melbourne and Geelong Zone and a new compressor station at Stonehaven Ballarat Zone and a tie-over of the Sunbury lateral to the BLP pipeline, or a Sunbury branch pipeline duplication Of the new electricity DSN connection applications currently being processed by AEMO, over 1,000 MW are for new gas powered generation (GPG) in Victoria See Chapter 9 for more information
Energy and demand forecasts	The electricity energy and maximum demand forecasts for 2010 reflect similar trends to those established in the 2009 VAPR The gas supply and demand forecasts reflect no change since the 2009 VAPR Update (published in November 2009), which forecast a 13% increase in gas demand by 2019 See Chapter 3 for more information

Development of the VAPR

AEMO continuously reviews and revises its documentation to improve the relevance and value of its publications for the stationary energy sector. Table 3 lists the changes and innovations implemented by the VAPR for 2010.

[1] See http://www.sp-ausnet.com.au/CA2575630006F222/Lookup/general/$file/TCPR2009.pdf

Table 3 – New content in 2010

	Title	Description of approach
Chapter 1	Introduction	The introduction now incorporates a description of the relationship between the VAPR and AEMO's other planning documents
Chapter 2	Emerging issues and trends for 2010	This new chapter provides a: • summary of work to-date on the AEMO and ElectraNet Joint Interconnector Feasibility study - the study aims to identify options to economically increase interconnector capacity to export power from South Australia to other National Electricity Market (NEM) load centres. The study has a 20-year outlook period, and covers both incremental and Greenfield projects • discussion about plans for electricity transmission collector hubs, prompted by the large number of connections and connection proposals in Victoria's south west • discussion about potential gas and electricity transmission investment synergies and the consideration of gas transmission as an alternative to electricity DSN network development, and • review of the planning process undertaken by AEMO following the severe summer bushfire season of 2008/09. Based on this, AEMO performed a constraint assessment using a 5% probability of exceedence (5% POE) maximum demand (MD) forecast for the Rowville-Springvale 220 kV line. The review also recommended further work in other areas such as transmission outage models and temperature models for transformer ratings
Chapter 3	Existing network adequacy	This chapter now includes a: • more explicit definition of the capability of the gas DTS, identifying the impact operating pressure and system demand have on pipeline capacities, and • discussion about the relationship between frequently binding constraint equations and Victorian spot market outcomes
Chapter 6	Fuel outlook	This new chapter describes the traditional fossil fuel outlook for Victoria's stationary energy sector. This shows that Victoria has significant brown coal reserves and adequate gas reserves
Chapter 8	Planning Overview	The scenarios used in the VAPR have been mapped to scenarios developed in consultation with energy industry stakeholders for the NTNDP
Chapter 9	Transmission development	This chapter now provides more information to assist with the development of demand-side options for addressing electricity DSN constraints

Infrastructure investment

A summary of investment in electricity infrastructure in Victoria

Two recent changes are influencing investment in the Victorian electricity DSN:

- The growth in peak demand has been delayed due to reduced consumption from energy intensive industries and increased energy efficiency policies, both of which reduce the need for investment in the electricity DSN.
- There has been a significant increase in the number of generation connection enquiries, which are now driving the most significant component of likely Victorian transmission network investment.

Investment drivers have also been affected by the high proportion of peaking and intermittent generation connection enquiries and applications to the network west of Melbourne. Modelling suggests that, at times of peak demand, this generation will have the effect of backing off some constraints east of Melbourne, allowing higher demand to be met by existing transmission network assets. In brief:

- AEMO is actively processing over 5,000 MW of new generation connection enquiries
- there are plans for $233 million of distribution network connection modifications as highlighted in the 2009 Transmission Connection Planning Report, and
- there is a significant 10-year capital replacement program currently being carried out by SP AusNet totalling $297 million in years 1 to 5, and a further $276 million by year 10.

The 5-year outlook for transmission network investment

For the electricity DSN, the 5-year outlook derives from a cost-benefit analysis of projects for each region for each year of the forecast period. This analysis is based on a simulation that uses NEM dispatch data and demand projections from the 2009 VAPR. It also uses critical plant capabilities to determine probable usage of the electricity DSN and a quantification of possible unmet load.

For gas, the analysis behind the 5-year outlook identifies system constraints by assuming 25 TJ/d of demand from existing GPG plant on top of the 1 in 20 year winter peak day demand (using the system demand forecasts published in the November 2009 VAPR Update). The analysis then assesses possible augmentation projects for each region based on this demand.

Transmission constraints (electricity and gas)

Electricity transmission constraints identified for further assessment (5-year outlook)

Table 4 summarises electricity DSN constraints from the 5-year outlook that have been highlighted for further detailed assessment and potential Regulatory Investment Test for Transmission (RIT-T) analysis along with ranges of possible network solutions to address each of them. The sum of the lowest cost options for each constraint is $190 million and the sum of highest is $625 million. This large range arises since possible solutions to transmission constraints consist of small capital expenditure projects as well as larger capital expenditure works projects. Each of these projects delivers higher or lower benefits in accordance with its cost. To proceed, a project identified for a RIT-T analysis must be economically justifiable, i.e. the capital expenditure delivers more value than costs. This further cost-benefit assessment will determine the optimum solution in each case, which may be that no project is economically justified.

Table 4 – Electricity transmission constraints and possible solutions (5-year outlook)

Constraint	Possible network solution	Cost estimate ($M)
Eastern Corridor		
Transient stability export limit for Victorian export to New South Wales and South Australia	Braking resistor installation at Hazelwood Terminal Station	17–26
	Static VAr Compensator (SVC) installation at Dederang Terminal Station	72–108
South-West Corridor		
Elevated levels of voltage unbalance on the Moorabool–Heywood 500 kV line	Installation of individual phase-controllable SVCs	36–108
	Installation of additional line transpositions	45–83
Heywood 500/275/22 kV transformer loading	New (third) 500/275/22 kV transformer installation at Heywood Terminal Station	33–50
Greater Melbourne and Geelong		
Rowville 500/220 kV transformer loading	New (third) 500/220 kV transformer installation at Rowville Terminal Station	50–65
	New (third) 500/220 kV transformer installation at Rowville Terminal Station, including increased East Rowville–Rowville 220 kV line rating from a twin to quad bundled conductor	62–81
	New (third) 500/220 kV transformer installation at Rowville Terminal Station, including a new (underground) East Rowville–Rowville 220 kV circuit	66–86
	New (third) 500/220 kV transformer installation at Rowville Terminal Station, including establishing a new 220 kV terminal station at Narre Warren	93–121
Regional Victoria		
Ballarat–Moorabool 220 kV line loading	New (third) Ballarat–Moorabool 220 kV circuit installation (strung on existing towers)	21–32
	Increased Geelong–Moorabool No.1 220 kV circuit rating to 75°C conductor design temperature	23–35
	Increased Geelong–Moorabool No.1 220 kV circuit rating to 82°C conductor design temperature	26–38
Ballarat–Bendigo 220 kV line loading	Increased Ballarat–Bendigo 220 kV line rating to 75°C conductor design temperature	28–42 [1]
	Replacement of the existing Ballarat–Bendigo 220 kV line with a double circuit line	150–225
Geelong–Moorabool 220 kV line loading	Increased rating of the Geelong–Moorabool 220 kV line terminations to match the conductor rating	5–8
	New double circuit Geelong–Moorabool 220 kV line installation	21-25
1 Estimate includes line cost only.		

Table 5 summarises gas DTS constraints in each of the 5 zones that are triggered by any or a combination of the following three factors - system demand increase, new GPG and greater gas export. Table 5 shows possible solutions based on current modelling from the 5-year outlook.

Table 5 – Gas transmission constraints and possible solutions (5-year outlook)

Constraint	Possible network solution	Trigger
Gippsland Zone		
Warragul	Warragul branch pipeline duplication	Anticipated winter 2012 increase in industrial/Tariff D demand
Pakenham South	Pakenham South branch duplication The pipeline owner has indicated that duplication of the small diameter section of this lateral is being undertaken, and is expected to be complete by the end of June 2010	Increased system demand leading to high gas velocity on the branch pipeline
Western Zone		
Western Transmission System	A new system injection point	Increased system demand and low or no injection coming from Iona – timing prior to winter 2014
Northern Zone		
Shepparton/Echuca Culcairn (exports)	Upgrade maximum allowable operating pressure (MAOP) to 8.8 MPa from Wollert to Euroa Wollert Compressor Station upgrade, and reverse compression at Springhurst A new compressor station at Euroa is required to further increase export capacity	Increased system demand, especially gas export of approximately 28 TJ/d to New South Wales
Melbourne and Geelong Zone		
Maroondah Highway	A Yarra Glen to Lilydale link	Increased system demand gas export to New South Wales
South West Pipeline	A new compressor station at Stonehaven	New entry GPG, gas export
Ballarat Zone		
Sunbury	Operate Wandong pressure limiter at high outlet pressure	Increased system demand and export to New South Wales Prior to winter 2010
	Tie over the Sunbury lateral to the BLP pipeline and Sunbury branch pipeline duplication	Increased system demand and export to New South Wales Prior to winter 2012

Ten-year outlook

To ensure consistency between all AEMO planning documents and studies, a set of five National Transmission Network Development Plan (NTNDP) scenarios have been developed.

Using the inputs from the NTNDP scenarios, as well as preliminary market modelling results, AEMO has detailed five scenarios specifically for the VAPR 10-year electricity outlook. The VAPR scenarios, which are designed to capture the limits of transmission infrastructure development that may be required, describe the potential location and type of new generation within Victoria as well as the potential changes in Victorian imports and exports.

The VAPR scenarios, which represent possible trends in the generation mix expected under the NTNDP scenarios, are not intended to be predications of the state of generation in 10 years, but to represent the bounds of reasonable possibility. The VAPR scenarios also account for new electricity and gas connection enquiries from AEMO.

Table 6 summarises how the five scenarios have been used in the VAPR (see Chapter 8 for more detailed descriptions).

Table 6 – Scenarios used for the 10-year electricity outlook

Scenario name	Scenario description
Scenario 1 **Fast rate of change**	• Substantial new gas generation in the Eastern Corridor, combined with no existing generator retirement • Growth on the gas DTS from GPG in the Eastern Corridor • Rising imports from South Australia into Victoria from geothermal generation • Substantial exports into New South Wales from both Eastern Corridor generation and South Australia • Moderate growth in demand-side participation (DSP) and GPG on the gas DTS in Greater Melbourne and Geelong.
Scenario 2 **An uncertain world**	• Substantial imports from New South Wales into Victoria • Moderate new investment in GPG in the South-West Corridor • Substantial export from Victoria into South Australia • Little or no gas DTS growth
Scenario 3 **A decentralised world**	• Substantial DSP in Greater Melbourne and Geelong • Substantial new wind generation in both the south west and regional areas, as well as supporting peaking GPG • Less generation than currently exists in the Eastern Corridor, with some conversion from coal to gas causing gas DTS growth • Moderate demand for GPG in Melbourne and Geelong, and additional demand on the gas DTS

Scenario name	Scenario description
Scenario 4 **Oil shock and adaptation**	• Substantial wind and gas generation in the South-West Corridor • Substantial geothermal and wind generation exports from South Australia to Victoria • Less generation than currently exists in the Eastern Corridor, with some conversion from coal to gas causing some gas DTS growth • Moderate growth in DSP and GPG on the DTS in Greater Melbourne and Geelong
Scenario 5 **Slow rate of change**	• Very little generation growth in Victoria • Substantial geothermal and wind generation exports from South Australia to Victoria • Little or no demand growth on the gas DTS • Little net power transfer between Victoria and New South Wales

Table 7 summarises the broader findings of the 10-year outlook scenarios for electricity and gas.

Table 7 – Key conclusions from 10-year electricity and gas outlook

10-year outlook	Summary of conclusions
Electricity	The VAPR identifies a number of electricity DSN projects that may be required in the 10-year outlook. These include the: **Eastern Corridor**, and Latrobe Valley to Melbourne 500 kV line works **South-West Corridor**, and new generation connections along the Moorabool-Heywood 500 kV line, new 500 kV line installations from Moorabool to Heywood, and a new 275 kV line installation from Heywood to South-East substation in South Australia **Northern corridor**, and a capacitor bank installation and series compensation at Dederang **Greater Melbourne/Geelong corridor**, and new 220 kV line cut-ins at South Morang and Ringwood, and **Regional Victoria**, and line uprating or replacement with new 220 kV lines for Ballarat to Horsham, Ballarat to Terang, Moorabool to Terang, Horsham to Red Cliffs, Kerang to Wemen to Red Cliffs, and Dederang to Glenrowan
Gas	The VAPR identifies a number of gas DTS projects that may be required in the 10-year outlook. These include the: **Gippsland Zone**, and Longford pipeline duplication upstream and downstream of Gooding **Northern Zone**, and pipeline duplication between Wollert and Barnawartha, and **Geelong/Melbourne Zone**, and a new Rockbank to Wollert pipeline and pipeline duplication from Iona to Lara

Long-term planning investigations

Table 8 summarises two significant studies into long-term electricity transmission requirements scheduled for 2010. Both studies are looking at transmission capabilities between NEM regions, potentially requiring Victorian electricity DSN development.

Table 8 – Long-term electricity planning investigations

Study	Description

Joint feasibility study on South Australian interconnection	• AEMO and ElectraNet are working on a joint interconnector feasibility study to examine cost-effective options to increase electricity interconnector capability between South Australia and other major load centres. Incremental augmentation options and greenfield options are being analysed over a 20-year outlook period
	• Options under consideration include incremental augmentations to existing interconnections (Heywood and Murraylink) and possible new HVDC and HVAC transmission between South Australia and Victoria and/or New South Wales
	• The four greenfield options currently under consideration are a:
	  • 500 kV double circuit AC line from Wilmington to Mt. Piper (1,100 km)
	  • 500 kV HVDC line from Wilmington to Mt. Piper (1,100 km)
	  • 500 kV double circuit AC line from Tepko to Yass via Horsham, Shepparton and Wodonga (1,050 km), and
	  • 500 kV double circuit AC line from Krongart to Heywood (125 km)

Feasibility study on improving interconnection between Victoria and New South Wales	• AEMO is studying the feasibility of upgrading the New South Wales to Victoria interconnector • The feasibility study objectives are to develop a range of cost-effective transmission augmentation options compatible with existing national transmission networks and considered feasible from an approvals and construction perspective. The proposed approach seeks to rely and build on the current joint feasibility study with ElectraNet as well as AEMO's NTNDP analysis • Current network augmentation options are being collated and refined. As with the ElectraNet joint feasibility study, both incremental and greenfields options will be considered with capacity increases of up to 1,000 MW

Energy and demand forecasts

Energy and maximum demand (MD) forecasts for electricity, and peak day and annual demand forecasts for gas form key inputs into electricity and gas transmission network planning and investment decisions.

Electricity forecasts

AEMO engaged KPMG Econtech to provide an updated assessment of the economic outlook and policy environment for the NEM regions in April 2010. The forecasts presented in the 2010 VAPR are consistent with the Victorian forecasts that will be published in AEMO's 2010 Electricity Statement of Opportunities (ESOO).

The electricity energy and MD forecasts were prepared by the National Institute of Economic and Industry Research (NIEIR) and AEMO in May 2010.

Table 9 shows the change in the electricity forecasts from 2009 to 2010.

Table 9 – Electricity forecast summary

	2010 VAPR	2009 VAPR	Change
Summer 2010/11 10% POE Native MD	10,783 MW	10,702 MW	81 MW (0.8%)
Winter 2010 10% POE Native MD	8,347 MW	8,262 MW	85 MW (1.0%)
2010/11 Annual Energy	52,092 GWh	51,436 GWh	656 GWh (1.3%)
2010/11 Australian GDP Growth	3.6%	4.0%	-0.4%
2010/11 Victorian GSP Growth	2.5%	2.7%	-0.2%

Table 10 shows the summer 10% probability of exceedence (POE) native MD is forecast to increase by 3.4% in 2010/11, from 10,425 MW in summer 2009/10 to 10,783 MW in summer 2010/11, increasing by an average of 239 MW, or 2.1% per annum, over the period from 2010/2011 to 2019/20 to reach 12,930 MW.

Table 10 – Electricity summer 10% POE native MD forecasts (medium economic growth scenario), 2010-2019 (MW)

2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
10,783	11,103	11,372	11,461	11,673	11,990	12,174	12,421	12,699	12,930

Table 11 shows the winter 10% POE MD native MD is forecast to increase by an average of approximately 120 MW, or 1.4 % per annum, over the period from 2010-2019.

Table 11 – Electricity winter 10% POE native MD forecasts (medium economic growth scenario), 2010-2019 (MW)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
8,347	8,429	8,650	8,733	8,816	8,886	9,010	9,175	9,289	9,431

Table 12 shows annual electrical energy consumption is forecast to increase by 0.4 % in 2010/11 to 52,092 GWh, from an estimated 51,870 GWh in 2009/10. From 2010/11 onwards, positive growth in consumption is expected, with an average growth rate of 0.9%, or 520 GWh, per annum to 2019/20.

Table 12 – Electricity annual native energy forecasts (medium economic growth scenario), 2010-2019 (GWh)

2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
52,092	53,404	54,272	53,856	53,930	54,103	54,889	55,746	56,208	56,804

Gas forecasts

The gas system demand and GPG forecasts presented in the 2010 VAPR were prepared by NIEIR in November 2009. The Victorian economic outlook used to prepare these forecasts was produced by NIEIR in September 2009. These results were published in AEMO's Victorian Annual Planning Report Update (VAPR Update [2]) in November 2009.

Table 13 shows the peak day gas demand forecasts for the forecast period.

Table 13 – Gas peak day demand forecasts, 2010-2019 (PJ/yr)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 in 2	1,181	1,193	1,197	1,198	1,204	1,209	1,213	1,223	1,231	1,238
1 in 20	1,296	1,310	1,315	1,317	1,323	1,330	1,334	1,347	1,356	1,365

Table 14 shows the annual gas demand given a medium economic growth scenario for the forecast period.

Table 14 – Gas annual system demand forecasts (medium economic growth scenario), 2009-2018 (PJ/yr)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average Annual Growth 2010-2019
208.2	210.1	210.7	211.1	211.4	211.9	212.3	213.1	213.9	214.6	0.34%

[2] See http://www.AEMO.com.au/index.php?action=filemanager&folder_id=492&pageID=7736.

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Chapter 1 Introduction

AEMO performs a number of key roles within Victoria's electricity and gas markets, one of which involves planning Victoria's electricity Declared Shared Network (electricity DSN) and gas Declared Transmission System (gas DTS), which provides a key link in the supply chain to the State's 2.2 million electricity and 1.4 million gas customers.

Various gas and electricity market synergies are now making it increasingly appropriate to consider both gas and electricity when planning either transmission network. Market mergers and acquisitions are tending to link the markets organisationally, and government action to streamline regulation is linking them institutionally, while at the same time, energy suppliers are pursuing potential gas powered generation (GPG) opportunities, which is increasingly linking the two markets physically.

In response to these developments, the 2010 Victorian Annual Planning Report (VAPR), which covers the stationary energy sector (reticulated natural gas and electricity), continues to reflect emerging electricity and gas market synergies by combining gas and electricity information within the same cover.

The combined planning approach

Combining the approach to planning the electricity and gas networks, presents numerous challenges, including reconciling differing APR publication dates, planning horizons and forecasting requirements.

The 2010 VAPR partially satisfies AEMO's obligations under Section 5.6.2A of the National Electricity Rules (NER) and Rule 323 of the National Gas Rules (NGR), which require AEMO to produce two planning documents for Victoria:

- An annual planning report covering the electricity DSN is published by 30 June each year. This report sets out the peak and annual demand forecasts, and reviews the adequacy of the electricity DSN for the next 10 years.
- An annual planning review covering the gas DTS is published by 30 November each year. This review provides an assessment of the supply-demand outlook and the adequacy of system capacity, as well as providing additional information about maintenance plans, gas reserves and gas pipeline developments.

The combined VAPR, published in June, satisfies these requirements, with the exception of the latest gas forecast information, which can only be prepared using the most recent winter observations once the June-August peak winter period ends, and information about Liquefied Natural Gas (LNG) usage for the following winter period. As in previous years, this information will be published in the 2010 VAPR Update in November 2010, along with information about gas supply.

Navigating the VAPR

The VAPR uses colour coded section headings to assist with navigating the document. Blue indicates subject matter involving gas, and red indicates electricity. Intermediate information is neutrally identified to indicate more general content.

Key aspects of Victoria's electricity and gas industries

Despite many similarities, there are still some fundamental differences between the gas and electricity industry segments, including the different roles AEMO plays as:

- electricity planner, where it plans and procures services and is therefore responsible for the delivery of the system, and
- gas planner, where it provides advice about network services, leaving final decisions and investment to market participants.

Table 1-1 lists the comparative features of the electricity and gas industries in Victoria.

Summer peak electricity demand is a prominent feature driving electricity DSN investment. Gas DTS investment, however, is driven by a winter day peak, with increased GPG gas demand during electricity demand peaks presenting new challenges for the gas DTS, especially with the use of linepack and other storage to cope with rapid gas demand variations.

In Victoria, two transmission asset owners dominate the market, with SP AusNet owning the electricity DSN and APA Group owning the gas DTS. Jemena, TRUenergy, Origin Energy and International Power own major inter-state gas interconnections and gas storage facilities.

Table 1-1 – Comparative features of the electricity and gas industries in Victoria

Feature	Electricity	Gas
Industry structure and ownership	• Private ownership in Victoria and South Australia, and of generation and retail in Queensland. High levels of government ownership in other States • Active regulation of mergers and acquisitions by the ACCC • Diverse company structures with some generation/retail integration as well as gas/electricity retail integration	• Private ownership • Ring fencing of costs enforced by the ACCC • Some large, vertically integrated companies • Some integration of gas/electricity retail
Wholesale market	• National market spanning five regions, aligned with State boundaries • Half-hour spot price defined ex-post, highly variable • Production scheduled for the current day plus the following 48 half-hour intervals • In Victoria, five major distributors and ten transmission-connected generators • Parallel financial market to hedge spot prices	• State-based • Victorian daily price defined ex-ante, relatively stable • Production scheduled for current day and day ahead • In Victoria, three major distributors, six injection points • Long-term physical supply contracts • Move to Short-Term Trading Market
Transmission contracts	• Open access for generators at no cost • Location pricing signals, varied annually in accordance with the NER, produce revenue to match the amount determined by the AER's economic regulation of transmission businesses	• 'Open access market carriage' in Victoria, various forms of 'contract carriage' in other States • Rates ($/GJ) for injection into and withdrawal from the gas DTS are relatively stable • In other States, access to single pipelines is regulated under the National Gas Access regime and associated transport prices are calculated under the national Gas Code or determined by competition
Physical market	• Electricity cannot be stored, so supply and demand must be balanced at all times • Long distance transmission losses can be large at peak demand times	• Gas can be stored, allowing balancing to be carried out at (daily or within day) intervals • Transmission losses are minimal (compressors create some shrinkage)

Transmission assets	• Power lines and cables • Transformation and switching stations • Ancillary facilities (reactive power support, and series compensation for long lines) • Automatic control systems	• Pipelines • Compressors • LNG storage • Underground storage • Termination and control facilities (city gates, regulators, limiters, etc)
Capacity constraints	• Power line sag and conductor strength due to heating • Transformer heating • Fault levels (short circuit currents that can be safely interrupted) • Transient and other system stability criteria • Voltage maintenance	• Linepack (gas storage in pipelines) • Pipeline operating pressure (maximum/minimum limits) determined by pipe diameter

1.1 AEMO's planning documents

In 2010, AEMO will publish six planning documents, some originally published by AEMO's predecessor organisations, and some altogether new publications. While individually satisfying unique demands for energy market information from AEMO's various planning roles, a key aim has been to ensure that their common elements provide a consistent and coherent message.

The VAPR satisfies AEMO's Victorian gas and electricity transmission planning roles. AEMO will also publish the South Australian Supply and Demand Outlook (SASDO), outlining South Australian electricity supply, demand and fuel information, at the same time as the VAPR.

In August, AEMO will publish the Electricity Statement of Opportunities (ESOO), which provides an outlook for electricity supply and demand in the National Electricity Market (NEM) for the next 10 years. The ESOO will provide a 10-year outlook again this year, focussing on years 3-10. This year AEMO will also produce the Power System Adequacy report, which is a new publication focussing on electricity supply and demand for the next two years.

In November, AEMO will publish the VAPR update, and by the end of the calendar year will also be publishing its second Gas Statement of Opportunities (GSOO) and the inaugural National Transmission Network Development Plan (NTNDP).

Table 1-2 lists the six planning documents and the Power System Adequacy report to be produced by AEMO in 2010, and the unique and common elements of each.

Table 1-2 – AEMO's planning documents

	Victorian Annual Planning Report (VAPR)	South Australian Supply and Demand Outlook (SASDO)	Power System Adequacy Report	Electricity Statement of Opportunities (ESOO)	Victorian Annual Planning Report Update (VAPR Update)	National Transmission Network Development Plan (NTNDP)	Gas Statement of Opportunities (GSOO)
Publication date	By 30 June	By 30 June	By 31 August	By 31 August	By 30 November	By 31 December	By 31 December
Published by	Planning Dept	Planning Dept	Operations Dept	Planning Dept	Planning Dept	Planning Dept	Planning Dept
Focus	Victorian Gas and Electricity	South Australian Electricity	NEM Electricity	NEM Electricity	Victorian Gas	NEM Electricity	Eastern Australian Gas
Outlook	10 years	10 years	2 years	10 years	5 years	20 years	20 years
Gas forecasts	✓	n/a	n/a	n/a	✓	n/a	✓
Electricity forecasts	✓	✓	✓	✓	n/a	✓	n/a
Scenario planning	✓	✓	n/a	✓	n/a	✓	✓
Network & modelling	✓	n/a	n/a	n/a	n/a	✓	n/a
Market modelling	n/a	n/a	n/a	✓	n/a	✓	n/a

1.2 About annual electricity and gas planning

1.2.1 About annual electricity and gas planning

Under Section 5.6.2A of the NER, AEMO is required to undertake an annual electricity planning review and publish an annual planning report by 30 June each year. This review considers:

- the forecast loads and overall demand provided by distribution network service providers (DNSPs) and the National Institute of Economic and Industry Research (NIEIR)
- planning proposals for future connection points
- a forecast of constraints and any inability to meet network performance requirements, and
- an analysis of all proposed augmentations to the electricity DSN.

Under Rule 323 of the NGR, AEMO is required to undertake an annual gas planning review that is published by 30 November each year. This review considers:

- forecasts of peak day, peak hour and annual gas demand
- expansions or extensions to the gas DTS
- an assessment on overall supply, demand and capacity, and
- information on gas storage.

1.2.2 Planning information

Electricity planning information is intended to enable market participants and other interested parties to formulate and propose options to relieve identified constraints, including options involving components of local generation and demand-side participation (DSP), and any other options providing economically efficient outcomes. In brief, this information includes:

- an overview of the existing electricity DSN's adequacy to meet both actual and forecast maximum demands (MDs)
- a list of committed augmentations
- forecasts of seasonal MD and annual energy for the next 10 years
- analysis of potential electricity DSN constraints, and options to alleviate these constraints, coupled with the benefits of upgrades/augmentations, and
- an outlook for the next 10 years, based on the demand forecasts for 2019/20, taking into account a series of supply scenarios for the purposes of establishing possible electricity DSN augmentation requirements.

Gas planning information is provided for the primary purpose of allowing market participants and interested parties to make informed decisions relating to planning pipeline or production facilities and formulating market strategies. In brief, this information includes:

- an overview of the gas DTS and current system operations and developments, and a review of demand and supply for the year
- peak day and annual gas supply and storage forecasts
- peak day forecasts of the gas DTS's capacity to deliver gas supplies, including the demand-supply-capacity outlook for the next five years
- peak day and winter forecasts of LNG requirements for within-day balancing
- a long-term network development outlook considering future system constraints, and
- monthly demand forecasts and a monthly demand-supply outlook for the next twelve months.

While AEMO is required to provide planning information to the gas industry, it is not AEMO's role to act on, or ensure that other parties act on, the information it provides, and AEMO does not direct gas DTS augmentation.

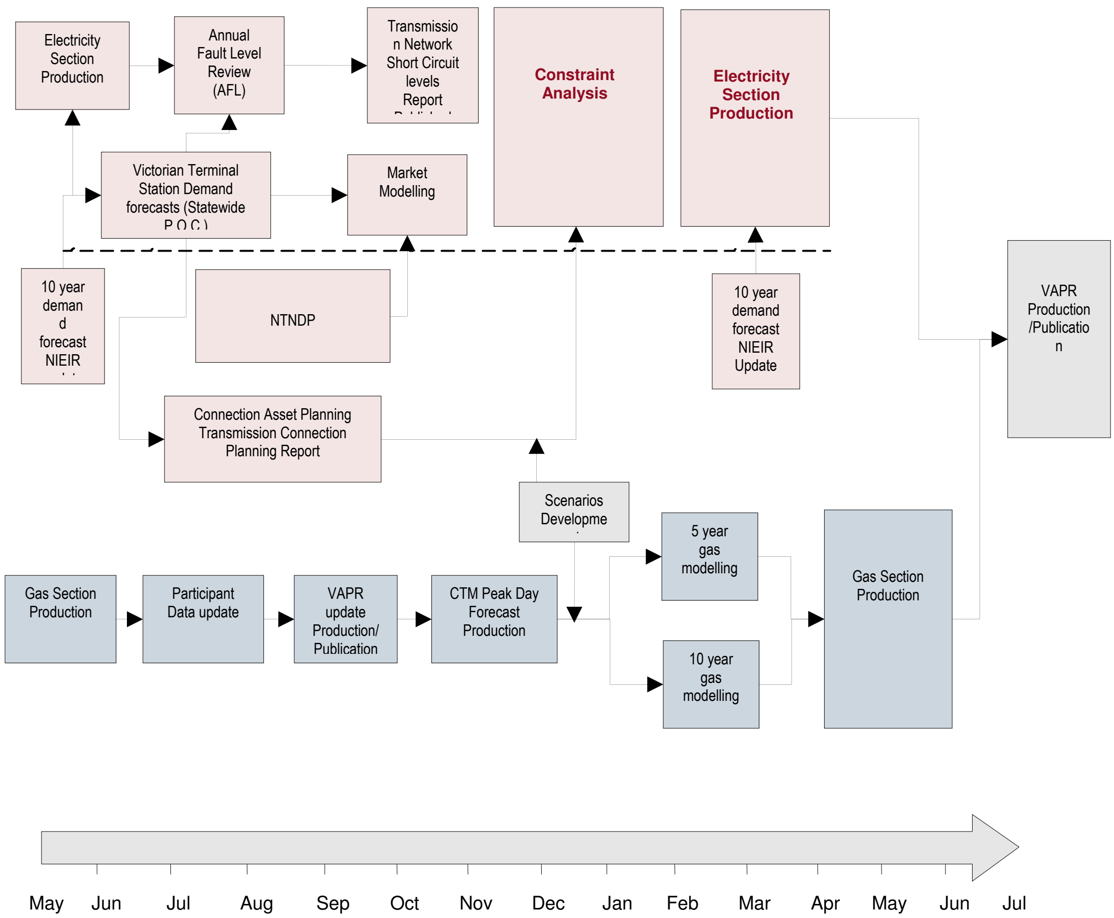
1.3 Producing the VAPR

Figure 1-1 shows a summary of the VAPR production process. Taking over a year to complete, the electricity planning process begins with the Victorian 10-year forecast update currently provided by NIEIR. Prior to the publication of the VAPR, AEMO starts the annual fault level review, using data from the Victorian distribution businesses (DBs) and SP AusNet, which establishes the 5-year fault level forecasts. This data also enables the forecasting of terminal station demand.

The gas planning process begins by collecting 5-year forecasts from participants in Victoria. These forecasts are published in the VAPR update before 30 November each year. Following the publication of the VAPR update, AEMO begins the Custody Transfer Meter peak day forecast production, which is used to develop scenarios for the 5-year and 10-year modelling work.

See also Chapter 8 for more information about AEMO's planning processes.

Figure 1-1 – The VAPR production process



1.4 AEMO's Victorian electricity planning and development role

AEMO is the transmission network service provider (TNSP) for Victoria's electricity DSN, as set out under the NER. As the Victorian TNSP, AEMO's primary driver is to ensure the electricity transmission network's long-term reliability for the transport of electricity between generation and load centres.

1.5 AEMO's Victorian gas planning and development role

AEMO is the system operator and provides information on gas planning for Victoria's gas DTS, as set out under the NGR. A key driver for AEMO is to ensure the daily and long-term reliability of the gas DTS, which transports gas between gas suppliers and customers.

Victoria's gas industry

Outside Victoria, the wholesale supply of gas in eastern Australia is dominated by long-term, highly customised bilateral gas supply contracts entered into on an infrequent basis with a limited number of end-users. Invariably these contracts are highly confidential. Historically there has also been a tendency for producers operating under joint venture arrangements to market their gas jointly.

In 1999, the Victorian Government adopted a unique market model for Victoria, making one of AEMO's legacy organisations (VENCorp) the independent system operator of both the physical spot market and the gas DTS. As the independent system operator in 2010, AEMO:

- balances gas supply and demand and transportation capacity on a daily basis through a centrally co-ordinated scheduling process, and sets the market price, and
- undertakes a number of other functions including identifying gas DTS constraints and forecasting production and demand, as well as demand variances and demand peaks.

Victoria's physical gas spot market

The Victorian spot market enables users to trade daily gas supply imbalances (the difference between contracted gas supply quantities and actual requirements). The spot market is settled as a net market. This means that market participants pay for the excess of actual withdrawals over actual injections, or receive payment for the excess of actual injections over actual withdrawals. The spot market determines the price paid or received.

The gas DTS operates as a network with a number of injection points including Longford, Iona, VicHub, BassGas, Culcairn and the LNG facility at Dandenong. This system is owned by the APA Group, and operates under an open access model independently operated by AEMO (which does not require users to enter into capacity-based transportation contracts, unlike 'contract carriage').

The Short-Term Trading Market

In Victoria, the wholesale and retail gas markets will run in parallel with the emerging national gas market, the Short-Term Trading Market (STTM). The STTM is a market for the trading of natural gas at the wholesale level at defined hubs between pipelines and distribution systems.

The STTM will initially provide hubs in Sydney and Adelaide, and additional hubs are intended for the future. Each hub is scheduled and settled separately, but all hubs operate under the same rules. These hubs are the transfer points through which gas is transmitted via pipelines and facilities and delivered to the distribution networks. All gas supplied through a hub is transacted in the STTM, including gas that is supplied under existing long-term contracts. Gas is traded a day ahead of the actual gas day, and the day-ahead price (the ex-ante market price) is applied to all gas that is supplied according to the market schedules through the hub on the gas day. A market price is set each day at each hub for clearing all trades in the ex-ante market. Anyone with the necessary agreements and authorities is able to buy and sell gas in the STTM.

Previously, a retailer might purchase gas directly from a producer and pay someone to deliver its gas to the network. With the STTM, ‘shippers’ deliver gas to be sold in the market, and ‘users’ buy gas for delivery to consumers. The same organisation may also sell gas into the market and purchase gas from the market, but it does so at the daily market price, selling under the same terms as any other shipper, and buying under the same terms as any other user.

If an organisation has gas that is excess to its requirements, it can sell the gas the next day on the open market, or if demand is higher than expected, it can bid to purchase the extra gas, when and if it needs to. This gives participants more choice in purchasing gas supplies. Furthermore, price transparency ensures that the price of gas set daily by the market properly reflects the true supply-demand situation, which in turn provides a more reliable price indicator for future investment in production, transmission, and distribution infrastructure.

The STTM will operate in conjunction with the underlying gas supply, transportation and network contracts, while the physical operation of pipeline or network assets will be maintained by owners of the infrastructure.

Subject to further development and approvals, the STTM is expected to commence in September 2010, after a market trial. The existing retail gas markets in New South Wales and South Australia will operate in conjunction with the STTM.

1.6 Changes since 2009

Changes to the VAPR since 2009 are shown in Table 1-3.

Table 1-3 – New content in 2010

2010 VAPR chapter	Title	Description of approach
Chapter 1	Introduction	The introduction now incorporates a description of the relationship between the VAPR and AEMO's other planning documents
Chapter 2	Emerging issues and trends for 2010	This new chapter provides: • A summary of work to date on the AEMO and ElectraNet Joint Interconnector Feasibility study. This study aims to identify options to economically increase interconnector capacity to export power from South Australia to other National Electricity Market (NEM) load centres. The study has a 20-year outlook period, and covers both incremental and Greenfield projects • A discussion of plans for electricity transmission collector hubs, prompted by the large number of connections and connection proposals in Victoria's south west • A discussion of potential gas and electricity transmission investment synergies and the consideration of gas transmission as an alternative to electricity DSN network development • A review of the planning process undertaken by AEMO following the severe summer bushfire season of 2008/09. Based on this, AEMO performed a constraint assessment using a 5% probability of exceedence (5% POE) demand forecast for the Rowville-Springvale 220 kV line. The review also recommended further work in other areas, such as transmission outage models and temperature models for transformer ratings
Chapter 3	Existing network adequacy	This chapter now includes: • A more explicit definition of the capability of the gas DTS, identifying the impact operating pressure and system demand have on pipeline capacities • A discussion on the relationship between electricity DSN constraints and Victorian price outcomes
Chapter 6	Fuel outlook	This new chapter describes the traditional fossil fuel outlook for Victoria's stationary energy sector.
Chapter 8	Planning Overview	The scenarios used in the VAPR have been mapped to scenarios developed in consultation with energy industry stakeholders for the NTNDP
Chapter 9	Transmission development	This chapter now provides more information to assist in the development of demand-side options for addressing electricity DSN constraints

1.7 Contacting AEMO

AEMO welcomes discussion regarding the issues raised in the VAPR. For more information, contact:

AEMO Planning

Post: GPO Box 2008, Melbourne VIC 3001

Phone: 1300 361 011

Email: infocentre@aemo.com.au

Chapter 2 Emerging issues and trends for 2010

This chapter discusses topical transmission planning ideas and emerging trends, and provides information on current thinking, including possible solutions to current planning issues covering both electricity and gas. The topics cover the benefits of scale, coordination and the creation of various options and approaches.

Three of the chapter's topics – the Joint Interconnector Feasibility study between the Australian Energy Market Operator (AEMO) and ElectraNet, the discussion relating to potential gas and electricity transmission investment synergies, and the plans for electricity transmission collector hubs – address these broad issues. The fourth topic – a review of the planning process in light of extreme hot weather – addresses the specific planning challenges identified by the experiences of February 2009.

This chapter's content is based on areas of work in transmission planning that AEMO has been involved with over the last 12 months, and is intended to provide general information to market participants and other interested parties. This information is not definitive, and interested parties seeking further information or clarification about any of the reviews, issues or observations presented here can contact AEMO planning (see Chapter 1 for contact information).

In this chapter:

- Section 2.1 discusses the AEMO and ElectraNet Joint Interconnector Feasibility study, which is examining options to economically increase interconnector transfer capabilities between South Australia and other National Electricity Market (NEM) load centres.

  As well as highlighting the cooperation between AEMO and ElectraNet on an issue of potential significance to National Electricity Market (NEM) transmission development, the study also provides an example of the way AEMO would like to work with transmission network service providers (TNSPs) as part of their annual planning reviews and AEMO's National Transmission Network Development Plan (NTNDP) process to develop significant, large-scale project options.
- Section 2.2 discusses the plans for electricity transmission collector hubs, which has been prompted by the large number of connections and connection proposals in Victoria's south west. It has been included to provide an outline of AEMO's current thoughts on the most effective and economical approach to their co-ordination.
- Section 2.3 discusses potential gas and electricity transmission investment synergies, and the feasibility of gas transmission as a viable alternative to electricity transmission network development.

  When planning the Victorian electricity Declared Shared Network (electricity DSN), AEMO has a responsibility to consider alternatives to electricity transmission augmentations. Where AEMO can identify viable options, it can facilitate the development of appropriate solutions. A clear example of this is in considering the relative merits of developing either gas transmission pipelines or radial electricity transmission lines closer to gas resources.
- Section 2.4 discusses a review of the planning process undertaken by AEMO following the severe summer bushfire season of 2008/09.

  This review was conducted to establish whether existing planning methodologies are under-estimating extreme temperature risks and if so, whether changes to these methodologies should be considered and what may be required.

2.1 Joint planning feasibility study with ElectraNet

2.1.1 Introduction

The South Australian region possesses extensive renewable energy resources with significant development potential. The extent to which these resources can be leveraged to meet the challenges of climate change and a low carbon intensity future, however, may be limited by the existing ability to export energy from South Australia.

This section provides information about the joint feasibility study being undertaken by ElectraNet Pty Ltd [3] and AEMO, examining various transmission development options to economically increase interconnector transfer capabilities between South Australia and other NEM load centres. It has been included because of its relevance to Victoria, and to highlight the cooperation between AEMO and ElectraNet on an issue of particular significance to NEM transmission development.

This work was initiated in December 2009 and commenced in February 2010 when AEMO and ElectraNet agreed on its scope and principles, and set up a joint working group. The work is planned to be finalised by September 2010.

The study considers a 20-year time horizon, and involves:

- developing a range of feasible and cost-effective transmission development options
- determining reasonable cost estimates (considered feasible from an approvals and construction perspective) for each of the options proposed
- developing reasonable market development scenarios and using simulation techniques to assess each option's economic merit, and
- reporting on each option's technical and economic feasibility.

The study also provides an example of the way AEMO would like to share information about transmission development and work with the TNSPs as part of their annual planning reviews and AEMO's National Transmission Network Development Plan (NTNDP) process to develop significant, large-scale project options.

2.1.2 Deliverables

At the conclusion of the feasibility study, ElectraNet and AEMO intend to publish a joint report outlining the analysis and findings. Providing input into the NTNDP and future Victorian and South Australian annual planning reports, the joint report will specifically indicate:

- which options (if any) have a reasonable prospect of satisfying the Regulatory Investment Test - Transmission (RIT-T)
- areas where there is uncertainty about the assessed benefits or costs
- which scenarios show higher and lower benefits for each option, and
- the key assumptions and data the analysis is based on, so it can be validated by interested parties.

The joint report will be a feasibility study, not a comprehensive investment test assessment.

[3] The South Australian TNSP.

2.1.3 Project background

Two interconnectors currently connect Victoria and South Australia.

The Heywood AC interconnector involves a 275 kV AC link connected between the Heywood 275/500 kV terminal station in Victoria and the South East 275 kV substation in South Australia, and has an upper thermal limit of 460 MW (set by the 500/275kV transformers at Heywood).

The Murraylink DC interconnector, with a capacity of 220 MW, involves a high voltage DC link connected between the Red Cliffs 220 kV substation in Victoria and the Monash 132 kV substation in South Australia, and suffers from existing limitations due to the nearby 132 kV network in South Australia and the 220 kV network in Victoria (see the network map on the inside front cover of the VAPR).

In terms of combined interconnector capability, power flow in the:

- South Australia to Victoria direction can be limited by thermal limits of the nearby 132 kV network in South Australia and oscillatory limits (the sum of the power flow on the Heywood AC and Murraylink DC interconnectors must be less than or equal to 420 MW), and
- Victoria to South Australia direction can be limited by the voltage or thermal limits of the 220kV network and voltage stability in South Australia.

AEMO is in the process of reviewing the combined Heywood and Murraylink limit after a review by ElectraNet indicated that it potentially can be increased beyond the current 420 MW. The results of this review are expected to be published on the AEMO website by July 2010.

2.1.4 Study methodology

The feasibility study, which was stimulated by ElectraNet's original findings, initially involved reviewing the current performance of the interconnectors between Victoria and South Australia to form the reference case. Viable options have since been identified to improve capacity, involving either incrementally augmenting the existing network, or greenfield projects (new transmission projects with no existing transmission infrastructure).

For both the incremental and greenfield options, market modelling (with an outlook period of up to 30 years using a range of scenarios similar to those described in Chapter 6) will identify the optimal solutions by considering the transmission issues and the impacts on the electricity market.

2.1.5 Preliminary transmission options

Possible preliminary incremental augmentation options include the following:

- The addition of a third 500/275 kV transformer at Heywood and reconfiguration of the Heywood 500 kV switchyard.
- Dynamic line rating improvements for the:
  - Tailem Bend-South East 275 kV lines
  - South East-Heywood 275 kV lines, and
  - Robertstown-Monash 132 kV lines.
- Additional static (shunt capacitors) and dynamic (SVC) reactive power support.
- Series compensation for the Tailem Bend-South East 275 kV lines.

These augmentation options will also require some level of replacement or upgrade of existing transmission network plant and equipment to facilitate increased interconnector capability. Emergency control schemes may also be required to provide reliable and secure power system operation at higher power transfer levels.

Possible preliminary greenfield options include the following:

- A 500 kV AC double circuit line (with series compensation) from Wilmington, near Davenport in South Australia, to Mt. Piper in New South Wales.

- A bidirectional 500 kV DC link from Wilmington, near Davenport in South Australia, to Mt. Piper in New South Wales.
- A 500 kV double circuit line (with series compensation) from Tepko, near Tungkillo in South Australia, to Yass in New South Wales. This will be routed via Horsham, Shepparton and Wodonga.
- A 500 kV AC double circuit line from Krongart, near Penola in South Australia, to Heywood in Victoria.

These projects may also require the following supporting projects:

- Reconstruction of the Davenport-Brinkworth-Para 275 kV line as a double line.
- A Krongart-Tepko 275 kV double circuit line.
- A Sydenham-Shepparton 500 kV AC double circuit line.
- A South Morang-Dederang-Wagga-Bannaby 330 kV single circuit line, and
- A Yass-Bannaby 500 kV AC double circuit line.

2.1.6 Next steps

AEMO has created a dynamic web-site [4] that enables comments to be made on the work-to-date. The results of the joint planning feasibility study with ElectraNet will be reported in the second half of 2010.

2.2 Connecting generation clusters to the Victorian transmission network: a technical perspective

2.2.1 Introduction

AEMO has reviewed the technical issues arising from connecting multiple generating systems, in close proximity and within similar timeframes, to the transmission network supporting Regional Victoria and the Victorian South-West Corridor.

This section provides a summary of the technical issues and the approach AEMO is currently investigating for connecting new generation to this network. This information has been included due to the large number of connections in Victoria's south-west, and to outline AEMO's current thoughts on their effective co-ordination. A solution is required in advance of a decision about the new Scale Efficient Network Extensions (SENEs) currently being considered by the Australian Energy Market Commission (AEMC) given the immediate needs of generators requiring connection to the Victorian electricity DSN.

AEMO's options for connecting new generation in Victoria include:

- dedicated terminal station connections
- existing terminal station connections, and
- developing collector hubs.

Developing collector hubs (which provide single connection points for multiple generators in close proximity) is AEMO's preferred solution to meet this challenge.

[4] See http://share.aemo.com.au/jfs

AEMO will keep interested parties notified of any relevant developments with regards to the proposed concept of generation cluster connections and transmission hub collection (collector hubs).

2.2.2 The current situation

AEMO's strategic objective is to develop an economical and technically robust approach to connecting generation to the transmission network.

As the Victorian electricity DSN transmission network service provider (TNSP), AEMO receives and typically processes connection applications on a case-by-case basis, each of which addresses the short and long-term impact of its integration with the electricity DSN.

The technical requirements for connecting new generation primarily depend on the:

- timing of the connection application
- location of the connection
- complexity of the connection arrangements and their flexibility for future development
- impact on the electricity DSN's reliability, and
- project commissioning order, relative to other projects connecting to the electricity DSN in the same area.

National carbon policies are changing both the generation types being developed and the connection locations, leading to increasing numbers of connection applications and enquiries from potential generators in the process of developing generation proposals.

Additionally, there are a number of generation proposals that have been or are in the process of being assessed by local councils or the Minister for Planning.

AEMO has received the equivalent of approximately 5,000 MW of Victorian transmission system connection applications and enquiries. Of these, approximately 3,600 MW are expected to be connected to the 500 kV lines between Portland and Geelong or the 220 kV lines out of Ballarat.

These proposals, which aim to capitalise on Victoria's substantial wind and gas resources and the existing transmission infrastructure along the south-western coast of Victoria and in the Ballarat area, pose new challenges for transmission planning due to their dispersed nature and associated uncertainty.

Potential future transmission network capability limitations mean AEMO will also possibly face the following issues:

- Maintaining the transmission network's reliability and continuity of power flow, particularly through high-capacity interconnections.
- Developing sufficient transmission capability, taking into account current connection applications and expected future generation developments.
- Ensuring timely availability of transmission capacity to connected generation.
- Keeping the system's connection costs to a minimum by reducing the planned transmission network outages required for connecting new generation to the transmission system.

The technical challenge for AEMO is to facilitate the connection of new generation at least cost, while maintaining current levels of power quality and ensuring transmission network reliability. For example, proposed wind generation developments may exceed the network's capability in the Ballarat area (the Moorabool-Ballarat-Horsham 220 kV transmission lines) and between Moorabool and Heywood (the Moorabool-Heywood 500 kV line).

2.2.3 Option 1 – dedicated terminal station connection

AEMO's typical connection process is to establish a new terminal station at a particular location on the generator's request. New generators favour this approach when the existing terminal station is either distant from its fuel source or requires substantial augmentation to enable the connection.

In these cases, AEMO adopts a 'facilitatory' approach when connecting, which specifies that the terminal station's configuration must not impede the connection of future generation at that location, nor adversely affect transmission network reliability or system security.

A drawback of this approach is that a large number of generating systems connecting in relatively close proximity will potentially affect reliability. The network's availability is also reduced by the number of required planned outages when connecting new generation to the electricity DSN.

As a result, this arrangement presents significant potential costs for existing generators and does not capture the economic benefits that can be obtained by sharing the connection assets.

2.2.4 Option 2 – existing terminal station connection

Generation with highly transportable fuel may elect to connect at an existing terminal station. This solution is technically simple when the terminal station has significant spare capacity and the reliability or system security requirements (such as the ability to handle transmission system faults) will not be violated.

The benefits of this approach, however, depend on the availability of a fuel resource near a terminal station. When this is not the case, significant cost may be incurred from building either a fuel transport structure from the resource site to a terminal station (e.g. a gas pipeline) or transmission lines for transporting electricity generated from a location near the fuel resource to a terminal station (e.g. wind-generated electricity).

2.2.5 Option 3 – developing collector hubs

A collector hub basically provides a single transmission network connection for a number of generating systems in close proximity. Connecting new generation to collector hubs at appropriate locations within a particular area, like Regional Victoria or the South-West Corridor, provides the following benefits:

- Transmission network reliability is improved with fewer connection points.
- There are fewer transmission outages during the construction and connection of generating systems, and a likely reduction in the number of planned and unplanned outages.
- Generation proponents can readily incorporate planned connection arrangements and readily available infrastructure into their project planning.
- Accommodating future connections and system augmentation is easier.

2.2.6 Collector hub location criteria

The proposed criteria for locating collector hubs include the following:

- There is sufficient concentration of energy resources around the location to enable a generation cluster.
- They are close to an existing transmission corridor and align with future transmission development plans.
- The location minimises the connection costs for each generating system in the cluster.
- The number of current generation enquiries, connection applications and projects with planning application submissions to the Victorian Government for location in sufficient proximity.

- The likelihood that generation within the cluster will increase its generating capacity in the future.
- The ability of stakeholders to mitigate collector hub development environmental impacts.
- Accessibility to the collector hub site for construction and associated construction transport infrastructure (such as roads, bridges, etc.).
- The availability of easements or land for the collector hub's construction and for connecting transmission lines.

Based on these criteria, a collector hub is likely to be centrally located within a cluster of generating systems, and closer to the largest generating system within the cluster. Centrally positioning a hub reduces the cost of building higher-capacity lines and the overall loss in power transmission to the collector hub.

2.2.7 AEMO's conclusion

AEMO considers the development of collector hubs to be an economical and technically robust approach for dealing with the long-term technical challenges associated with connecting multiple generating systems in close proximity and within the same timeframes.

To ensure the long-term reliability of increasing generation connection to Victoria's electricity DSN, AEMO is presently investigating the development of collector hubs along the 220 kV network in Regional Victoria and the 550 kV network in the South-West Corridor.

2.3 Gas and electricity transmission synergies

2.3.1 Introduction

AEMO is receiving a significant number of connection enquiries and applications from new gas powered generators (GPG) in response to climate change policies. Some of this generation will be connecting to both the Victorian electricity Declared Shared Network (DSN) and the gas Declared Transmission System (gas DTS), while others will only connect to the electricity DSN and via dedicated pipelines to gas basins.

This section provides high-level information about AEMO's current considerations in terms of facilitating economically rational and effective energy infrastructure investment decisions.

AEMO currently provides information that facilitates decisions for economically efficient investment in gas markets. AEMO also plans, procures and directs augmentations for the electricity DSN. The provision of information that enables the market to make fully informed and reasoned decisions, and that minimises uncertainty, is critical to both these roles.

As a result, a balance is required between informing the market about the costs, risks, opportunities and consequences of decisions that may affect gas markets and AEMO's own functions in regards to planning and procuring electricity transmission services that deliver desired or required outcomes.

2.3.2 A historical perspective

Transmission investment planning, in both gas and electricity systems, has traditionally been reactive. For example, some developments, such as the BLP pipeline, are supported by an economic cost-benefit test while others are typically sized and constructed to suit the commercial decisions of investors. Similarly, electricity transmission infrastructure has traditionally been designed to meet forecast load growth based on a range of forecast scenarios.

As a result, energy planning to date has not involved making decisions that considered the relative merits of investing in either gas or electricity infrastructure, or both.

This will become even more challenging as carbon policies require AEMO to consider optimal investment strategies and options. For example, analysing electricity transmission augmentation benefits under the RIT-T requires consideration as to whether the development or expansion of a gas transmission pipeline to serve a generator or group of generators delivers greater benefits than building a radial transmission line closer to a gas resource. In this example, it may be even more efficient for gas transmission pipeline developments to be sized to serve a number of potential GPGs. This is similar to the concept of Scale Efficient Network Extensions (SENEs) currently being considered by the AEMC, or AEMO's proposed collector hub developments for the electricity DSN (see Section 2.2 for more information). Both concepts attempt to provide the most economic augmentations by pre-empting future developments.

2.3.3 Future opportunites

AEMO does not direct gas transmission augmentations. In order to play some part in facilitating efficient investment outcomes, however, AEMO can provide information to the market.

The kind of information AEMO provides may potentially include the cost of constructing pipelines based on different dimensions, land acquisition and environmental considerations through defined parts of the state, and the potential capacity and line-pack outcomes of those developments, which can then be compared to the costs and benefits of developing an electricity transmission alternative.

This approach will also require an improved information framework that considers the benefits, costs and risks of pre-emptive transmission investments.

In the future, AEMO will need to work with pipeline owners and operators in Victoria, including non-gas DTS participants, as it considers and assesses new electricity transmission network developments.

2.4 Victorian planning review - extreme hot weather

In 2009, a series of extreme temperature and bushfire events resulted in a number of incidents involving the Victorian electricity DSN. This section summarises the conclusions from the review of AEMO's current electricity planning approach in the context of these events.

2.4.1 Introduction

Undertaken by Nuttall Consulting, the AEMO Heatwave/Bushfire review's objective was to recommend improvements to the probabilistic electricity transmission planning methodology applied in Victoria, and specifically the associated assumptions and criteria (described in AEMO's planning criteria - see Chapter 8, Section 8.2, for more information), as well as the design parameters associated with procuring new transmission assets.

The data and processes of four main areas of Victorian planning methodology were reviewed:

- electricity demand
- asset ratings
- outage events, and
- maximum design temperatures.

A further aspect of the review included an analysis of the implications of climate change. As well as input from AEMO, the review involved:

- an industry survey of a number of national and international electricity transmission businesses to explore views about planning for extreme temperatures and bushfire risk, and
- a meeting with SP AusNet to explore issues associated with plant design parameters.

2.4.2 Electricity demand

AEMO bases its prediction of unserved energy on three separate maximum demand (MD) forecasts.

Each forecast is expressed as the probability that an MD will be exceeded in a particular year, which for summer is largely related to the probability of high temperatures. The most onerous case analysed by AEMO is the 10% probability of exceedence (POE) (or 1 in 10 year) MD.

Annual unserved energy is calculated for each of these three forecasts, and the most likely value estimate is based on the average of the three.

The review considered several aspects of this planning methodology, covering the use of only three MD forecasts, the preparation and use of annual hour-by-hour demand traces associated with each forecast, and the weighted averaging approach used to determine the most likely costs of unserved energy. Based on an analysis of AEMO's temperature and MD forecasting data, the review established three key findings:

- The MD does not always appear to plateau at the most onerous 10% POE MD case presently analysed. Rather, there is a risk that the MD can continue to increase as the POE reduces, and could be appreciably higher at the lowest probabilities. The 2% POE (or 1 in 50 year) MD, for example, could be as much as 6% to 9% higher than the 1 in 10 year outcome.
- The existing approach may underestimate the most likely unserved energy because augmentation timings are sensitive to its accuracy, and the unserved energy can be associated with higher levels of demand than the most onerous 10% POE MD case presently analysed.
- The preparation of demand traces requires care (although the analysis does not suggest that the existing traces are inappropriate). This is because the calculated unserved energy for a specific MD forecast is sensitive to the assumed demand trace, which may lead to a significant over- or under-estimation of the unserved energy associated with a particular MD forecast.

2.4.3 Asset ratings

A number of AEMO systems hold data on thermal ratings for specified plant and temperature assumptions. A number of models are also used that define ambient temperature-rating relationships for many transmission assets.

The main areas under review in this area included identification of gaps in AEMO's thermal rating knowledge, and the accuracy of the existing models, particularly at high temperatures.

The review of AEMO's systems, coupled with discussions with SP AusNet to determine its views on likely thermal rating effects at extreme temperatures, established three key findings:

- Comprehensive temperature-rating data for transmission lines and associated substation connection equipment exists and is used effectively by AEMO.
- Some gaps in AEMO's knowledge-base for other asset types (such as transformers, reactive plant, generating systems, and DC links like Basslink and Murraylink) do exist, but are unlikely to present significant risks.
- The temperature-rating models currently used by AEMO can be considered appropriate up to around 46-47°C. Above this level, it becomes less certain. It is unlikely; however, that any de-rating (the fall in rating due to increasing temperature) above these temperatures will result in

significantly greater unserved energy, due to the very low probability these temperatures will occur.

2.4.4 Outage events

AEMO uses a transmission line outage model that is independent of time, season or temperature. The model derives from historical Victorian transmission network outage data.

The review of this area examined the relationship between high temperatures and the probability of a Victorian transmission outage, and whether the outage models can allow for other information associated with the asset state (e.g. age, condition, or loading).

The analysis of AEMO's historical outage database, coupled with discussions with SP AusNet to determine its views on the performance of assets at high temperatures, established two key findings:

- A relationship exists between high temperatures and the probability of a Victorian transmission outage. This may mean that AEMO is underestimating the risks associated with a specific MD scenario. The extent of this issue, however, could not be determined within the scope of this review and the feasibility of addressing it.
- It may be too difficult to develop generic planning models that generally account for asset states (e.g. their condition). A pragmatic approach, based on a case-by-case evaluation, may be more appropriate.

2.4.5 Maximum design temperatures

AEMO uses a functional specification to define operating requirements when it procures new transmission services. This specification requires a continuous rating up to 40°C for facilities in the Melbourne region, and 42°C in rural areas. It also requires a supplier to define the de-rating that will occur up to 47°C.

The main issue for the review was whether these specifications are appropriate for existing climate conditions and the associated planning risks.

The key finding from this review is that the maximum temperature parameters in AEMO's existing functional specifications are appropriate for the current climate conditions.

2.4.6 Implications of climate change

Projections from the Australian Government indicate that maximum temperatures may rise by from 0.5-1.5°C by 2030, and by 1.0-3.0°C by 2050 [5]. Importantly, these small changes in temperature may result in more substantial changes in the likelihood of extreme temperatures.

Broadly, however, the projected increases in temperature (and associated probability changes) are not expected to significantly affect the review's findings in terms of the overall planning assumptions (assumptions associated with electricity demand, asset rating, and outage events). The annual planning process, which is largely based on recent historical data, is expected to track climate change with a relatively insignificant lag.

Climate change projections are, however, far more relevant for the specification of new transmission assets, which may have a life of at least 40-50 years. As such, the probability that temperatures will exceed maximum temperature limits in the existing functional specification will increase significantly

[5] Climate change in Australia – Technical Report, available on www.climatechangeinaustralia.gov.au.

over the life time of new assets. Current climate change projections indicate that the maximum temperature limits may need to be increased by 2-3°C to ensure that the probability they will be exceeded by the end of their life is similar to the probability faced by similar types of assets now.

2.4.7 Industry survey

Eleven transmission companies, both national and international, were surveyed as part of the review. The aim of the survey, which involved questions on 10 broad areas of asset planning, was to provide the review with additional support so the findings could be tested against industry practice.

The responses indicated no significant matters contradicting the review's findings.

2.4.8 Victorian planning review - extreme hot weather recommendations

Electricity demand

The Heatwave/Bushfire review found a number of areas where the existing planning methodology may be under-estimating unserved energy due to extreme temperatures. Based on these findings, it was recommended that AEMO undertake further investigations to assess their significance in terms of actual planning decisions.

Asset ratings

The review found a number of other matters for consideration, which included:

- requesting temperature capability information from Victorian generators and the DC interconnectors
- improving the joint planning protocol with SP AusNet
- developing a transformer temperature-rating model for planning purposes
- enhancing the tender evaluation process to explicitly consider the level of de-rating offered, and
- increasing the maximum temperature limits in the specifications for new assets by 2-3°C to allow for the projected increase in extreme temperatures due to climate change.

2.4.9 Further work in response to the review

Electricity demand

As a specific response to the recommendations on electricity demand, AEMO has assessed the impact of using a more onerous MD scenario than the present 10% POE (1 in 10 year) MD, by assessing the Rowville–Springvale 220 kV line loading with both a 10% POE MD as well as a 5% POE (1 in 20 year) MD, and comparing the impact. See Chapter 9, Section 9.3.4, for more information about this assessment.

The assessment's key conclusions suggest the following:

- A 5% POE MD advances the forecast energy at risk by approximately three years. Due to the reduced probability of a 5% POE MD occurring, however, overall probability-weighted market benefits are not expected to significantly differ for the different MDs considered. As a result, an emerging transmission network limitation may be identified earlier, but the benefits of augmentation to alleviate that limitation will still occur at approximately the same time.
- The advance in timing of the forecast energy at risk is caused by a combination of increased line loading due to a higher forecast MD, and reduced line ratings due to higher forecast temperatures (resulting from using a temperature-dependant dynamic line rating).

Asset ratings

Although no significant risks were identified, AEMO will, where possible, seek to further its understanding of the temperature effect on asset ratings across all transmission assets.

Outage events

AEMO will review historical data sets to assess confidence levels in the correlation between sets of outage cases and ambient temperature, to establish the suitability of historical data set use as a basis for updating outage models.

Maximum design temperatures

The maximum design temperatures currently being used are deemed to be suitable. AEMO will discuss the ratings of new transmission assets with future asset providers.

Chapter 3 Existing Network Adequacy

This chapter presents information about the existing electricity Declared Shared Network (the electricity DSN) and its ability to meet 2009/10 summer maximum demand (MD) conditions, and the gas transmission network for the 12-month period to December 2009. This information includes a review of gas supply and demand, and a summary of gas Declared Transmission Network (gas DTS) operations and developments.

Electricity

This chapter aims to assist existing or potential users of the electricity DSN to:

- understand electricity DSN constraints, and
- identify locations where the transmission network is:
- currently robust, and further load or generation is unlikely to require immediate new investment, or
- approaching the limits of its capability, and further load or generation is likely to require network investment or alternative solutions, such as demand-side participation (DSP).

Gas

This chapter provides an overview (focussing on bulk gas transfers) of pipeline gas injections, withdrawals, normal operating boundaries, and spare capacity. In this context:

- gas DTS/pipeline capacity refers to the maximum demand that can be met on a sustained basis under a defined set of operating conditions (see the Glossary for more information), and
- normal pipeline operating boundaries refer to the normal range of injections into a pipeline due to operational requirements and other contributing factors, as well as anticipated gas DTS augmentations.

In this chapter:

- Section 3.1 provides high-level information about the electricity DSN and gas DTS.
- Section 3.2 provides information about Victoria's electricity DSN layout, DSN loadings during the forecast 2009/10 summer MD, transmission network adequacy at the time of the MD, fault levels and the available headroom relative to the capability of existing circuit breakers at Victorian terminal stations, and key terminal stations for review.
- Section 3.3 provides information about committed augmentations in the Victorian electricity DSN.
- Section 3.4 provides a basic description of Victoria's gas DTS, its pipelines, injection points, and gas regions.
- Section 3.5 describes the peak day and annual demand and supply levels for 2009.
- Section 3.6 provides a comparison of the levels of demand and supply for 2009.
- Section 3.7 details the maximum allowable pipeline injections and contributing factors to pipeline operating boundaries for each main pipeline within the gas DTS.
- Section 3.8 details the various gas DTS developments commenced or concluded throughout the year.

3.1 Network adequacy synergies

This section highlights specific network adequacy synergies relevant to the 2010 VAPR and the relationship between electricity and gas.

The majority of Victoria's electricity is generated in the Latrobe Valley from brown (and some black) coal, via power stations operating at base load. Electricity is also generated in open-cycle gas turbine (OCGT) power stations (a type of gas powered generation (GPG)) and at hydroelectric stations in the alpine region of North East Victoria. This generation is predominantly operated at low load factors to meet peak or rapidly fluctuating demand. An increasing number of wind turbines are being built and their operation is dictated by wind levels. Electricity is also usually imported from Tasmania and New South Wales, and exported to South Australia (although these flows can often be reversed).

The majority of Victoria's gas is supplied from Bass Strait via processing plants in Gippsland. Other sources are also located off the south coast of Victoria, and cover the area from Bass Strait (east of Melbourne) to the Otway Basin (west of Melbourne). Although Victoria has, via the gas DTS, exported and imported gas to and from New South Wales in the past, this exchange recently fell to minimal volumes. Other pipelines also link the gas DTS to New South Wales, South Australia and Tasmania, enabling significant gas flows between the States.

While there are significant points of electricity and gas demand spread throughout Victoria, the majority of this demand derives from the Greater Melbourne and Geelong region. As a result, both transmission networks:

- are characterised by major energy flows and associated network development challenges around Greater Melbourne and Geelong, and
- have major routes that run due east, north, and south west of Melbourne. Other key centres linked by both networks include Ballarat and Bendigo.

The capital base valuations for each network are:

- $2,191 M[6] for the electricity DSN, and
- $524 M[7] for the gas DTS.

A map of both networks can be found on the inside front cover of the VAPR.

3.1.1 The Victorian electricity Declared Shared Network

Victoria's electricity transmission infrastructure can be broadly described as a combination of the following elements:

- Infrastructure in the greater metropolitan area of Melbourne and Geelong to deliver electricity to distribution networks spread through the various cities and suburbs in this region.

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[6] AER (January 2008), 'SP AusNet's Transmission Determination 2008/09 – 2013/14 Final Decision', p.7.

[7] ACCC (14 November 2007), 'Draft Decision on the Revised Access Arrangement', GasNet, p.14.

- Three major electricity transmission corridors (Eastern, Northern and South West) to move bulk energy to the major demand centres and to and from other National Electricity Market (NEM) regions.
- Infrastructure to deliver energy to provincial cities and other demand centres in the regional areas of the State.

A diagram of the Victorian electricity DSN can be found in the fold-out section at the back of the VAPR. The diagram shows Victoria's electricity DSN, comprising various transmission lines and transformers linking power stations to the distribution system, and electrical equipment at approximately 50 terminal stations across the State. The transmission lines operate at a range of voltages:

- 500 kV transmission primarily transports bulk electricity from generators in the Latrobe Valley to Melbourne (a major load centre), and then on to the major smelter load and interconnection with South Australia
- 330 kV transmission interconnects with the New South Wales region
- 275 kV transmission interconnects with the South Australian region via Heywood
- two new High Voltage Direct Current (HVDC) interconnections now form a second connection with South Australia via Red Cliffs and a connection with Tasmania, and
- 220 kV transmission supplies the metropolitan area and major regional cities.

The transmission lines cover a total circuit distance of approximately 6,000 kilometres.

3.1.2 The Victorian gas Declared Transmission System

The gas DTS comprises pipelines extending from Longford in the east of Victoria, across to Portland in the south west, and northwards to Culcairn in New South Wales. The main gas DTS pipelines include the:

- Longford to Melbourne pipeline (Longford-Dandenong-Wollert)
- South West Pipeline (SWP) (Brooklyn-Geelong-Iona)
- New South Wales interconnect (Wollert-Wodonga-Culcairn), and
- Western Transmission System (WTS) from Iona to Portland (integrated into the gas DTS in 2003).

See also Chapter 7 for more information about gas transmission capacity.

Pipelines forming part of the gas DTS but not representing main corridors includes the:

- Dandenong-West Melbourne and South Melbourne-Brooklyn pipelines, and
- Ballarat pipeline (Brooklyn-Ballarat-Bendigo).

A diagram of the gas DTS pipelines can be found in the fold-out section at the back of the VAPR.

Cost structures

Transmission costs constitute between 3% and 7% of the total delivered cost for electricity and gas. Although this total delivered cost has grown over the years, the relative cost component percentages have largely remained the same. In the future, however, these cost structures may change as emissions costs are incurred by suppliers, increasingly remote gas sources are introduced, and as emerging transmission technologies become cost competitive.

3.2 Electricity 2009/10

This section presents a basic description of the Victorian electricity DSN, and details of its performance under the peak demand experienced on 11 January 2010.

The purpose of this section is to assist potential or existing network users to understand transmission network constraints, and identify locations where the network is:

- currently robust and unlikely to require new investment in the near future, and
- approaching the limits of its capability, and further load is likely to require investment or an alternative solution like demand-side participation (DSP).

3.2.1 The Victorian electricity Declared Shared Network

The Victorian electricity DSN has developed and evolved from the early parts of the twentieth century when the Victorian Government sought to take advantage of Victoria's large coal reserves in the Latrobe Valley.

In 1917 the Brown Coal Advisory Committee recommended establishing an Electricity Commission to develop Victoria's brown coal reserves, and construct a power station and transmission lines. This led to the establishment of the State Electricity Commission of Victoria (SECV).

The first capital works carried out by the SECV involved developing the Yallourn Power Station, briquette factory, and open-cut brown coal mine in the Latrobe Valley. Expansion was also carried out at the Newport Power Station, which was fuelled by imported black coal and Yallourn briquettes. Work on hydroelectric power also commenced with the Rubicon Hydroelectric Scheme to the north-east of Melbourne.

Today's Victorian transmission network comprises various transmission lines and transformers that link power stations to the distribution system. Operating 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 onto the major smelter load and interconnection with South Australia in the west. Strongly meshed 220 kV transmission services the metropolitan area and major regional cities of Victoria, while the 330 kV transmission interconnects with New South Wales. The 275 kV transmission provides for the interconnection with South Australia. Victoria also has direct current (DC) interconnection with South Australia and Tasmania.

The electricity transmitted through the extra high voltage transmission is converted to lower voltages at terminal stations where it then supports the distribution system. There are a total of 58 terminal stations and 144 transformers in Victoria. The total circuit distance covered by transmission lines is approximately 6,600 kilometres.

3.2.2 Victorian electricity Declared Shared Network loading

Sections 3.2.3 to 3.2.7 describe the Victorian electricity DSN, broken down into the following regions:

- Eastern Corridor
- South-West Corridor
- Northern Corridor
- Greater Melbourne and Geelong, and
- Regional Victoria.

Each section includes a transmission network diagram indicating how close the particular network elements were to their thermal limits under the peak load condition for 2009/10, which occurred at 16:00 AEDST (15:00 AEDT) on 11 January 2010.

In each diagram, the line and transformer loadings are shown as a percentage of their continuous ratings [8], with the:

- first figure representing system normal operation (intact, or 'N' elements in service)
- second figure representing the maximum loading on a network element following the loss of the most critical network element (leaving 'N-1' elements in service)
- line loading figures included with the relevant line (the upper figure representing 'N', the lower figure representing 'N-1'), and
- transformer loadings included in a table.

Although some elements show a contingency ('N-1') loading greater than 100% of the continuous rating, these overloads are within short-term ratings. A range of post-contingent actions, using automatic controls or remote manual intervention (for example, rescheduling generation, reconfiguring the network, and/or load shedding) ensure the transmission system remains in a satisfactory operating state after a critical contingency.

The percentage loadings do not reflect other limitations that may result from stability or voltage collapse considerations.

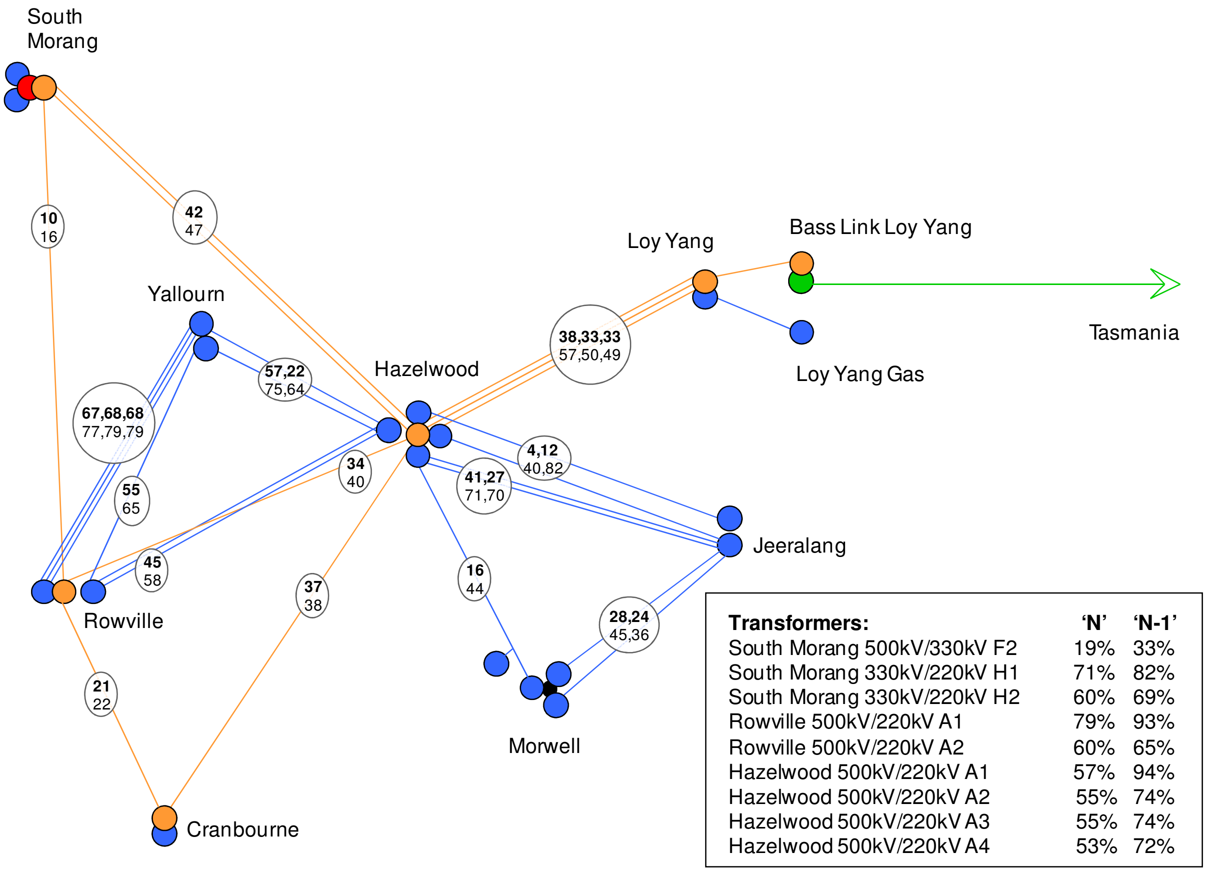
3.2.3 Eastern Corridor

The Eastern Corridor connects the greater Melbourne load centre to generation in the Latrobe Valley. One of the oldest electricity corridors to Melbourne, it still dominates Melbourne's electricity supply, despite electrical connection to hydroelectric schemes to the north and to the adjoining NEM regions.

[8] A continuous rating represents the maximum MVA loading an item of plant can indefinitely carry. These ratings assume a 44.3ºC ambient temperature, consistent with hot summer conditions that are likely to produce a maximum demand. Line ratings are also based on the standard 0.6 m/s wind speed, except in some cases where wind monitoring is installed and ratings based on 1.2 m/s wind speed typically apply on hot days.

Figure 3-1 shows the electrical layout of the Eastern Corridor's electricity transmission network assets.

Figure 3-1–Eastern Corridor



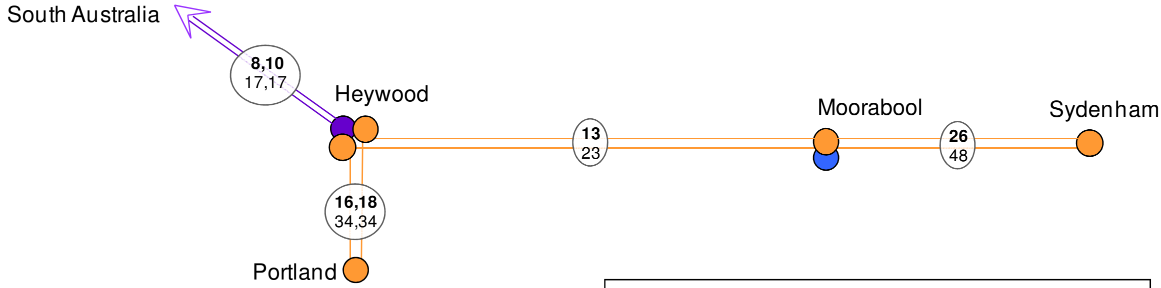
Transformers:	'N'	'N-1'
South Morang 500kV/330kV F2	19%	33%
South Morang 330kV/220kV H1	71%	82%
South Morang 330kV/220kV H2	60%	69%
Rowville 500kV/220kV A1	79%	93%
Rowville 500kV/220kV A2	60%	65%
Hazelwood 500kV/220kV A1	57%	94%
Hazelwood 500kV/220kV A2	55%	74%
Hazelwood 500kV/220kV A3	55%	74%
Hazelwood 500kV/220kV A4	53%	72%

With the installation of new generation, constraints may emerge (see Chapter 9 for more information about transmission network development and constraints).

3.2.4 South-West Corridor

The South-West Corridor connects the Greater Melbourne and Geelong load centres with Heywood, Portland, and South Australia. Although 220 kV transmission was originally established to supply load to South Western Victoria, 500 kV transmission was subsequently established to supply the Portland aluminium smelter. The last 25 years have seen this corridor's role develop, with electricity connections made to South Australia. Figure 3-2 shows the electrical layout of the South-West Corridor's electricity transmission network assets.

Figure 3-2–South-West Corridor



Transformers:	'N'	'N-1'
Heywood 500kV/275kV M1	11%	25%
Heywood 500kV/275kV M2	15%	25%
Moorabool 500kV/220kV A1	45%	74%
Moorabool 500kV/220kV A2	46%	74%

There is considerable spare thermal capability in the South-West Corridor, compared with the existing supply requirements for the Portland smelter, Geelong and Regional Victoria load, and transfer to South Australia through Heywood. Stability and power quality issues, however, may limit power flows ahead of thermal considerations.

3.2.5 Northern Corridor

The Northern Corridor includes the interconnection to the New South Wales region. This corridor also includes electrical transmission for the Victorian hydroelectric stations of Dartmouth, Eildon, McKay Creek and West Kiewa.

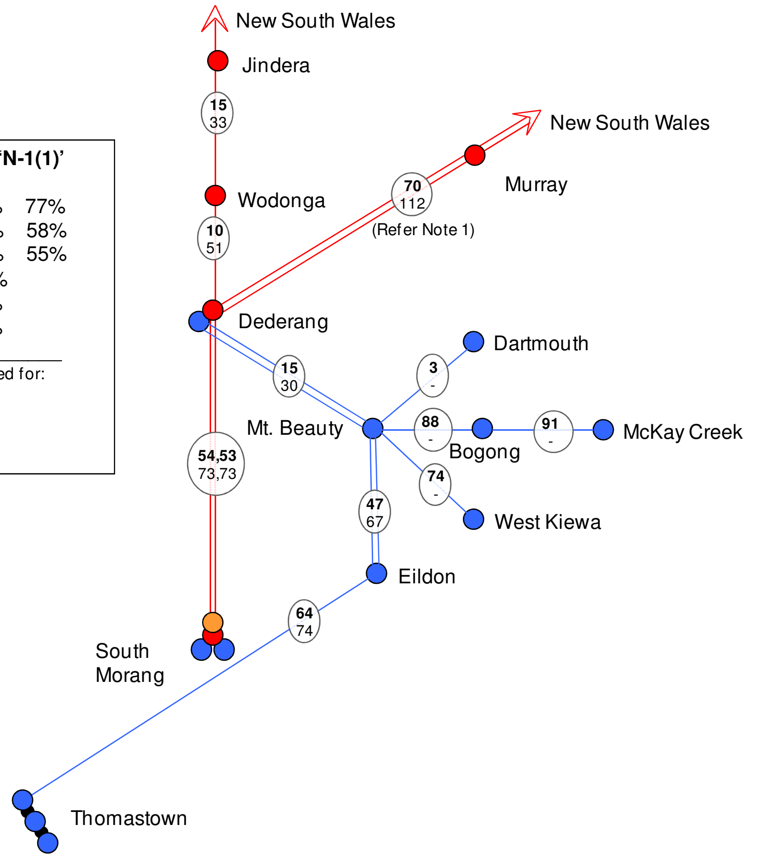
Figure 3-3 shows the electrical layout of the Northern Corridor's electricity transmission network assets, and includes:

- 330 kV transmission lines between Dederang and Murray
- 330 kV transmission lines from Dederang to Wodonga to Jindera (New South Wales)
- 330 kV transmission lines between Dederang and South Morang, and
- 220 kV transmission lines to connect the Victorian hydroelectric stations between Dederang and the Greater Melbourne and Geelong load centre.

Figure 3-3–Northern Corridor

Transformers:	'N'	'N-1'	'N-1(1)'
Dederang 330kV/220kV H1	77%	112%	77%
Dederang 330kV/220kV H2	58%	83%	58%
Dederang 330kV/220kV H3	55%	81%	55%
South Morang 500kV/330kV F2	19%	33%	
South Morang 330kV/220kV H1	71%	82%	
South Morang 330kV/220kV H2	60%	69%	

Note (1): DDTS 330 kV bus split arrangement is operated for:
1. Outage of a DDTS – MSS 330 kV line.
2. Outage of a DDTS 330/220kV transformer.



The apparent 'N-1' overloading of the:

- Dederang 330 kV/220 kV transformers are within short-term ratings and are managed by the DBUS-Transformer scheme for loss of a DDTS transformer
- Dederang to Murray 330 kV lines are within short-term ratings and are managed by the DBUS-Line scheme for loss of a Dederang-Murray 330 kV line, and
- Dederang to South Morang 330 kV lines are within short-term ratings.

The overload is currently mitigated by generation rescheduling and load shedding.

With the installation of new generation, or increases in the interconnector capacity, constraints may emerge (see Chapter 9 for more information about transmission network development and constraints).

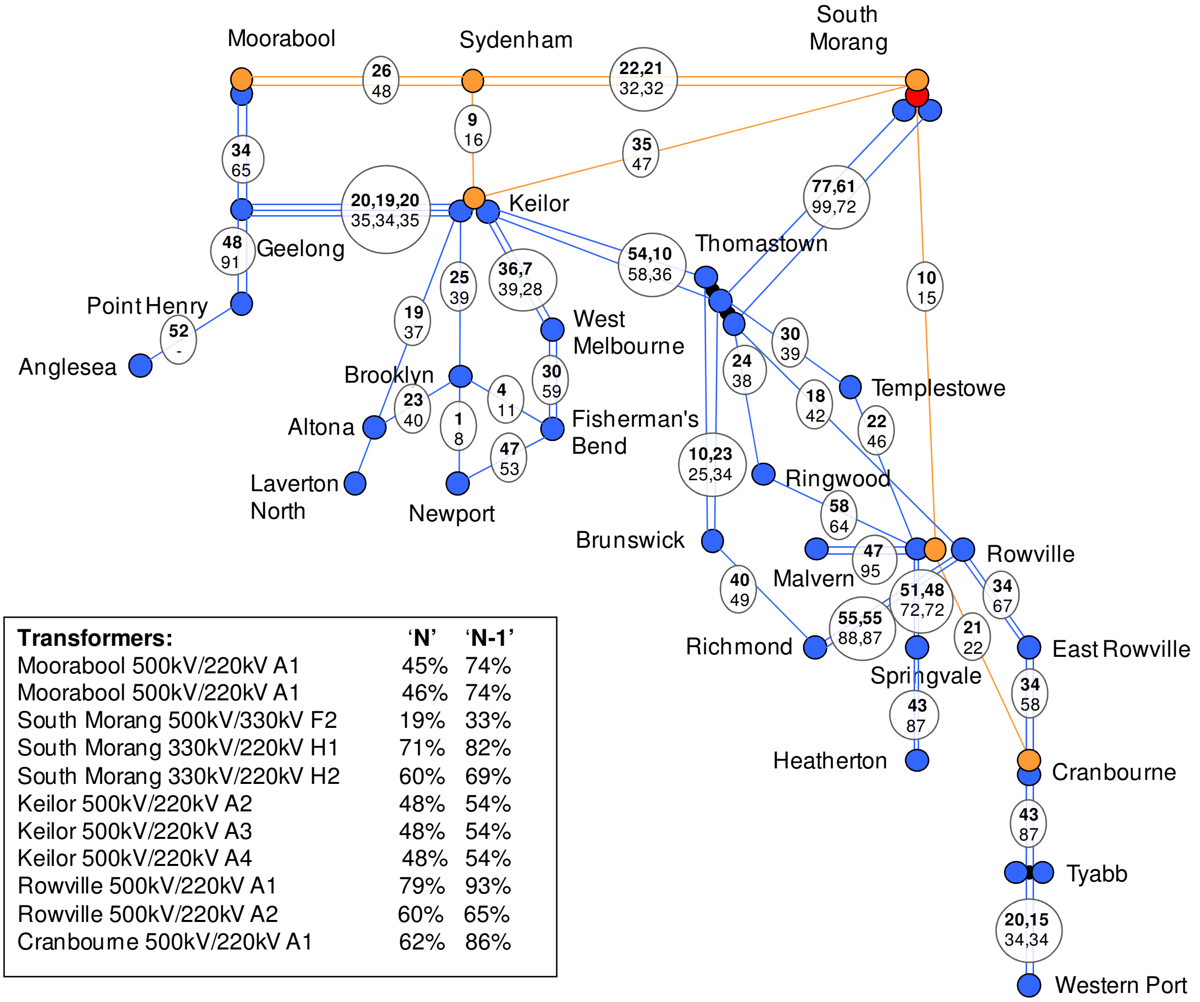
3.2.6 Greater Melbourne and Geelong

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 including an:

- outer 500 kV high-capacity ring around most of the territory being supplied, and
- inner 220 kV ring and radial connections (mainly supplied from the outer ring) to connection points spread throughout the area.

Figure 3-4 shows the electrical layout of Greater Melbourne and Geelong's electricity transmission network assets.

Figure 3-4–Greater Melbourne and Geelong



Transformers:	‘N’	‘N-1’
Moorabool 500kV/220kV A1	45%	74%
Moorabool 500kV/220kV A1	46%	74%
South Morang 500kV/330kV F2	19%	33%
South Morang 330kV/220kV H1	71%	82%
South Morang 330kV/220kV H2	60%	69%
Keilor 500kV/220kV A2	48%	54%
Keilor 500kV/220kV A3	48%	54%
Keilor 500kV/220kV A4	48%	54%
Rowville 500kV/220kV A1	79%	93%
Rowville 500kV/220kV A2	60%	65%
Cranbourne 500kV/220kV A1	62%	86%

With the installation of new generation or load connection, constraints may emerge (see Chapter 9 for more information about transmission network development and constraints).

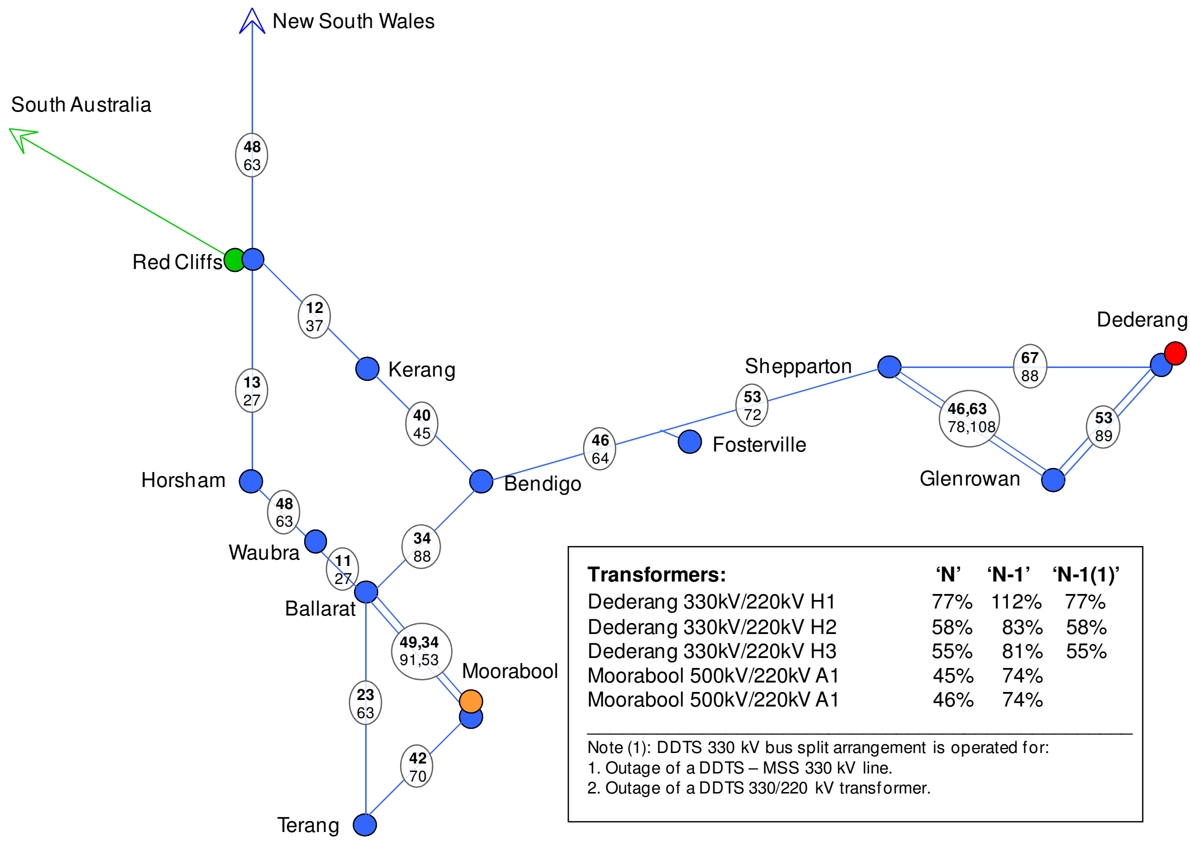
3.2.7 Regional Victoria

Victoria’s regional areas are mainly served by a 220 kV transmission network that delivers energy to provincial cities and regional load centres.

A number of Regional Victoria’s transmission lines also form parallel paths with the Northern Corridor, and are significantly influenced by import and export levels between Victoria and New South Wales, and to a lesser extent by the level of demand at Regional Victoria terminal stations, as well as the amount of transfer across the HVDC interconnector between Berri in South Australia and Red Cliffs in Victoria.

Figure 3-5 shows the electrical layout of Regional Victoria’s electricity transmission network assets.

Figure 3-5 – Regional Victoria



The apparent 'N-1' overloading of the following components are addressed in the transmission network development plan:

- The Dederang 330 kV/220 kV H1 transformer is within its short-term rating and is managed by the DBUS-Transformer scheme for loss of a Dederang transformer, and
- The Shepparton to Glenrowan 220 kV No. 3 line is within its short-term rating and is managed by rescheduling generation and load shedding.

3.2.8 Network adequacy at time of maximum demand

Demand at the time of the system snapshot for the 2009/10 summer was 9,916 MW, which was close to the 10% POE summer scheduled MD of 9,918 MW.

Taken at 15:00 AEST (16:00 AEDT) on 11 January 2010, the system snapshot was as follows:

• Victorian native demand	9,916 MW
• Ambient temperature	42.3 ºC
• Import from New South Wales	170 MW
• Import from Tasmania	590 MW
• Export to South Australia (HYTS link)	76 MW
• Export to South Australia (Murraylink)	46 MW
• Murray generation	1,497 MW

The 2009/10 MD occurred in the half hour ending at 16:00 AEST (17:00 AEDT) on 11 January 2010, with a total Victorian native demand of 10,143 MW (half-hourly average).

The Victorian electricity DSN has been economically designed to support an MD of approximately 10,800 MW, depending on the availability of generation and import from Tasmania via Basslink. The transmission network was operated satisfactorily within its design capability during the year.

3.2.9 Impact of Victorian transmission constraint equations

This section presents information about the most frequently binding Victorian transmission constraint equations (and the average Victorian spot price at the time) for 2008 and 2009. This is the first time the VAPR presents this information (representing another aspect of electricity DSN capability), which is provided as a high-level overview relating to the impact of transmission constraint equations across all periods. Only thermal, voltage stability and oscillatory stability constraint equations were considered.

Fully assessing the market impacts relating to binding constraint equations theoretically requires relaxing the relevant constraint equation and re-running a National Electricity Market Dispatch Engine (NEMDE) simulator. The relaxation (or removal) of a binding constraint equation that coincides with high spot market prices, however, may not result in lower market prices. For example, relaxing binding Constraint Equation A may cause Constraint Equation B to bind, which may also impact market price and dispatch outcomes. Where relaxation does not lead to lower price outcomes, the market impact assessment should also consider relaxing the constraint equations that bind in the simulated re-run.

The 2010 VAPR does not provide this assessment.

Binding Victorian transmission constraint equations, 2008

Figure 3-6 shows the 21 most frequently binding Victorian constraint equations for 2008. Three are voltage stability constraint equations, six are transient stability constraint equations, and twelve are thermal constraint equations.

Figure 3-7 shows the correlation between constraint equations binding in 2008 and the average Victorian spot price (on a logarithmic scale). This shows that in 2008, transient stability and voltage stability constraint equations bind at prices below $100/MWh, and thermal constraint equations bind at all price levels.

Table 3-1 lists a description of each constraint equation and the network limit it defines.

Binding Victorian transmission constraint equations, 2009

Figure 3-8 shows the 20 most frequently binding Victorian constraint equations for 2009. Five are voltage stability constraint equations, four are transient stability constraint equations, and eleven are thermal constraint equations.

Figure 3-9 shows the correlation between constraint equations binding in 2009 and the average Victorian spot price (on a logarithmic scale). This shows that in 2009, a large number of constraint equations bind when the price is less than $100/MWh, and that transient stability constraint equations bind at lower prices than thermal constraint equations, which bind at all price levels.

Table 3-2 lists a description of each constraint equation and the network limit it defines.

Figure 3-6 – Binding Victorian transmission constraint equation hours, 2008

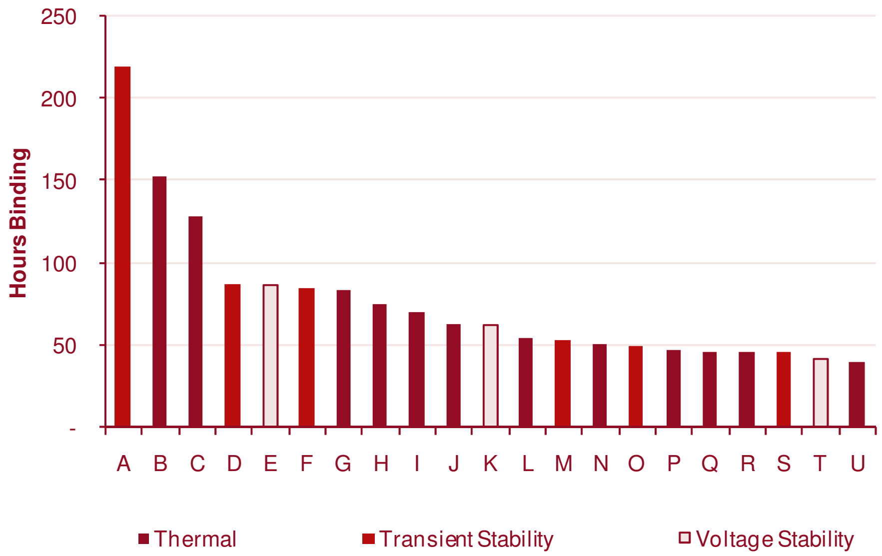


Figure 3-7 – Binding Victorian transmission constraint equation hours and average Victorian spot prices, 2008

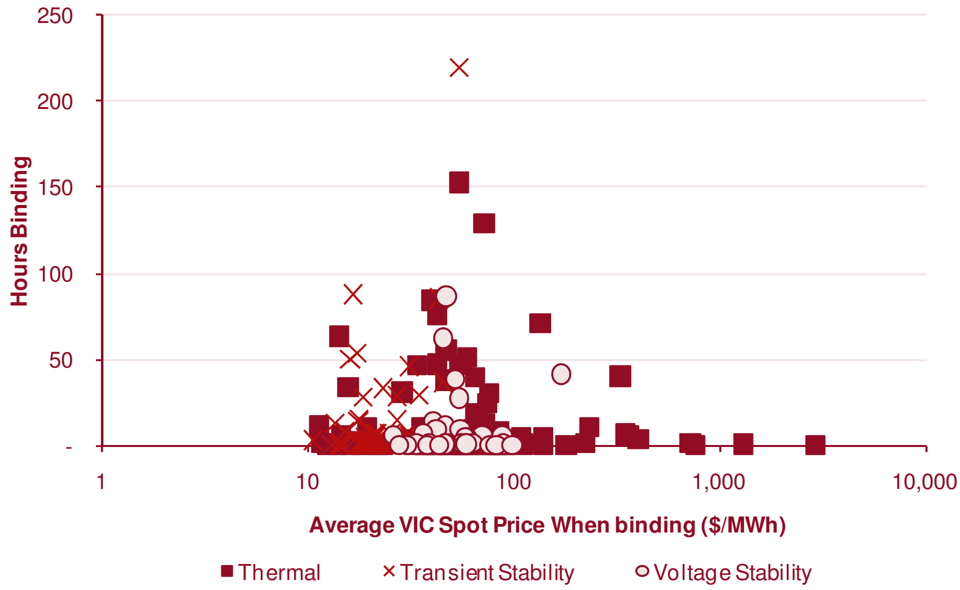


Table 3-1 – Binding Victorian transmission constraint equations, 2008 (shown in Figure 3-6)

Label	Constraint equation	Definition
A	V::S_NIL	Victoria to South Australia stability limit for loss of one Northern Power Station generator due to a 2-phase to ground fault close to the generator
B	S>>V_NIL_SETX_SETX	Avoid overloading the remaining South East 275/132 kV transformer given the trip of one South East 275/132 kV transformer (feedback constraint)
C	S>V_NIL_NIL_RBNW	Limit power flows from South Australia to Victoria on Murraylink to avoid overloading North West Bend to Robertstown 132 kV line.
D	V::N_NILVE_BL_R	When Basslink is exporting to Tasmania, limit Victorian interconnector power flows and Victorian generation to avoid transient instability for fault and trip of the Hazelwood to South Morang 500kV line, radial mode at Hazelwood
E	H^^V_NIL_1_P	Limit Snowy to Victoria power flows and Snowy generation to avoid voltage collapse for the loss of the largest Victorian generating unit, 3/5 or 2-5 tied parallel modes or modified radial mode with 1-2 tied
F	N::H_KC_VC1	New South Wales to Snowy Transient Limit for situation where one Kemps Creek SVC (static VAR compensator) is out of service
G	T>>T_NIL_BL_220_6B	For Basslink in service, avoid overloading the Palmerston to Sheffield 220kV line (flow to South) for loss of a Sheffield to Georgetown 220kV line (feedback constraint)
H	S>>V_NIL_DVBG_DVBR	Limit power flows on Murraylink and South Australia generation to avoid overloading the Davenport to Brinkworth 275 kV line for trip Davenport to Bungama line
I	H>>H-NIL_C	Avoid overloading the Upper Tumut to Murray (65) transmission line on Lower Tumut-Murray(66) trip (feedback constraint)
J	V>>V_NIL_2A_R	Limit Victorian interconnector power flows and Victorian generation to avoid pre-contingent overloading the South Morang 500/330kV (F2) transformer, Yallourn unit 1 in 500kV mode, radial mode at Hazelwood
K	N^^V_NIL_1_P	Limit power flows from New South Wales to Victoria, Victorian generation and New South Wales generation to avoid voltage collapse for loss of the largest Victorian generating unit, 3/5 or 2-5 tied parallel modes or modified radial mode with 1-2 tied
L	V>>V_DDTX_A	When Dederang No.2 or No.3 330/220kV transformer is out of service, the constraint limits Victorian generation and Victorian interconnector power flows to avoid pre-contingent overload of the Dederang No.1 transformer
M	V::N_NILQE_BL_R	When Basslink is exporting to Tasmania, constraint limits Victorian interconnectors, power flows from Queensland to New South Wales on QNI and Victorian generation to avoid transient instability for fault and trip of a Hazelwood to South Morang 500kV line, radial mode at Hazelwood
N	S>V_NWRB2_RBNW1	When the North West Bend to Robertstown No2 line is out of service, the constraint limits South Australia to Victoria power flows on Murraylink to avoid overloading the Robertstown to North West Bend 1 line
O	V::N_NILVF_BL_R	When Basslink is exporting to Tasmania, limits power flows on Victorian interconnectors and Victorian generation to avoid transient instability for fault and trip of a Hazelwood to South Morang 500kV line, radial mode at Hazelwood
P	S>>V_XCG_TUTB_PATX	When the Cherry Gardens to Tailem Bend & Cherry Gardens to Tungkillo 275kV lines are out of service and the Cherry Gardens to Mt barker 132 kV line is out of service, the constraint avoids overloading Para 275/132kV transformer on trip of Tungkillo to Tailem Bend (feedback constraint)
Q	V>V_HWTS_TX1_PAR_3-5	Outage of Hazelwood #1 or #2 500/220kV transformer, 3-5 Parallel, Jeeralang split with Jeeralang B connected to Hazelwood #1 or #2 220kV bus, avoid O/L Hazelwood to Rowville #1 and #2 220kV lines for loss of Hazelwood #2 or #1 500/220kV transformer
R	V>V_NIL_RADIAL_1-2_5	Limits Yallourn unit 1 + Hazelwood + Jeeralang + Bairnsdale + Morwell to avoid overloading the Hazelwood 500/220kV A3 transformer given the trip of A4 transformer, Yallourn unit 1 in 500kV mode, Hazelwood Radial Mode with 1&2 busses tied (3&4 busses remain split)
S	V::S_CGMB_NPS	When the Cherry Gardens to Mt. Barker 132kV line is out of service; the constraint is the Victoria to South Australia transient stability limit given the trip of Northern Power Station
T	V^SML_NSWRB_2	When the NSW Murraylink runback scheme is out of service, constraint limits power flows from Victoria to South Australia on Murraylink to avoid voltage collapse for loss of Darlington Pt to Buronga (X5) 220kV line
U	H>>H-NIL_O	Avoids Upper Tumut to Murray(65) line overloading on Lower Tumut-Wagga(051) + 970,990,99M ex_Yass lines trips (feedback constraint)

Figure 3-8 – Binding Victorian transmission constraint equation hours, 2009

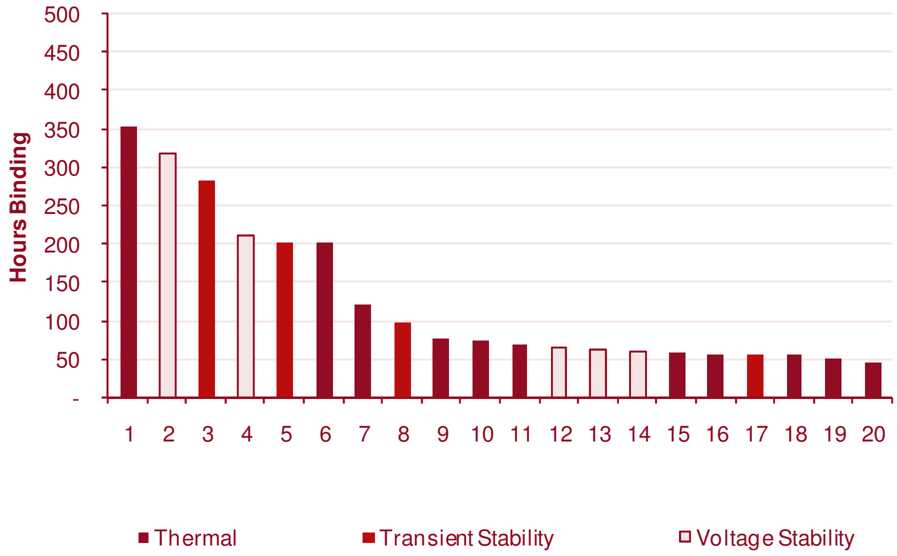


Figure 3-9 – Binding Victorian transmission constraint equation hours and average Victorian spot prices, 2009

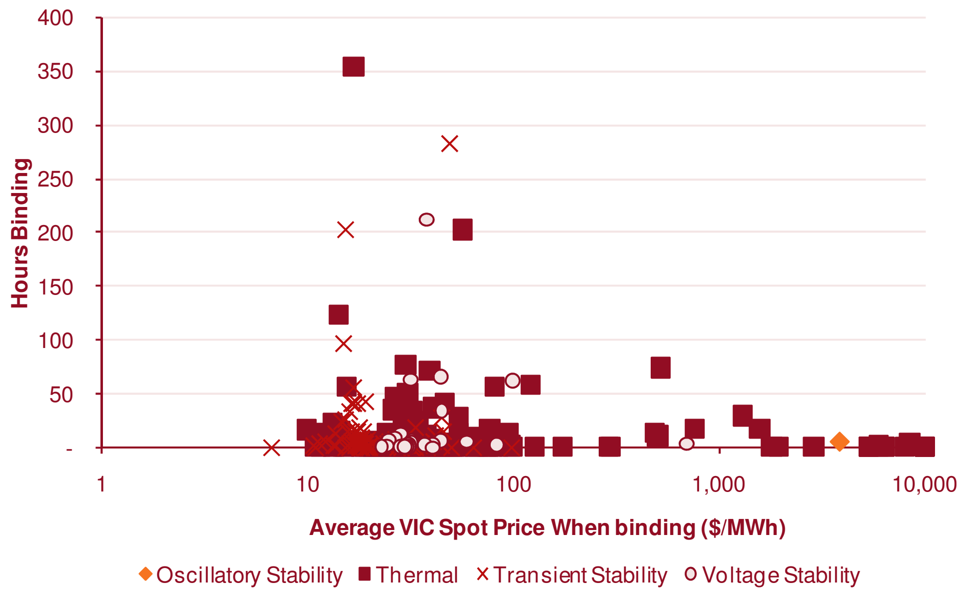


Table 3-2 – Binding Victorian transmission constraint equations, 2009 (shown in Figure 3-8)

Label	Constraint equation	Definition
1	V>>V_NIL_2B_R	Limit Victorian interconnector flows and generation to avoid pre-contingency overloading the South Morang 500/330kV (F2) transformer when Yallourn Unit 1 is in 220kV mode & Hazelwood in radial mode
2	V^^S_NIL_NPS_SE_OFF	Victoria to South Australia Long Term Voltage Stability limit (South East Capacitor out of service) for the loss of one of Northern Power Station generator
3	V::S_NIL	Victoria to South Australia Transient Stability limit for the loss of one Northern Power Station generator due to a 2 phase to ground fault close to the generator
4	N^^V_SM_SCAP_R	In place for the South Morang 330kV series capacitor being out of service to limit New South Wales to Victoria power flows and Snowy generation to avoid voltage collapse following the trip of the largest Victoria generating unit in radial mode
5	V::N_SMCSVE_R	In place for the South Morang 330kV series capacitor being out of service to limit Victorian generation and Victorian interconnector power flows to avoid transient instability for the fault and trip of a Hazelwood to South Morang 500kV transmission line in radial mode
6	S>V_NIL_NIL_RBNW	Limit South Australia to Victoria power flows on Murraylink to avoid overloading the North West Bend to Robertstown 132kV transmission line
7	V>>V_NIL_2A_R	Limit Victorian interconnector power flows and Victorian generation to avoid pre-contingent overloading of the South Morang 500/330kV (F2) transformer, when Yallourn unit 1 is in 500kV mode & radial mode at Hazelwood
8	V::N_SMCSVD_R	In place for South Morang 330kV series capacitor being out of service to limit Victorian generation and Victorian interconnector power flows to avoid transient instability for fault and trip of a Hazelwood to South Morang 500kV line in radial mode
9	N>>N-MNMP_ONE_1	In place for the Marulan to Mt. Piper (35 or 36) line being out of service to avoid Mt Piper to Wallerawang 330kV line (70) overloading given the outage of the Mt Piper-Wallerawang 330kV line (71) (feedback constraint)
10	V>V_NIL_4	Limits Hazelwood units 3, 4 & 5 to avoid an overload of the Hazelwood 500/220kV No.1 transformer when Hazelwood is in radial mode
11	S>>V_NIL_SETX_SETX	Avoid overloading the remaining South East 275/132 kV transformer given the trip of one of the South East 275/132 kV transformers (feedback constraint)
12	N^^V_NIL_1	Limits power flows from New South Wales to Victoria, Victorian generation and NSW generation to avoid voltage collapse given the loss of the largest Victorian generating unit
13	V^^S_TBCP_NPS_SE_OFF	For the outage of the Tailem Bend 100 MVAr Capacitor Bank; the constraint is a Victoria to South Australia Long Term Voltage Stability limit (South East Capacitor out of service) for loss of one Northern Power Station generator
14	V^SML_NSWRB_2	When the New South Wales Murraylink runback scheme is out of service, the constraint limits Victoria to South Australia on Murraylink power flows to avoid voltage collapse for the loss of the Darlington Point to Buronga (X5) 220 kV line
15	N>>V-NIL_O	Constraint prevents overloading the Upper Tumut to Murray (65) given the Lower Tumut-Wagga(051) + 970,990,99M ex_Yass lines tripping (feedback constraint)
16	T>>T_NIL_BL_220_6B	When Basslink is in service, avoid overloading the Palmerston to Sheffield 220kV transmission line (for flows to South) given the loss of a Sheffield to Georgetown 220 kV transmission line (feedback constraint)
17	V::N_SMCSQE_R	When the South Morang 330 kV series capacitor is out of service, the constraint limits Victorian generation and Victorian interconnector power flows to avoid transient instability for fault and trip of a Hazelwood to South Morang 500kV line in radial mode
18	S>>V_NIL_RBTX_WTMW4	Limit power flows from South Australia to Victoria on Murray Link and South Australian generation to avoid overloading the Waterloo - MWP4 transmission line given the trip of one Robertstown Transformer
19	S>VML_NWCB6023_TX2	For the outage of the North West Bend_CB6023, limit power flows from South Australia to Victoria on Murraylink to avoid North West Bend transformer#2 overloading given the trip of the North West Bend - Robertstown transmission line
20	V>>V_HWTS_TX3_3-5MOD	With the outage of Hazelwood #3 or #4 500/220kV transformer, 3-5 Parallel, Jeeralang split with JLGS A connected to Hazelwood #3 or #4 220kV bus, the constraint avoids overloading the Hazelwood #4 or #3 500/220kV transformer given the loss of the Rowville to Yallourn #5 220 kV transmission line

High-impact Victorian transmission constraint equations

To identify transmission constraint equations with the highest market impact, the product of the total binding hours for the year and the average Victorian spot prices at the time the equation bound (in $/MWh) have been ranked.

Table 3-3 lists the 10 Victorian transmission constraint equations (with Victorian parameters available to NEMDE for optimisation) during 2008 that have been assessed as having the greatest impact on Victorian market outcomes.

Table 3-3 – High impact Victorian transmission constraint equations, 2008

Constraint equation	Definition	Average Vic spot price when binding ($/MWh)	Hours binding flat	Constraint equation type
H>>H-NIL_O	Avoid Upper Tumut to Murray(65) overload on Lower Tumut-Wagga(051) + 970,990,99M ex_Yass lines trips (a feedback constraint equation)	331.05	39.83	Thermal
H>>H-NIL_C	Avoid Upper Tumut to Murray (65) overload on Lower Tumut-Murray(66) trip (a feedback constraint equation)	135.51	70.50	Thermal
H^^V_NIL_1_P	Limit Snowy to Victoria and Snowy generation to avoid voltage collapse for loss of the largest Vic generating unit, 3/5 or 2-5 tied parallel modes or modified radial mode with 1-2 tied	47.19	86.25	Voltage Stability
N::H_KC_VC1	Outage of one Kemps Creek SVC, New South Wales to Snowy Transient Limit	43.76	85.25	Transient Stability
N^^V_NIL_1_P	Limit New South Wales to Victorian interconnector, Victorian and New South Wales generation to avoid voltage collapse for loss of the largest Victorian generating unit, 3/5 or 2-5 tied parallel modes or modified radial mode with 1-2 tied	45.46	61.92	Voltage Stability
V>>V_DDTX_A	Outage of Dederang No.2 or No.3 330/220kV transformer, limit Victorian generation and interconnectors to avoid pre-contingent overload of the Dederang No.1 transformer	47.33	55.08	Thermal
V>V_HWTS_TX1_PAR_3-5	Outage of Hazelwood #1 or #2 500/220kV transformer, 3-5 Parallel, Jeeralang split with Jeeralang B connected to Hazelwood #1 or #2 220 kV bus, avoid overloading Hazelwood to Rowville #1 and #2 220kV lines for loss of Hazelwood #2 or #1 500/220 kV transformer	55.45	46.25	Thermal
V>V_NIL_4	Limit Hazelwood units 3, 4, and 5 to avoid overload on Hazelwood 500/220kV No.1 transformer, Hazelwood in radial mode	65.00	39.25	Thermal
V>>V_X_DDTX2_3_DBUSS	Outage of Dederang No.2 or No.3 330/220kV transformer and DBUSS transformer control scheme, limit Victorian generation and interconnectors to avoid overloading the Dederang No.1 transformer for loss of the other Dederang transformer	76.27	30.25	Thermal
N>>N-URWGYC-1_X5OS_1	Outage of Uranquinty-Wagga(9R1)+Wagga-Yanco(994)+X5_TS, avoid Wagga-Uranquinty(9R2) overload on Wagga-Darlington Pt(63) trip; auto-disabled if X5_TS in service	347.89	6.42	Thermal

Table 3-4 lists the 10 Victorian transmission constraint equations (with Victorian parameters available to NEMDE for optimisation) during 2009 that have been assessed as having the greatest impact on Victorian market outcomes.

Table 3-4 – High impact Victorian transmission constraint equations, 2009

Constraint equation	Definition	Average Vic spot price when binding ($/MWh)	Hours binding flat	Constraint equation type
V>V_NIL_4	Limit Hazelwood units 3,4,5 to avoid overload on Hazelwood 500/220kV No.1 transformer, Hazelwood in radial mode	520.95	74.17	Thermal
V>>V_NIL_1B	Limit Victorian interconnectors and Victorian generation to avoid overloading Dederang to Murray No.2 330kV line for loss of the parallel No.1 line, 15 minute line ratings	1,567.60	16.92	Thermal
V::V_1900	Upper limit into Victoria of 1900 MW	3,822.67	5.75	Oscillatory Stability
N>>N-NIL_DPTX	Avoid Darlington Point Tx3 or Tx4 overload on trip of the other	759.65	17.67	Thermal
CA_SPS_3893391F_06	Constraint Automation, overload ROTS_YPS8_220 at YPS for CTG LVCB on trip of ROTS-YPS7 220 kV line	7,938.17	1.17	Thermal
CA_SPS_3893391F_04	Constraint Automation, overload HWPS_ROTS1_220@HWPS for CTG LVCE on trip of HWPS-ROTS2 220KV line	5,934.49	1.42	Thermal
CA_SPS_3893391F_10	Constraint Automation, overload ROTS_YPS8_220 @YPS for CTG LVCA on trip of ROTS-YPS6 220 kV line	10,000.00	0.83	Thermal
N^^V_SM_SCAP_R	Outage of South Morang 330kV series capacitor, limit New South Wales to Victorian interconnector and Snowy generation to avoid voltage collapse for trip of the largest Victorian generating unit in radial mode	38.41	212.17	Voltage Stability
V>>V_NIL_1A	Limit Victorian interconnectors and Victorian generation to avoid overloading Dederang to Murray No.1 330 kV line for loss of the parallel No.2 line, 15 minute line ratings	10,000.00	0.75	Thermal
V>>V_NIL_4A	Limit Victorian interconnectors and Victorian generation to avoid exceeding the continuous rating of the No.1 Dederang 330/220 kV transformer with the DBUSS-Transformer control scheme armed	484.51	14.08	Thermal

Conclusions

Some general conclusions can be drawn from this analysis. In any given year, different types of constraint equations have different impacts on market outcomes. For example, thermal constraint equations and an oscillatory constraint equation had the greatest impact in 2009, while in 2008, thermal, voltage stability, and transient stability constraint equations had the most significant impact.

The Victorian constraint equations found to be most frequently binding, or that bound at the times of the highest prices in Victoria, were not necessarily those with the highest impact. Thermal constraint equations have tended to dominate the analysis, which is expected, given the majority of NEM transmission network constraint equations manage electricity DSN thermal limits.

Only one constraint equation, V>V_NIL_4 (which is in place to avoid overloading the Hazelwood 500/220 kV No. 1 transformer when Hazelwood is operating in a radial mode by limiting generation from Hazelwood Units 3, 4 and 5) was indentified in Table 3-3 and Table 3-4 as a high impact Victorian transmission constraint equation for 2008 and 2009.

3.2.10 Terminal station fault levels

When a fault occurs, such as a short circuit caused by an object coming into contact with one or more phases, the current flowing through the short circuit and the adjacent system can be significantly larger than the system is designed to handle continuously. Circuit breakers are switches designed to interrupt fault currents quickly to prevent damage to plant and danger to personnel.

When calculating terminal station fault levels, AEMO:

- is responsible for ensuring that fault levels are within circuit breaker interrupt capabilities
- makes assumptions about system load levels, generation, transmission and interconnection development
- models forecast summer 10% POE MD with expected voltage levels at each node, and
- models all generators and transmission plant normally in service.

AEMO calculates:

- maximum three phase and single phase to ground busbar short-circuit currents
- the maximum short-circuit currents for several different permissible modes of power system operation, and
- the symmetrical short-circuit current magnitudes flowing to a three phase or single phase to ground bus fault immediately after the occurrence of the fault (i.e. current phase angles and DC offsets are excluded).

Fault impedance is taken to be zero (all faults are assumed to be solid short circuits). Earth return impedance for a single-phase-to-earth fault is included in the zero sequence impedance.

The maximum prospective short-circuit currents at each bus are determined on the assumption that all generation and electrical networks are in service. Normally open points, which are only closed to maintain supply during rearrangement of the system, are assumed to be open.

Current fault levels

Victoria's electricity DSN exhibited adequate local circuit breaker interrupt capability at all locations during the 2009/10 summer.

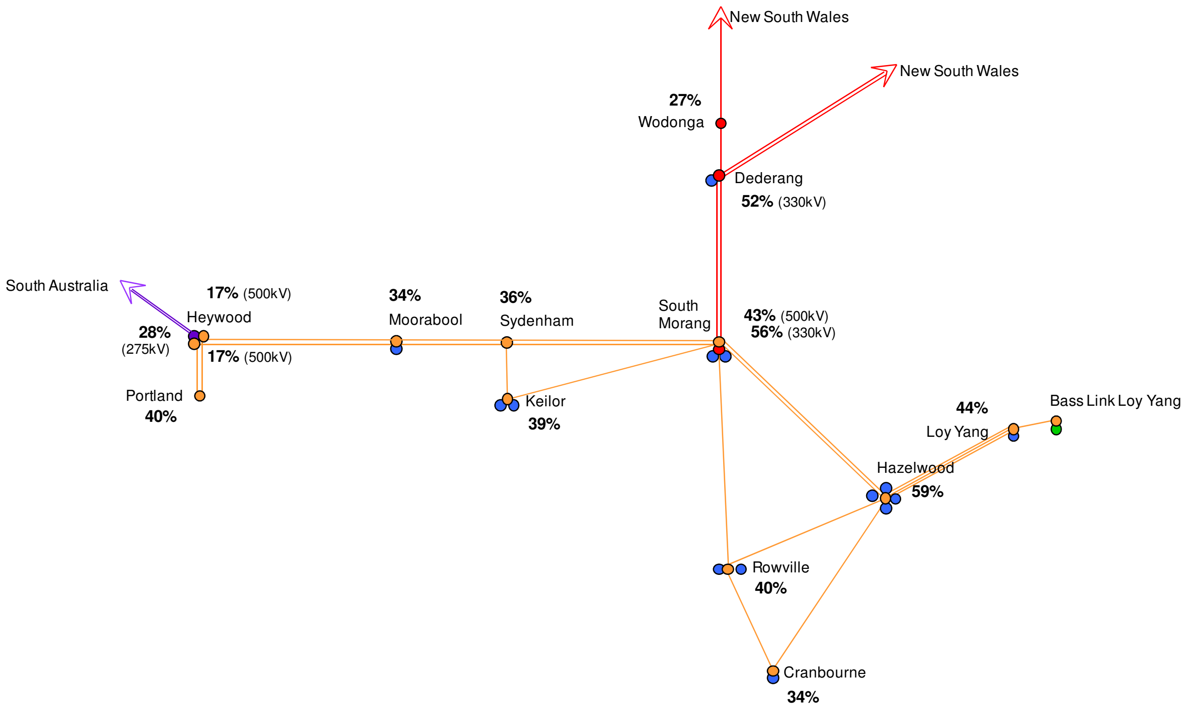
The following sections and figures present the calculated fault levels at each terminal station as a percentage of the lowest rated circuit breaker capability within that terminal station, based on AEMO's 2009 fault level review.

Fault levels at 500 kV, 330 kV and 275 kV

The five year analysis shows that fault levels at 275 kV, 330 kV and 500 kV voltage levels are:

- well below circuit breaker interrupt capability (in the range of 17% - 59% of capability), and
- unlikely to constrain development at any of these voltage levels within the foreseeable future.

Figure 3-10 – 500 kV, 330 kV, 275 kV fault levels for 2009/10



Fault levels at 220 kV

The five year analysis shows that fault levels at the 220 kV level are:

- approaching the circuit breaker interrupt capability at a number of terminal stations, and
- above 95% of the lowest circuit breaker interrupt capability at ten 220 kV terminal stations during the 2009/10 summer. This indicates that augmentations at or in the vicinity of these stations may include fault level mitigation.

Where 2009/10 fault levels exceed the capability of the lowest rated circuit breaker at that terminal station, the fault current flowing through that circuit breaker would not exceed its capability as the breaker would not be exposed to the full fault current.

Figure 3-11 – Northern Corridor/South-West Corridor/Regional Victoria 220 kV fault levels for 2009/10

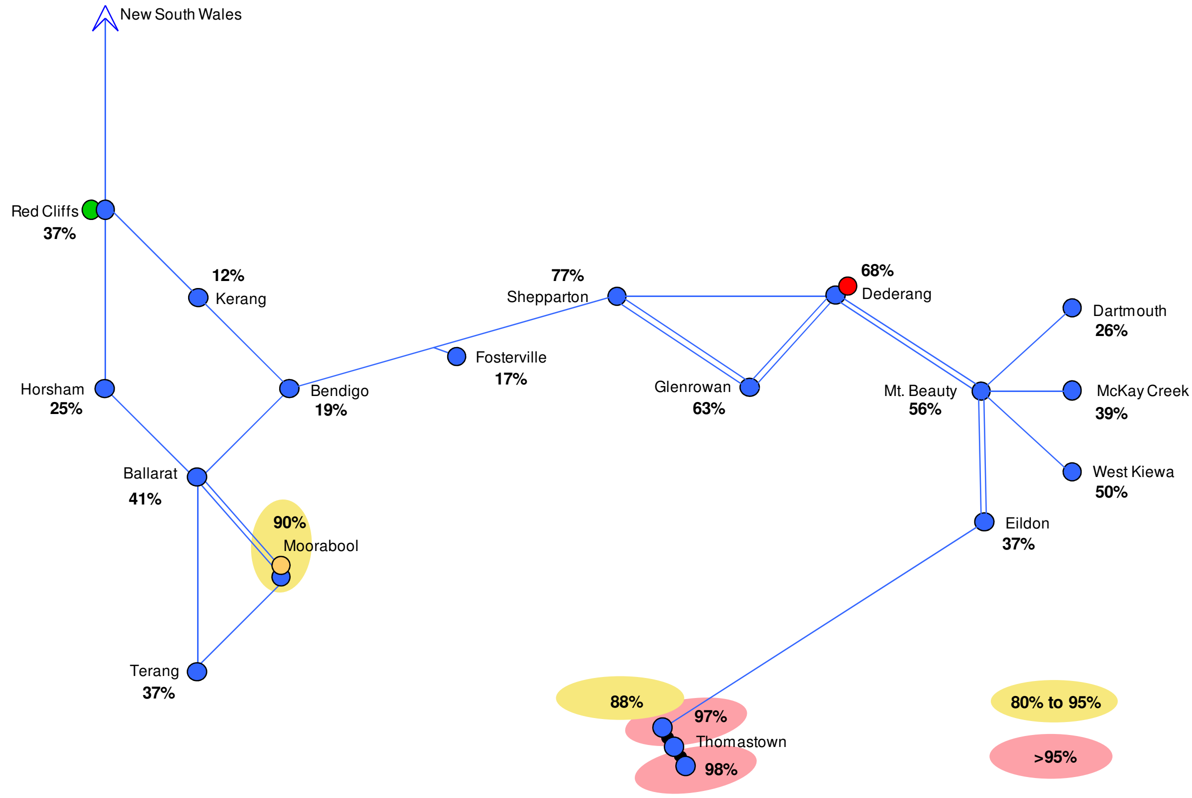
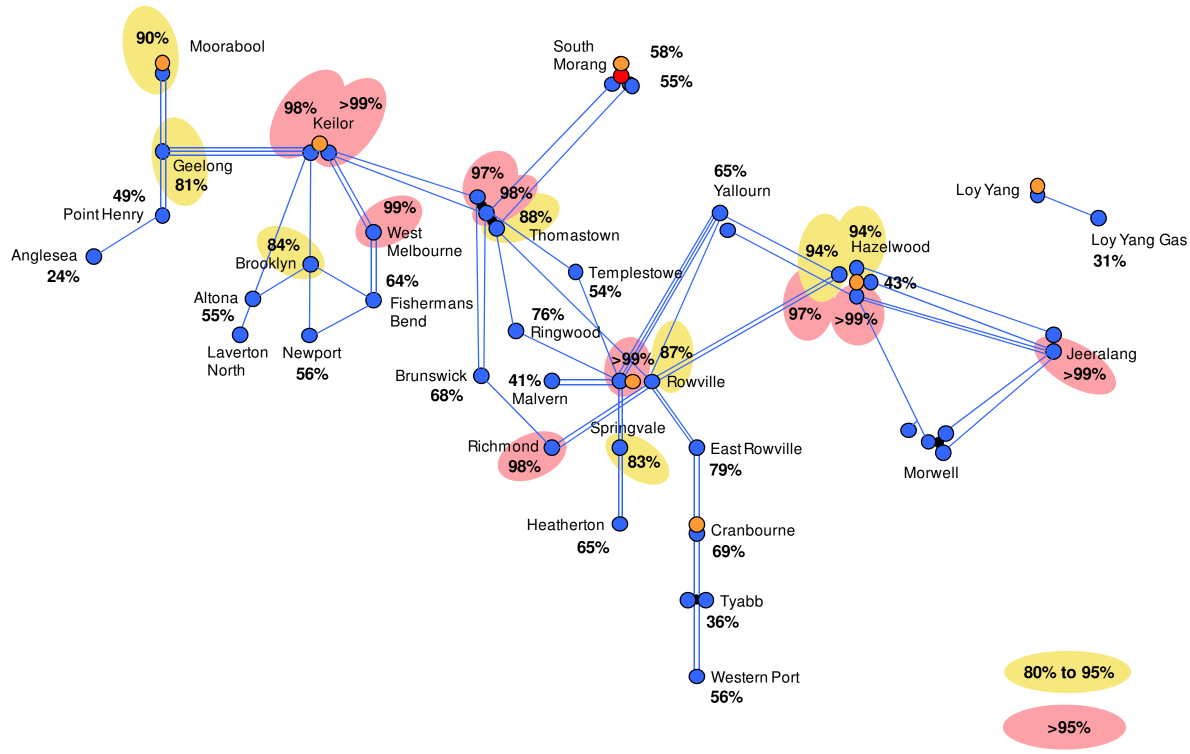


Figure 3-12 – Greater Melbourne and Geelong/Eastern Corridor 220 kV fault levels for 2009/10



Fault levels at 66 kV and 22 kV

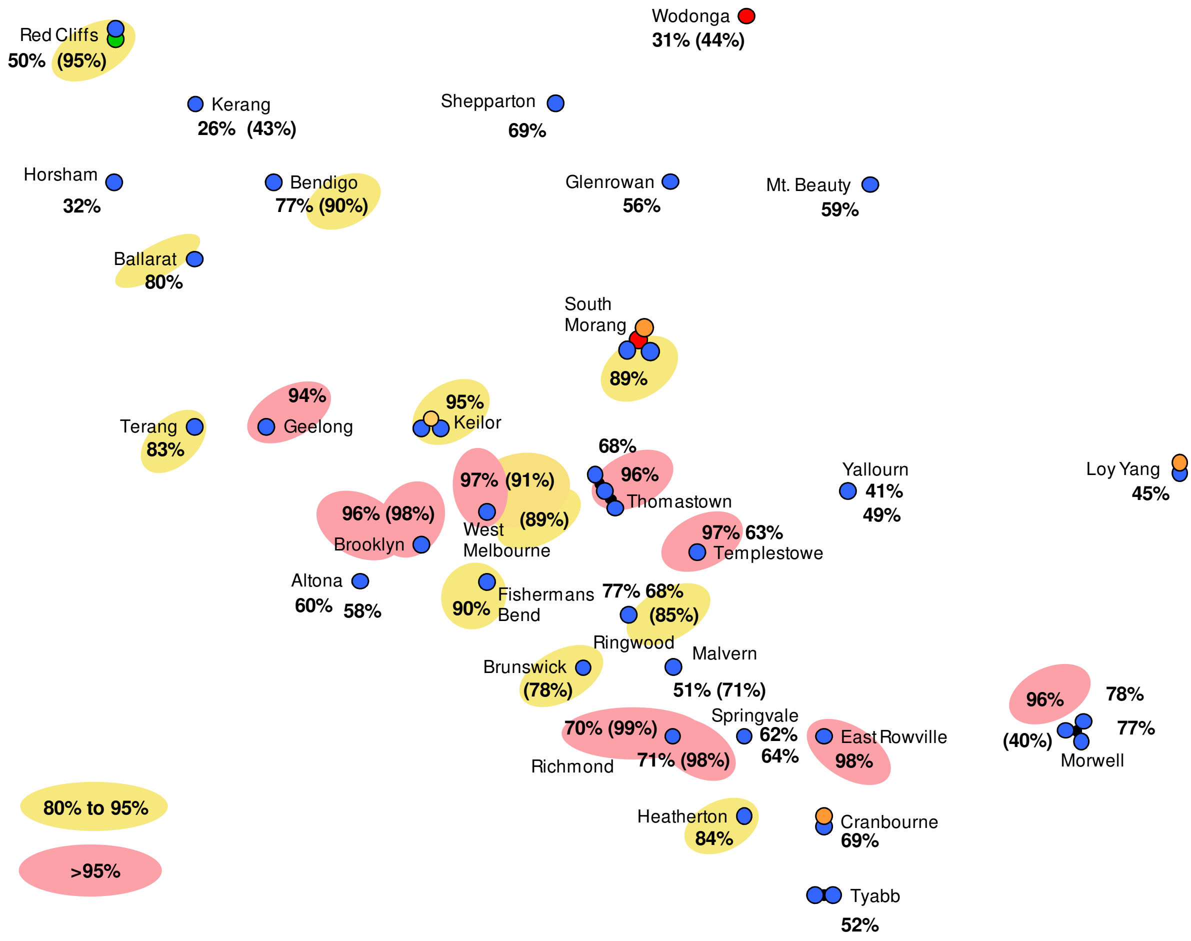
The five year analysis shows that fault levels at 66 kV and 22 kV are:

- approaching the circuit breaker interrupt capability at a number of terminal stations, and
- above 95% of the lowest circuit breaker interrupt capability at eight 66 kV and 22 kV terminal stations during the 2009/10 summer. This indicates that augmentations at or in the vicinity of these stations may include fault level mitigation.

Where 2009/10 fault levels exceed the capability of the lowest rated circuit breaker at that terminal station, the fault current flowing through that circuit breaker would not exceed its capability as the breaker would not be exposed to the full fault current.

Bracketed numbers represent 22 kV fault levels as a percentage of breaker ratings.

Figure 3-13 – 66 kV and (22 kV) fault levels for 2009/10



Key terminal stations for review

Fault levels at some 220 kV, 66 kV and 22 kV buses, particularly in the Greater Melbourne and Geelong region, are close to circuit breaker capabilities, and they are forecast to exceed these over the next five years. This will not occur within the 5-year planning period for the following terminal stations (because the lowest rated circuit breaker's capability is not exposed to the full fault current or agreed fault level ratings):

- Hazelwood
- Jeeralang

- Keilor
- Rowville
- Thomastown, and
- West Melbourne.

If new projects proceed as modelled (see Section 3.2.11 for more information), short circuit currents are forecast to exceed the installed circuit breaker capability or agreed fault level ratings at a number of other locations over the forecast period 2009/10-2013/14.

Table 3-5 lists the terminal stations forecast to exceed the installed circuit breaker capability or agreed fault level ratings.

Table 3-5 – Insufficient circuit breaker capability forecasts

Forecast occurrence	Terminal station	Comment
Summer 2009/10	South Morang 66 kV	Fault level mitigation option is already in place to address this
	Jeeralang 220 kV	Fault level mitigation is currently managed operationally and long term solution is to be investigated
Summer 2010/11	Richmond 220 kV	Fault level mitigation to be handled as part of generator connection process
	East Rowville 66 kV	Fault level mitigation options are currently being investigated by Distribution Businesses
	Rowville 220 kV (No. 3 & 4 buses)	Fault level issue has been addressed following SP AusNet's re-assessment of fault level ratings
	Thomastown 220 kV (No. 3 bus)	Fault level mitigation will be handled by SP AusNet's station refurbishment
	Keilor 220 kV	Fault level mitigation will be handled by SP AusNet's station refurbishment
Summer 2011/12	Brooklyn 66 kV	Fault level mitigation to be handled as part of station rebuild
Summer 2012/13	Brunswick 66 kV	Fault level mitigation to be handled as part of connection process

3.2.11 Fault level impacts from electricity DSN projects

Fault levels over the next five years will be influenced by the following electricity DSN and connection asset/sub-transmission projects:

- likely generation development in South-West Victoria and the Ballarat and Mount Beauty areas
- a second 500/220 kV transformer at Cranbourne
- a third 330/220 kV transformer at South Morang
- a third 220/66 kV transformer at Cranbourne
- a fourth 220/66 kV transformer at East Rowville, and
- two 220/66 kV transformers at Brunswick in 2010/11 and a third transformer in 2012/13.

AEMO is aware of a range of other proposals for the connection of new generation to both the transmission and distribution networks, and sufficiently progressed proposals are considered in the VAPR.

The establishment of wind farms and other types of embedded generation is expected to increase short circuit currents at 220 kV, 66 kV, and 22 kV buses, depending on their size and location.

In South Australia and New South Wales, only new generation developments close to the Victorian border significantly impact Victorian short circuit currents. Except Uranquinty generation, no other new developments are considered.

New generation in Tasmania will not impact short circuit currents, since the interconnector is an HVDC link.

Managing fault levels

Fault levels are rising due to increasing loads, new generation connections, and network augmentations. In particular, new generators connecting near critical terminal stations at voltage levels of 220 kV and below will significantly impact fault levels. As a result, fault level management is a critical issue at a number of locations within the Melbourne metropolitan area.

Options to mitigate problems associated with increasing fault levels include:

- operational switching arrangements (for example, splitting buses or open-ending lines)
- automatic control schemes to open and/or close appropriate circuit breakers (if feasible)
- replacement of affected circuit breakers or other plant
- installation of fault current limiting reactors to lines and/or bus-ties, and
- installation of neutral reactors on transformer secondaries (where these are not already installed).

Factors influencing the selection of the most appropriate options include the:

- terminal station's location
- magnitude of the problem, and
- cost of the solution.

Historically, implementing operational switching arrangements has been the most effective and economic way of managing fault levels, having facilitated fault level maintenance at critical locations within circuit breaker interrupt capabilities for many years. However, in some instances the application of operational arrangements and the possible reduction in plant redundancy means this solution may not always be technically viable or economic.

3.3 Committed augmentations – electricity transmission

This section presents a summary of committed and recently completed electricity DSN augmentation projects. Previously committed or recently completed projects have appeared in previous APRs as planned augmentations. The projects are categorised as either:

- New Large Transmission Network Assets (capital cost > $20M)
- New Small Transmission Network Assets ($5M < capital cost < $20M)
- Minor Network Augmentations (capital cost < $5M), or
- New or Modified Connections.

Table 3-6 lists a summary of committed or recently completed electricity DSN augmentation projects.

Table 3-6 – Electricity DSN augmentation projects

Project category	Description	Status
New or Modified Connections funded by third parties	Mortlake Gas Generation Augmentation: Mortlake Power Station Expected implementation: late 2010	Committed
	Ryans Corner and Hawkesdale planned Augmentations: Tarrone Terminal Station Expected implementation: late 2012	Planned
	Macarthur Wind Farm Augmentation: Macarthur Terminal Station Expected implementation: mid 2012	Planned
	Tarrone Gas Generator Augmentation: Tarrone Power Station Expected implementation: late 2012	Planned
	Shaw River Power Station Augmentation: Shaw River Terminal Station Expected implementation: Stage 1 – March 2012 timing of remaining stages determined as required by the market	Planned
	Mt Gellibrand Wind Farm Augmentation: 220kV Connection into Terang Terminal Station Expected implementation: Mid 2012	Planned
	Mt Mercer Wind Farm Augmentation: new Elaine Terminal Station Expected implementation: To be advised	Planned
	Ararat Wind Farm Augmentation: BATS – HOTS 220kV line Expected implementation: June 2013	Planned
	Berry Bank Wind Farm Augmentation: 220kV Ballarat - Terang Transmission line Expected implementation: Early 2013	Planned
	Lexton Wind Farm Augmentation: 220kV connection into Ballarat Terminal Station Expected implementation: September 2012	Planned
	Mortlake Wind Farm Augmentation: 220kV connection into Terang Terminal Station Expected implementation: Third quarter of 2013	Planned
	Silverton Wind Farm Augmentations: Stage 2 – Red Cliffs Terminal Station Expected implementation: To be advised	Planned
	East Rowville Terminal Station Expected implementation: November 2010	Committed
	Brunswick Terminal Station 220/66 kV development	Planned
	Wemen Terminal Station 220/66 kV development	Planned
	Bendigo Terminal Station 220/22 kV development	Planned
	Geelong Terminal Station	Planned

3.3.1 New or modified connections funded by third parties

Mortlake Gas Generation

Origin Energy Pty. Ltd. has proposed a new power station near Mortlake. A new 500 kV switchyard is to be established at Mortlake to enable connection to the electricity DSN. The new Mortlake Power Station will be cut in to the existing No 2 Moorabool-Heywood 500 kV line.

The proposed service date is by the end of 2010.

Ryans Corner & Hawkesdale Wind Farm

Union Fernosa has proposed a wind farm to connect to No2 Moorabool - Heywood 500kV transmission line. The connection point will be at a new Hakesdale Terminal Station. The capacity of the wind farm is planned at 350MW.

The proposed service date is by the end of 2012.

Macarthur Wind Farm

AGL in a joint venture with Meridian has proposed a wind farm consisting of up to 183 wind turbines with a capacity of up to 450 MW in total capacity. This generating system will be connected to the No 1 Moorabool – Heywood 500kV transmission line.

Tarone Terminal Station will also be established to connect the proposed wind farm.

The proposed service date is by early to mid-2012.

Tarrone Gas Generator

AGL Energy Limited has proposed a new 512 MW gas-fired power station for connection to the No. 1 Moorabool-Heywood 500 kV transmission line. The connection point will be shared with the Macarthur Wind Farm at the new Tarrone Terminal Station. The capacity of the generator is planned at 512MW.

The proposed service date is by the end of 2012.

Shaw River Power Station

Santos has proposed a new power station in the vicinity of the Orford locality in south-western Victoria. A new 500 kV switchyard is to be established at the site to allow for the connection of the proposed Shaw River Power Station to the transmission network.

The new Shaw River Power Station will connect to the existing No 1 Moorabool – Heywood /Alcoa Portland 500 kV line.

The project is expected to be completed in three stages beginning in 2012, with timing of subsequent stages determined by the market.

Mt Gellibrand Wind Farm

Acciona Energy has proposed a wind farm of approximately 100 wind turbine generators in South West Victoria.

A 220kV transmission station has also been proposed to connect to the Moorabool – Terang transmission line. The Mt Gellibrand wind farm will be connected to this station.

The proposed service date is the middle of 2012.

Mt Mercer Wind Farm

Mt Mercer Wind Farm Pty. Ltd. has proposed a new 130 MW wind farm south of Ballarat, with a new 132 kV transmission line between Mt Mercer Wind Farm and the Ballarat Terminal Station.

The proposed service date is yet to be advised.

Ararat Wind Farm

RES Australia Pty. Ltd. has proposed a new 183 MW wind farm south of Horsham for connection to a new 220 kV transmission line at the Ballarat Terminal Station.

The proposed service date is by June 2013.

Berry Bank Wind Farm

Union Fernosa has proposed a new Berry Bank Wind Farm to be connected at 220kV between Ballarat and Terang Terminal Stations. The capacity of the wind farm is planned at 250MW.

The proposed service date is by early 2013.

Lexton Wind Farm

Origin Energy Pty Ltd has proposed a 38 MW wind farm in the North West of Ballarat. The connection will be via a new 220kV line into Ballarat Terminal Station.

The proposed service date is by September 2012.

Mortlake Wind Farm

Acciona Energy has proposed a 150 MW wind farm in the North of Terang. The proposed connection will be at 220 kV at Terang Terminal Station.

The proposed service date is by the third quarter of 2013.

Silverton Wind Farm

Silverton Wind Farm Developments Pty Ltd has proposed the development of a wind farm located 3km north of Silverton. The maximum power generated is likely to be in excess of 1,000MW.

The wind farm will be connected to Broken Hill substation (in NSW) and Red Cliffs Terminal Station (in Victoria).

The proposed service date for the connection of the wind farm is to be advised.

East Rowville Terminal Station

Jemena Ltd. (on behalf of United Energy Distribution) and SPI Electricity Pty. Ltd. (SPIE) have jointly proposed to establish a fourth 220/66 kV transformer at the East Rowville Terminal Station together with the necessary 220kV shared asset and 66 kV switchgear and control.

The proposed service date is by November 2010.

Brunswick Terminal Station

CitiPower has submitted a connection application for a new 66 kV supply from the existing Brunswick Terminal Station.

The initial stage of the proposed connection comprises two transformers connecting to an extended No. 1, 220 kV bus, and a new No. 3, 220 kV bus.

Wemen Terminal Station

Powercor has submitted a connection application for a new terminal station located in the vicinity of Wemen, for connection to the existing Kerang-Red Cliffs 220 kV transmission line.

New transformer projects

Connection applications have been received for the development of new transformers at the following terminal stations:

- Geelong
- Keilor
- Cranbourne
- Bendigo.

3.4 Gas 2009

This section presents:

- a basic description of the gas DTS, its pipelines, injection points, and gas regions or zones
- the peak day and annual demand levels for 2009, including system demand, gas powered generation (GPG) demand and export demand
- the peak day and annual supply levels for 2009, and a comparison of the levels of demand and supply
- information about specific pipeline injections and withdrawals, and the contributing factors to normal pipeline operating boundaries for each main gas DTS pipeline, and
- information about the various system developments commenced or concluded throughout the year.

3.4.1 The gas transmission system

The gas market involves injections and withdrawals of gas, and the balancing of gas flow in or through the gas transmission system. The gas transmission system primarily comprises the gas DTS, with connections to non-gas DTS pipelines (other pipelines not forming part of the gas DTS). A map and a detailed topographical diagram of the gas DTS can be found in the fold-out section at the back of the VAPR.

The Victorian gas transmission system has evolved since the early 1950s when manufactured gas was produced from brown coal in the Latrobe Valley.

Natural gas was discovered in Bass Strait in 1965 in the Barracouta field and subsequently in the Marlin field. Oil was also discovered in the Kingfish field in 1967. Subsequently the Longford Gas Plant 1 and the Crude Stabilisation Plant were constructed, and in 1969 the supply of natural gas to Melbourne consumers began. The rapid expansion of the gas system had commenced, with individual systems and country towns that were previously supplied by manufactured gas being converted to natural gas.

Natural gas was later also discovered in the Otway Basin at North Paaratte and a pipeline constructed to Allansford to supply Warrnambool. Over time, the Western Transmission System (WTS) was extended to supply Portland, Cobden, Koroit and Hamilton by 1995.

The interconnection of the Victorian and New South Wales systems was achieved in 1998. Following an explosion at Longford in late 1998, the planned South West Pipeline (SWP) from Iona to Lara was fast tracked for completion, enabling the integration of the WTS and the gas DTS.

3.4.2 Injection points, key infrastructure and typical gas flow

The gas DTS receives gas via the following system injection points:

- Longford – located at Longford, with gas supplied by Exxon-Mobil/BHP Billiton/Southern Natural Gas Development (SNGD). The group procures gas from the Bass Strait gas fields in Gippsland.
- VicHub – located at Longford with gas flow to and from New South Wales through the Eastern Gas Pipeline (EGP).
- BassGas – located at Pakenham with gas supplies from the Yolla gas field via a gas plant located at Lang Lang.
- Iona – located near Port Campbell with gas supplies from the Iona gas plant and the Underground Gas Storage (UGS) facility. Gas from the Casino gas field is processed at the Iona gas plant and flows to the gas DTS through the Iona injection point.

- SEA Gas – located adjacent to Iona and the UGS facility. Gas from the Minerva gas field flows to this injection point.
- Otway – located near Port Campbell with gas supplies from the Thylacine and Geographe gas fields. Gas from Thylacine and Geographe can also be injected into the gas DTS at the SEA Gas and Iona injection points.
- Culcairn – located in New South Wales. Gas from the Moomba gas field is injected at Culcairn and flows into the gas DTS via the New South Wales interconnect. Longford gas can also be exported to New South Wales via Culcairn.
- The Liquefied Natural Gas (LNG) facility – located at Dandenong, LNG is stored, vaporised, and injected into the gas DTS as required.

points shows the location of each system injection point.

Figure 3-14 – gas Declared Transmission System injection points

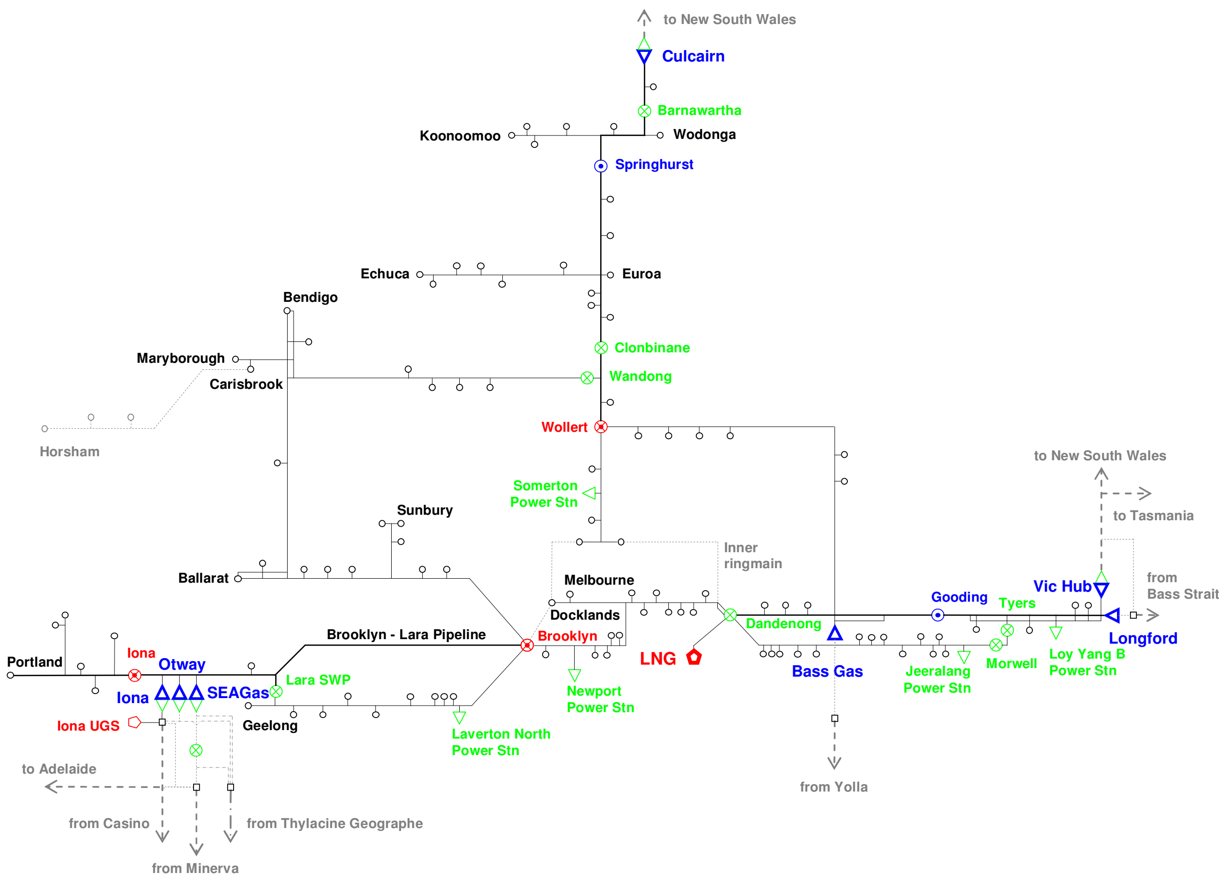


Figure 3 -15 – gas Declared Transmission System main pipelines shows the location of the main gas DTS pipelines.

Figure 3-15 – gas Declared Transmission System main pipelines

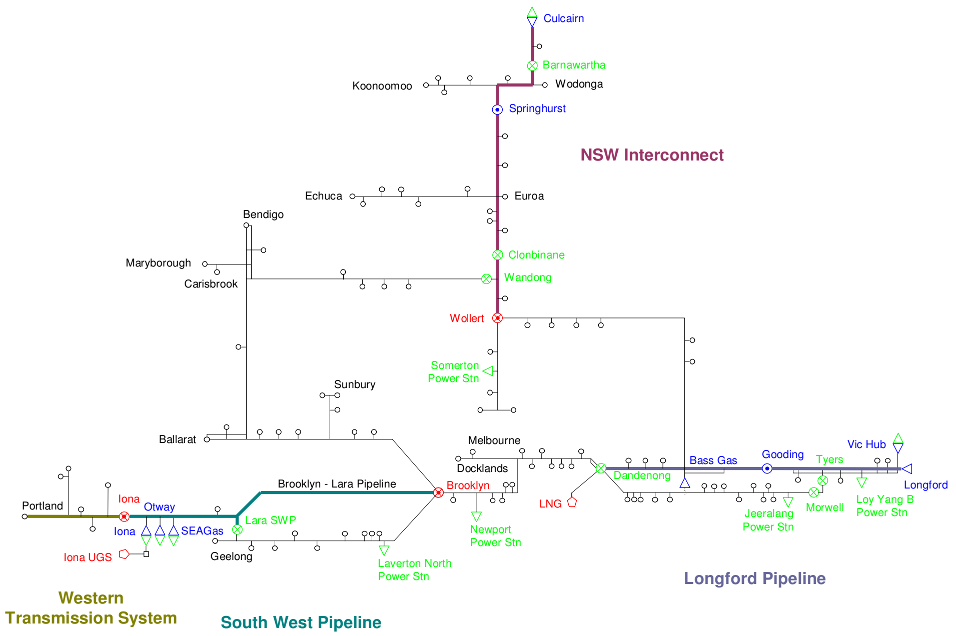
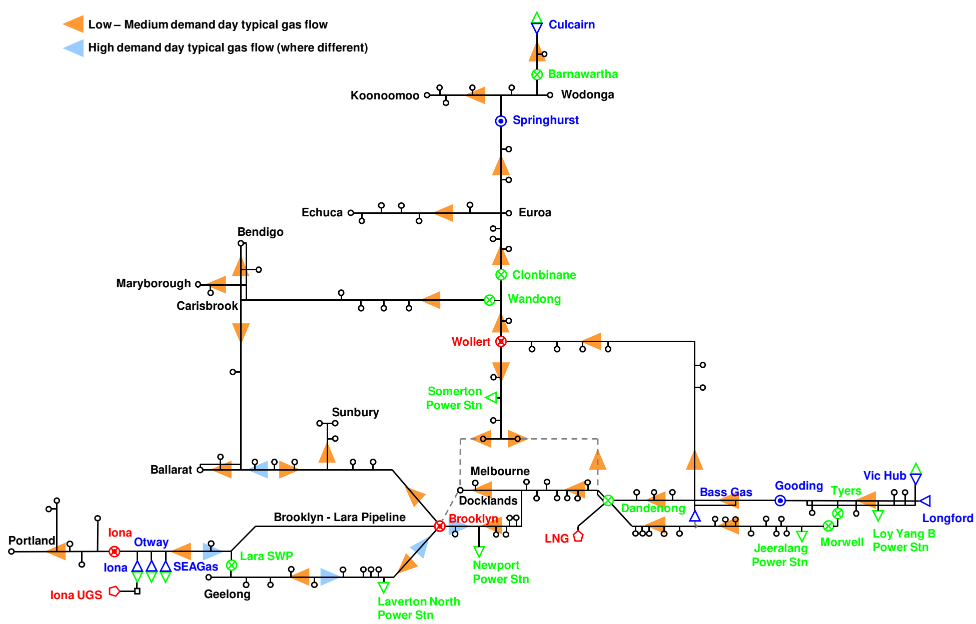


Figure 3-16 shows the direction of typical gas flows within the gas DTS on low to medium and high demand days.

Figure 3-16 – gas Declared Transmission System typical gas flows



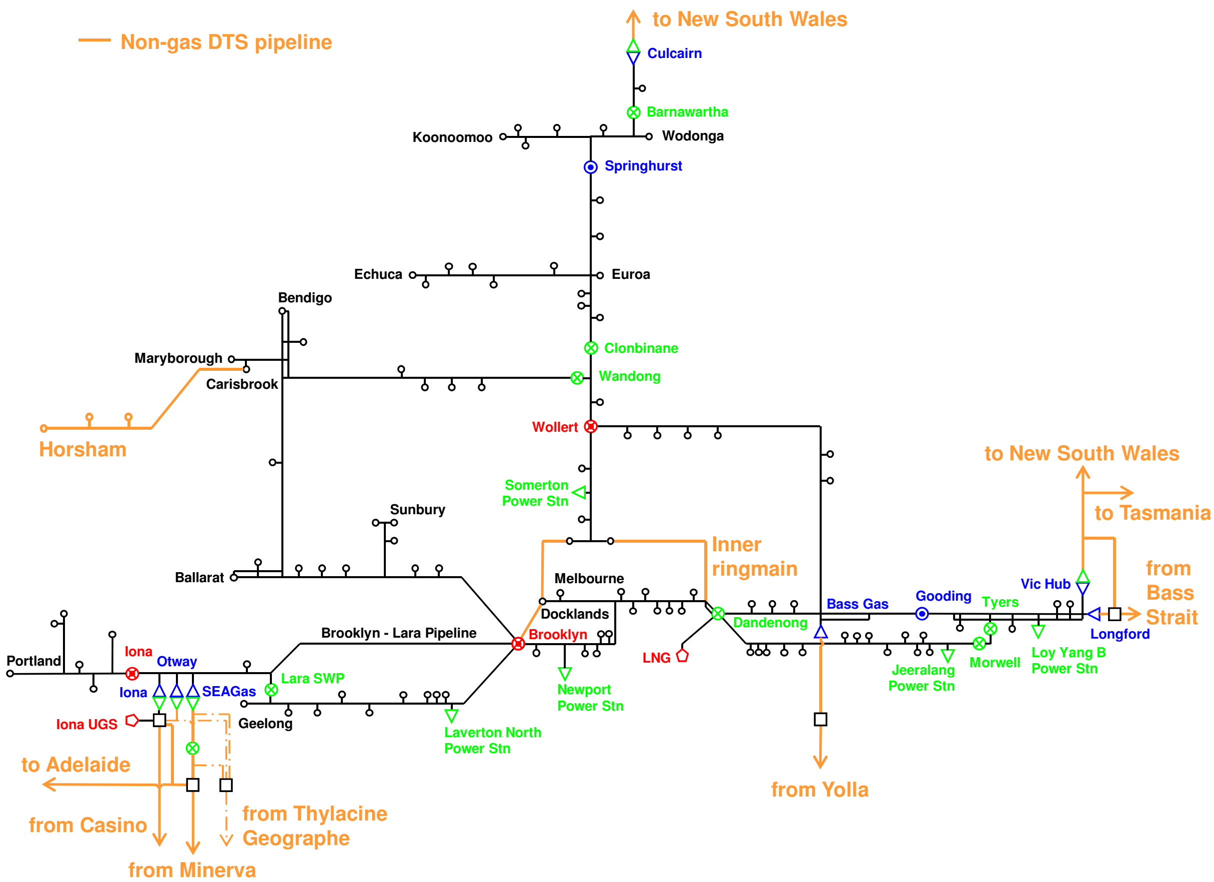
3.4.3 Non-gas Declared Transmission System pipelines

Pipelines not forming part of the gas DTS (but connected to it via gas market withdrawal/injection points) include the following pipelines:

- EGP (from Longford to Wilton, New South Wales) - the bi-directional connection at Longford is known as the VicHub interconnect.
- SEA Gas Pipeline (from Iona to Adelaide, South Australia) - this pipeline has two connections, one to the UGS facility, and one to the gas DTS (known as the SEA Gas interconnect).
- BassGas Pipeline (from the Lang Lang gas field to Pakenham) - the connection at Pakenham is primarily a transmission injection point (commissioned in June 2006).
- Otway Pipeline (from Thylacine and Geographe gas field to Iona) - this pipeline is connected to the UGS and SEA Gas pipeline for transport to South Australia and to the gas DTS through the SEA Gas interconnect.
- Carisbrook to Horsham Pipeline - the connection at Carisbrook is a gas DTS transmission withdrawal point.
- Tasmanian Pipeline (from Longford to Bell Bay, Tasmania) - this pipeline is connected to the EGP.

Figure 3-17 shows the location of the non-gas DTS pipelines.

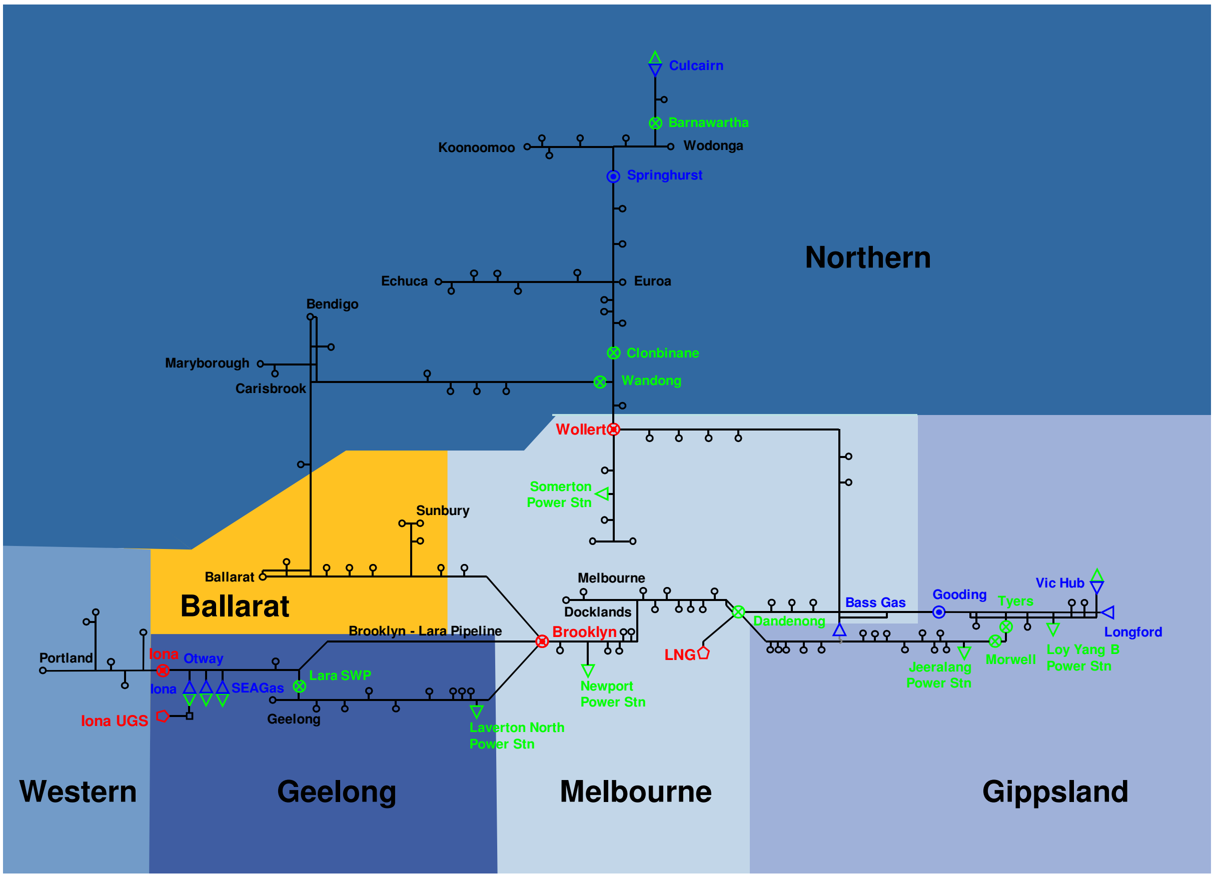
Figure 3-17 – Non-gas Declared Transmission System pipelines



3.4.4 Gas regions

The gas market comprises six regions: Gippsland Zone, Western Zone, Northern Zone, Melbourne and Geelong Zone, and Ballarat Zone. Demand forecasts are required for each region as well as the gas DTS as a whole. Figure 3-18 shows the location of each gas region.

Figure 3-18 – Gas regions



3.5 Demand and supply

3.5.1 Peak day demand

Total demand refers to system demand, GPG demand, and exports. System demand refers to demand from Tariff V and Tariff D customers excluding GPG (see the 2009 VAPR Update available on the AEMO website for more information on Tariff V and Tariff D demand). The 2009 peak day occurred on 9 June 2009, with a system demand of 1,121 TJ. This was the coldest day in the 2009 winter on an effective degree day (EDD) basis, with an EDD of 13.8, below the current 1 in 2 and 1 in 20 year weather standards of 14.55 and 16.8 respectively. This compares with the 2008 VAPR Update's peak day system demand forecast for 2009 of:

- 1,163 TJ for a 1 in 2 peak day on a day with EDD of 14.35, and
- 1,269 TJ for a 1 in 20 peak day on a day with EDD of 16.5.

Table 3-7 lists the breakdown of demand in 2009 for the peak day.

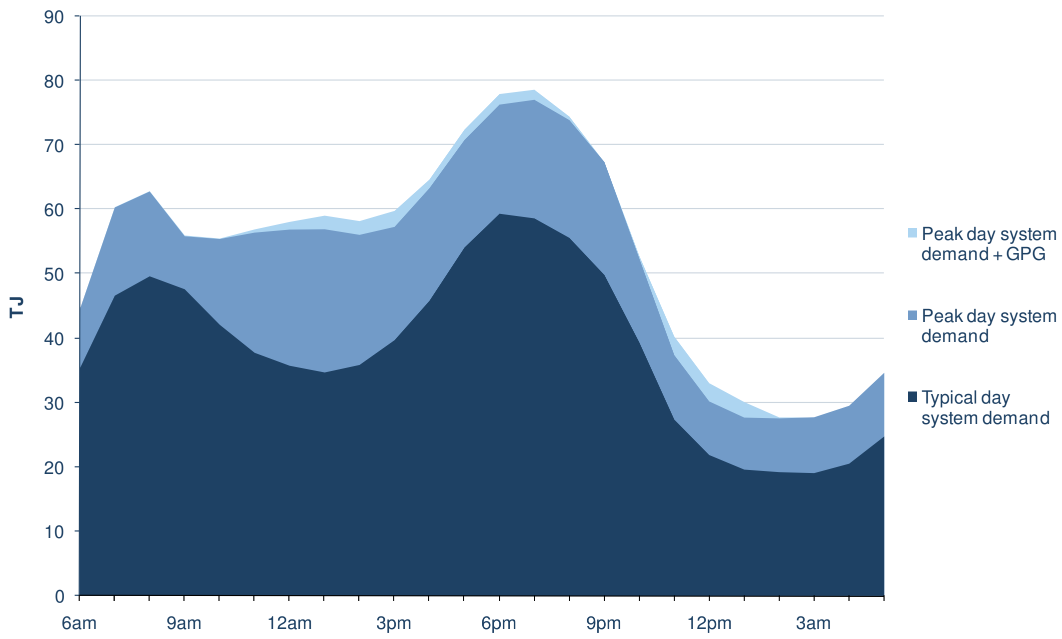
Table 3-7 – Peak day demand, 2009 (TJ/d)

Demand source	9 June 2009	% of Total
System Demand	1,120.9	95.8
GPG	49.2	4.2

Demand source		9 June 2009	% of Total
Export	Iona [1]	0.0	0.0
	Bass Gas	0.0	0.0
	Culcairn	0.0	0.0
	SEA Gas	0.0	0.0
	VicHub	0.0	0.0
Total demand		1,170.1	100.0
1. Iona withdrawals are delivered to the UGS or exported to South Australia			

Figure 3-19 shows a comparison of the peak day hourly demand profile with a more typical hourly demand profile.

Figure 3-19 – Peak day/typical hourly system demand profile comparison (TJ/hr)



3.5.2 Annual demand

Total demand [9] was 226.42 PJ for the 12 months to 31 December 2009, with 124.19 PJ (approximately 55%) of this demand occurring during the winter peak period (May to September). This compares with the total demand in 2008 of 241.46 PJ, with 136.90 PJ of this demand (approximately 57%) occurring during the winter peak period.

Table 3-8 lists the breakdown of demand in 2009 for the year and for the winter period.

[9] Total demand for the period comprises system demand, Iona withdrawals (and exports), GPG demand, and other exports.

Table 3-8 – Annual demand, 2009 (PJ/yr)

Demand source		Twelve months to December 2009	% of Total	May to September 2009	% of Total
System demand		204.33	90.25	118.06	95.06
GPG		17.73	7.83	5.87	4.73
Export	Iona [1]	0.00	0.00	0.00	0.00
	Bass Gas	0.04	0.02	0.001	0.01
	Culcairn	4.23	1.87	0.21	0.17
	SEA Gas	0.00	0.00	0.00	0.00
	VicHub	0.08	0.03	0.04	0.03
Total demand		226.42	100.00	124.19	100.00

1. Iona withdrawals are delivered to the UGS or exported to South Australia.

System demand

System demand for the 12 months to 31 December 2009 was 204.33 PJ (approximately 90% of the total demand). This compares with the system demand in 2008 of 212.80 PJ (approximately 88% of total demand).

System demand covers the industrial, commercial and residential sectors (Tariff D and Tariff V). See Chapter 3 for more information about system demand for 2009.

GPG demand

GPG demand for the 12 months to 31 December 2009 was 17.7 PJ (approximately 7.8% of the total demand). This compares with GPG demand in 2008 of 22.95 PJ (approximately 9.5% of the total demand). Figure 3-20 shows the annual GPG demand over the last five years. The significant increase in GPG demand in 2007 was largely due to drought-induced hydroelectric and coal-fired generation capacity limitations leading to an increased reliance on GPG to meet electricity demand.

Figure 3-20 – Gas powered generation demand 2005-2009 (PJ/yr)

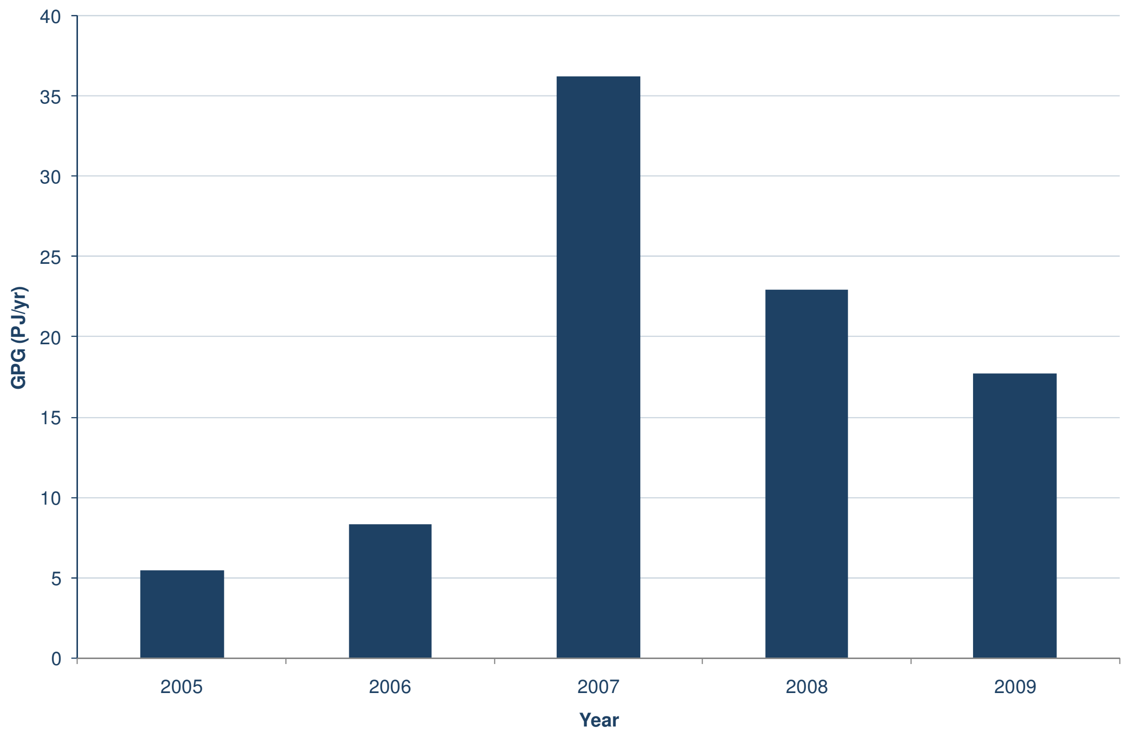
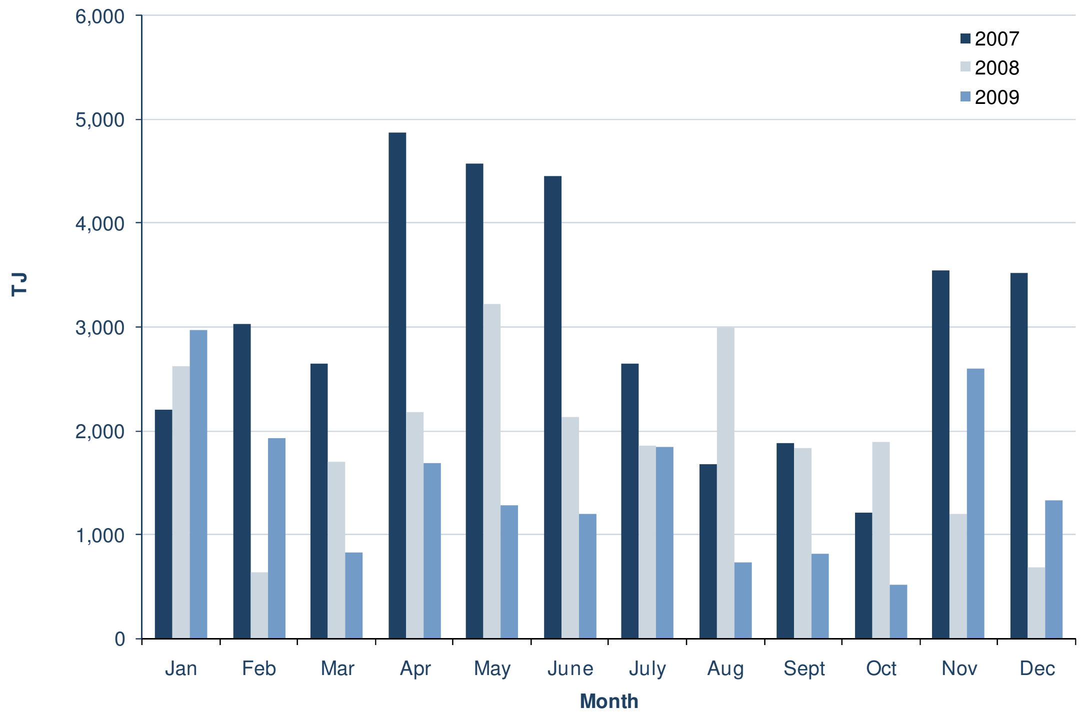


Figure 3-21 shows monthly GPG demand over the last three years. GPG demand in 2009 was 17.7 PJ. GPG demand in 2007 was unusually high when compared to previous years, with relatively high levels of demand continuing from the shoulder period through to the beginning of winter (May/June). Previously, GPG demand has been highest in the shoulder periods, due to the scheduling of coal-fired generation maintenance.

Figure 3-21 – Gas powered generation monthly demand 2007-2009 (TJ/mth)



Export demand

Export demand for the 12 months to 31 December 2009 was 4.35 PJ (approximately 1.9% of the total demand). This compares with export demand for the 12 months to December 2008 of 5.71 PJ (approximately 2.4% of the total demand).

Exports represent actual physical flows from the gas DTS, either via an interconnect or into the UGS facility. Total exports for the period were:

- 4.23 PJ via Culcairn (down from 4.33 PJ in 2008), showing virtually no change
- 0.04 PJ via BassGas (the same as 0.04 PJ in 2008), showing no change from 2008
- 0.08 PJ via VicHub (down from 0.09 PJ in 2008), showing a decrease due to market factors and operating conditions at Longford, and
- 0.00 PJ via Iona (down from 1.11 PJ in 2008), showing insignificant Iona exports for 2009. The decrease was due to market conditions.

3.5.3 Peak day supply

The 2009 peak day occurred on 9 June 2009, with total supply (including LNG) of 1,183.0 TJ. The 12.9 TJ difference between demand and supply on this day was due to linepack changes over the course of the day.

Table 3-9 lists the breakdown of supply in 2009 for the peak day.

Table 3-9 – Peak day supply, 2009 (TJ/d)

Injection point	(TJ/d)	% of Total
Longford	828.2	70.0
VicHub	0.0	0.0
BassGas	63.4	5.4
Total Longford, VicHub and BassGas	891.6	75.4
Iona UGS	211.3	17.9
SEA Gas	55.4	4.7
Otway	0.0	0.0
Total Iona and SEA Gas	266.7	22.5
Culcairn	63.4	2.1
Total (excluding LNG)	1183.0	100.0
LNG [1]	0.0	0.0
Total (including LNG)	1183.0	100%
1. This represents scheduled LNG only.		

3.5.4 Annual supply

Gas market supplies totalled 224.9 PJ for the 12 months to 31 December 2009. Longford and VicHub supplies were 147.8 PJ for 2009 (approximately 66% of total supply). This compares with 186.1 PJ in 2008 (approximately 77% of total supply). The BassGas connection, with the capacity to inject 67 TJ/d, provides an increasingly important source of additional supply for the Longford to Dandenong pipeline. BassGas supplies were 17.21 PJ in 2009 (approximately 8% of total supply), compared to 16.5 PJ in 2008 (approximately 6.9% of total supply).

A total of 72 TJ (131 tonnes) of Liquefied Natural Gas (LNG) was scheduled and vaporised over this period. This represented a significant decrease from 2008, and is largely attributed to the decrease in GPG demand and milder weather conditions resulting in lower demand. See Section 3.5.2 for more information about GPG demand. See Chapter 5, Section 5.3.7, for more information about historical LNG use and current modelling involving profiled injection rates at Iona.

Table 3-10 lists the breakdown of supply in 2009 for the year and for the winter peak period.

Table 3-10 – Annual supply, 2009 (PJ/yr)

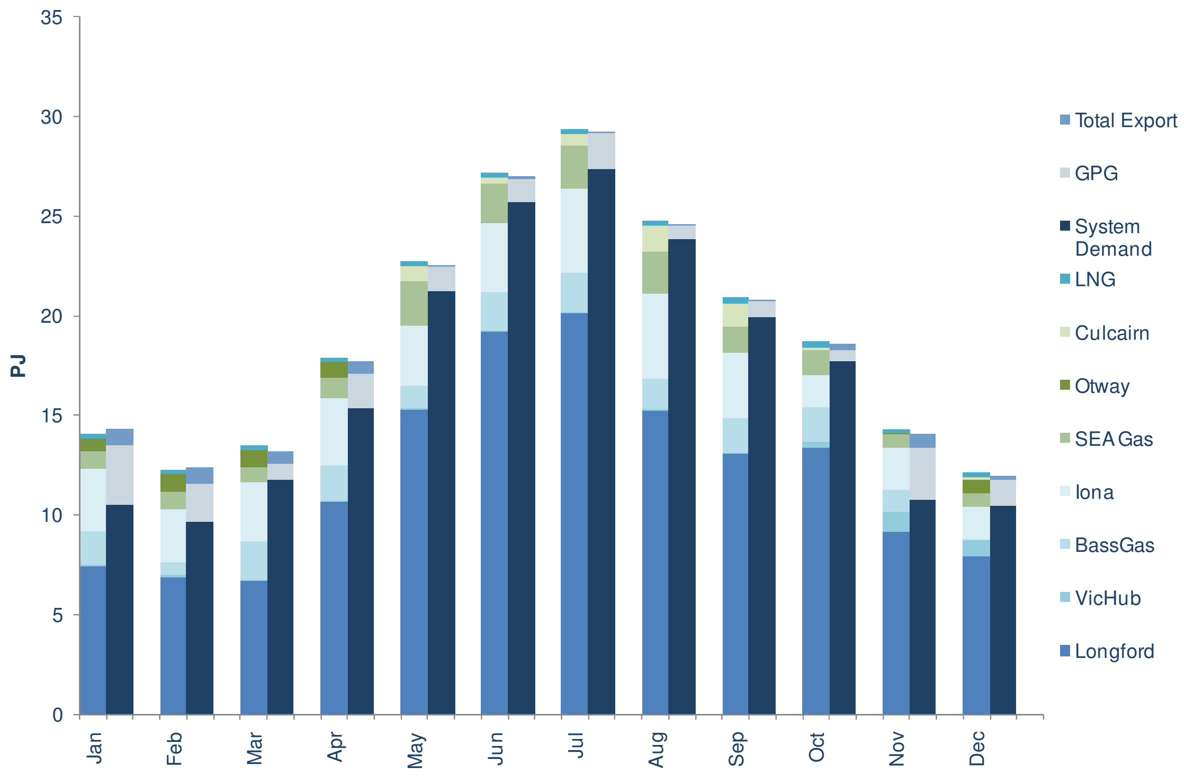
Injection point	12 months to December 2009	% of Total	May to September 2009	% of Total
Longford	145.37	64.64	83.17	65.21
VicHub	2.46	1.09	0.1	0.08
BassGas	17.21	7.65	8.31	6.51
Total Longford, VicHub and BassGas	165.04	73.38	91.58	71.80
Iona UGS	35.57	15.82	18.15	14.23
SEA Gas	16.01	7.12	9.80	7.68
Otway	3.94	1.75	3.94	3.09
Total Iona, SEA Gas and Otway	55.52	24.69	31.89	25.00
Culcairn	4.35	1.93	4.09	3.20
Total (excluding LNG)	224.91	100.00	127.55	100.00
LNG [1]	0.00	0.00	0.00	0.00
Total (including LNG)	224.91	100.00	127.55	100%
1. This represents scheduled LNG only.				

3.6 Demand and supply comparison

3.6.1 Monthly demand and supply comparison

Figure 3-22 shows the components of demand and supply for the 12-month period. In general, monthly demand and supply was lower during 2009 when compared to 2008, especially for the winter months except June. A large proportion of this overall decrease can be attributed to the milder weather conditions and decrease in GPG demand. Other changes in demand include the fall in exports at Iona. Exports in 2009 were much lower during the months of May to October, compared to 2008.

Figure 3-22 – Monthly demand and supply comparison, 2009 (PJ/month)



3.7 Pipeline injections, withdrawals and operating boundaries

This section details the maximum allowable pipeline injections and contributing factors to pipeline operating boundaries for each main pipeline within the gas DTS. The System Security Guidelines provide information about minimum pressure requirements [10].

This section also provides an overview, focussing on bulk gas transfers, of gas DTS pipeline gas injections, withdrawals, normal operating boundaries, and spare capacity. In this context:

- transmission system/pipeline capacity refers to the maximum demand that can be met on a sustained basis under a defined set of operating conditions (see the Glossary for more information), and
- normal pipeline operating boundaries refer to the normal range of injections into a pipeline due to operational requirements and other contributing factors, as well as anticipated gas DTS augmentations.

Table 3-11 lists a summary of the currently allowable maximum pipeline injections, pipeline operating boundaries, and withdrawals. Nominal values are used, but reference is also made (where appropriate) to the range of injections for different operating conditions. These capacities assume a

[10] See the AEMO website for more information about the System Security Guidelines.

flat profile (a constant injection rate) for gas supply injections and a winter peak demand profile (unless otherwise specified).

See Section 3.4, for more information about the location of key gas DTS infrastructure, including gas DTS and non-gas DTS pipelines, system injection points, city gates, compressor stations, and the LNG storage facility.

Table 3-11 – Pipeline injections, withdrawals, and operating boundaries

Pipeline	Allowable maximum pipeline injections (TJ/d)	Normal pipeline operating boundary (TJ/d)	Comment
Longford to Melbourne	1,030	990-1,030	Longford to Melbourne pipeline injections are 990 TJ/d with coincident injections from Esso and VicHub. This can increase to 1,030 TJ/d with further coincident injections from BassGas (at Pakenham). These capacities are based on Longford pressures not exceeding 6,750 kPa When BassGas is injecting, and on reaching pipeline capacity, injections at Longford need to be reduced in the ratio of 1 to 3 to compensate See Section 3.7.1 for more information
South West Pipeline (from Iona)	347	220-315	South West Pipeline injection rates at Iona depend on the pipeline's pressure and Geelong system withdrawal zone demand Providing for the maintenance of Western Transmission System supply security, a winter operating pressure at the beginning-of-day at Iona of: • 9000 - 10,000 kPa enables injections of 347 TJ/d, and • 8,500 kPa enables injections of 315 TJ/d. See Section 3.7.2 for more information
South West Pipeline (to Iona)	129 [1]	38-129	Allowable withdrawals at Iona (which occur mostly during summer) fall when the Laverton North gas power generation (GPG) plant is operating. During winter, Iona withdrawals are greatly reduced compared to summer. In fact, due to market forces it is expected that Iona will inject during winter See Section 3.7.3 for more information
New South Wales Interconnect (imports)	92	35~92	92 TJ/d can be imported when both the Young Centaur compressor and the Springhurst compressor are operating. If the Springhurst compressor is not operating, import capacity is 60 TJ/d. If the Young compressor is not operating, import capacity is 50 TJ/d. If neither compressor is operating, import capacity is 35 TJ/d See Section3.7.4 for more information
New South Wales Interconnect (exports - summer)	50	0-50	Summer exports to New South Wales are normally 25 TJ/d. With commissioning of the compressor at Culcairn and favourable operating conditions in both Victoria and New South Wales, up to 50 TJ/d can be exported
New South Wales Interconnect (exports - winter)	10	0-10	Winter exports are limited to 10 TJ/d under ideal circumstances, due to expected gas DTS linepack, pressure and compression operating conditions See Section 3.7.5 for more information
Western Transmission System	28	17-28	Western Transmission System injections at Iona of 17-22 TJ/d are possible with Iona compression and Iona pressures of 4,000 kPa to 4,300 kPa. This can increase to 28 TJ/d with sufficient injections from Iona See Section 3.7.6 for more information
1. This refers to maximum withdrawals from Iona rather than maximum injections into the SWP			

3.7.1 Longford to Melbourne pipeline

Pipeline injections and withdrawals

The modelled injections into the Longford to Melbourne pipeline are 990 TJ/d, when injections are solely from Longford. This figure assumes:

- injections from the Exxon-Mobil plant and VicHub (only) at Longford
- that there are no injections from BassGas
- favourable operating conditions (for example, sufficient beginning-of-day linepack), and
- that all compressors and other transmission assets are available.

Longford pipeline modelling assumes a Longford operating pressure of up to 6,750 kPa. High pressures at Longford, especially overnight, can cause the Exxon-Mobil plant to back off injections. BassGas injections at Pakenham of 60 TJ/d increase the Longford to Melbourne pipeline's injection capacity to a maximum of 1,030 TJ/d. When BassGas is injecting, and on reaching pipeline capacity, injections at Longford need to be reduced in the ratio of 1 to 3 to compensate.

Pipeline operating boundary - contributing factors

Factors affecting the operating boundary include:

- system linepack and Longford morning peak pressures (for example, low linepack and morning peak pressures reduce Longford's capacity to inject gas)
- demand forecast accuracy and its impact on the scheduling of gas injections (leading to an unexpected reduction in linepack and a potential increase in scheduled injections)
- Gooding and Wollert Compressor Station (CS) operations, and
- GPG in the Latrobe Valley and other intermittent sources of significant gas demand.

3.7.2 South West Pipeline (from Iona)

Pipeline injections and withdrawals

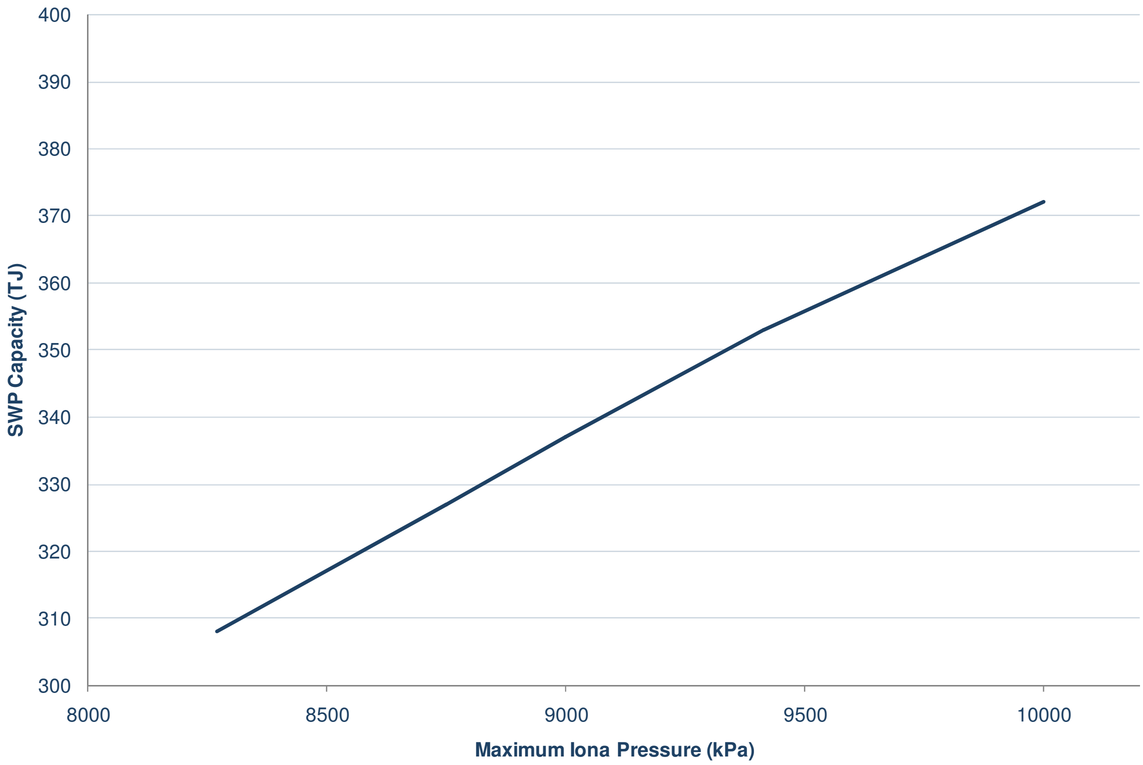
Under normal conditions, current operating strategy requires Iona to operate at 8,500 kPa at beginning-of-day, producing an SWP operating boundary of approximately 315 TJ/d. This operating boundary allows gas from Longford to be stored within the SWP on days when demand is lower than forecast, and the pressure at Longford is close to 6,750 kPa.

The current capacity of the SWP (from Iona to Lara) is declared to be 347 TJ/d, which is the amount of gas that can be transported from Iona towards Melbourne. Modelling has shown that the pipeline's capacity differs under different operating conditions.

Figure 3-23 shows the relationship between SWP capacity and maximum operating pressures at Iona. The SWP can transport 353 TJ/d based on an average of 9,000 kPa at Iona (corresponding to a maximum operating pressure of approximately 9,500 kPa on the diagram) and can transport up to 372 TJ/d on a 1 in 20 peak day under ideal conditions if the pipeline is operating at its maximum allowable operating pressure (MAOP) of 10,000 kPa at Iona. However, for operational reasons, it is considered impractical to operate the pipeline at MAOP.

AEMO is currently reviewing the declared capacity of the SWP with a view to potentially revising it on the basis of the latest modelling.

Figure 3-23 – SWP capacity with varying Iona pressure



Pipeline operating boundary - contributing factors

Factors affecting the SWP operating boundary include:

- demand uncertainty
- linepack management requirements, and
- beginning-of-day pressure at Iona.

Allowing the pipeline to be operated at pressures approaching its MAOP enables increased injections. High pipeline pressures, however, create operational issues for the gas DTS. For example, warmer than expected weather and lower daily demand increase the risk of high pressure at Longford, especially overnight. Inability to shift linepack to the SWP due to high pressure at Iona can cause the Exxon-Mobil plant to back-off injections, possibly resulting in a risk to system security (depending on the time required to restore the plant to full capacity).

On the other hand, operating the pipelines at lower pressures (for example, 4,000 kPa) reduces linepack. This reduces pipeline capacity and operational responsiveness to potential system security threats on high demand days.

In winter, an Iona beginning-of-day pressure of 8,500 kPa enables injections of 315 TJ/d, including additional WTS flow. This provides a reasonable balance of injections, usable system linepack, operational responsiveness from Iona, and the ability to accommodate a linepack increase if overnight temperatures unexpectedly rise, causing a reduction in demand. The analysis of LNG requirements for within-day balancing (see Chapter 6 for more information) also assumes SWP injections of approximately 220 TJ/d.

Pressure management issues at Iona occur due to the day-to-day variations in Iona injections. In the future, regular high Iona injection levels may require an increase in Iona beginning-of-day pressure and gas DTS linepack targets. This can, however, reduce operational flexibility in managing linepack.

3.7.3 South West Pipeline (to Iona)

Pipeline injections and withdrawals

The capacity to withdraw at Iona currently depends on the throughput of the Brooklyn Compressor Station. Based on summer conditions, and after meeting demand from the Geelong Zone and the WTS [11], the maximum modelled withdrawals from the SWP at Iona are:

- 129 TJ/d with the BLP pipeline coupled with the operation of Unit 11 and Unit 12, and a minimum pressure of 4,300 kPa at Iona
- 38 TJ/d if only Unit 11 is available, and
- 65 TJ/d if only Unit 12 is available.

Factors leading to a future reduction in the requirement to transport gas to Iona include the:

- likelihood of year-round SEA Gas injections (in the medium term)
- the requirement to inject gas at Iona to meet system demand, and
- development of new supplies from the Otway Basin, such as the Casino, Minerva, Geographe and Thylacine gas fields.

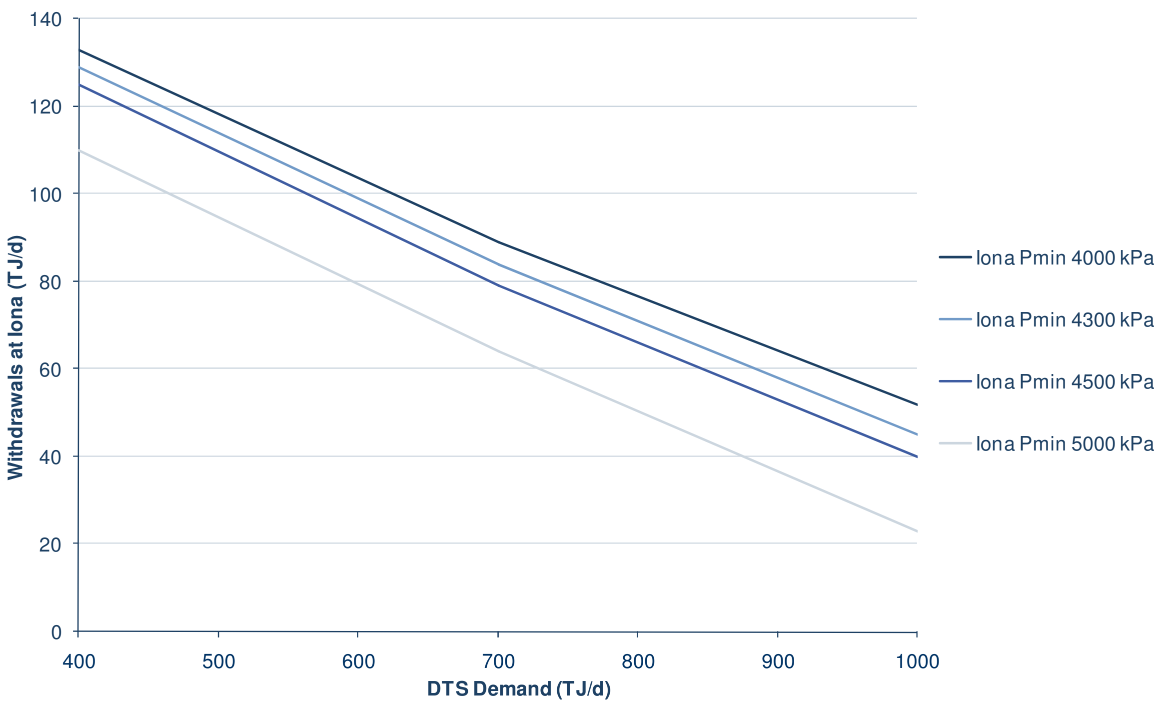
Withdrawals from the SWP at Iona can be shared between the UGS, the SEA Gas interconnect, and the WTS.

Figure 3-24 shows the effect of different levels of system demand and different minimum Iona pressures on the ability to withdraw at Iona. The modelling assumes there is no GPG operating downstream of Brooklyn.

Simulations for the summer period indicate that there is a reduction in withdrawal capability of approximately 1 TJ/d for every 10 TJ/d of GPG demand at Newport and by 10 TJ/d for every 10 TJ/d of GPG demand at Laverton North.

[11] Approximately 10-19 TJ/d is required to meet WTS demand. Part of the Brooklyn CS capacity can also be used to supply the Ballarat pipeline in winter.

Figure 3-24 – Withdrawals at Iona as a function of gas DTS demand



Pipeline operating boundary - contributing factors

Factors affecting the operating boundary (for possible Iona withdrawals) include the:

- demand downstream of Brooklyn (including the Laverton North GPG, Geelong Zone and WTS loads), and
- minimum operational pressure requirements at Iona.

During the shoulder season (September or October), minimum pressure requirements to ensure adequate SWP linepack are:

- approximately 4,300 kPa (depending on system conditions), and
- 4,500 kPa to provide the additional linepack to meet a 1 in 20 peak demand load in the WTS.

These figures allow for the management of a possible load increase from Laverton GPG if gas is withdrawn at Iona.

Modelling indicates that maintaining Iona's beginning-of-day pressure at 5,000 kPa (during the higher demand days from Sunday to Thursday in the non-winter period) will provide an extra 12 TJ of linepack available for reserve to improve overall system security [12].

Future increases in Iona's minimum pressure targets may be required for at least part of the year so as to:

- provide sufficient SWP security margins to ensure supply security to the WTS, and
- help manage Iona withdrawals in combination with withdrawals at the Laverton North GPG.

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[12] See the AEMO website for more information about the System Security Guidelines.

The requirement to maintain Iona at higher pressure, however, will lead to a reduction in the ability to withdraw gas at Iona.

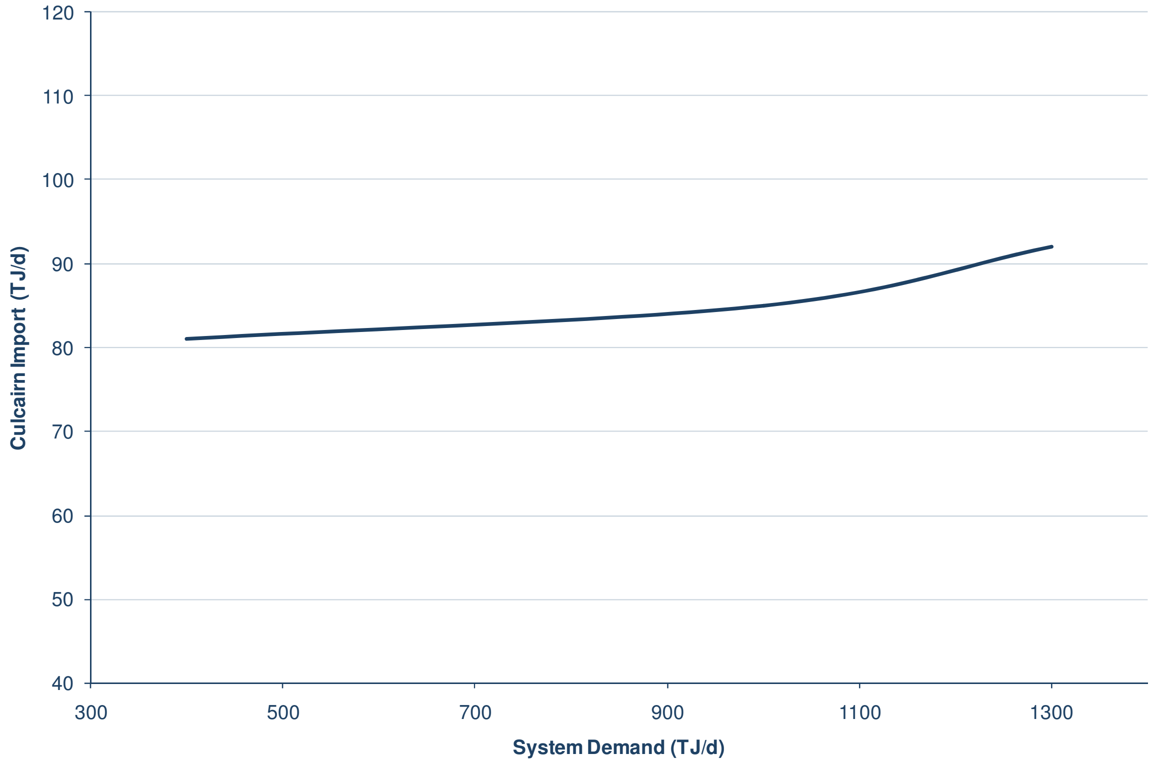
3.7.4 New South Wales interconnect (imports)

Pipeline injections and withdrawals

It was reported last year that the Young and Springhurst compressors are available to assist Victorian gas import via Culcairn. When both the Young and Springhurst compressors are operating, the maximum Culcairn import capacity is 92 TJ/d.

Figure 3-25 shows the effect of different levels of system demand on the maximum possible capability to import gas at Culcairn. The modelling assumes the Young compressor has adequate power to operate at constant discharge pressure of 8,500 kPa, the Springhurst compressor is operating, the Uranquinty Power Station is not in operation, and the system was set up to maximize the import.

Figure 3-25 – Imports from New South Wales through Culcairn



If the Springhurst compressor is not operating, the import capacity is 60 TJ/d. If the Young compressor is not operating, the capacity is 50 TJ/d. If both compressors are unavailable, the approximate import capacity is 35 TJ/d.

The pipeline owner has advised of its commitment to commission the Wagga-Wagga Loop between Young and Culcairn in New South Wales. The loop could increase the import capacity from 92 TJ/d to approximately 120TJ/d based on the similar operation conditions of the gas DTS and the MSP system.

Pipeline operating boundary - contributing factors

Factors affecting the operating boundary include:

- gas DTS demand in Victoria and system demand in New South Wales
- operational constraints in New South Wales, and
- Northern Zone linepack.

No firm or non-firm supplies from New South Wales have been advised for the forecast period.

3.7.5 New South Wales interconnect (exports)

Pipeline injections and withdrawals

APA Group commissioned a new compressor at Culcairn during 2009. Previously, pressures north of Culcairn were regularly too high to enable exports from the gas DTS via the New South Wales interconnect during winter.

Exports during winter and increased exports during summer when gas DTS demand is low, can now be achieved.

Pipeline operating boundary - contributing factors

Factors affecting the operating boundary include the:

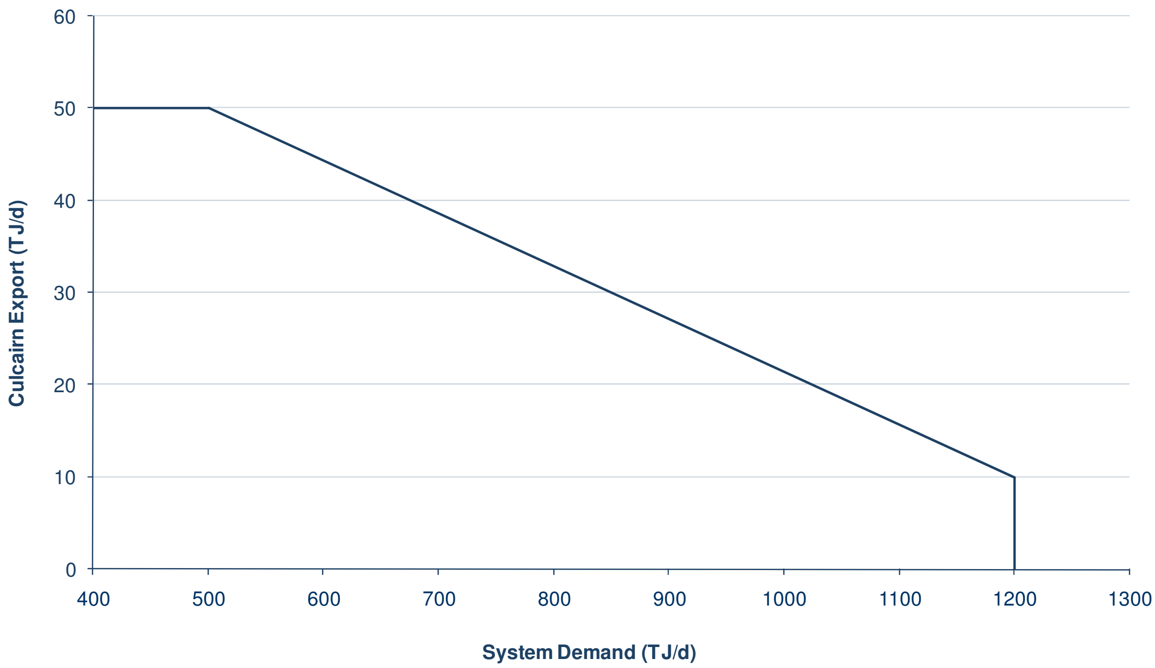
- pressures on the New South Wales side of the interconnect
- demand levels in the gas DTS and New South Wales
- length (260 km) and diameter (300 mm) of the pipeline from Wollert to Barnawartha
- Wollert CS capacity, and
- Northern Zone linepack.

Export operations have limited flexibility due to an inability to switch from imports to exports on a daily or a within-day basis. Import to export mode changes require advance planning of a day or more, providing time for adequate pressurisation of the Northern Zone to enable exports.

Figure 3-26 shows the relationship between Culcairn export capacity via the New South Wales Interconnect and gas DTS demand. These exports are achievable with a pressure at Culcairn of 3,000 kPa due to the operation of the Culcairn compressor.

In winter, the ability to export to New South Wales declines due to higher peak winter demand in the gas DTS and Northern Victoria.

Figure 3-26 – Exports to New South Wales at 3,000 kPa minimum pressure at Culcairn



3.7.6 Western Transmission System

Pipeline injections and withdrawals

The maximum modelled injections into the WTS are 28 TJ/d (assuming injections at Iona support Iona pressures of at least 7,500 kPa for the current demand forecast). This is not a firm capacity and requires high net injections at Iona over consecutive days to maintain the pressure.

Pipeline operating boundary - contributing factors

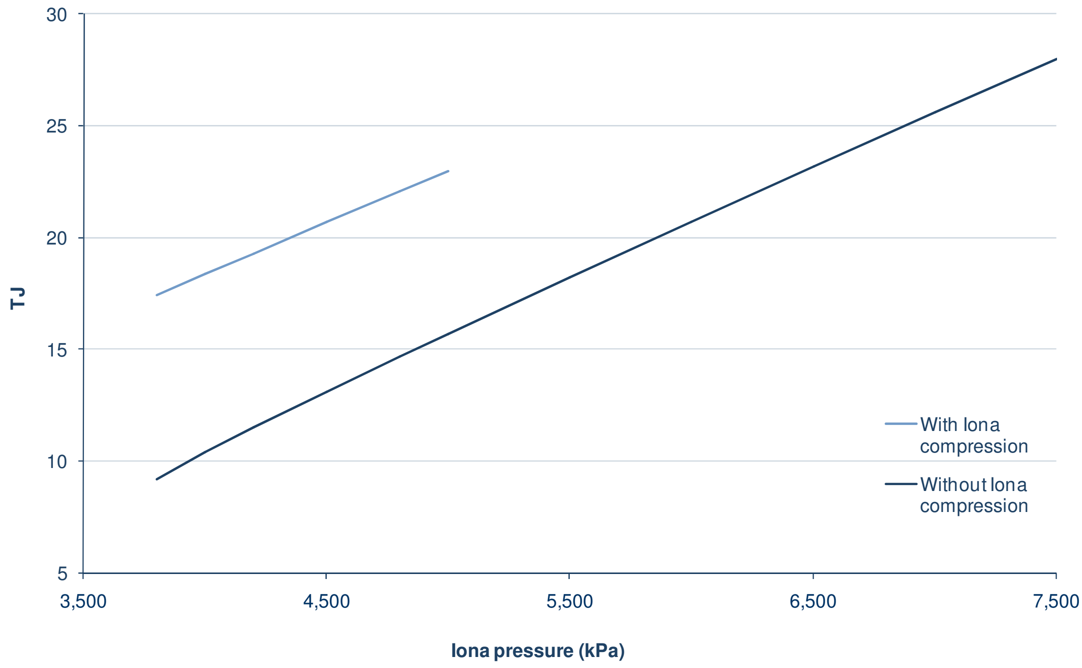
Factors affecting the operating boundary include the:

- WTS load growth (given its fringe location), and
- pressures at Iona.

Depending on the preceding day's SWP gas flows, Iona pressures may be high enough to supply WTS demand without using the Iona compressors.

Figure 3-27 shows the relationship between injections into the WTS and the pressures at Iona.

Figure 3-27 – Western Transmission System injections and Iona pressures



The WTS has unique operational pressure requirements. In terms of WTS demand:

- compression at Iona is required to meet moderate and peak demands when SWP pressures at Iona are relatively low
- without Iona compression, the SWP's minimum pressure at Iona of 3,800 kPa is lower than the normal 4,300 kPa minimum operational requirement and limits supplies to approximately 10 TJ/d, which is insufficient except on days of low summer demand - with Iona compression, the same minimum pressure at Iona will enable supplies of approximately 18 TJ/d, and
- peaks can occur in September and October (or both), due to the region's increased food and dairy processing plant activity, when the Iona UGS can also be in withdrawal mode.

Peak WTS demand is currently forecast to grow. As a result of this growth, Iona pressures higher than 4,300 kPa are required to meet peak demand in winter, as well as in September and October when Iona is in withdrawal mode and SEA Gas is not injecting. Iona pressures will need to increase to approximately 4,500 kPa by 2012, however, to maintain WTS security of supply on a 1 in 20 day.

When Iona is not injecting gas, the WTS can be supplied with Gippsland gas via the Brooklyn Compressor Station. Brooklyn compression can build Iona pressures over 12 to 24 hours to around 5,000 kPa if gas is not being withdrawn at Iona. This pressure enables security of supply to the WTS on a moderate demand day without further compression at Iona.

If the Iona compressor's discharge pressure is approximately 6,500 kPa, the WTS fringe pressures at Portland and Hamilton fewer than 1 in 20 peak day conditions can be maintained until 2013.

3.7.7 System capacity

The modelled maximum individual capacities of the gas DTS pipelines are as follows:

- The Longford pipeline is 1,030 TJ/d, with Longford injecting 970 TJ/d and BassGas injecting 60 TJ/d.
- The SWP pipeline is 347 TJ/d.
- The New South Wales interconnect is 92 TJ/d.

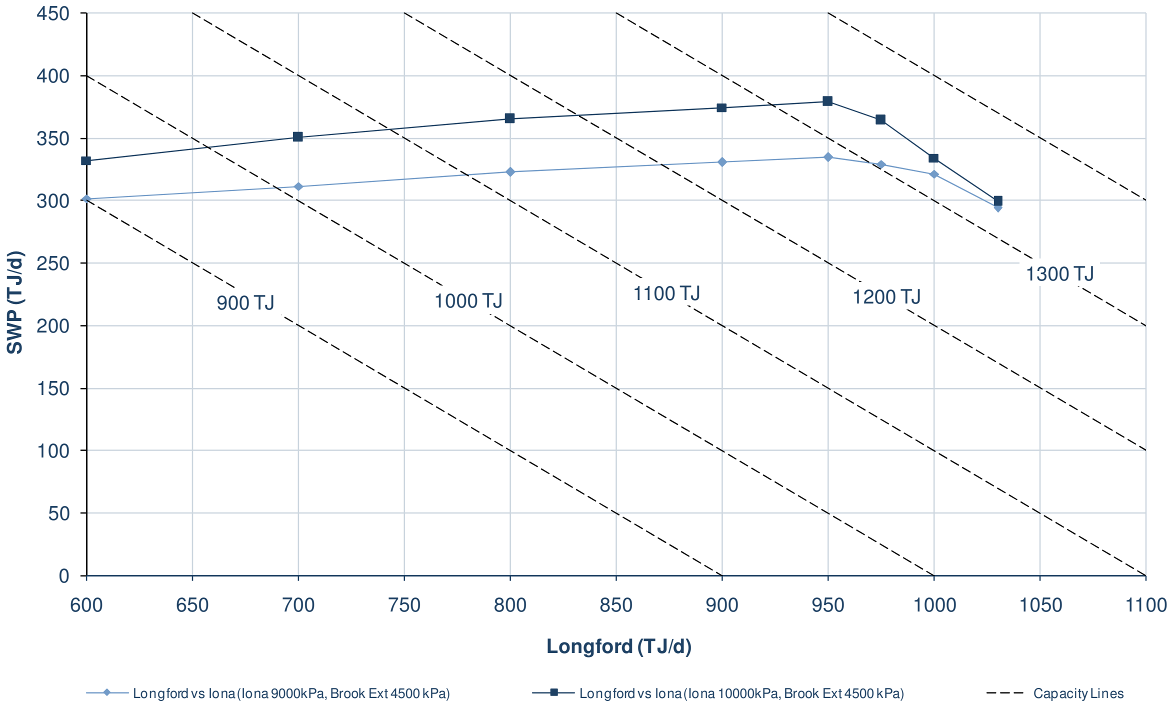
Due to transmission system constraints, however, total gas DTS pipeline capacity is not determined by summing these capacities.

Figure 3-28 shows the gas DTS system capacity under a simplified scenario where Culcairn flow is assumed to be zero. The upper line shows the SWP capacity when Iona operates at up to 10,000 kPa, and the lower line shows the SWP capacity when Iona operates at up to 9,000 kPa. The oblique lines show the total system demand. Figure 3-28 shows with Iona operating at pressure up to 9,000 kPa the maximum system capacity is 1,316 TJ/d.

This figure shows the limits of system capacity with a feasible operational region below and to the left of the coloured lines. The upper area tends to maximise Iona injections and the right hand region maximises Longford injections.

With Iona operating at up to 10,000 kPa, the system can achieve 1,330 TJ/d.

Figure 3-28 – Gas transmission system capacity [13]



3.8 Committed augmentations – gas transmission

This section provides information about new and modified connections and developments commenced or concluded throughout the year.

[13] Figure prepared using 2009 Custody Transfer Meter (CTM) forecast.

3.8.1 New and modified connections

Table 3-12 lists the committed new or modified gas DTS connections for 2009/10.

Table 3-12 – New and modified gas DTS connections

Location	Description	Completion date
Castlemaine, Chiltern, Cranbourne East, Damum, Epping, Hampton Park, Lyndhurst	Meter upgrades	2010
Wyndham Vale	A new connection	Winter 2010

3.8.2 Pakenham South branch pipeline duplication

Modelling has found that the 80 mm section of the Pakenham South branch pipeline can experience very high gas velocities under peak demand conditions. APA Group has indicated that duplication of the small diameter section of this lateral is expected to be completed by end of June 2010.

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Chapter 4 Demand forecasts

This chapter presents electricity and gas demand forecasts for the forecast period (2010-2019), covering the:

- Victorian electricity annual energy and maximum demand (MD) for electricity
- peak day system demand and annual demand for gas supplied through the gas Declared Transmission System (gas DTS), and
- demand from gas powered generators (GPG) supplied from the gas DTS.

AEMO uses these forecasts to identify future Victorian transmission constraints and to quantify potential development proposals.

Electricity

The electricity energy and MD forecasts, which form key inputs into Victorian electricity Declared Shared Network (electricity DSN) planning, were prepared by the National Institute of Economic and Industry Research (NIEIR) and AEMO in May 2010.

AEMO engaged KPMG Econtech to provide an updated assessment of the economic outlook and policy environment for the National Electricity Market (NEM) regions in April 2010, including high and low economic growth scenarios, which was used to prepare the forecasts in this chapter.

The forecasts presented in the VAPR are consistent with the Victorian forecasts that will be published in AEMO's 2010 Electricity Statement of Opportunities (ESOO).

Gas

The gas system demand and GPG forecasts were prepared by NIEIR in November 2009. The Victorian economic outlook used in their preparation was produced by NIEIR in September 2009.

The 2009 Victorian Annual Planning Report Update (VAPR Update), available from the AEMO website, provides an overview of the annual gas system demand forecast inputs and the forecast approach. The report also includes:

- information about the peak day forecast methodology and the probability of exceedence (POE) weather standards
- a comparison of the 2008 and 2009 gas DTS peak day and annual demand forecasts for the period 2010-2018
- information about economic growth forecasts
- details about GPG demand forecasts, and
- information about the demand forecasts by gas region.

Unless otherwise stated, 'system demand' refers to demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum), and excludes GPG demand, exports, and gas withdrawn at Iona.

In this chapter:

Section 4.1 provides AEMO's 2010 Victorian electricity annual energy and MD forecasts, including:

- information about key definitions and the forecast approach

- summer peak demand forecasts for 2010/11-2019/20
- winter peak demand forecasts for 2010- 2020
- annual electricity consumption forecasts for 2010/11- 2019/20
- demand-side participation (DSP) forecasts
- a comparison of the 2009 and 2010 VAPR forecasts, and
- semi-scheduled and non-scheduled generation forecasts.

Section 4.2 presents an overview of the gas demand forecasts developed in November 2009 and published in the 2009 VAPR Update, including:

- peak day gas demand forecasts for 2010- 2019
- annual system demand for 2010- 2019
- GPG demand for 2010- 2019, and
- export demand (and export levels).

4.1 Electricity demand forecasts

Definitions of native energy and maximum demand

Native energy and native MD refers to the load supplied by scheduled, semi-scheduled, and significant non-scheduled generating units.

Scheduled and semi-scheduled (a new registration category that came into effect on 31 March 2009) generating units are dispatched by AEMO through the central dispatch process. Non-scheduled generating units are not dispatched by AEMO, and significant non-scheduled generating units have a nameplate rating of 1 MW or more and AEMO has access to the unit's actual generation data [14].

Generally generating units with an aggregate nameplate rating of:

- 30 MW or more are classified as scheduled or semi-scheduled (unless AEMO approves otherwise), and
- less than 30 MW are classified as non-scheduled (unless AEMO approves otherwise).

Generating units with a nameplate rating of 30 MW or more can be classified as non-scheduled if it is impractical for the unit to participate in AEMO's central dispatch process. Prior to 31 March 2009, this included generators with intermittent output such as wind generation. From 31 March 2009, generating units with intermittent output can be classified as semi-scheduled.

The energy and MD forecasts presented in this chapter are made on a native basis. Forecasts of significant non-scheduled generation are also provided, as both annual energy projections and expected levels of generation at the time of the forecast MD. Scheduled and semi-scheduled forecasts can be calculated by subtracting the significant non-scheduled MD forecasts from the

[14] Significant non-scheduled generators included in AEMO's 2010 VAPR forecasts include the existing and committed Victorian wind farms (Challicum Hills, Codrington, Toora, Wonthaggi, Yambuk, Portland and Waubra) and mini-hydros (Clover and Rubicon).

native MD forecasts. These forecasts are consistent with the forecast demand supplied by generation dispatched through AEMO's central dispatch system.

Forecast basis

AEMO's annual energy forecasts are prepared using a high-level top-down econometric approach. The economic scenario and electricity market inputs were developed for the forecasts by KPMG Econtech. The forecasting impacts from energy and environmental policy measures were developed by NIEIR.

The native energy forecasts represent total annual growth in Victorian electricity consumption. The native MD forecasts represent the growth in electricity consumed in the single half-hour when electricity usage is at its greatest for the year.

The key drivers of energy consumption growth include:

- economic conditions, in particular Victorian gross state product (GSP) growth
- population growth
- energy and environment policy measures and price assumptions, and
- stock and technological changes in electrical equipment and appliances.

The key drivers of MD, in addition to economic and policy impacts, include:

- weather conditions
- air conditioning or electric space heating penetration, and
- customer responsiveness to weather conditions.

NIEIR develop peak demand forecasts for summer and winter using a simulation approach to forecast probability distributions for the range of possible demand outcomes. The simulation model incorporates assumptions regarding space heating and cooling appliance penetration, customer behaviour, and warming trends developed by NIEIR from research and consumer surveys. The 10%, 50% and 90% POE MD forecasts are prepared for each energy forecast, representing the 90th, 50th and 10th percentiles of the distribution of MD for each season.

The forecasts assume that no DSP occurs at the time of the MD, and forecasts for DSP are presented separately.

See the Victorian Electricity Forecast Report (available on AEMO's website) for more information about the electricity annual energy and MD forecasting methodology.

Scenario assumptions

Three scenarios were developed: a base or medium economic growth scenario (representing KPMG Econtech's best estimate of the outlook for the Australian economy), a high growth scenario (optimistic) and a low growth scenario (pessimistic).

The principal source of uncertainty for the energy forecasts involved the timing and the impact of Australian Government policies and schemes, including the CPRS. The significant uncertainty created by the shelving of this policy means that the assumptions relating to it should be taken into account when considering the 2010 forecasts. For the medium growth scenario, NIEIR developed the assumptions regarding the impact of energy and environmental policy on electricity price and demand. These impacts were reduced for the high energy scenario (i.e., assumed to cause a smaller reduction in electricity used), and increased for the low energy scenario to account for the inherent uncertainty in policy measure impacts.

Summary of the 2010 energy and maximum demand projections

Under the medium growth scenario, Victoria's summer 10% POE MD is forecast to increase by 3.4%, from 10,425 MW in 2009/10 to 10,783 MW in summer 2010/11, and at an average rate of 2.1% per annum over the forecast period to reach 12,930 MW by 2019/20.

Victorian energy use is forecast to increase by 0.4% over 2010/11 to 52,092 GWh. After 2010/11, average growth in energy consumption is expected to increase at an average rate of 0.9% per annum over the forecast period to reach 56,804 GWh.

This is lower than the 1.4% per annum growth experienced over the previous 10 years, reflecting the impact of government energy policies on energy demand, including the assumed introduction of a Carbon Pollution Reduction Scheme (CPRS).

4.1.1 Summer native maximum demand forecasts

Ten-year forecasts

Table 4-1 lists the forecast summer 10%, 50%, and 90% POE native MDs. From the start of the forecast period, the summer 10% POE native MD is projected to grow each year by:

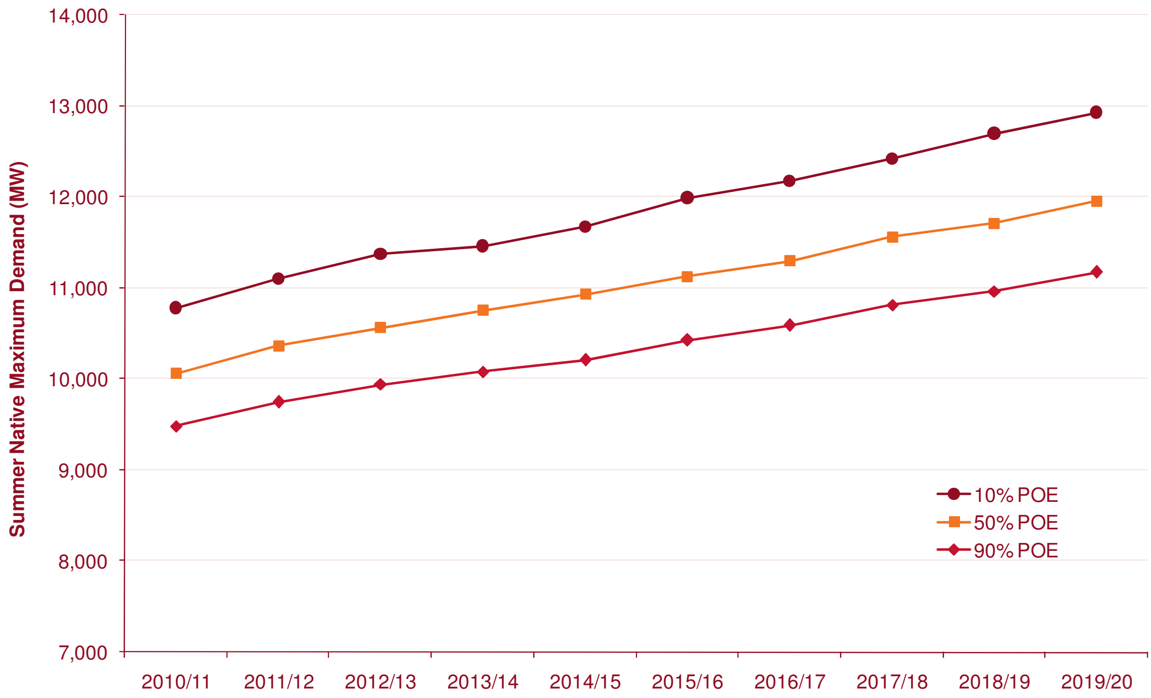
- 2.0% under the medium growth scenario
- 2.4% under the high growth scenario, and
- 1.7% under the low growth scenario.

Table 4-1 - Summer native maximum demand forecasts (MW)

Year	POE	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High	10%	10,911	11,244	11,598	11,716	11,963	12,339	12,542	12,826	13,163	13,461
	50%	10,188	10,503	10,764	10,999	11,208	11,457	11,643	11,943	12,141	12,452
	90%	9,604	9,878	10,134	10,318	10,471	10,740	10,915	11,170	11,368	11,635
Medium	10%	10,783	11,103	11,372	11,461	11,673	11,990	12,174	12,421	12,699	12,930
	50%	10,063	10,367	10,567	10,754	10,934	11,129	11,302	11,566	11,712	11,959
	90%	9,481	9,747	9,941	10,083	10,211	10,426	10,589	10,815	10,965	11,173
Low	10%	10,670	10,903	11,120	11,193	11,365	11,639	11,751	11,962	12,242	12,445
	50%	9,952	10,168	10,343	10,495	10,638	10,793	10,896	11,127	11,281	11,503
	90%	9,372	9,552	9,724	9,831	9,923	10,102	10,198	10,394	10,554	10,739

Figure 4-1 shows the summer 10%, 50%, and 90% POE native MD forecasts under the medium growth scenario for the forecast period.

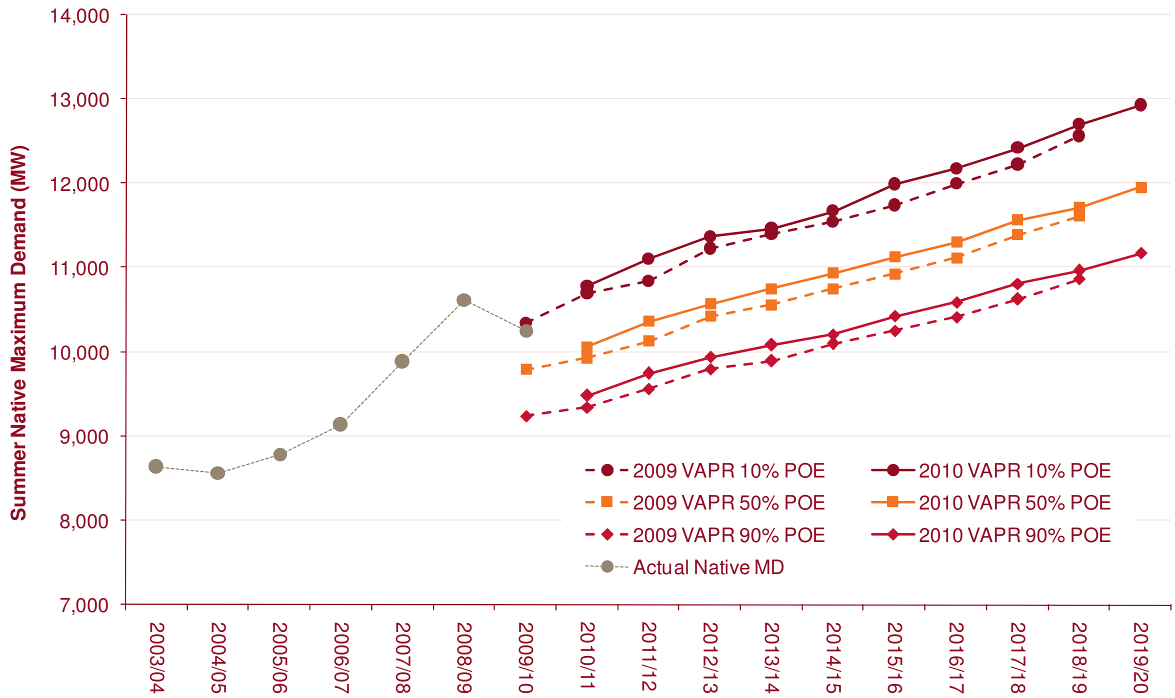
Figure 4-1 – Summer native maximum demand forecasts - medium growth scenario (MW)



Forecast comparison (summer native maximum demand)

Figure 4-2 compares the 2009 and 2010 VAPR summer native MD forecasts. Compared to the 2009 VAPR, the current forecasts for the medium growth summer 10% POE MD are 81 MW, 127 MW and 133 MW higher for the 2010/11, 2014/15 and 2018/19 financial years, respectively.

Figure 4-2 – Comparison of summer native maximum demand forecasts (MW)



4.1.2 Winter native maximum demand forecasts

Ten-year forecasts

Table 4-2 lists the forecast winter 10%, 50%, and 90% POE native MDs. From the start of the forecast period, the forecast 10% POE winter native MD is projected to grow each year by:

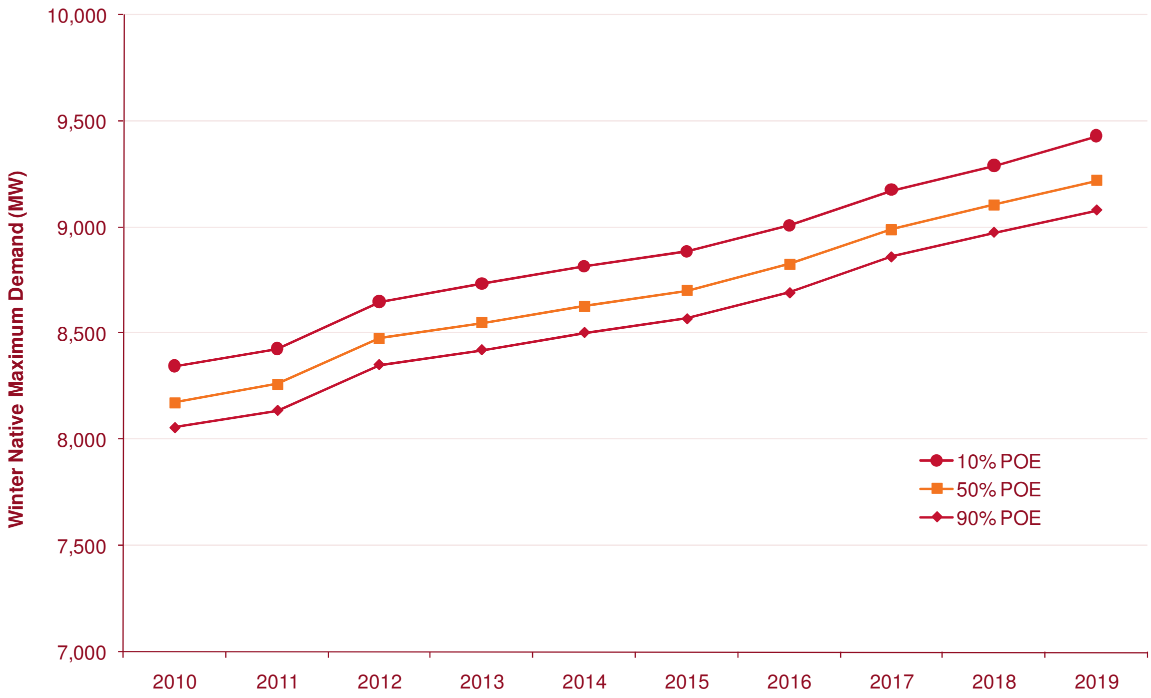
- 1.4% under the medium growth scenario
- 1.7% under the high growth scenario, and
- 1.0% under the low growth scenario.

Table 4-2 – Winter native maximum demand forecasts (MW)

Year	POE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High	10%	8,450	8,538	8,829	9,011	9,125	9,207	9,383	9,538	9,681	9,860
	50%	8,295	8,386	8,670	8,839	8,948	9,035	9,212	9,365	9,509	9,659
	90%	8,176	8,260	8,543	8,706	8,817	8,899	9,073	9,230	9,373	9,513
Medium	10%	8,347	8,429	8,650	8,733	8,816	8,886	9,010	9,175	9,289	9,431
	50%	8,176	8,262	8,477	8,550	8,629	8,702	8,828	8,991	9,107	9,220
	90%	8,057	8,137	8,353	8,422	8,503	8,572	8,695	8,863	8,977	9,081
Low	10%	8,285	8,283	8,433	8,535	8,585	8,622	8,711	8,812	8,900	9,053
	50%	8,132	8,133	8,278	8,370	8,418	8,459	8,551	8,650	8,740	8,868
	90%	8,014	8,008	8,154	8,243	8,294	8,331	8,421	8,524	8,614	8,733

Figure 4-3 shows the winter 10%, 50%, and 90% POE native MD forecasts under the medium growth scenario for the forecast period.

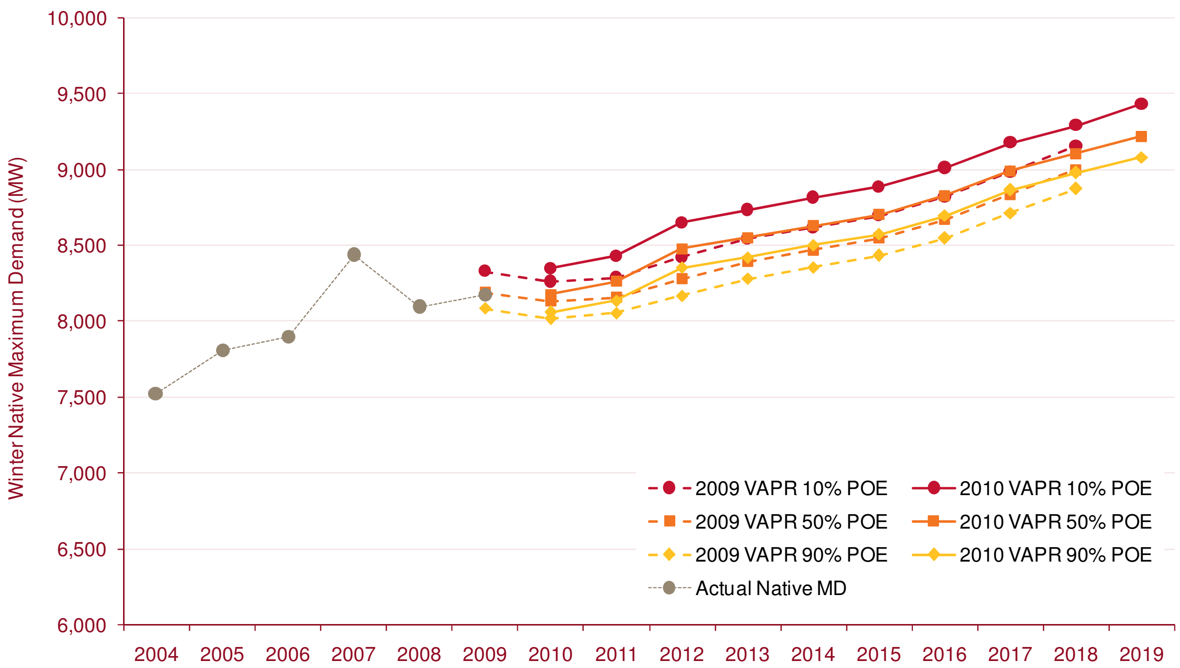
Figure 4-3 – Winter native maximum demand forecasts - medium growth scenario (MW)



Forecast comparison (winter native maximum demand)

Figure 4-4 compares the 2009 and 2010 VAPR winter native MD forecasts. Compared to the 2009 VAPR, the current forecasts for the medium-growth winter 10% POE MD are 85 MW, 199 MW and 137 MW lower for the 2010, 2014 and 2018 calendar years, respectively.

Figure 4-4 – Comparison of winter native maximum demand forecasts (MW)



4.1.3 Native energy forecasts

Ten-year forecasts

Table 4-3 lists the native energy forecasts, which are projected to grow each year, from the start of the forecast period commencing 1 July 2010, by:

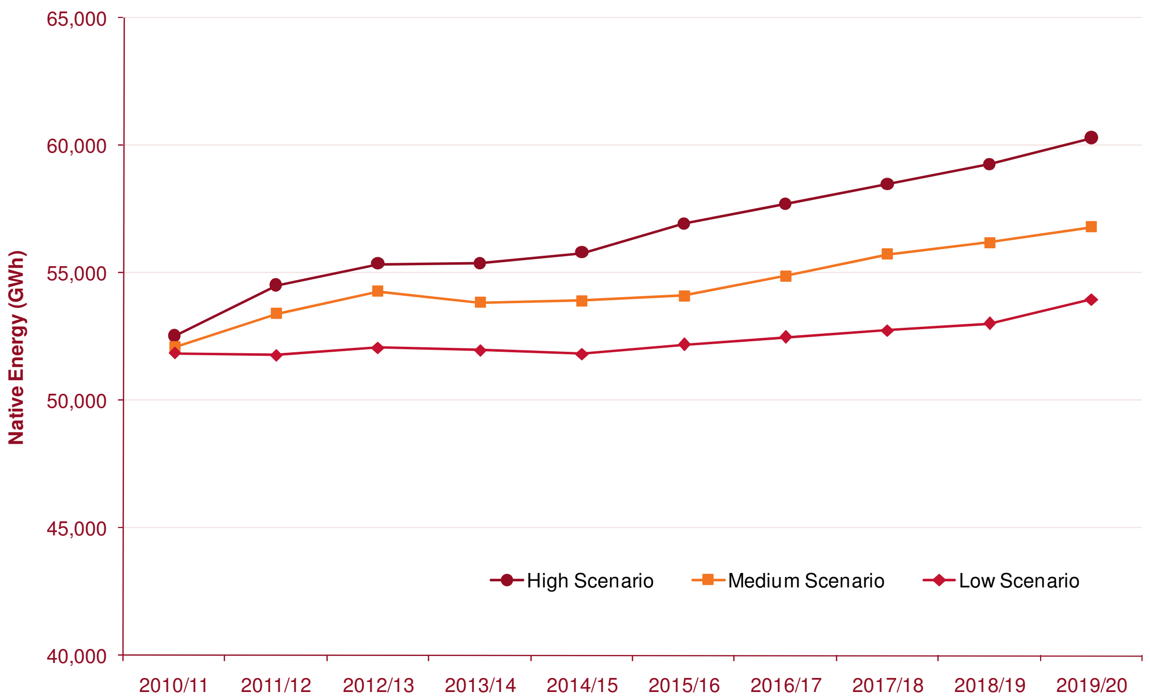
- 0.9% under the medium growth scenario
- 1.5% under the high growth scenario, and
- 0.2% under the low growth scenario.

Table 4-3 – Native energy forecasts (GWh)

Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High	52,539	54,515	55,357	55,383	55,796	56,919	57,716	58,488	59,256	60,306
Medium	52,092	53,404	54,272	53,856	53,930	54,103	54,889	55,746	56,208	56,804
Low	51,865	51,793	52,067	51,977	51,823	52,192	52,488	52,750	53,017	53,972

Figure 4-5 shows the native energy forecasts for the high, medium and low growth scenarios for the forecast period.

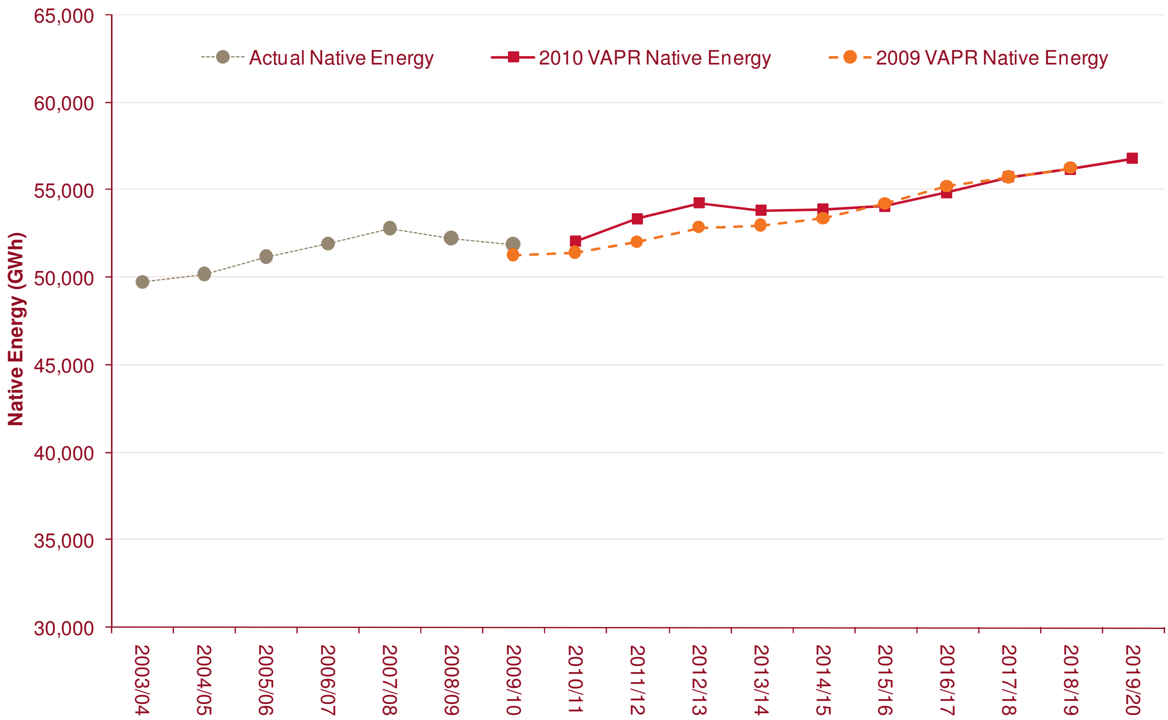
Figure 4-5 – Native energy forecasts (GWh)



Forecast comparison (native energy)

Figure 4-6 compares the 2009 and 2010 VAPR native energy forecasts. Compared to the 2009 VAPR, the current forecasts are higher for the first five financial years but are almost the same from 2015/16 onward under the medium growth scenario.

Figure 4-6 – Comparison of native energy forecasts (MW) (medium growth scenario)



The 2010 native energy forecasts are higher in the first five years mainly due to higher economic projections and a lower assumed impact of government policies. The reduction to the 2010 Native energy forecasts from 2013/14 is mainly due to Carbon price assumptions (see Appendix E.3 for more information).

4.1.4 Demand-side participation forecasts

Demand-side participation (DSP) refers to voluntarily reducing electricity consumption in response to a change in market conditions, such as the spot price.

Participating customers enter into confidential DSP contracts with their respective retailers. Details of these contracts are not available to the market. To obtain confidential DSP information, AEMO, in conjunction with the Load Forecasting Reference Group (LFRG), surveys Victorian distributors, retailers, large industrial customers and a demand response aggregator to collect information about:

- actual DSP that occurred during selected 2009/10 summer and 2009 winter peak demand times, and
- anticipated levels of DSP.

Table 4-4 lists the level of Victorian:

- committed DSP (aggregated), which is the contracted quantity of DSP available at times of high summer and winter demand, and
- non-committed DSP that may be available at times of high demand, depending on market conditions.

Table 4-4 – AEMO survey of Victorian demand-side participation, 2010 (MW)

Year	Committed
AEMO 2010 Survey	54 MW

4.1.5 Major loads

In April 2009, Alcoa announced it was reducing production at its Portland Aluminium Smelter plant by 15% from 1 July 2009. This resulted in the following assumptions for the 2010 VAPR energy and MD forecasts:

- Under the medium growth scenario, smelter production will return to normal (pre-2008/09 production levels) in late 2011, remaining that way for the rest of the forecast period.
- Under the high growth scenario, smelter production will return to normal in mid-2010, and then grow at just under 2% per annum for the rest of the forecast period.
- Under the low scenario, smelter production will be lower than expected in 2009/10, before a partial recovery over the next three years, then returning to 90% of normal production levels for the rest of the forecast period.

The forecasts account for the planned Victorian desalination plant at Wonthaggi [15], details of which assume a 150 GL capacity installed in 2011/12 under all scenarios, increasing to:

- 200 GL in 2016/17 under the medium growth scenario
- 200 GL in 2015/16 and up to 220 GL in 2017/18 under the high growth scenario, and
- 170 GL in 2017/18 under the low scenario.

4.1.6 Comparison of the 2009 and 2010 VAPR forecasts

Table 4-5 lists a comparison of the 2009 and 2010 VAPR forecasts.

Table 4-5 – Summary of 2010/11 forecasts (VAPR 2010 compared with VAPR 2009)

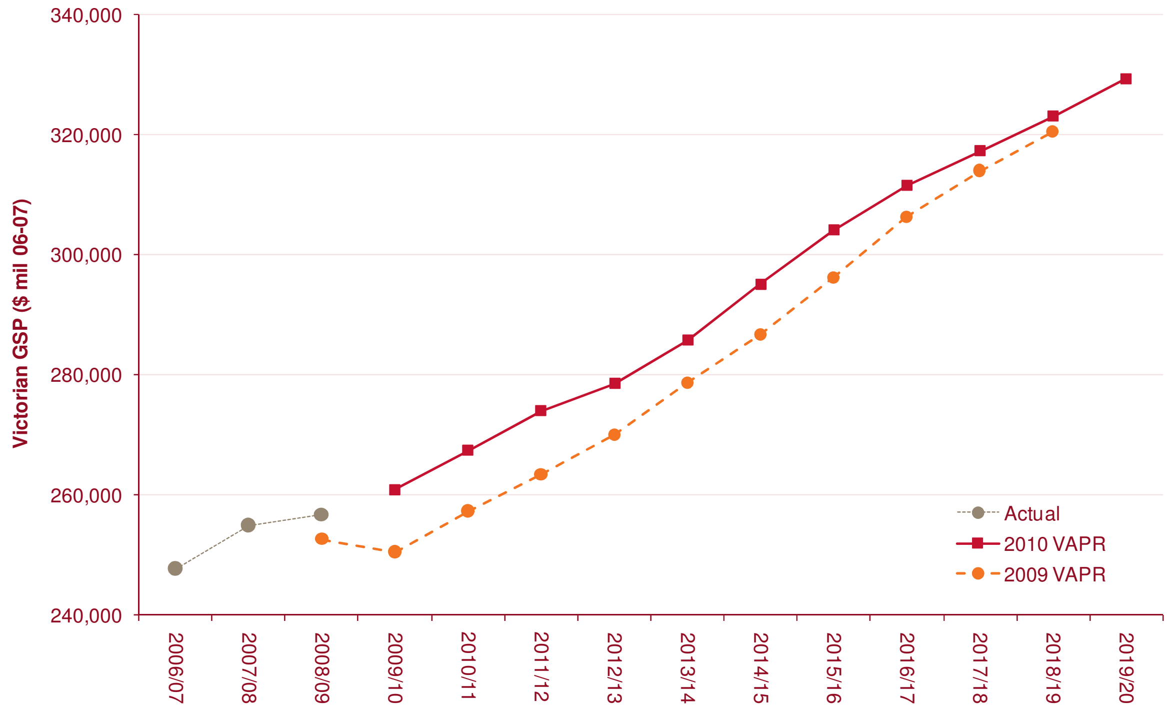
	2010 VAPR	2009 VAPR	Change
Summer 2010/11 10% POE Native MD	10,783 MW	10,702 MW	81 MW (0.8%)
Winter 2010 10% POE Native MD	8,347 MW	8,262 MW	85 MW (1.0%)
2010/11 Annual Energy	52,092 GWh	51,436 GWh	656 GWh (1.3%)
2010/11 Australian GDP Growth	3.6%	4.0%	-0.4%
2010/11 Victorian GSP Growth	2.5%	2.7%	-0.2%

The quick recovery of the Australian economy has driven the change in the outlook. In the 2009 VAPR, Australian GDP and Victorian GSP were projected to grow at -0.2% and -0.8% over the 2009/10 financial year, respectively. The current estimates for the 2009/10 year are 2.3% and 1.6% for GDP and GSP, respectively.

Figure 4-7 shows the Victorian GSP projections used to develop both sets of forecasts.

[15] http://www.dpi.vic.gov.au/DSE/nrenpl.nsf/LinkView/5249619A2A213442CA2573BE007EEAA992FBC7C133A6F520CA2572DA007FAB8B.

Figure 4-7 – 2009 and 2010 Victorian GSP forecast comparison



The 2010 VAPR annual energy consumption forecast for 2010/11 has increased by more than 650 GWh when compared with the 2009 VAPR forecast. Most of the increase is due to faster than previously projected economic recovery.

When compared with the 2009 forecasts, the increases in the 2010 summer and winter MD forecasts, of 0.8% and 1.0%, respectively, is also a result of the increase in the forecast Victorian GSP.

4.1.7 Semi-scheduled and non-scheduled generation forecasts

From 2010/11-2019/20, native energy is forecast to grow by 0.9% under the medium growth scenario. Using the projections of semi-scheduled and non-scheduled generation supplied by KPMG Econtech, and AEMO's wind generation projections, the annual electricity load supplied by:

- semi-scheduled generation is forecast to grow by an average of 57% per annum
- non-scheduled generation is forecast to grow by an average of 9.8% per annum, and
- scheduled generation is forecast to decline by an average of approximately -0.4% per annum.

Figure 4-8 shows projections of future wind farm capacity based on KPMG Econtech's projections. The projections assume that all future wind developments with an aggregate nameplate rating of 30 MW or more will be classified as semi-scheduled.

Figure 4-8 – Installed wind capacity projection (MW)

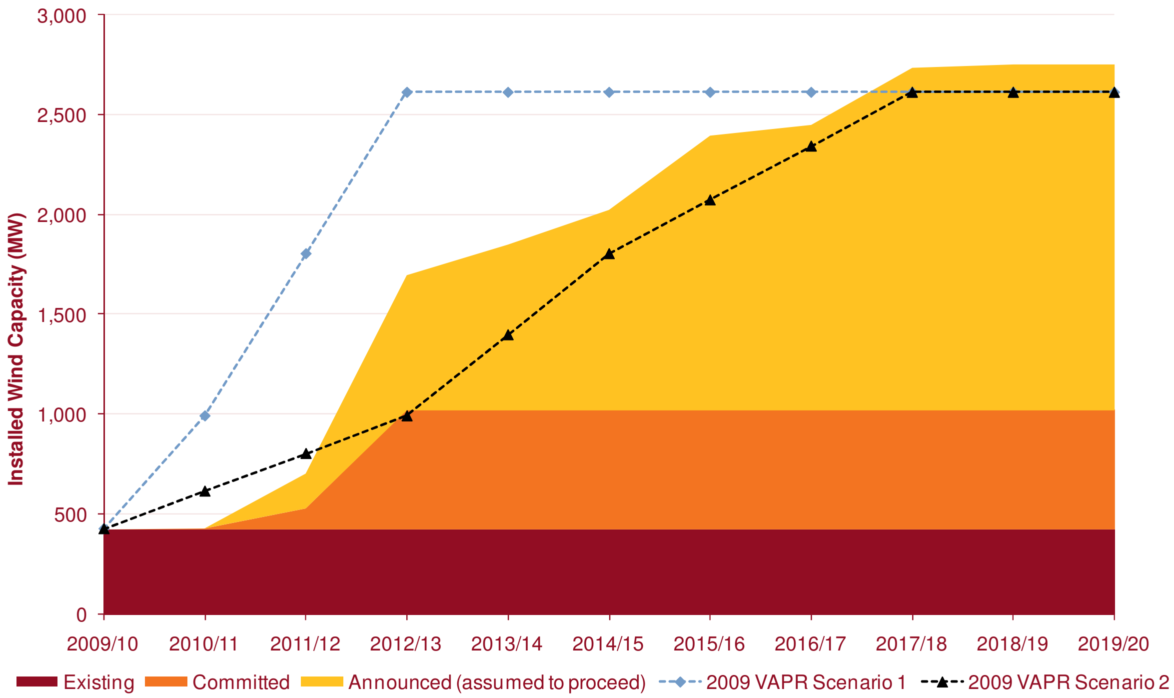


Figure 4-9 shows a breakdown of generation types contributing to the medium growth scenario native energy projections.

Figure 4-9 – Energy contribution projection (GWh)

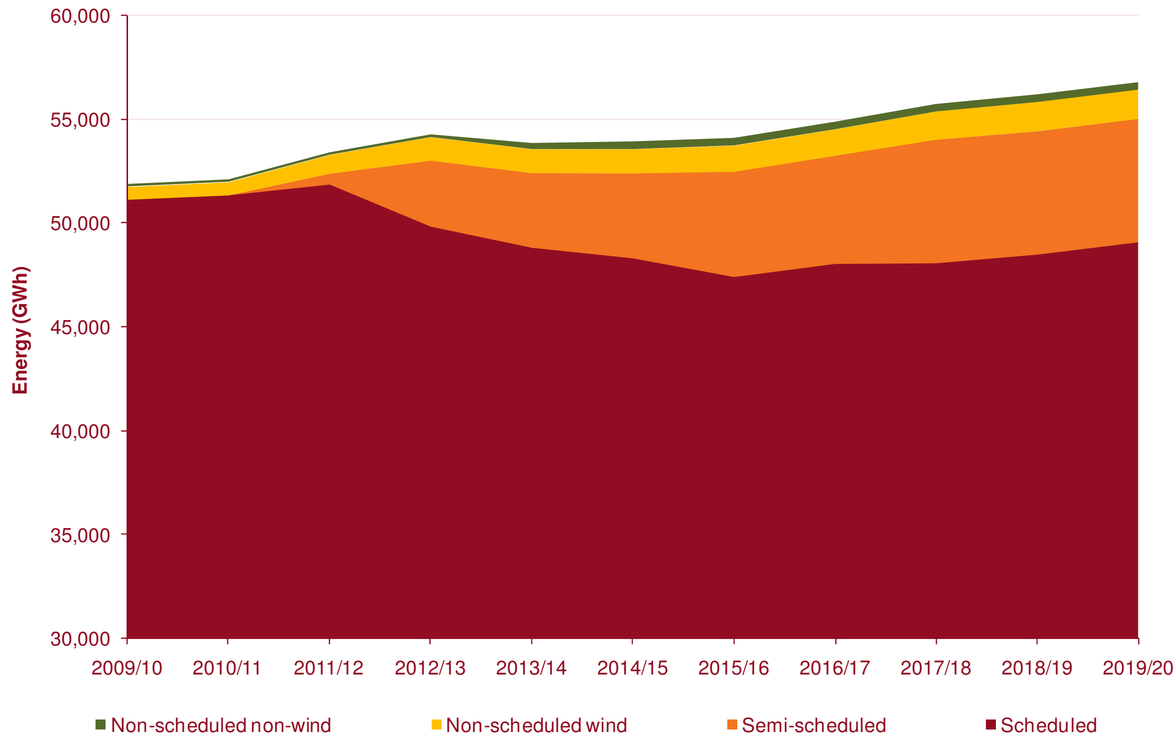


Table 4-6 lists the projections of non-scheduled generation capacity, energy contribution (i.e. annual generation) and contribution to the summer and winter MD (i.e. generation level).

Table 4-6 – Projections of non-scheduled generation

Year	Capacity (MW)	Energy Contribution (GWh)	Summer MD Contribution (MW)	Winter MD Contribution (MW)
2010/11	472	747	51	38
2011/12	493	1,017	58	42
2012/13	585	1,258	132	88
2013/14	629	1,438	165	109
2014/15	629	1,524	165	109
2015/16	657	1,619	168	111
2016/17	663	1,637	168	111
2017/18	691	1,725	170	113
2018/19	713	1,784	172	114
2019/20	713	1,784	172	114

The non-scheduled generation capacity growth rates have increased from a 2009 forecast of 3% per annum, to a 2010 forecast of 4.8% per annum from 2010/11-2018/19.

Semi-scheduled generation capacity is expected to grow by 55% per annum over the forecast period.

4.1.8 Further information

Terminal station forecasts

In addition to the regional native energy and MD forecasts, AEMO prepares forecasts for points of connection within the Victorian electricity DSN. Maximum active power and reactive power demands for the 10% and 50% POE forecast levels, for each of the financial years 2009/10 to 2018/19 inclusive, are provided for each terminal station in Victoria.

System participants supply AEMO with the forecast maximum levels of active demand and associated reactive demand that they expect to be supplied to their licensed distribution area over the next 10 years (separated according to their points of connection at each terminal station). Once received, the forecast information is aggregated to produce consolidated bottom-up terminal station forecasts. These forecasts, which were prepared in September 2009, are presented in Appendix E4. An updated set of forecasts will be prepared and published on AEMO's website in September 2010.

Related publications

This chapter of the VAPR presents the 10-year native energy and MD forecasts, as well as the non-scheduled generation forecasts. Appendix E1 presents historical Victorian electricity energy and demand and an assessment of the 2009 VAPR forecasts. Appendix E2 presents the Victorian GSP forecast forecasts. Appendix E3 summarises the government policy assumptions.

Additional information relevant to the forecasting process is available in a series of related publications:

- The Victorian Electricity Forecast Report 2010 (available on AEMO's website [16]). This report contains information on the energy and MD forecasting methodologies.
- KPMG Econtech's reports (which will be published with the 2010 AEMO ESOO). These three reports contain energy policy, economic scenario, and electricity market inputs (reports 1 and 2) and semi-scheduled and non-scheduled generation forecasts (report 3).
- Terminal Station Demand Forecasts 2009/2010-2018/2019 (available on AEMO's website).

4.2 Gas demand forecasts

This section provides a summary of the gas demand forecasts published in the 2009 VAPR Update in November 2009. This report is available on AEMO's website and includes detailed forecasts for the:

- annual, peak day and peak hour system demand for 2010-2019
- annual, peak day and peak hour demand by gas region for 2010-2019
- monthly peak day and peak hour demand for the system and by gas region for 2010
- GPG forecasts for 2010-2019, and
- gas export demand.

An updated set of gas demand forecasts for system demand and for GPG will be prepared and published by AEMO by the end of November 2010.

4.2.1 Peak day demand forecasts

Peak day demand forecasts are prepared for a medium economic growth scenario, and exclude withdrawals from Iona, GPG demand, and export demand.

[16] http://www.AEMO.com.au

Table 4-7 lists the 1 in 2 and 1 in 20 peak day system demand forecasts.

Table 4-7 – Peak day system demand forecast, 2010-2019 (TJ/d)

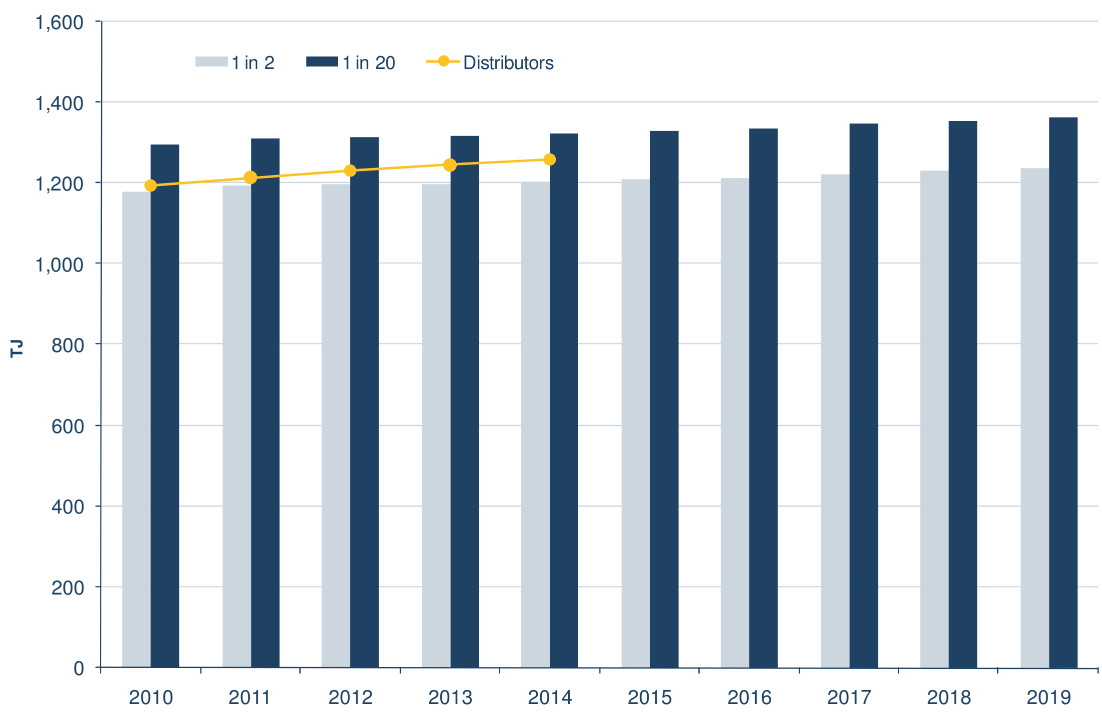
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average Annual Growth
1 in 2	1,181	1,193	1,197	1,198	1,204	1,209	1,213	1,223	1,231	1,238	
Annual Growth		1.02%	0.34%	0.08%	0.50%	0.42%	0.33%	0.82%	0.65%	0.57%	0.53%
1 in 20	1,296	1,310	1,315	1,317	1,323	1,330	1,334	1,347	1,356	1,365	
Annual Growth		1.08%	0.38%	0.15%	0.46%	0.53%	0.30%	0.97%	0.67%	0.66%	0.58%

Peak day demand is sensitive to weather conditions, with an increasing component of heating load expected on colder winter days. The peak day forecasts are presented for two weather standards:

- The 1 in 2 peak day represents a milder standard, with weather conditions for the day expected to be exceeded once every two years, or a 50% probability of exceedence (POE), or the peak day demand during an average winter.
- The 1 in 20 peak day represents more severe weather conditions, expected to be exceeded once in 20 years, or a 5% POE. This is the planning standard for assessing gas supply adequacy and transmission system capacity.

Figure 4-10 shows the 1 in 2 and 1 in 20 peak day forecasts, compared with the 1 in 2 peak day forecasts produced by distribution businesses.

Figure 4-10 – Peak day system demand forecast, 2010-2019 (TJ/d)



4.2.2 Annual demand forecasts

Table 4-8 lists the annual demand forecasts for low, medium and high growth scenarios.

Table 4-8 – Annual system demand forecasts, 2010-2019 (PJ/yr)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average annual growth 2010-2019
System demand											
High	212.5	215.4	217.2	218.6	220.1	221.6	223.1	225.1	226.9	228.8	0.83%
Medium	208.2	210.1	210.7	211.1	211.4	211.9	212.3	213.1	213.9	214.6	0.34%
Low	204.4	205.2	204.8	204.1	203.5	202.9	202.3	202.1	201.8	201.5	-0.16%
System demand by tariff group (medium growth)											
Tariff V	123.2	124.2	124.7	125.1	125.8	126.6	127.4	128.6	129.7	130.8	0.67%
Tariff D	85.0	85.9	86.0	86.0	85.6	85.2	84.9	84.5	84.2	83.8	-0.16%

Tariff V demand increases are driven by population growth, employment levels and household income, and are mitigated by improved gas appliance efficiency, increased reverse cycle air conditioner usage for heating, and reduced water heating demand due to lower water usage. Factors affecting Tariff D demand include building cycle sensitivities and increased manufacturing sector competition from overseas imports.

4.2.3 Gas powered generation demand

AEMO's 2009 VAPR Update provided GPG demand forecast updates following a series of developments, including:

- the expected Australian Government CPRS, which will affect the gas demand for GPG located in Victoria
- the planned commissioning of Stage 1 of Mortlake Power Station (550 MW Open Cycle Gas Turbine) in October 2010 with associated dedicated gas pipeline, and
- planned and publicly announced GPG projects with plans to source gas without contributing to demand on the Victorian gas DTS.

Historically, GPG demand has been sensitive to a number of factors, including:

- weather conditions, particularly during extreme weather events in summer and winter when peak electricity demands are highest
- unplanned generation plant outages
- contractual arrangements between electricity retailers and individual GPGs, and
- planned load transfers associated with National Electricity Market (NEM) adequacy of supplies and regional capacity transfers.

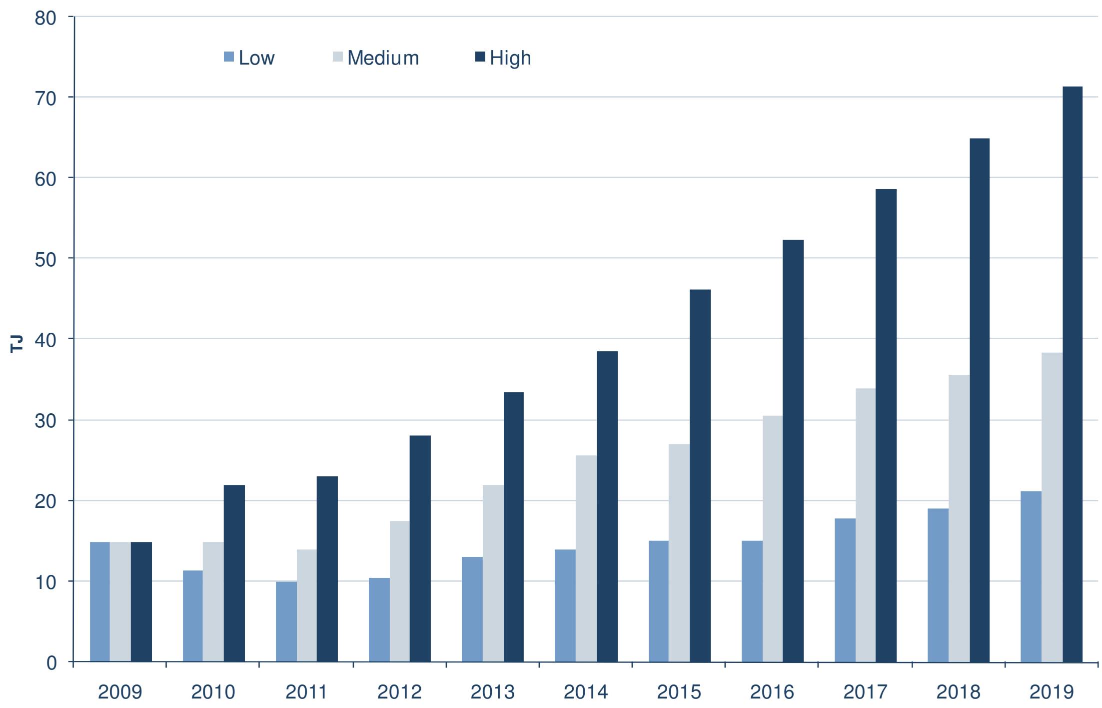
The factors that make up the total GPG demand forecasts are:

- capacity support for planned and unplanned generation plant outages
- peak support for high electricity demands
- drought support due to water restrictions on hydroelectric and coal-fired generation, and
- carbon signals.

Forecasts are prepared for a low, medium and high GPG gas demand scenario.

Figure 4-11 shows GPG demand growth under all three scenarios. These forecasts are indicative only, since annual GPG demand is highly variable. For example, annual GPG demand averaged 9.7 PJ from 2000 to 2006, and 29.6 PJ from 2007 to 2008. The GPG scenarios shown here include only gas DTS-connected GPG demand.

Figure 4-11 – Low, medium and high gas DTS-connected GPG gas demand growth, 2010-2019 (PJ)



It is expected that the majority of the GPG growth will be driven by increased output from existing GPG. Under the high growth scenario, additional demand from new Open Cycle Gas Turbine (OCGT) or Combined Cycle Gas Turbine (CCGT) plant, or the conversion of existing OCGT to CCGT, is forecast on the gas DTS.

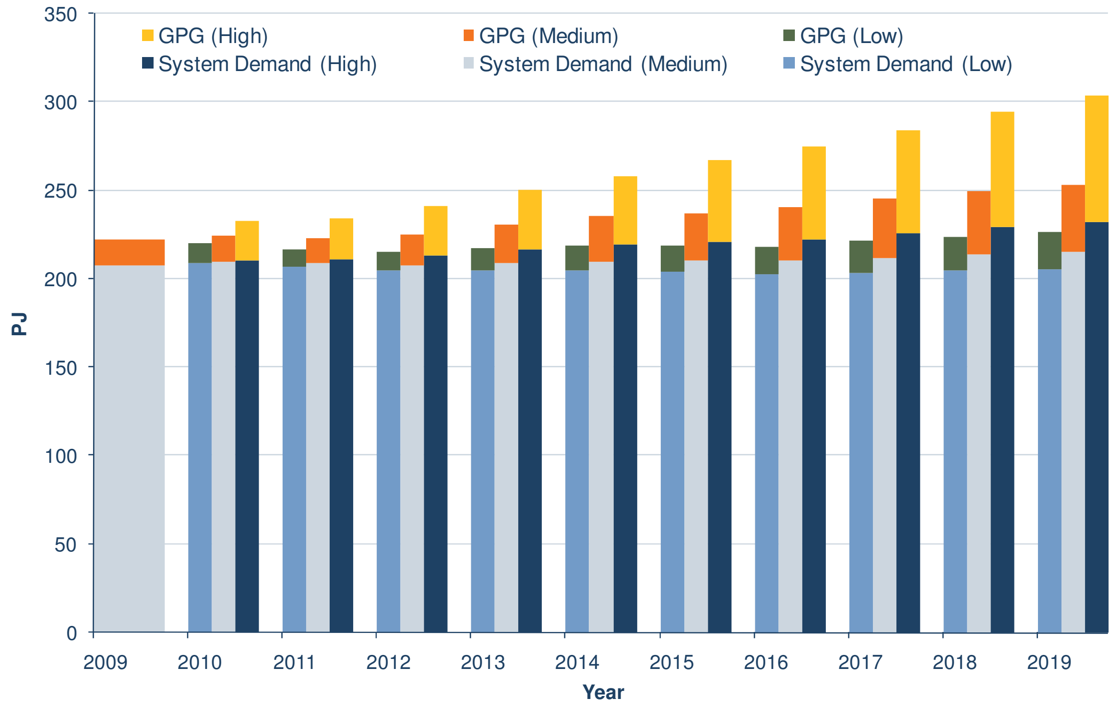
Table 4-9 lists the annual demand forecasts for the low, medium and high growth scenario combined with a low, medium and high GPG demand scenario, respectively.

Table 4-9 – Annual system and GPG gas demand forecast, 2010-2019 (PJ)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average annual growth 2010-2019
High	234.5	238.4	245.3	252.0	258.7	267.8	275.4	283.7	291.9	300.2	2.78%
Medium	223.1	224.0	228.3	233.1	237.1	238.9	242.9	247.2	249.4	252.9	1.40%
Low	215.8	215.2	215.3	217.1	217.4	218.0	217.3	219.9	220.8	222.8	0.35%

Figure 4-12 shows the annual system demand and GPG gas demand forecasts for the low, medium and high growth scenarios for the period 2010-2019.

Figure 4-12 – Annual system and GPG gas demand forecast, 2010-2019 (PJ)



4.2.4 Export demand scenarios

In the past, exports to New South Wales via Culcairn normally occurred outside the winter peak period. Injections occurred at Culcairn from June to August in 2006, while 2007 experienced net exports all year round. This trend has continued throughout 2008 and there have been no net imports through Culcairn. Higher exports have occurred since commissioning of the compressor at Culcairn in readiness for commissioning of the Uranquinty Power Station in New South Wales. For the 12 months to the end of September 2009, there were exports of 4.6 PJ for October 2008 to April 2009, and imports of 3.9 PJ for May 2009 to September 2009 at Culcairn, compared to exports of 3.5 PJ for the year to September 2008. It is reasonable to assume that exports may increase in the future at Culcairn.

Interstate export via VicHub is currently negligible. Exports at VicHub can be delivered to either New South Wales or Tasmania. No significant change is expected to VicHub exports in 2010. Additional GPG in New South Wales may provide the opportunity for increased exports to New South Wales from VicHub.

4.2.5 Gas region forecasts

See the 2009 VAPR Update (available on the AEMO website) for more information about forecast annual, monthly, peak day, and peak hour system demand by gas region. See Chapter 3 for more information about the gas regions.

Chapter 5 Supply Forecasts

This chapter presents supply forecasts for electricity and gas for the forecast period (2010-2019 and 2010-2014, respectively). This includes forecasts of Victorian electricity supplies, and of annual and peak day supplies of gas transported through the gas Declared Transmission System (DTS).

Electricity

The electricity supply forecasts are presented in AEMO's 2009 Electricity Statement of Opportunities (ESOO). They include details about scheduled generation, committed projects (generation), and wind power generation (installed capacities).

Gas

The gas supply forecasts are based on information published in the 2009 VAPR Update (November 2009), and provided by gas producers, storage providers and market participants. They assume that events affecting supply in markets elsewhere are unlikely to interrupt gas supplies to the Victorian market.

In this chapter:

- Section 5.1 provides high-level information about electricity and gas interactions relevant to electricity and gas supplies.
- Section 5.2 presents forecasts of peak day electricity supplies.
- Section 5.3 presents forecasts of peak day, monthly (for 2010), and annual gas supplies and storage, including information about Liquefied Natural Gas (LNG) requirements for within-day balancing.

5.1 Supply forecast synergies

This section highlights specific supply synergies relevant to the 2010 VAPR and the relationship between electricity and gas.

Victoria's electrical energy and gas is sourced mostly from the Latrobe Valley/Gippsland area, east of Melbourne. Almost 80% of Victoria's electricity generating capability is located in the Eastern Corridor, while almost 70% of peak day gas supply capability comes from Gippsland, with the region forecast to supply over 90% of Victoria's total gas demand in 2010.

Current gas supply forecasts provided by participants indicate a reduced reliance on gas from Gippsland over the next five years.

5.2 Electricity supply

5.2.1 Electricity supply forecast

Information about the summer and winter electricity supply forecasts by region and power station can be found in AEMO's 2009 ESOO. See Chapter 7, Section 7.2.1, for a more detailed supply and demand balance forecast for summer 2009/10.

Table 5-1 lists a summary of the terminal stations, connection types, fuel types and heat rates for each power station.

Table 5-1 – Generation connections, fuel types, and heat rates [17]

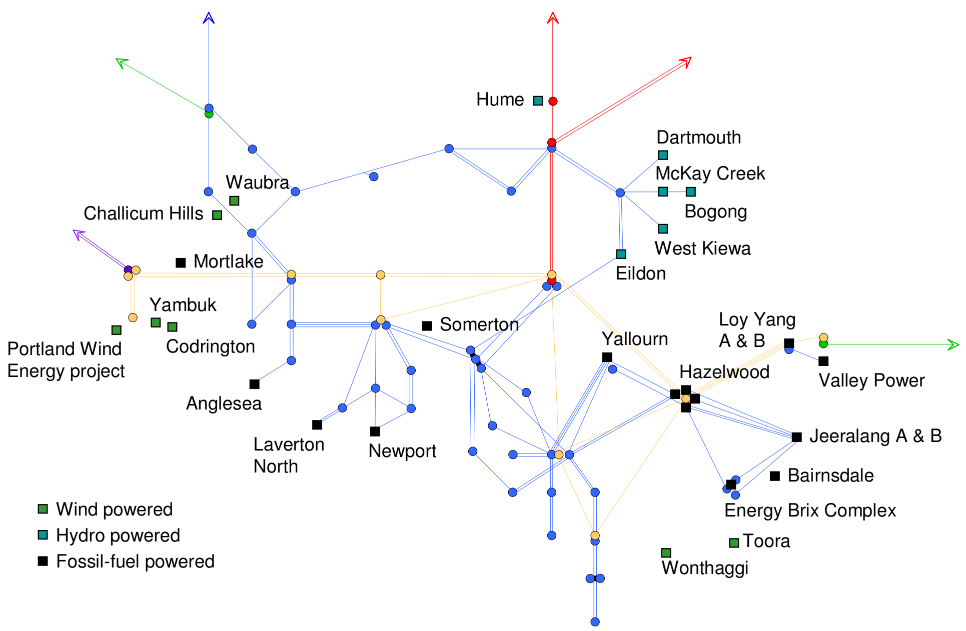
Generation	Terminal station	Connection voltage	Fuel type	Thermal efficiency	Heat rate (MWh sent out per TJ fuel burnt)
Eastern Corridor					
Bairnsdale	Not applicable	66 kV	Gas Turbine/OCGT	34%	94
Hazelwood	Hazelwood	500 kV and 220 kV	Brown Coal	22%	61
Jeeralang A	Jeeralang	220 kV	Gas Turbine/OCGT	22.9%	64
Jeeralang B	Jeeralang	220 kV	Gas Turbine/OCGT	22.9%	64
Loy Yang A	Loy Yang	500 kV	Brown Coal	27.2%	76
Loy Yang B	Loy Yang	500 kV	Brown Coal	26.6%	74
Energy Brix Complex	Morwell	220 kV	Brown Coal	24%	67
Toora Wind Farm	Not applicable	66 kV	Wind Farm		n/a
Valley Power	Loy Yang	220 kV	Gas Turbine/OCGT	24%	67
Wonthaggi	N/A	66kV	Wind Farm		n/a
Yallourn	Yallourn	500 kV and 220 kV	Brown Coal	23.5%	65
South-West Corridor					
Mortlake	Heywood – Moorabool loop	500 kV	Gas Fired	32%	89
Codrington	Not applicable	66 kV	Wind Farm		n/a
Cape Bridgewater (APD 220 kV)	Portland (APD Smelter)	220 kV	Wind Farm		n/a
Yambuk (TGTS 66 kV)	Not applicable	66 kV	Wind Farm		n/a
Northern Corridor					
Bogong	McKay Creek	220 kV	Hydro		n/a
Dartmouth	Dartmouth	220 kV	Hydro		n/a
Eildon	Eildon	220 kV	Hydro		n/a
Hume (VIC)	Wodonga	66 kV	Hydro		n/a
McKay Creek	McKay Creek	220 kV	Hydro		n/a
West Kiewa	West Kiewa	220 kV	Hydro		n/a

[17] Source: ACIL Tasman, 'Fuel Resource, New Entry and Generation Costs in the NEM', Draft Report – Feb 2009.

Generation	Terminal station	Connection voltage	Fuel type	Thermal efficiency	Heat rate (MWh sent out per TJ fuel burnt)
Greater Melbourne and Geelong					
Anglesea	Anglesea	220 kV	Brown Coal	27.2%	76
Laverton North	Laverton North	220 kV	Gas Turbine/OCGT	30.4%	85
Newport	Newport	220 kV	Steam Turbine	33.3%	93
Somerton	Not applicable	66 kV	Gas Turbine/OCGT	24%	67
Regional Victoria					
Waubra	Ballarat – Horsham Loop	220 kV	Wind Farm		n/a
Challicum Hills	Ballarat – Horsham loop	66 kV	Wind Farm		n/a

Figure 5-1 shows the location of the generation listed in Table 5-1. Where generation is connected below 220 kV and is not adjacent to a terminal station, it is not shown as connected to the transmission network, and its approximate position is given as rough guide only.

Figure 5-1 – Generation locations



5.3 Gas supply

5.3.1 Peak day gas supply forecasts

For planning purposes, gas supply is classified as either firm or non-firm, where:

- firm supply is the aggregate contracted maximum daily quantity (MDQ) available to the market through commercial arrangements between market participants and gas producers or storage providers, and
- non-firm supply is subject to market participants offering gas on the gas day, and may depend on interconnecting pipeline operating conditions and contracts.

Table 5-2 lists a summary of the forecast winter peak day firm and non-firm supplies by gas region and injection point for the forecast period. It also provides a comparison with the 2009 VAPR forecast for 2010.

The gas supply forecasts are provided by market participants in accordance with the National Gas Rules (NGR). As a result, this update does not provide an extended supply forecast to 2019.

Table 5-2 – Peak day gas supply forecast, 2010-2014 (TJ/d)

Gas region	Injection point	2010 (2009 VAPR)	2010	2011	2012	2013	2014
Gippsland Zone	Longford firm	925	969.5	982.5	893	891	891
	Longford non-firm	130	134.5	148	168.3	162.3	166.7
	VicHub firm	70	63	60	0	0	0
	VicHub non-firm	40	10	0	0	0	0
	BassGas firm	67	67	67	67	67	67
Total Longford, VicHub and BassGas		**1,232**	**1,244**	**1,257.5**	**1,128.3**	**1,120.3**	**1,124.7**
Western Zone	Iona UGS firm	500	288	236	236	236	236
	Iona UGS non-firm	0	282	334	334	334	334
	Otway firm	0	189	189	189	189	189
	Otway non-firm	0	0	0	0	0	0
	SEA Gas firm	78	110	110	100	100	100
	SEA Gas non-firm	9	1.5	1.5	1.5	5	5
Total Iona and SEA Gas[1]		**587**	**870.5**	**870.5**	**860.5**	**864**	**864**
Northern Zone	Culcairn firm	0	35	35	35	35	35
	Culcairn non-firm	10	15	15	15	15	15

Total (excluding LNG)		**1,829**	**2,164.5**	**2,178**	**2,038.8**	**2,034.3**	**2,038.7**
Melbourne and Geelong Zone	LNG firm[2]	87	87	87	87	87	87
Total (including LNG)		**1,916**	**2,251.5**	**2,265**	**2,125.8**	**2,121.3**	**2,125.7**

1. It is understood that the total for Iona and SEA Gas is available to both South Australia and Victoria and the quantity available to the Victorian Market will be dependant on the market

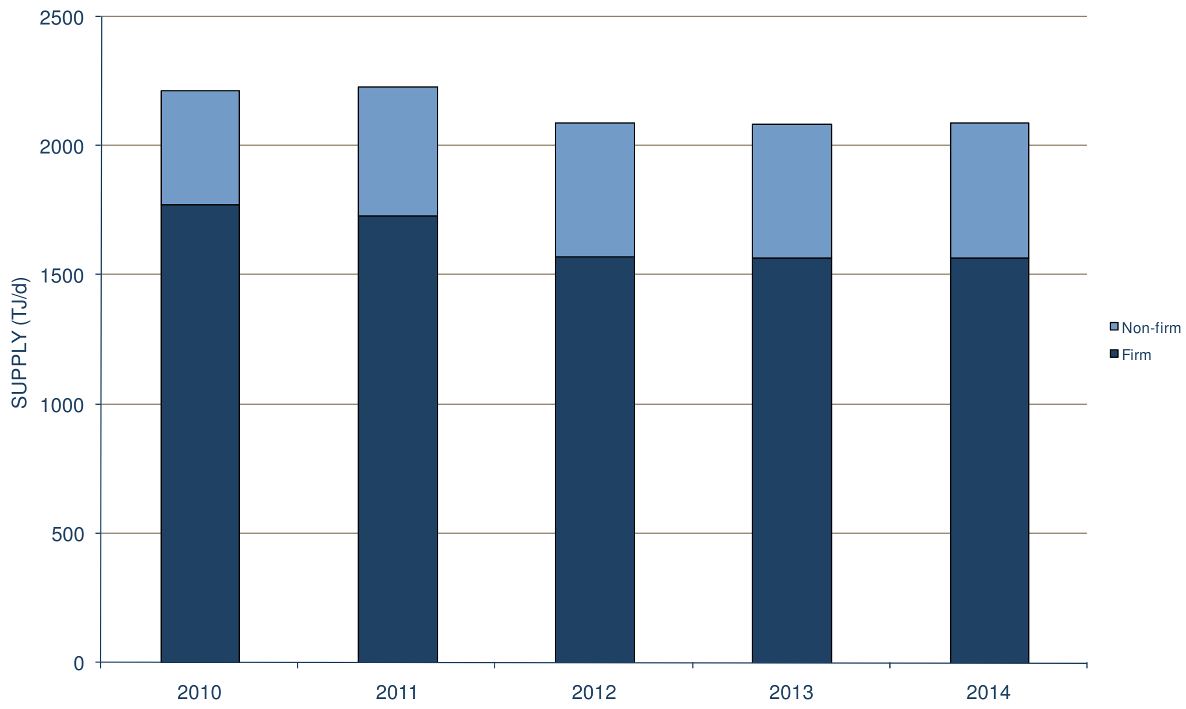
2. APA Group advises that all retailer contracts for LNG storage expire on 31 January 2011

The forecast totals represent an aggregate of the individual sources of supply at each location, as provided by market participants. For example, supply from the Casino field is included in the Iona/Underground Storage (UGS) forecast for the forecast period.

It should be noted that the producers at Longford are negotiating for further contracted capacity for 2010 onwards.

Figure 5-2 shows the total winter peak day firm (including LNG) and non-firm supplies for the forecast period.

Figure 5-2 – Peak day gas supply forecast, 2010-2014 (TJ/d)



5.3.2 Annual gas supply forecasts

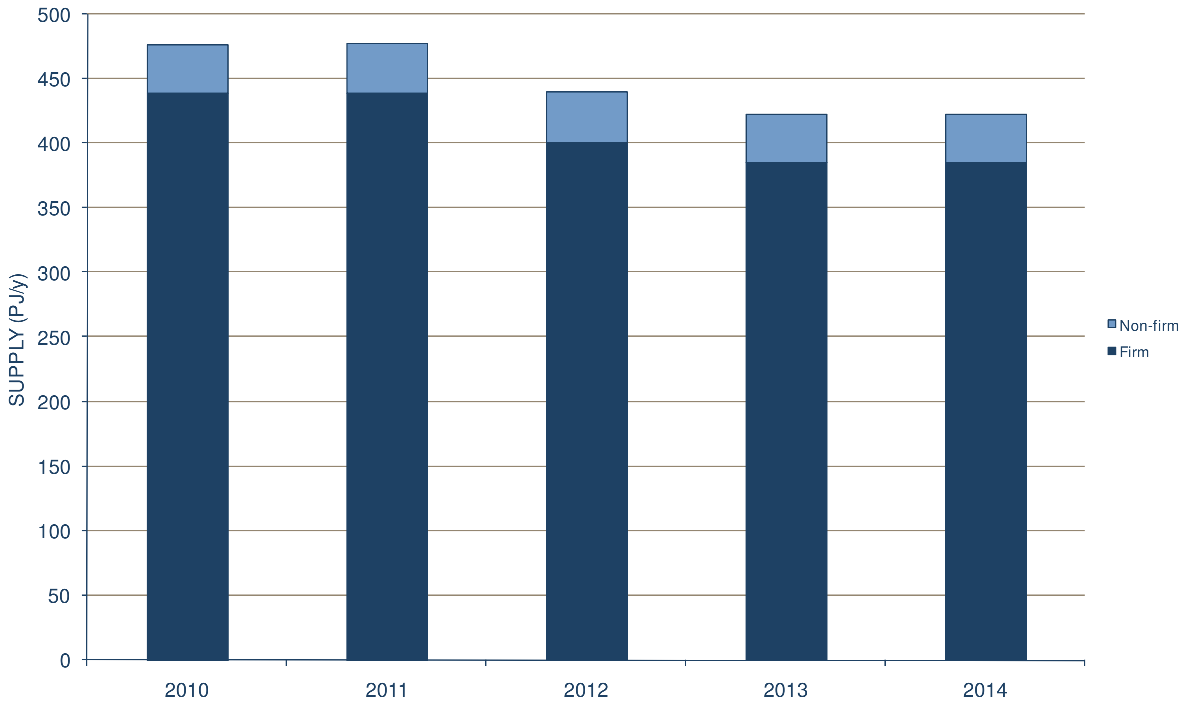
Table 5-3 lists a summary of the annual firm (excluding LNG) and non-firm supplies by gas region and injection point for the forecast period.

Table 5-3 – Annual gas supply forecast, 2010-2014 (PJ/yr)

Gas region	Injection point	2010	2011	2012	2013	2014
Gippsland Zone	Longford firm	295.2	302.2	285.5	268.5	268.5
	Longford non-firm	33.9	38.1	38.6	35.4	35.7
	VicHub firm	18.0	18.0	0.0	0.0	0.0
	VicHub non-firm	3.0	0.0	0.0	0.0	0.0
	BassGas firm	20.0	21.6	21.3	22.7	22.8
	BassGas non-firm	0.0	0.0	0.0	0.0	0.0
	Total Longford, VicHub and BassGas	**370.1**	**379.9**	**345.4**	**326.6**	**327**
Western Zone	Iona UGS firm	50.1	40.6	40.6	40.6	40.6
	Iona UGS non-firm	0.0	0.0	0.0	0.0	0.0
	Otway firm	54.0	54.0	54.0	54.0	54.0
	Otway non-firm	0.0	0.0	0.0	0.0	0.0
	SEA Gas firm	2.2	2.9	0.0	0.0	0.0
	SEA Gas non-firm	0.5	0.5	0.5	1.8	1.8
	Total Iona and SEA Gas	**106.8**	**98.0**	**95.1**	**96.4**	**96.4**
Northern Zone	Culcairn non-firm	0.0	0.0	0.0	0.0	0.0
	Total (excluding LNG)	**476.9**	**477.9**	**440.5**	**423.0**	**423.4**
Melbourne and Geelong Zone	LNG firm	0.5	0.5	0.5	0.5	0.5
	Total (including LNG)	477.4	480.4	441	423.5	423.9

Figure 5-3 shows the total annual firm (excluding LNG) and non-firm supplies for the forecast period.

Figure 5-3 – Annual gas supply forecast, 2010-2014 (PJ/yr)



5.3.3 Monthly peak day gas supply forecasts for 2010

This section presents the monthly demand forecasts and the monthly demand-supply outlook for January-December 2010.

Table 5-4 lists the monthly peak day firm and non-firm supply forecasts provided by participants. The quantities available at each system injection point have been adjusted to reflect plant maintenance outages, recall times and ramp rates (where applicable). These adjustments particularly affect the LNG and UGS facilities. Participants have indicated that there are contracts for imports and exports for gas through Culcairn. What occurs on any day will be market-driven.

Total reported gas supply increases are mainly due to increases reported from the Otway basin.

Table 5-4 – Monthly firm and non-firm supply, July 2010-December 2010 (TJ/d)

	Jul	Aug	Sep	Oct	Nov	Dec
Longford	1,094.0	1,094.0	1,094.0	1,104.0	1,104.0	1,104.0
VicHub	72.5	72.5	72.5	72.5	72.5	72.5
BassGas	67.0	67.0	0	67.0	0	67.0
Iona	570.0	570.0	570.0	0	570.0	570.0
SEA Gas	111.5	111.5	111.5	111.5	111.5	111.5
Otway	189	189	189	189	189	189
Culcairn	35.0	35.0	35.0	35.0	35.0	35.0
LNG	87	87	87	43	43	87
Total Supply	2,226.0	2,226.0	2,159.0	1,622.0	2,125.0	2,236.0

Monthly peak day demand-supply scenarios

Table 5-5 lists the monthly peak day demand-supply scenarios, including GPG demand and exports.

Table 5-5 – Monthly peak day demand-supply scenarios, July-December 2010 (TJ/d)

	Jul	Aug	Sep	Oct	Nov	Dec
Nominal Supply (excluding LNG)	1,316	1,316	1,316	1,316	1,030	1,030
Scheduled LNG	37	37	37	0	0	0
1 in 20 System Demand	1,296	1,296	1,296	940	846	689
Exports [1]	35	35	35	51	58	66
GPG	20	20	20	100	100	150
Surplus	2	2	2	225	26	125
Spare LNG	50	50	50	43	43	87

1. Exports assumed for illustration purposes for the supply/demand balance

It is assumed that total system supply from November to December is constrained to 1,030 TJ/d, being the current Longford pipeline injection capacity. This is taken as a worst case scenario for this time of year when Iona may not be injecting.

From recent experience, supply will be available from Otway sources in non-winter months. It is also assumed that 1,316 TJ/d is available for the May-October period, based on the aggregate of deliverable supply from the Longford pipeline and Iona (no supply is assumed via Culcairn). Scheduled maintenance at Longford during November-March is not expected to affect total supplies from Longford, VicHub and BassGas. See Chapter 5 for more information about the peak day transmission system capacity forecasts.

The monthly peak day demand-supply scenario assumes that:

- 1 in 20 peak day system demands will apply every month, except for December-February, where the forecasts instead assume that GPG demand drives peak gas DTS demand on very hot days - as a result, summer peak day system demand forecasts are adjusted to have no heating demand for December-February
- there will be minimal exports from June-September on 1 in 20 peak days
- there may be approximately 70 TJ/d of exports/Iona withdrawals from December-February with lower values over the shoulder and winter period of up to 35 TJ/d
- up to 200 TJ/d of GPG demand occurs in January and February, and
- due to the severity of the June-September system demand profile, LNG is required for within-day balancing on peak days. In 2010, approximately 37 TJ of LNG is expected to be required on 1 in 20 peak days in June-September based on the modelling of within-day balancing LNG requirements (see Sections 5.3.6 and 5.3.7 for more information about LNG requirements).

5.3.4 Gas supplies and storage

See Chapter 3 for information about the gas DTS, its pipelines, injection points, and regions.

Longford

The Longford plant, located near Sale in South Gippsland, processes gas flowing from the Bass Strait's Gippsland Basin gas fields and injects it into the gas DTS via the Longford metering station. The Longford plant is the largest producer of gas for the Victorian market.

The winter peak day firm supply from Longford is 969 TJ/d for 2010. There is a slight decrease in the reported firm supply in 2010 that can be explained by the market taking a shorter-term approach to entering into firm supply contracts, and new supplies from the Otway Basin. As a result, there will be a greater reliance on non-firm supplies from 2010 onwards. It is expected that participants will negotiate further firm supplies closer to the time.

VicHub

VicHub, located at Longford, has a system injection point for gas flow from the Eastern Gas Pipeline (EGP). VicHub has a winter peak day injection capacity of up to 110 TJ/d. Current advice, however, has supply for winter 2010 at 63 TJ/d firm and 10 TJ/d non-firm. It has been advised that this will remain the same for the forecast period.

BassGas

BassGas, located near Pakenham, is the system injection point for gas from the offshore Yolla gas field, which is supplied via the BassGas undersea pipeline and processed at Lang Lang. The winter peak day firm supply from BassGas is 67 TJ/d for the forecast period.

Iona

The Iona gas plant facility, located near the township of Port Campbell in South West Victoria, has a winter peak day processing/injection capacity of approximately 570 TJ/d, and is the processing and system injection point for gas from the offshore Casino gas field.

The operating boundary of the South West Pipeline (SWP) during normal winter operations limits the scheduling of gas for gas DTS injection at Iona to 315 TJ/d. However, the current declared capacity of the SWP is 347 TJ/d (see Chapter 3, Section 3.7.2, for more information about the SWP capacity). Iona gas is also injected into the SEA Gas pipeline for export to South Australia.

The 18 PJ holding capacity of the UGS is assumed to be full or nearly full before the start of each winter. Holding capacity will be increased to 20 PJ during 2010 and further increased to 22 PJ for 2011. Higher Iona UGS firm supply forecasts are due to additional contributions from the Casino gas field.

SEA Gas

The SEA Gas processing facility, located near the township of Port Campbell in South West Victoria, is the system injection point for gas from the offshore Minerva gas field, and the Otway Basin, Geographe and Thylacine gas field supply developments. From this injection point, gas can be injected into the gas DTS, the SEA Gas pipeline (for export to Adelaide) or the UGS.

The winter peak day firm supply from SEA Gas is 100 TJ/d in 2010. Additional supply from SEAGas (up to plant capacity) may be available to the gas DTS, depending on market conditions.

Otway

The Otway gas plant located north of Port Campbell in South West Victoria began production in September 2007.

Conventional gas from the offshore Thylacine and Geographe gas fields in the Otway basin is transported via an offshore and onshore pipeline, and is processed at the Otway gas plant.

Gas from the Otway plant can be injected into the Victorian gas DTS through the Otway, SEA Gas or Iona injection points.

Culcairn

The New South Wales interconnect, which is metered at Culcairn in New South Wales, has the capacity to import 92 TJ/d into the Victorian gas market when both the Young and Springhurst compressors are operating, and the Uranquinty Power Station is offline. Participants indicate that supplies of 35 TJ/d will be firm for 2010, and an extra 15 TJ/d will be non-firm in later years. Other participants indicate that there may be export at Culcairn.

APA GasNet has informed AEMO that gas DTS augmentation in the Northern Zone will be completed during winter 2010. This will involve installing two new compressors at the Wollert Compressor Station, pipeline operating pressure uprating of the Wollert to Euroa pipeline, and installation of flow reversal capability at the Springhurst Compressor Station.

LNG

The Dandenong LNG storage facility liquefies and stores LNG for maintaining system security on high demand days and for peak shaving. LNG is also critical for managing system security in the event of restrained supply or transmission failure from Longford or Iona. The existing LNG tank has a storage capacity of 12,000 tonnes (659 TJ) [18]. See Section 5.3.8 for information about the LNG Security Reserve.

Assumptions involving the LNG storage facility include the following:

- The LNG tank will be full or nearly full prior to the start of each winter.
- A firm vaporising capacity of up to 100 tonnes per hour (t/h) will be available over 16 hours for peak shaving [19]. This capacity equates to the vaporisation of 87 TJ/d, reflecting the contracted firm rate for the forecast period.

Normally, LNG is not scheduled from the beginning-of-day, but is included in a reschedule later in the day [20]. For within-day balancing purposes, LNG only effectively supports system pressures when injected by 10 pm on the day it is required.

Given LNG is only available for peak shaving over 11 hours rather than the contracted time of 16 hours, peak day planning assumes 60 TJ/d is available for within-day balancing [21]. After 10 pm, further LNG injections only build up linepack for the following day.

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[18] APA Group advise that as of September 2009, 1 tonne of LNG has an energy equivalent of 54.9 GJ.

[19] This is based on APA Group's firm LNG rate, which allows for an outage of one of three pumps and one of three vaporiser units.

[20] LNG can be scheduled from the beginning-of-day.

LNG liquefaction to replenish stock levels is planned on a monthly basis, with the potential to order liquefaction of up to 1,500 tonnes per month, averaging approximately 50 tonnes per day (2.7 TJ/d).

5.3.5 Peak day Liquefied Natural Gas requirement

This section presents an analysis of LNG requirements for peak day within-day balancing and for the winter peak periods (May to September) for the forecast period (2010-2014).

This chapter presents forecasts of the daily supply of gas available for injection. Transmission constraints and pipeline operating boundaries, however, limit daily supply. As a result, LNG is required on high demand days to address within-day constraints due to limited pipeline capacity and usable linepack.

LNG use falls into one of three categories (the first two categories are modelled for this analysis):

1. LNG required for within-day balancing, scheduled out of price-merit order (to manage transmission constraints, supply or transmission outages).
2. LNG required for peak shaving on very high demand days, scheduled in price-merit order.
3. LNG scheduled in merit order on high demand days because it is priced lower than scheduled gas from other marginal supplies (such as Iona or VicHub).

The Longford and BassGas plants generally have adequate supply and capacity over the summer months to support system demand, GPG demand, and withdrawals at Iona, Culcairn and VicHub. Therefore LNG would not normally be required in summer.

To analyse future demand growth and assess the adequacy of gas supplies and LNG storage during winter, AEMO uses two measures that involve forecasting LNG requirements for:

- peak days using deterministic modelling, and
- the winter peak period using probabilistic modelling, based on outcomes from simulations applying the full range of weather conditions.

See Appendix G 3 for more information about deterministic and probabilistic modelling, and within-day balancing. See Chapter 3 for more information about summer peak export capacities.

5.3.6 Peak day Liquefied Natural Gas requirement

Table 5-6 lists the LNG requirements for 1 in 2 peak day modelling. System demand is based on the current five-year forecasts and GPG demand is based on an assumed 90 TJ/d (making the total demand approximately equal to a 1 in 20 day). The table also includes the LNG requirements for both flat and profiled injection rates at Iona.

Profiled injection rates refer to the practise of higher injections in the morning and lower injections in the afternoon. See Chapter 8 for information about the application of gas planning criteria. See Appendix G 4 for more information about profiled injections.

Table 5-7 lists the LNG requirements for 1 in 20 peak day modelling with no GPG demand, and with injections at Iona at a flat rate and a profiled rate.

Table 5-8 lists the LNG requirements for 1 in 20 peak day modelling with an assumed 25 TJ/d GPG demand (observed in July 2007), and with injections at Iona at a flat rate and a profiled rate.

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[21] The LNG used at 100 t/h for 11 hours (11 am-10 pm) is 1,100 tonnes (60 TJ).

The results for 1 in 2 peak day and 1 in 20 peak day LNG requirements demonstrate that the LNG required before 10 pm will not exceed the 60 TJ/d available for within-day balancing in 2010. This is the case for both flat and profiled injection rates at Iona, although to a lesser extent with a profiled injection rate.

In both the 1 in 2 and 1 in 20 peak day cases, profiled injection rates at Iona can be used to supplement the role of LNG in addressing within-day constraints and usable linepack.

Despite the latter's greater total demand, more LNG is used in the 1 in 2 peak day case compared to the 1 in 20 peak day case, as it is assumed that most of the GPG will be used before 10 pm. This depletes linepack more than system demand for the same total demand.

Table 5-6 – 1 in 2 peak day LNG requirement with GPG demand, 2010-2014 (TJ/d)

	2010	2011	2012	2013	2014
Forecast system demand	1,181	1,193	1,197	1,198	1,204
Assumed GPG demand	90	90	90	90	90
LNG requirement for flat injection rate at Iona	46	50	51	52	54
LNG requirement for profiled injection rate at Iona	27	31	32	32	34

Table 5-7 – 1 in 20 peak day LNG requirement, 2010-2014 (TJ/d)

	2010	2011	2012	2013	2014
Forecast system demand	1,296	1,310	1,315	1,317	1,323
Assumed GPG demand	0	0	0	0	0
LNG requirement for flat injection rate at Iona	37	40	42	42	44
LNG requirement for profiled injection rate at Iona	19	24	26	26	28

Table 5-8 – 1 in 20 peak day LNG requirement with GPG demand, 2010-2014 (TJ/d)

	2010	2011	2012	2013	2014
Forecast system demand	1,296	1,310	1,315	1,317	1,323
Assumed GPG demand	25	25	25	25	25
LNG requirement for flat injection rate at Iona	49	55	57	58	61
LNG requirement for profiled injection rate at Iona	36	42	45	46	49

5.3.7 Winter period Liquefied Natural Gas requirement

At the start of each winter, LNG storage is normally 626 TJ (11,400 tonnes). Considering a normal refill rate each month, 600-700 TJ [22] represents a high-level gauge of whether there will be sufficient

[22] This range assumes that LNG storage is at full capacity at the beginning of winter.

LNG supplies for winter. An LNG requirement in excess of this level in any given year means that there is a possibility that storage may be insufficient if refill rates remain the same.

LNG enables a rapid response to changing demand due to its variable injection rate and its proximity to the Dandenong City Gate (a critical system pressure point). As a result, GPG demand significantly influences LNG use, as GPG withdrawals represent a much greater volume over a shorter timeframe than industrial or residential loads. To avoid drops in linepack and pipeline pressure, this demand requires a faster response from supply sources, which is achieved with the vaporisation and injection of LNG.

Table 5-9 lists the forecast LNG requirement for the winter peak period, with injections at Iona at a flat rate.

Table 5-10 lists the forecast LNG requirement for the winter peak period, with injections at Iona at a profiled rate. These figures are presented as a theoretical exercise and make no allowance for limitations to profiling that may result from other peak day condition considerations.

The analysis presented in the tables incorporates:

- three GPG forecast scenarios
- the profiling of existing open cycle gas turbine (OCGT) gas demand using actual winter GPG demand data from 2004, 2006 and 2007, and
- the assumption that the combined cycle gas turbine/s (CCGT) will be running at full capacity during winter.

The results demonstrate that the use of profiled injection rates at Iona will enable a substantially reduced winter LNG requirement. This is because:

- the BLP pipeline effectively increases system capacity and linepack, and
- profiled injection rates at Iona provide supply flexibility similar to that provided by LNG. Iona is also situated near the Brooklyn City Gate, which also enables access to key system pressure points.

Under the high GPG demand scenario, major augmentation could be required for 2013 for the flat injection case and 2014 for the profiled injection case.

Table 5-9 – Winter period LNG requirement, flat injection rate, 2010-2014 (TJ/winter)

Low GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	0	0	0	0	0
1 in 2 winter (50% POE)	30	29	28	32	31
1 in 20 winter (5% POE)	115	115	115	131	132
Medium GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	0	0	1	7	18
1 in 2 winter (50% POE)	62	72	97	141	190
1 in 20 winter (5% POE)	187	194	258	331	423
High GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	10	21	52	108	175
1 in 2 winter (50% POE)	160	212	317	461	645
1 in 20 winter (5% POE)	366	454	664	897	1162

Table 5-10 – Winter period LNG requirement, profiled injection rate, 2010-2014 (TJ/winter)

Low GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	0	0	0	0	0
1 in 2 winter (50% POE)	9	8	8	11	12
1 in 20 winter (5% POE)	85	85	85	90	93
Medium GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	0	0	0	0	0
1 in 2 winter (50% POE)	31	36	54	88	130
1 in 20 winter (5% POE)	139	152	198	266	343
High GPG demand					
	2010	2011	2012	2013	2014
19 in 20 winter (95% POE)	0	0	20	53	110
1 in 2 winter (50% POE)	104	150	247	361	523
1 in 20 winter (5% POE)	295	381	555	766	1040

Historical Liquefied Natural Gas use

Winter LNG use over the last nine years (2001-2009) averaged 152 TJ. LNG use in 2007 increased significantly as a result of the increase in GPG demand, which was driven by market conditions and the reduced availability of generation due to drought. The dramatic reduction in LNG use in 2008 and 2009 was mainly due to commissioning of the BLP pipeline in 2008.

Table 5-11 lists the winter LNG use for the last nine years.

Table 5-11 – Historical winter LNG use

	2001	2002	2003	2004	2005	2006	2007	2008	2009
TJ	29	217	175	199	88	270	321	45	26
Tonnes	525	3,974	3,206	3,631	1,615	4,918	5,827	823	471

Occasional supply outages (approximately every three years) may require significant extra LNG vaporisation of 1,000-2,000 tonnes. See Chapter 4 for the demand forecasts for the forecast period.

5.3.8 Liquefied Natural Gas system security reserves

Previously AEMO held 1,500 tonnes (83 TJ) of LNG allocation and stock in reserve. As of 1 February 2010, this holding was reduced to zero. AEMO has the right, however, to obtain a security reserve if conditions change.

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Chapter 6 Fuel Supply

The National Electricity Market (NEM) relies on coal for around 85% of its power generation, with another 8% supplied by gas, and the remainder supplied by hydro, wind, and liquid fuels.

While gas powered generation's (GPG) contribution to the NEM is relatively small, it has grown at an annual average rate of 13.9% over the last five years, and consumes nearly 30% of total gas production.

Victorian generation is mostly fuelled by brown coal, supplemented by hydro and gas-fired peaking generation, with liquid fuels playing only a relatively minor role due to their higher costs, and only used by two power generators as back-up fuel.

There is an abundant brown coal reserve exclusively used for power generation.

Victoria is also the largest gas-consuming State on the east coast. In 2009, however, only 10% of that consumption was used for power generation. Gas use in Victoria has been growing at an average rate of 1.6% per annum over the last five years and mostly consists of manufacturing and residential use.

This chapter will present a brief overview of the fuel mixes on the east coast of Australia, focussing on the Victorian stationary energy sector.

In this Chapter:

- Section 6.1 presents a breakdown of Victorian fuel usage for electricity generation.
- Section 6.2 discusses the sources and use of gas as fuel in Victoria.
- Section 6.3 discusses the use of coal as fuel in Victoria.
- Section 6.4 presents information about the use of different liquid fuel types.
- Section 6.5 discusses fuel prices and impacts.

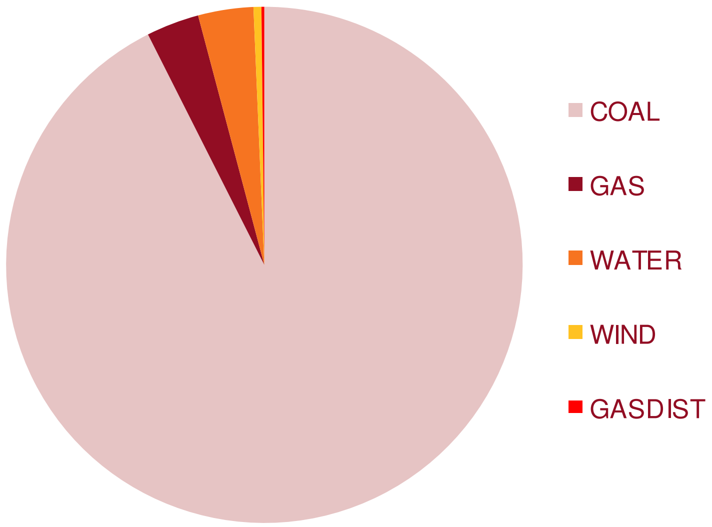
The information in this chapter has been based on a report received by AEMO from EnergyQuest titled "Fuel Supplies in the National Electricity Market – Report for the Australian Energy Market Operator."

6.1 Historical fuel usage for electricity generation

Brown coal is the fuel source for 90% of Victoria's electricity generation. The brown coal power stations provide base-load requirements and are in general unsuitable to respond to sudden changes in demand. Generation from fuels like gas and hydro provide the extra capacity to respond to peak demand periods.

Figure 6-1 shows the relative percentage of total generation in 2008/09 by fuel source. It shows that coal is the dominant fuel source for Victoria's electricity generation.

Figure 6-1 – Victorian Electricity Generation by Fuel Source (2008-09)



Source: AEMO, 2010

6.2 Gas fuel usage in Victoria

The east coast of Australia has six major gas producing basins:

- The Surat and Bowen basins west of Brisbane produce growing volumes of coal seam gas (CSG) as well as some conventional gas.
- The Cooper Basin in the north-east of South Australia and the south-west of Queensland produces conventional gas.
- The offshore Gippsland, Otway and Bass basins in the south of Victoria produce conventional gas.

The pattern of gas production is changing, with falling production from the Cooper Basin, growing Queensland CSG production, and significant production from the offshore Otway and Bass basins in Victoria. New South Wales and South Australia both rely on Victoria for around half their gas demand and Queensland is now exporting CSG to the southern States.

Eastern Australia has just over 100,000 PJ of gas reserves and resources (3P plus 2C,[23] or 160 times current production. CSG comprises 75% of 2P reserves and nearly 80% of total gas reserves and resources. There are also substantial reserves and resources off the Victorian coast, with the Gippsland, Otway and Bass basins amounting to 10,800 PJ or 30 times current Victorian production.

The Gippsland Basin is currently the largest gas-production basin on the east coast. Gas production comes primarily from fields developed by the ExxonMobil/BHP-Billiton Gippsland Basin Joint venture (GBJV), which is linked into the Longford-Dandenong Pipeline and the Victorian gas Declared Transmission System (gas DTS), the Eastern Gas Pipeline to Sydney (fully contracted and being

[23] These are estimated quantities that have a chance of being discovered under favourable conditions (3P) and estimated to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable (2C).

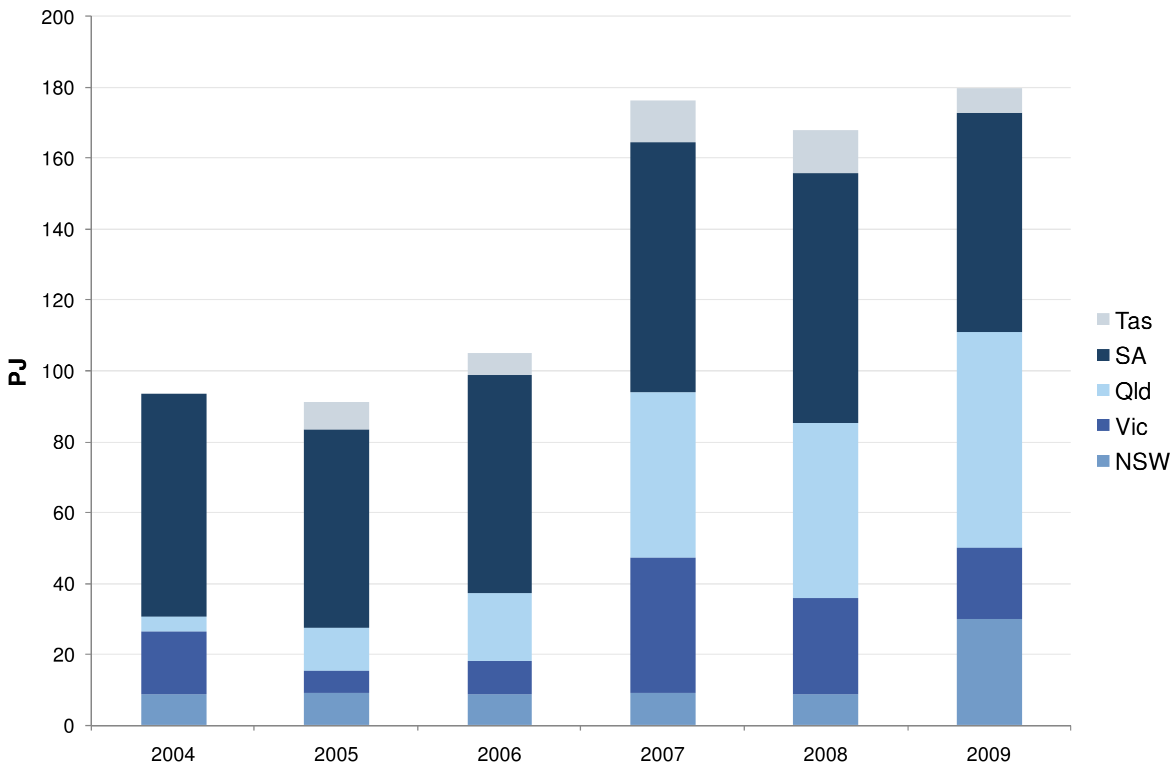
expanded), and the Tasmanian Gas Pipeline. GBJV gas production was down 14% in 2009 compared to 2008. This fall appears to have been due to Otway and Bass production substituting for Gippsland production (in other words, an increase in market share of non-Gippsland sources of gas). Further development of GPG in the LaTrobe valley, however, will lead to an increase in Gippsland gas utilisation.

The Otway Basin has three offshore fields producing gas (Minerva, Casino-Henry and Geographe-Thylacine), and three gas plants (Iona, Otway and Minerva), which are linked into the SEA Gas Pipeline to South Australia (fully contracted) and the South West Pipeline feeding into the Victorian gas DTS. Production has increased with the development of the Thylacine and, more recently, Henry fields. Current reserves are largely contracted to third parties for their own use.

Gas from Yolla, the Bass Basin's one producing gas field, is processed through the Lang Lang plant in Eastern Victoria and currently contracted to Origin Energy.

Figure 6-2 shows gas usage for GPG in the NEM.

Figure 6-2 – Victorian GPG gas usage relative to the NEM (2004–2009)



Source: EnergyQuest

While Victoria is the largest gas consumer on the east coast, using 216 PJ in 2009, it is a relatively small user of gas for GPG, consuming 20.1 PJ in 2009. Gas use for GPG peaked at 38.3 PJ in 2007 due to the drought, but this has since fallen. The major uses of gas are for manufacturing and residential demand.

Victoria has substantial gas reserves and resources, sufficient to supply the largest gas market on the east coast and export gas to New South Wales, South Australia and Tasmania. In the absence of substantial new discoveries, however, and in the context of rising industry costs for offshore development, costs are expected to increase in real terms over the long term, and higher prices may make it possible to commercialise tight onshore gas (natural gas which is difficult to access because of the nature of the rock and sand surrounding the deposit).

6.3 Coal fuel usage in Victoria

Australia has abundant black and brown coal resources in Queensland and New South Wales, and Victoria, respectively. The economic coal resource is 39 times the size of the economic gas resource on an equivalent energy basis. Australian coal production is expected to grow at an average rate of 1.8% per annum to 2030, driven by growth in exports averaging 2.4% per annum. Domestic coal consumption is expected to fall at an average rate of 0.8% per annum, reflecting a fall in its share of domestic electricity generation.

According to Geoscience Australia and ABARE (2010), Eastern Australia demonstrates economic coal resources of 70 billion tonnes, or over one million petajoules (PJ), of which Queensland and New South Wales black coal comprises almost 70%.

Table 6-1 lists a summary of the state of Eastern Australian coal production and resources as at 2009.

Table 6-1 – Eastern Australian coal production and resources, 2009

			Economic Resources 2008			Coal 2009		
State	**Basin**		**Mt**	**PJ**	**Heat Value MJ/kg**	**Production Mt**	**Exports Mt**	**Domestic Mt**
Queensland	Bowen, Surat, Galilee	Black Coal	18,000	419,200	22.0-24.0	190	168	22
New South Wales	Sydney, Clarence Morton	Black Coal	15,800	356,400	22.9	143	106	37
Victoria	Gippsland	Brown Coal	36,800	356,900	9.7	65	0	65
South Australia	Leigh Creek	Black Coal	26	415	15.8	4	0	4
TOTAL			**70,626**	**1,132,915**		**402**	**274**	**128**
Sources: Geoscience Australia and ABARE (2010), (ABARE, 2010)								

Historically, only top-quality thermal coal has been exported, with lower-quality coal used for local generation. Typical specifications for thermal coal from the Newcastle fields are for a heating value of 28.3 MJ/kg and 15.1% ash compared with 25.0 MJ/kg and 22.0% ash for domestic thermal coal. Export demand has increased, however, for higher-ash coals for blending with lower-ash Indonesian coals.

There are substantial reserves of coal from existing sources to meet future power generation needs (subject to contractual arrangements with mine owners). At current production rates, the east coast has 100 years of economic black coal reserves and approximately 500 years of economic brown coal reserves at current levels of consumption.

In Victoria, brown coal is used exclusively for power generation. Due to the high moisture content of brown coal, however, it cannot be economically exported. Table 6-2 shows Victorian coal specifications. The coal has high moisture and low heating value. A number of coal seams are mined by open-cut. In 2008/09, production was 65 million tonnes (Mt) (663 PJ) supplying the five coal-fired power stations in the Latrobe Valley. HRL Technology is proposing a new 550 MW demonstration plant in the Latrobe Valley using integrated drying and gasification combined cycle technology.

Table 6-2 – Victorian coal specifications

	Moisture %	Ash %	VM %	Sulphur %	Heat Value MJ/kg
Yallourn Seam Y	65.5	1.7	51.1	0.3	7.1
Morwell Seam M1	60.1	3.3	48.2	0.4	8.8
Yallourn N Extension Seam M2	51.7	4.4	48.8	0.5	11
Loy Seam M 1B	62.5	1.5	51.3	0.4	8.1
Yang Seam M2	61.0	1.7	50.5	0.4	8.8
Source: EnergyQuest					

Table 6-3 lists the five Victorian Latrobe valley power stations and their supply sources, all of which are privately owned mine-mouth operations with a total generation capacity of 6,299 MW [24].

Table 6-3 – Victorian coal-fired power stations

Power station	Operating company	Coal field	Transport	Year of commissioning	Total capacity (MW)
Loy Yang A	Loy Yang Power	Loy Yang	Conveyor	1984-87	2,170
Hazelwood	Hazelwood Power	Hazelwood	Conveyor	1964-71	1,580
Yallourn W	TRUEnergy	Yallourn	Conveyor	1973-75 1981-82	1,420
Loy Yang B	International Power	Loy Yang	Conveyor	1993-96	965
Morwell	Energy Brix	Loy Yang Hazelwood	Conveyor	1958-62	164
Sources: ESAA (2009), Barton, Gloe, & Holdgate (1993) and company websites.					

In recent years Hazelwood Power has undertaken its Hazelwood West extension project. Loy Yang is mining Block 2 of the Loy Yang open cut mine, and will move on to Block 3 by around 2027. Yallourn is developing the Maryvale field for production from 2011 (requiring the diversion of the Morwell River). The Victorian Government has identified and implemented measures to protect future mining areas.

[24] Based on 2009 ESOO 2009/10 summer aggregate scheduled generation for Victoria.

6.4 Liquid fuel usage in Victoria

According to the Australian Energy Regulator (2009) approximately 0.1% of power generated in Australia in 2009 was generated using oil-based petroleum fuels as the primary fuel type [25].

Generating base load power from liquid fuels is significantly less economic than from gas or coal. Depending on the prevailing price, however, oil can be and is used economically for generating power to meet peak demand at times of high NEM prices, or to meet a generator's contractual supply commitments.

The main types of oil-based fuels used for power generation in Australia are diesel, kerosene, and fuel oil. Most peaking power stations that use liquid fuels use diesel as their primary fuel. Mt Stuart in Queensland uses kerosene as its primary fuel type. Torrens Island Power Station (TIPS) uses fuel oil as a back-up. Alternative liquid fuels such as biodiesel, LPG or condensate may be available in Australia, but are not regarded as mainstream alternatives for power generation.

In Victoria, diesel (or distillate) is used only as a back-up fuel for two principal plants at Newport and Jeeralang. Newport has large on-site storage connected by pipeline to the nearby Newport import fuel terminal. Jeeralang relies on the delivery of diesel by road tanker from the Melbourne and Hastings fuel terminals. TRUenergy advises that Jeeralang can operate continuously for only eight to twelve hours in extreme circumstances.

Diesel, kerosene and fuel oil costs generally track the price of crude oil. The indicative cost of fuel oil delivered to Torrens Island in South Australia in mid-February 2010, with oil prices around USD75 per bbl (USD/AUD exchange rate of 0.91) would have been around AUD804 per tonne or AUD18.78/GJ.

The indicative cost of supplying diesel or kerosene to other generators in South Australia, Victoria, New South Wales and Queensland in mid-February 2010 varied between AUD760 and AUD800 per tonne or AUD 16.5 to AUD 17.5/GJ.

Biodiesel is not currently seen as a reliable substitute for diesel for power generation in Australia, mainly due to limited reliable suppliers and concerns over quality and fuel stability.

6.5 Fuel prices

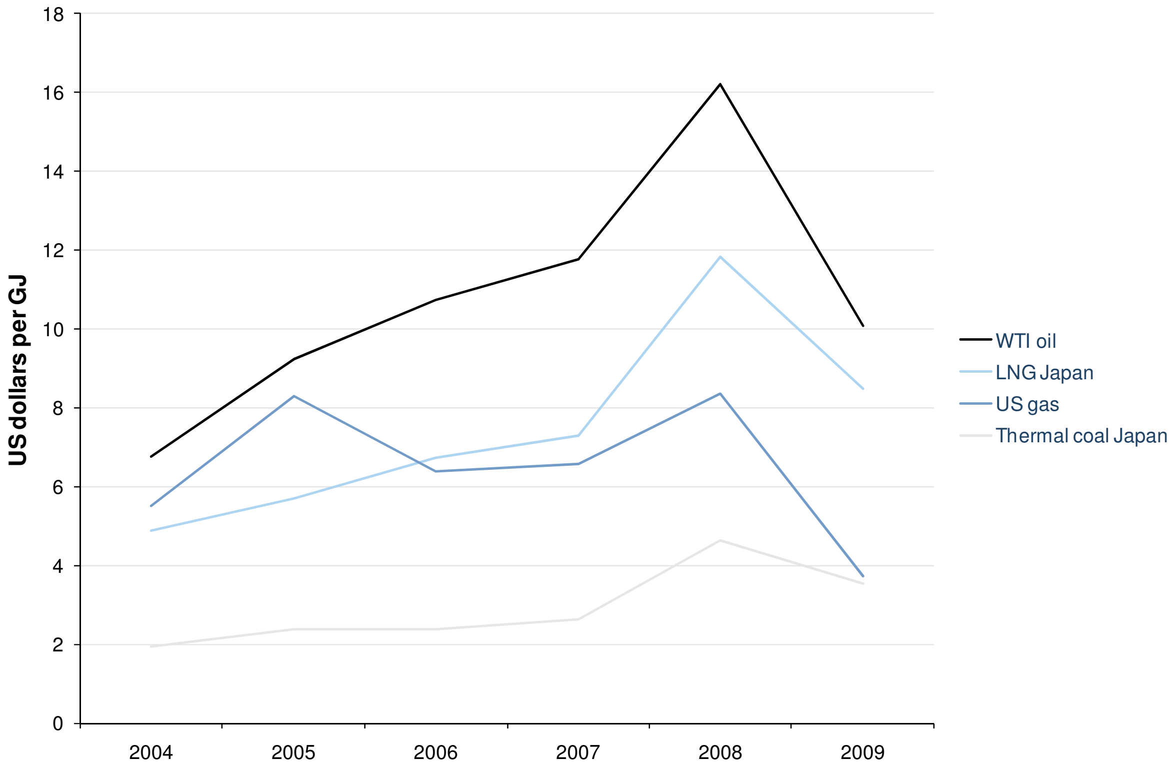
Relative fuel costs are an important determinant of fuel use. Figure 6-3 shows international fuel prices for West Texas Intermediate (WTI) oil, a US oil price benchmark, liquid natural gas (LNG) imported into Japan, US Henry Hub gas, and thermal coal imported into Japan, all expressed in USD per gigajoule (GJ) to standardise energy units.

Internationally, on an energy basis oil is the most expensive fuel (and WTI is crude oil, rather than the more expensive refined product) and coal is the cheapest. Gas imported into north Asia as LNG is indexed to oil prices and is relatively expensive.

[25] EnergyQuest

US gas prices, a global gas price benchmark, fell heavily in 2009 due to the recession and the increase in US gas production.

Figure 6-3 – International fuel prices



Sources: EnergyQuest, 2010

Coal

Coal and gas for NEM power generation are below international prices. Coal costs vary, depending on the type of coal, its quality, location in relation to the power station, and the nature of the contract. In many cases, coal deposits are owned by the generator, making it difficult to estimate costs. In cases where coal is purchased from third parties, prices are generally confidential. Coal, however, is generally the cheapest fuel source, ranging from below AUD0.50 per GJ in Victoria to between AUD1.00 and AUD2.00/GJ in New South Wales, Queensland and South Australia.

In comparison, spot prices for export of coal from Newcastle as at February 2010 were USD93.25 per tonne or around AUD3.90/GJ. Exports of thermal coal are sold both under long-term contracts (around 70%) and on a spot basis (around 30%).

Gas

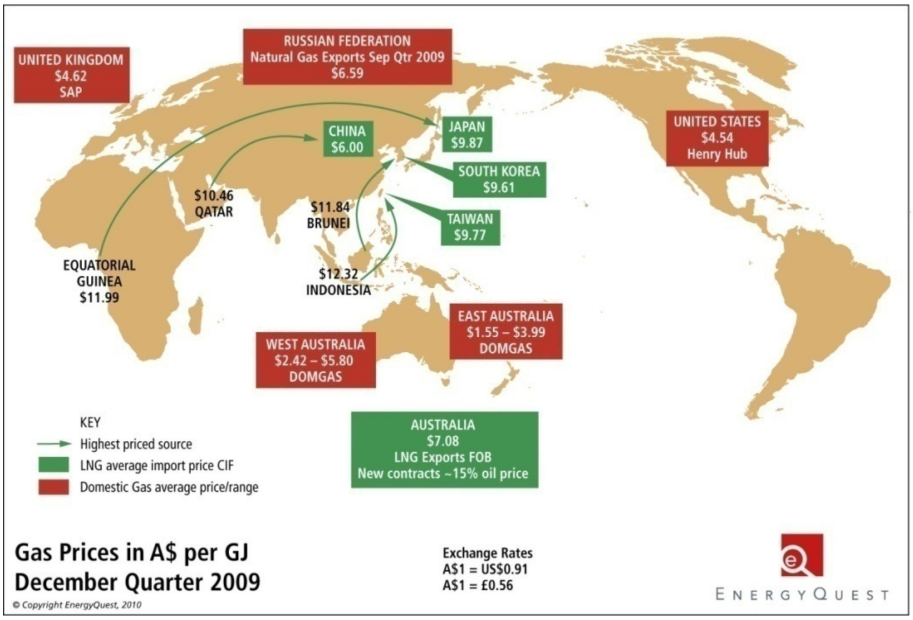
There continues to be a disparity between domestic gas prices and export prices. Although the long-term outlook may be for higher gas prices in real terms, spot prices are currently below contract prices. This situation reflects the economic downturn and increase in gas supply in both Queensland and Victoria.

Figure 6- 4 shows the international and Australian gas prices in AUD/GJ for the 2009 December quarter. The international figures include the UK system average price (SAP), the US Henry Hub spot gas price, the average export price for gas (predominantly pipeline gas) from Russia, and the

average landed import prices (shown in green boxes) for LNG into Japan, Korea, Taiwan and China. The arrows show the highest average price of imports into each country in the December quarter.

The figure also shows the average price for Australian LNG exports in the December quarter compared with domestic gas prices (ex-field). International prices continue to be higher than Australian domestic prices, giving rise to concerns that east coast gas prices may ultimately rise to international levels.

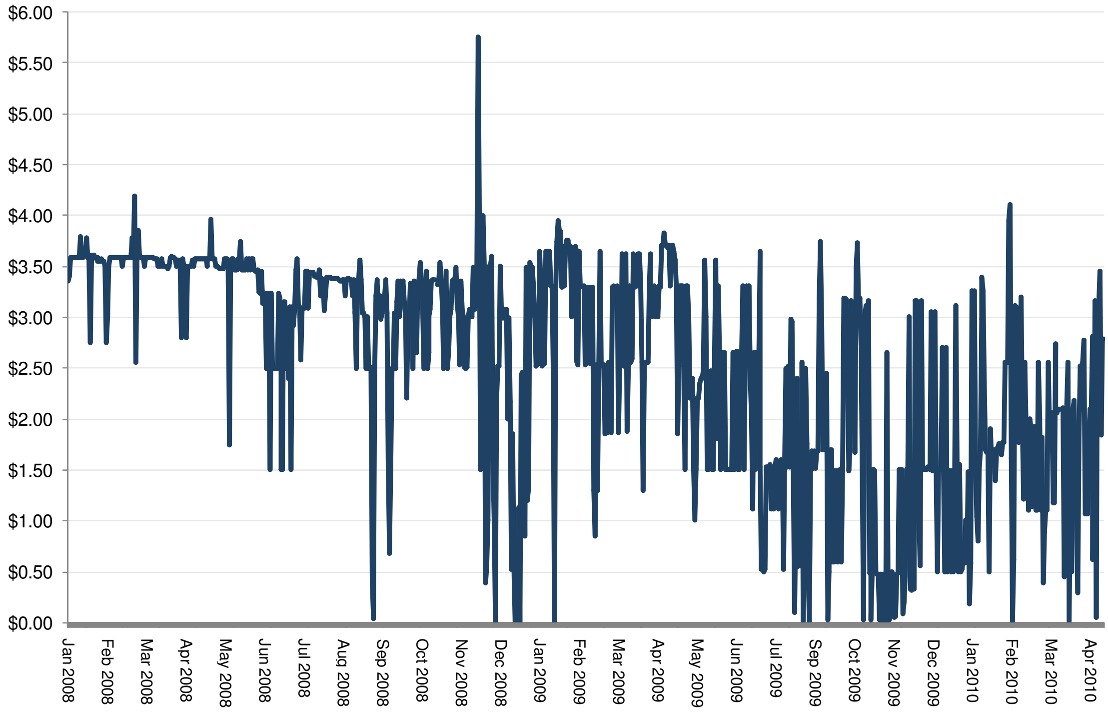
Figure 6- 4 – International gas prices



Source: EnergyQuest, 2010

Figure 6-5 shows the Victorian average daily spot price for gas. There are more occurrences of low prices in 2008/09, and an increase in price variability. The low prices may be due to the introduction of the BLP pipeline, which increased the capability to transport more gas from Iona, potentially encouraging competition between Iona and the Longford gas plant. Price variability is likely to have been caused by market bidding behaviour.

Figure 6-5 – Victorian average daily spot price for gas AUD/GJ



Source: AEMO, 2010

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Chapter 7 Supply, Demand and Transmission Capacity

This chapter presents regional supply-demand balance information for the Victorian electricity Declared Shared Network (electricity DSN) for the year 2009/10, and Victorian gas Distributed Shared Network (gas DTS) capacity forecasts for the forecast period (2010-2014). The gas projections include forecasts for the demand-supply-capacity outlook and peak day gas DTS capacity.

Electricity

In terms of the electricity DSN, this chapter aims to assist existing and potential transmission network users to understand:

- which regions the are net users and net generators of electrical energy
- what requirements enable the transmission system to transfer power between regions at times of peak demand, and
- whether the location of a new major load or generation is likely to change these requirements.

Gas

In terms of the gas DTS, this chapter aims to assist existing and potential transmission network users to understand the:

- capacity of the main pipelines to transfer gas to major demand centres, and
- extent to which the forecasts of deliverable gas supplies meet forecast demand.

In this chapter:

- Section 7.1 provides high-level information about electricity and gas interactions relevant to electricity DSN and gas DTS capabilities.
- Section 7.2 presents an overview of the active and reactive supply-demand balance for the forecast 2009/10 electricity summer maximum demand (MD).
- Section 7.3 presents information about the gas peak day demand-supply-capacity outlook for the gas DTS as a whole and specific pipeline injections and withdrawals, and the contributing factors to normal pipeline operating boundaries for each main gas DTS pipeline.
- Section 7.4 discusses gas transmission system capacity for gas powered generation (GPG).
- Section 7.5 presents information about spare gas DTS capacity for specific purposes and major loads.

7.1 Transmission capacity synergies

This section highlights transmission capacity synergies relevant to the 2010 VAPR and the relationship between electricity and gas. When the electricity and gas regional supply-demand balances and transmission capacities are considered together, a series of broad regional issues, in terms of the location of new GPG, can be identified.

Table 7-1 – Comparative regional issues of electricity and gas

Region	Electricity	Gas
Eastern Corridor/Gippsland Zone	The region is a major energy exporter, which drives the design of the network limits in this area. Any significant increase in generation is therefore likely to necessitate electricity DSN augmentation	The Longford plant is the largest producer of gas for the Victorian market. Significant increases in GPG and system demand may necessitate the augmentation of the Longford pipeline
South-West Corridor/Western Zone	The electricity DSN in this region is likely to be able to absorb the connection of new generation. Electricity DSN augmentation or generation constraint is likely to be required to control elevated levels of unbalanced voltages	The deliverable winter peak day firm supplies available to Melbourne from Iona are limited by the capacity of the South West Pipeline (SWP). The Western Transmission System (WTS) is currently unable to support significant (100 MW or more) new GPG
Northern Corridor/Northern Zone	The region is a net generator as well as a transporter of energy from New South Wales to Melbourne during times of high demand. Significant augmentation may be required to increase the region's ability to transfer more energy to Melbourne at these times	Spare pipeline capacity was very limited in 2009 following rapid demand growth in the zone. Committed augmentation in the zone will increase pipeline capacity, however additional compression north of Wollert will be required if demand in the zone continues to increase
Greater Melbourne and Geelong/ Melbourne and Geelong Zone	Any new generation connections are likely to increase fault levels, which at 220 kV and below are already close to acceptable limits at many metropolitan terminal stations. As a result, augmentation to manage increased fault levels is likely. Fault levels at 500 kV are not as problematic	Meeting gas demand in this zone is a primary driver behind the design of the gas DTS. As a result, any significant increase in demand, such as new GPG, is likely to require gas DTS augmentation
Regional Victoria/Ballarat Zone	New generation is likely to meet local demand in the region, and will reduce the burden on the electricity DSN. However, given the region's size and layout, in specific cases the expected flows on some individual lines may change radically, leading to constraints. The level of constraint depends on the location and size of generation	Increased demand in this zone, which is served by lateral rather than mains pipelines, will probably require significant gas DTS augmentation

Energy market size

In 2010, the stationary energy industry is forecast to supply approximately 408 petajoules (PJ) of energy to Victoria in the form of electricity (185 PJ or 45% of the total) and natural gas (208 PJ system demand and 15 PJ GPG totalling 223 PJ or 55% of the total). These figures include both electricity delivered by GPG and gas used by GPG (15 PJ) [26].

Gas energy is typically measured in petajoules (PJ), terajoules (TJ), and gigajoules (GJ). Electrical energy is usually measured in gigawatt-hours (GWh) and megawatt-hours (MWh).

One MWh is equivalent to 3.6 GJ and 1 PJ is approximately equal to 278 GWh.

[26] This potentially results in some inherent double counting of energy, given statistics are separately recorded for gas and electricity.

7.2 Electricity transmission capacity

This section presents a series of breakdowns of supply and demand, which, when considered with Victorian electricity DSN loading information (see Chapter 3) indicate the transmission network's adequacy for carrying existing power flows, and how significantly these vary across the network as a whole.

7.2.1 Active and reactive supply demand balance

Active power supply-demand balance

Table 7-2 shows the combined Victorian and South Australian reserve summer peak demand conditions forecast for 2009/2010. AEMO's Electricity Statement of Opportunites (ESOO) considers the Victorian and South Australian National Electricity Market (NEM) regions together, because the:

- supply-demand outlook for the two regions depends on the network capability for power flows into Victoria from New South Wales and Tasmania
- Victorian and South Australian interconnectors are unlikely to constrain power flows in or out of South Australia during high demand weather periods, and
- two regions have similar weather patterns.

The forecast 2009/10 supply-demand balance reflects the forecast maximum demand (MD) of 10,346 MW for summer 2009/10, with maximum import available from New South Wales and Tasmania, and all Victorian generation available to produce at maximum output at the time of the MD.

Table 7-2 – Summer 2009/10 supply-demand balance forecast (MW) [27]

	Source	MW
Supply	Victorian generation	9,947
	South Australian generation	3,847
	Import capability from New South Wales and Tasmania	594
	Total combined regional supply	**14,388**
Demand	Victorian forecast demand (10% POE scheduled MD)	10,346
	South Australian forecast demand (10% POE scheduled MD)	3,500
	Total combined regional demand	**13,846**
	Committed DSP [1]	(66)
Reserve	**Combined Victorian and South Australian reserve**	**608**

1. Committed DSP has been included in region generation (VIC: -54 MW, SA: -12 MW)

[27] Source: AEMO 2009 SOO Supply Demand Outlook, August 2009.

Table 7-3 shows the Victorian supply-demand balance forecast for 2010/2011 by region.

Table 7-3 – Summer 2009/10 Victorian supply-demand balance

Region	Generation	Summer 2009/10 capacity (MW)	Total generation + import %	Total generation + import MW	Net generation + import (MW)
Eastern Corridor	Bairnsdale	74		7,662	6,698
	Energy Brix Complex	164			
	Hazelwood	1,580			
	Jeeralang A	200			
	Jeeralang B	216			
	Loy Yang A	2,170			
	Loy Yang B	965			
	Valley Power	270			
	Yallourn	1420			
	Wind generation (Toora, Wonthaggi)	3 (33) [1]			
	Import from Basslink	600			
Distribution network service provider (DNSP) load			3.8%	396	
Generator auxiliary load			5.5%	568	
South-West Corridor	N/A			-448	-958
	Wind generation (Codrington and Portland Stage 1, 2 and 3 – Yambuk, Cape Bridgewater and Cape Nelson South)	12 (150)			
	Import from SA	-460			
DNSP load			0.0%	2	
Major industrial load			4.9%	508	
Northern Corridor	Bogong	140		2,429	2,306
	Clover	26			
	Dartmouth	0			
	Eildon	120			
	Hume (Victoria)	17			
	McKay Creek	160			
	West Kiewa	66			
	Murray 1 and 2	1,310			
	Import from NSW	590			
DNSP load			1.2%	123	
Greater Melbourne and Geelong	Anglesea	158		1,075	-5,993
	Laverton North	310			
	Newport	475			
	Somerton	132			
DNSP load			64.5%	6,671	

Region	Generation	Summer 2009/10 capacity (MW)	Total generation + import %	Total generation + import MW	Net generation + import (MW)
Major industrial load			3.5%	357	
Generator auxiliary load			0.4%	40	
Regional Victoria	N/A			-80	-1,331
	Wind generation (Challicum Hills, Waubra)	20 (245)			
	Import from Murraylink	-100			
DNSP load			12.1%	1,251	
Transmission losses [2]			4.2%	430	
Total generation and import [3]				10,638	
Total demand (load + losses)			100%	10,346	

1. This represents wind generation with 8% load factor of installed capacity and the values within the brackets show the installed capacities
2. Includes losses in transformers at the point of connection and in sub-transmission lines that connect terminal stations
3. In this supply/demand balance calculation, export from Victoria to South Australia is set at 560 MW

Reactive power supply-demand balance and Victorian maximum supportable demand

Irrespective of thermal limitations, Victoria's maximum supportable demand (as defined by reactive power and voltage constraints for summer 2008/09) was 10,800 MW and is constrained by a voltage control/level limitation. The maximum supportable demand has not been reassessed for summer 2009/10. With the inclusion of Bogong Power Station the 2009/10 maximum supportable will have marginally increased from 2008/09 maximum supportable demand of 10,800 MW published in the 2009 VAPR.

This is an amount that can be supported with all plant in service, and that allows for any credible contingency event.

Factors that determine the level of maximum supportable demand include:

- operating the system within acceptable voltage profiles and reactive reserve margins, both before and after a critical contingency
- maintaining voltage stability after any single credible contingency
- maintaining the reactive output of all existing generation within capability requirements of the National Electricity Rules (NER), and
- optimising the reactive output of all generation to maximise the overall network capability.

To ensure acceptable post contingency voltages and reserve margins, actual system demand is not allowed to exceed supportable MD.

Table 7-4 lists Victoria's reactive supply-demand balance for summer 2009/10 at a forecast 10,346 MW [28] (summer 2009/10 MD was 10,305 MW) for system normal conditions with all generation and transmission elements in service.

Table 7-4 – Reactive supply-demand balance at 10,346 MW (system normal)

Reactive supply	MVAr	Reactive demand	MVAr
Generation	1,715	Loads	3,669
SVCs and sync cons	-144	Line reactors	201
Line charging	2,863	Line losses	5,873
Shunt capacitors	5,281	Inter-regional transfer	138
Series capacitors	166	-	-
Total	**9,881**	**Total**	**9,881**

Table 7-5 lists the system reactive supply-demand balance following the most critical outage, which is the loss of the 500 MW Newport Power Station. The modelling of this critical outage assumes frequency control from New South Wales and Victorian generation.

As a result of the outage, the:

- import from New South Wales increases from 680 MW to 1,180 MW, causing an increase in active and reactive transmission power losses
- amount of reactive supply in Greater Melbourne and Geelong decreases, and
- increased requirement for reactive supply is met by the remaining generation, synchronous condensers, static VAr compensators (SVC), and series capacitors.

Table 7-5 – Reactive supply-demand balance at 10,346 MW (following loss of Newport)

Reactive supply	(MVAr)	Reactive demand (MVAr)	(MVAr)
Generation	2,848	Loads	3,669
SVCs and sync cons	-21	Line reactors	183
Line charging	2,693	Line losses	6,749
Shunt capacitors	4,899	Inter-regional transfer	135
Series capacitors	317		
Total	**10,736**	**Total**	**10,736**

[28] See the 2009 VAPR, Chapter 3, 'Demand Forecasts', Section 3.1.1.

7.3 Gas transmission capacity

This section presents forecasts of peak day gas DTS capacity and the demand-supply-capacity outlook for the forecast period (2010-2014).

7.3.1 Peak day demand-supply-capacity forecasts

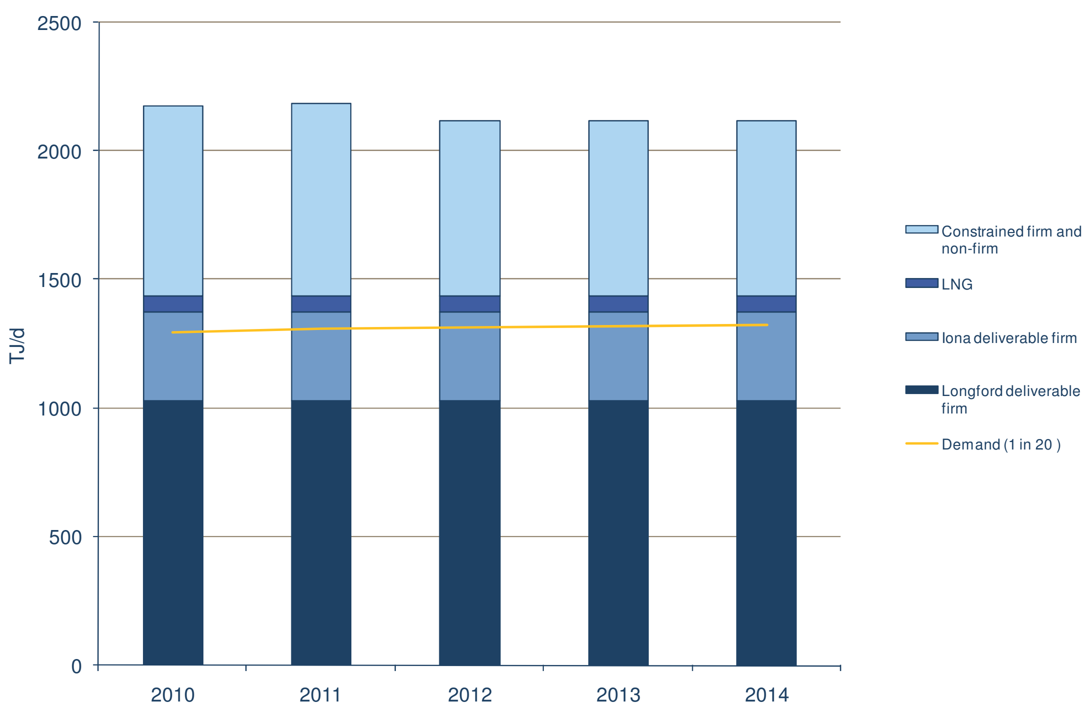
Under ideal weather conditions the deliverable supply from all system injection points is 1,316 TJ/d, comprising 1,030 TJ/d via the Longford to Melbourne pipeline and 286 TJ/d via the South West Pipeline (SWP). Including LNG, the total deliverable gas supply will be 1,376 TJ/d.

The non-winter peak day demand-supply-capacity assumptions account for different operating modes due to increased exports, plant maintenance, and the seasonality of firm supply.

Figure 7-6 provides an overview of the forecast peak day demand, supply, and transmission system capacity for the gas DTS. It also summarises the deliverable winter peak day firm supplies (as limited by pipeline capacity) and LNG (assumed to be a maximum deliverable of 60 TJ/d for within-day balancing), against the forecast 1 in 20 peak day demand, as well as showing firm supply from Iona, which is constrained by the existing pipeline capacity.

The capacity of the gas DTS limits Melbourne's access to gas supply from Iona and the Underground Gas Storage (UGS), even with the BLP pipeline, leading to a continued reliance on supply from Longford.

Figure 7-6 - Peak day demand, supply, and transmission system capacity forecast, 2010-2014 (TJ/d)



7.3.2 Peak day transmission system capacity by pipeline

AEMO's modelling identified the following maximum peak day injections or pipeline operating boundaries:

- 1,030 TJ/d at Longford (Exxon-Mobil and VicHub) and Pakenham (BassGas), via the Longford to Melbourne pipeline
- 315 TJ/d at Iona (Iona gas plant and UGS, and SEA Gas), via the South West Pipeline (SWP), however, the SWP can transport up to 347 TJ/d under favourable linepack conditions
- 92 TJ/d approximately at Culcairn (Moomba gas field/Culcairn imports) via the New South Wales interconnect [29], and
- 28 TJ/d at Iona, via the Western Transmission System (WTS).

The modelling scenarios assume that injections are available to meet peak demand. The scenarios also assume 60 TJ/d of LNG injection is available for within-day balancing, and will be required depending on the severity of the peak day profile and the beginning-of-day linepack conditions.

7.3.3 Longford to Melbourne pipeline

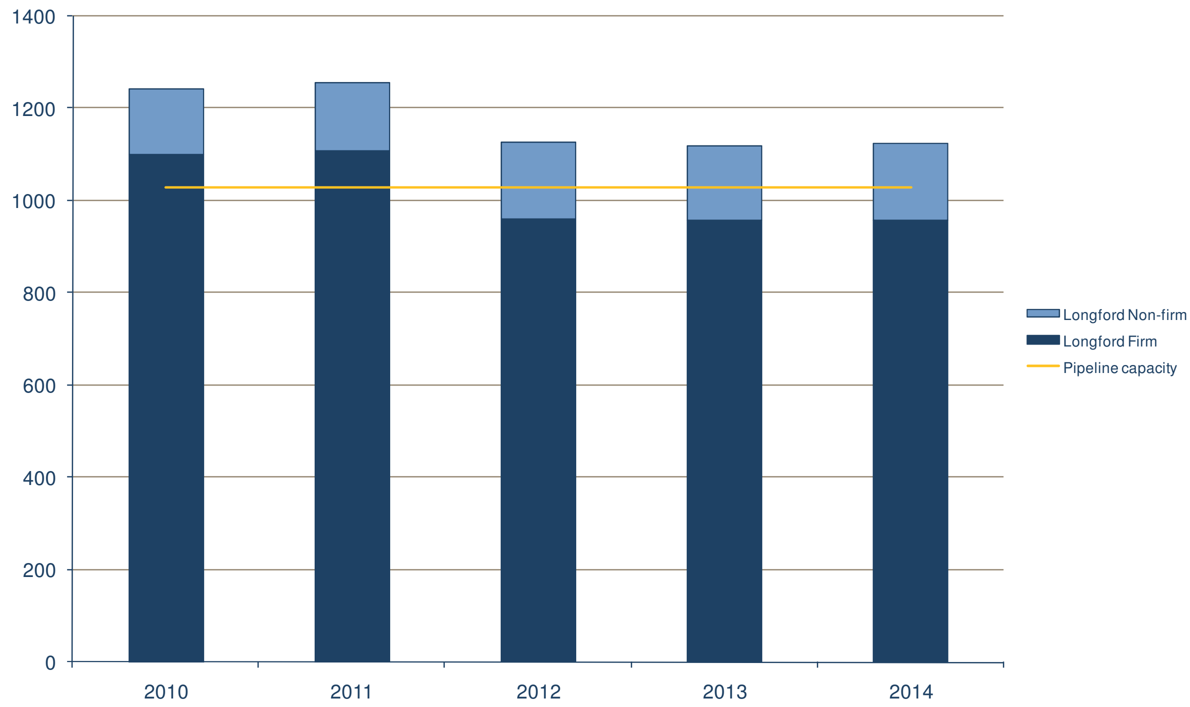
Figure 7-7 provides a comparison of the available supply from Longford, VicHub and BassGas against the available Longford to Melbourne pipeline capacity.

The maximum available plant capacity at Longford is 1,150 TJ/d but the combined supply from Longford, VicHub and BassGas is constrained to 1,030 TJ/d due to back-off effects on the Longford to Melbourne pipeline when pipeline capacity has been reached. While pipeline capacity remains constant for the forecast period, contracted supplies from the participants at Longford are decreasing. In 2010 and 2011, the 1,030 TJ/d limit from Longford to Melbourne is lower than the reported total contracted gas. It is understood that negotiations are proceeding on contracting additional Longford supply.

The quantity of gas that can be made available at Longford for injection into the gas DTS is higher than the pipeline capacity, indicating a potential to augment the Longford pipeline.

[29] This figure represents the potential pipeline capacity only – supplies from the Culcairn injection point include 35 TJ/d firm and 15 TJ/d non-firm for the forecast period.

Figure 7-7 - Total Longford, VicHub, and BassGas peak day supply and capacity forecast, 2010-2014 (TJ/d)

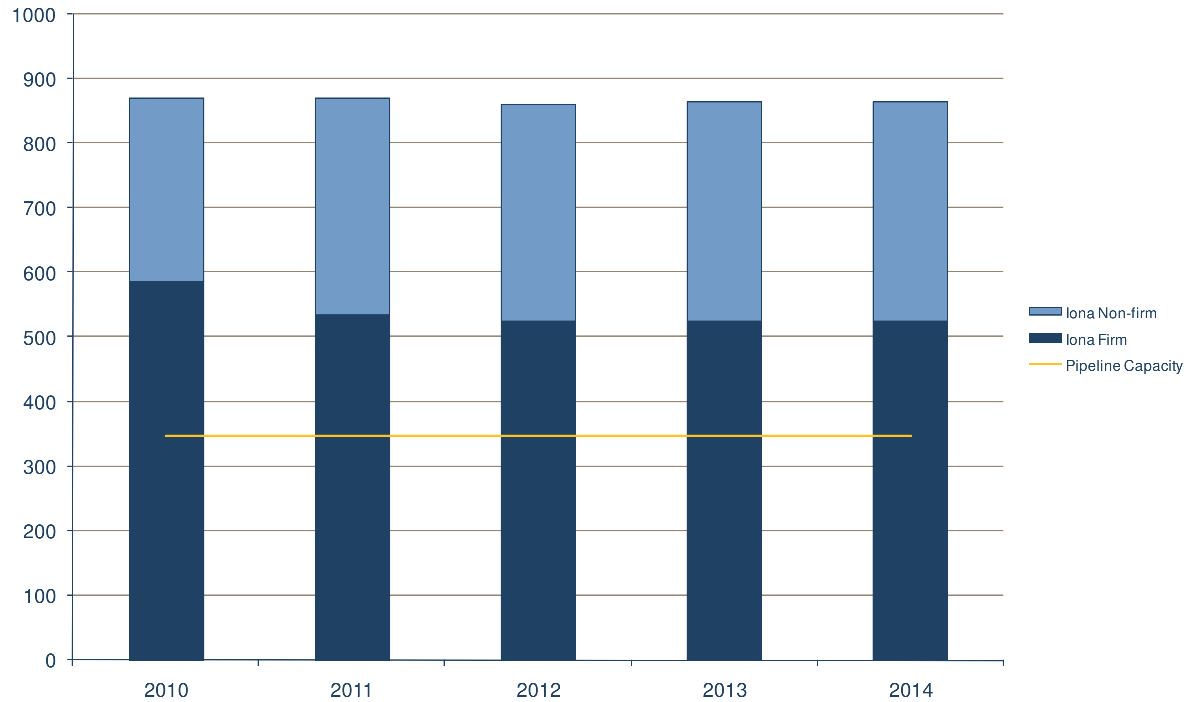


South West Pipeline

Figure 7-8 provides a comparison of the available supply from Iona and SEA Gas (including Otway) against the available SWP pipeline capacity. The figure indicates that pipeline capacity is the overriding constraint for suppliers injecting via the Iona and SEA Gas injection points, with the combined Iona and SEA Gas supplies being significantly larger than the pipeline's capacity.

Pipeline capacity currently constrains supply to 315 TJ/d due to normal winter beginning-of-day SWP operating pressures. The currently declared SWP capacity is 347 TJ/d which reflects system limitations at the time of the previous assessment. Previous modelling suggests that the SWP can achieve higher capacities. See Chapter 3, Section 3.7.2, for more information. AEMO is currently reviewing the declared capacity of the SWP.

Figure 7-8 – Total Iona and SEA Gas peak day supply and capacity forecast, 2010-2014 (TJ/d)



Increasing quantities of gas sourced from the Minerva and Thylacine fields are also likely to be offered into the gas market via the SEA Gas interconnect, resulting in competition with the UGS facility for limited SWP pipeline capacity.

The Otway plant is not connected to the gas DTS and therefore injections/withdrawals pass through the SEA Gas connection point. Total SEA Gas and Otway injections are limited to 200 TJ/d and withdrawals to 135 TJ/d based on the current SEA Gas connection agreement.

New South Wales interconnect

The New South Wales interconnect pipeline capacity for import is 92 TJ/d. Participants advise that there are 35 TJ/d firm and 15 TJ/d non-firm supplies from New South Wales for the forecast period. Gas offered into the Victorian market may be limited:

- when New South Wales and Victoria experience high demand at the same time, or
- subject to operating conditions and/or contractual arrangements on the Moomba-Sydney pipeline [30].

Western Transmission System

The WTS pipeline capacity is 28 TJ/d. This pipeline is currently supplied exclusively from Iona, for supply to the Western Zone.

[30] Peaking GPG at Uranquinty, near Wagga Wagga, can result in exports of 70 TJ/d in summer and 35 TJ/d in winter, affecting this pipeline's current operating conditions. AEMO has been advised by APA Group that they will complete augmentation of the compressor stations at Wollert and Springhurst.

7.4 Gas transmission system capacity for gas powered generation

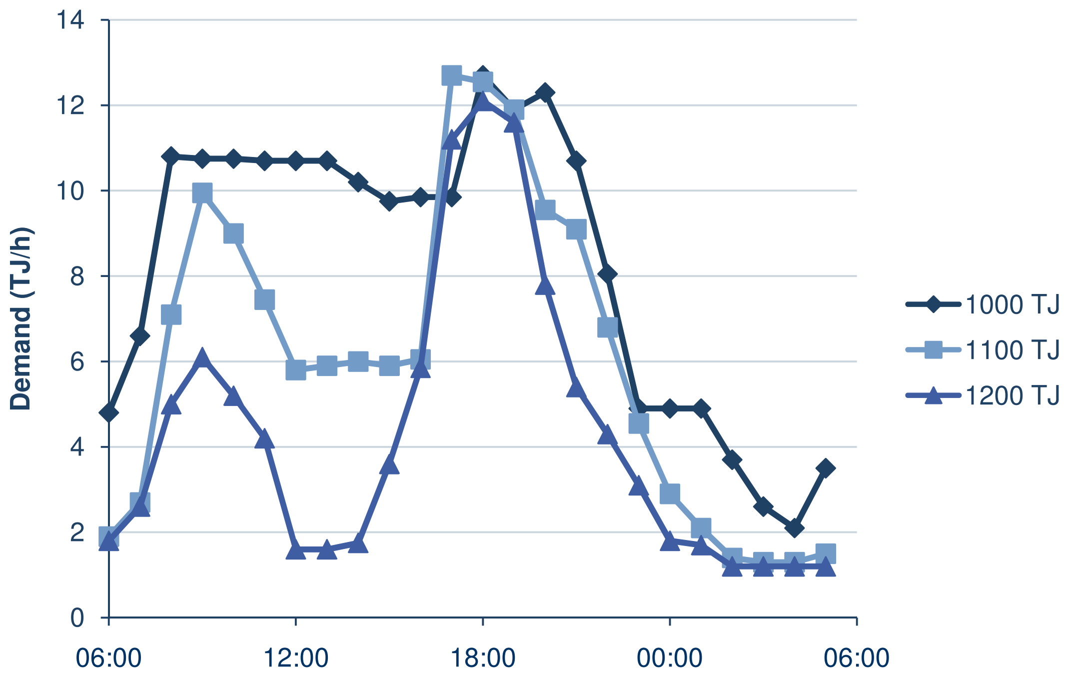
7.4.1 Spare transmission system capacity for gas powered generation

Depending on system demand and operating conditions on the day, planned or unplanned GPG can rapidly deplete linepack, potentially risking system security. The potential maximum hourly quantity (MHQ) of GPG can be very high relative to the hourly demand from all other industrial and commercial gas customers.

The approximate capacity of the gas DTS to support GPG demand for a typical 1 in 2 day is 130 TJ/d, decreasing to 30 TJ/d under 1 in 20 conditions. These figures are only approximations as system conditions and demand profiles vary from day-to-day.

Figure 7-9 shows a series of typical GPG demand profiles.

Figure 7-9 – Possible profiles of GPG demand for various levels of system demand (TJ/h)



Spare summer capacity has been modelled to determine gas availability for GPG. Table 7-10 lists the modelled spare capacities for summer GPG, showing:

- modelled spare capacity available at various gas DTS locations, expressed as a maximum daily quantity (MDQ) and corresponding maximum hourly quantity (MHQ) of demand fitting the test profile for a theoretical new load, and
- indicative pressures at each location. Some pressures rely on compressor operations, and result from one or both Brooklyn Compressor Station compressors (2,850 kW Unit 11 or 3,500 kW Unit 12) being in use for GPG demand at Laverton North and at Golden Plains (near Geelong).

Table 7-10 – Spare transmission system capacity for summer GPG

Zone	Location	MDQ (TJ)	MHQ (TJ)	Typical Minimum Pressure (kPa)
Gippsland	Latrobe Valley	150	19.9	4,200
	Pakenham	130	17.2	3,500
	South Morang	125	16.6	3,500
Melbourne and Geelong	Golden Plains (2C) [1]	24	3	4,000
Northern	Shepparton/Echuca	10	1.3	2,500
	Bendigo	22	2.9	3,200
1. 2C refers to two Brooklyn compressors (Unit 11 and Unit 12)				

These capacities apply to the relevant zones. Capacity taken up at any location within a zone will reduce capacity at other locations within the same and interrelated zones in direct proportion.

The results for Golden Plains assume no withdrawals at Iona, which would reduce spare capacity for GPG at this site on a one-for-one basis (approximately).

Most capacity is available on the 750 mm pipeline from Longford to Dandenong and from Pakenham to Wollert, whereas capacity is very limited for GPG peaking plants in the northern and central parts of the gas DTS.

The summer GPG cases:

- are modelled for a late summer day representing system demand of 500 TJ
- assume no injections to or withdrawals from either Culcairn or Iona, and
- assume all existing GPG plant is operating.

Based on actual sample data, total existing GPG demand is assumed to be 220 TJ/d. Newport demand is 83 TJ/d, Jeeralang is 45 TJ/d, Valley Power is 29 TJ/d, Somerton is 13 TJ/d, and Laverton North is 50 TJ/d.

The profile used for GPG test loads is based on the Jeeralang GPG peaking plant on a very hot day.

The gas DTS supplied up to 335 TJ/d to GPG demand during the heat wave in late January 2009 when system demand was 370 TJ/d.

7.5 Potential spare gas transmission system capacity due to augmentation

Demand from GPG substantially increased in 2007, with average weekday consumption of approximately 170 TJ. Meeting possibly significant future GPG demand during simultaneous periods of high system demand, however, will require gas DTS augmentation.

The Longford pipeline has four unduplicated sections between Tyers (line valve 4) and Bunyip (line valve 8). Duplication of all of these sections (by inserting four loops) will increase the capacity of the

Longford pipeline. The capacity increases resulting from each of the individual loop augmentations will vary depending on the order in which they are carried out.

Potential augmentations to increase the capacity of the SWP include installing compressors, pipeline duplication, and construction of the Rockbank to Wollert pipeline. The resulting capacity increases from each (or a combination) of these augmentations, will vary.

Chapter 8 Planning Overview

This chapter presents information about the inputs involved in planning for Victoria's electricity Declared Shared Network (electricity DSN) and the Gas Declared Transmission System (gas DTS).

In this chapter:

- Section 8.1 provides high-level information about electricity and gas interactions relevant to the electricity and gas planning role.
- Section 8.2 presents information about AEMO's electricity planning criteria, and the five and ten-year planning process.
- Section 8.3 discusses AEMO's gas planning criteria, and the 5-year and 10-year planning process.
- Section 8.4 provides information about the supply scenarios created to enable a study of the electricity DSN over the next 10 years.
- Section 8.5 presents information about gas planning criteria, gas scenario planning and scenario development.
- Section 8.6 presents information about gas and electricity scenario overlaps.

Victoria's energy transmission infrastructure framework

Victoria's transmission network combines a series of basic, large-scale infrastructure elements (see Chapter 3 for more information). Factors tending to preserve this infrastructure framework, ensuring that the existing Victorian infrastructure will remain relevant in the long term, include the following:

- The location of major long-term fuel sources.
- New investment in Victoria's (relatively mature) energy industry typically only represents a few percent of the industry's total asset value in any year.
- Existing infrastructure assets have a particularly long service life (typically several decades), and future demand growth is relatively low.
- New easements and sites are difficult to obtain, meaning that infrastructure topology changes tend to be relatively small.
- Greater Melbourne and Geelong continues to be dominant as the primary demand centre.

As a result of these factors, the likelihood is that future infrastructure development will evolve in the short to medium term using existing assets (especially sites and easements), rather than requiring significant changes.

8.1 Planning synergies

The different planning roles and approaches

In the electricity market, AEMO is responsible for planning and directing augmentations to Victoria's high voltage electricity DSN. In the gas market, AEMO is required to provide planning information and recommendations to the gas industry but it is not AEMO's role to act on the information it provides.

In planning the electricity DSN, AEMO's investment decisions are based on a cost-benefit analysis of energy at risk, which includes consideration of the probability-weighted impacts on supply reliability of unlikely, high-cost events such as:

- single and multiple outages of transmission elements, and
- unexpectedly high levels of demand.

This approach provides a sound actuarial estimate of the expected value of energy at risk, and aims to ensure that an economic balance is struck between the costs of:

- providing sufficient network capacity to remove all possible constraints, and
- some exposure to load levels that exceed the transmission network's capability for a few hours (at most) each year.

In short, while recognising that extreme loading conditions may occur, it may be uneconomic to provide the additional electricity DSN capacity required to prevent load shedding.

In contrast, AEMO bases the identification of the potential gas Declared Transmission System (DTS) augmentations on criteria involving the capability of the gas DTS to meet demand on a 1 in 20 winter peak day [31] (a peak day demand forecast for defined severe weather conditions and operating conditions that are expected to be exceeded, on average, once every 20 years).

The 1 in 20 winter peak day planning standard acts as the trigger for a more detailed assessment of a potential gas transmission network constraint (identified as part of an annual planning report). Following the identification of a potential constraint, AEMO informs the market (but cannot impose an obligation to act) by:

- identifying a range of options to address the constraint
- determining the option that best meets the National Gas Rules' (NGR) Economic Value test [32], and
- publishing a major system augmentation report.

Gas and electricity planning interactions

The economics and accessibility of new fuel sources is a significant variable shaping infrastructure investment over the next 25 years. While brown coal reserves are sufficient to supply Victoria's electricity needs for approximately 500 years at current rates of consumption, the same may not be true of gas reserves. However, brown coal's long-term viability is similarly uncertain due to Australian Government carbon policies, and it is not yet clear how successful clean coal technology will be in terms of delivering an economic solution (or when this may happen). See Chapter 6 for more information about Victorian fuel supplies.

As a result, and in parallel with the rapidly increasing impact of renewable technologies, gas powered generation (GPG) may dominate the medium-term development of both the electricity and gas transmission networks. If this occurs, it is likely that GPG plant will be located close to fuel sources or electricity demand centres, and (due to inter-regional trading risk) in the same market region as the load being served. Similarly, the specific location of Liquefied Natural Gas (LNG)

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[31] The gas planning criteria also consider 25 TJ/d of demand from existing GPG.

[32] Rule 79(2)(a) of NGR also allows for the detailed consideration of constraints on lateral parts of the gas DTS.

shipping terminals (if they become a local gas industry feature) may also influence gas transmission network topologies.

In order to consider the range of electricity and gas transmission network requirements that may arise, a number of different planning scenarios have been developed. These scenarios:

- are not predictions or long-term estimates
- lie within the bounds of reasonable possibility, and
- have been designed purely to capture the limits of the infrastructure development that may be required for a 10-year outlook.

Other scenarios that do not push the boundaries of infrastructure development have not been included.

8.2 Electricity planning

AEMO's planning role

AEMO is responsible for independently planning and directing the augmentation of Victoria's electricity DSN. In performing this role, AEMO:

- undertakes its responsibility in accordance with its licence obligations, the National Electricity Law (NEL), National Electricity Rules (NER), and the Victorian Electricity System Code, and
- assesses the feasibility of transmission projects using the Regulatory Investment Test for Transmission (RIT-T) and the Regulatory Test, as specified by the Australian Energy Regulator (AER).

It is AEMO's policy that electricity DSN [33] augmentations generally proceed with the option with the highest net economic benefit out of a range of other options. This does not apply where an augmentation is funded by a third party.

AEMO's planning criteria

In accordance with RIT-T [34] requirements, AEMO considers the benefits associated with transmission investment as accruing from, among other things:

- expected unserved energy (USE) reductions
- total National Electricity Market (NEM) generation fuel cost reductions
- transmission loss reductions
- plant capital cost deferrals, and
- ancillary service cost reductions.

[33] AEMO considers non-network options in addition to network options when assessing responses to identified needs.

[34] The RIT-T is to be in place as of 1 August 2010, in line with the Rule change introducing it on 1 July 2009. Previously, the Regulatory Test was used to assess all electricity network investments.

These benefits are then balanced against the cost of that investment. See Section 8.3 for more information about AEMO's planning criteria.

In establishing development investment options for each Victorian region for the next 10 years (the forecast period), AEMO takes two distinct approaches that involve a 5-year outlook and a 10-year outlook.

Five-year outlook

AEMO performs a detailed cost-benefit analysis for each region for the forecast period's first five years (years 1–5), based on a simulation that uses extrapolated NEM dispatch data and demand forecasts published in the 2009 VAPR to determine probable electricity DSN usage.

Forecast flow conditions are then compared with critical plant capabilities, enabling quantification of the possible exposure to USE.

Due to the relatively high degree of confidence short-term planning provides, possible augmentation timings can be confidently supplied. This is appropriate, given the potential lead times required for major augmentation works.

See Section 8.3 for more information about the 5-year outlook analysis.

Ten-year outlook

AEMO performs a scenario analysis for each region for the forecast period's final year (year 10), based on the forecast level of demand. This is necessary, given the range of possible sites for the new generation required to meet anticipated increases in demand. Five possible (mutually exclusive) supply scenarios, describe the plausible range of outcomes from future generation patterns.

The analysis of these scenarios overlays an indicative cost-benefit assessment of constraints that incorporates a deterministic and limited cost-benefit analysis. Due to the lower degree of confidence attached to this period, however, possible augmentation timings are indicative only.

See Section 8.4 for more information about the possible supply scenarios and the 10-year outlook analysis.

8.3 Planning for the 5-year outlook

Planning criteria

AEMO plans and develops the Victorian electricity DSN to ensure that it operates within system security and system performance obligations.

In developing its planning approach for Victoria, AEMO aims to:

- ensure that system security and performance obligations can be fulfilled in the most economic way, and
- plan the network with the optimal level of redundancy for particular circumstances.

To achieve this, AEMO assesses potential network developments by:

- weighing up individual development costs against the potential system benefits (benefits often being related to ensuring compliance with obligations such as generation re-dispatch or load shedding), and
- predicting the actions required to meet statutory obligations, by application of probabilistic planning techniques to determine expected benefits.

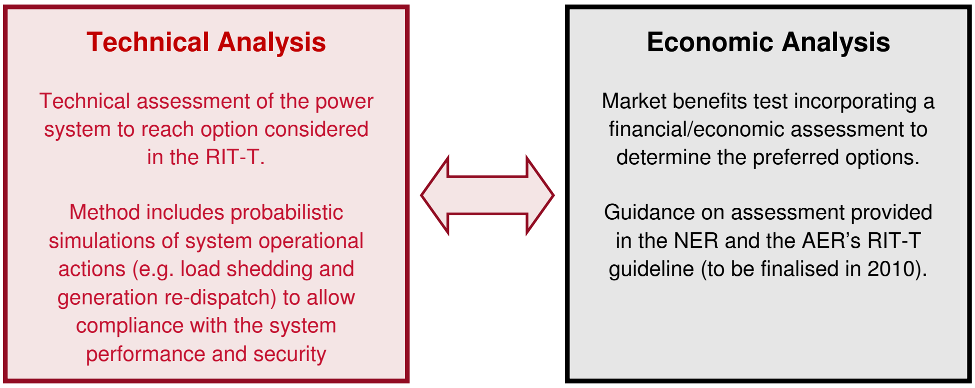
The Rules require augmentations to be assessed against the RIT-T and the Regulatory Test, as appropriate. When planning an electricity DSN augmentation under the RIT-T, AEMO compares a probabilistic assessment [35] of market benefits with the augmentation's cost, and augments the network to deliver the greatest net economic benefit.

Underpinning the cost-benefit analysis is a technical assessment of the current system with and with out the augmentation, which involves:

- a number of yearly demand and generation scenarios, and
- simulating future system operator actions, enabling each scenario's compliance with system performance and security obligations.

Figure 8-1 shows the relationship between the economic and technical analysis underpinning the RIT-T.

Figure 8-1 AEMO's planning assessments for the RIT-T



AEMO's Planning Criteria is currently being updated to reflect regulatory developments. The existing planning criterion is currently available on AEMO's website and provides additional information about the planning of the Victorian electricity DSN [36].

AEMO's power system technical assessment involves a number of yearly demand and generation scenarios, and an hour-by-hour simulation of the future system operator actions, enabling each scenario's compliance with system performance and security obligations.

This assessment examines three power system components, involving a market analysis, a network analysis, and a system operations analysis.

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[35] As required under the National Electricity Law, AEMO must apply a probabilistic (as distinct from a deterministic) approach to determining the benefit of an augmentation to the electricity DSN (section 50F).

[36] See http://www.aemo.com.au/planning/criteria.html.

The market analysis produces the demand and generation scenarios, providing hourly demand and generation dispatch and costs.

The network analysis calculates network loading under the system conditions the market analysis defines, including reactive power loading, voltage levels, and circuit thermal loadings. Power transfer limit calculations are based on system performance requirements and compared with network loadings, enabling a system performance compliance assessment for all probable system conditions.

The system operations analysis determines operational actions to ensure system security compliance, and uses network analysis output to determine appropriate actions, such as load shedding or generation re-dispatch. Probabilities are then applied to these actions, to account for uncertainties such as demand, generation unavailability, and network contingencies.

The 5-year analysis

AEMO's 5-year outlook is based on a NEM simulation to determine possible electricity transmission system usage. This simulation:

- uses published criteria to determine the value of constraints associated with critical transmission element loadings
- calculates transmission element loading using constraint equations and simulated generation dispatch and connection point load trace data, and uses simulated hourly temperatures to calculate transmission element ratings
- identifies potential overloads by comparing the calculated transmission element ratings and the potential loading, and
- considers both system normal conditions (all transmission plant in service), and outages of other transmission elements.

The frequency and extent of potential transmission element overloads are calculated from the simulation data. Where an overload occurs, operational actions required to remove it are identified, including electricity DSN re-configuration and generation rescheduling. Load reduction is applied when these measures are insufficient. The benefit of avoiding these operational actions is calculated and valued using the Value of Customer Reliability (VCR).

Value of Customer Reliability

The VCR is a measure of the cost of USE that aims to capture the value of energy to users. In simple terms it represents the cost to consumers of being without electricity, and is an important input for regulatory test assessments of planned electricity transmission augmentations in Victoria. Constraint costs are equal to the sum of the generation rescheduling and/or load reduction required to remove any overloads for the analysis period. The cost of the required operational action, in instances where the outage of a transmission element or generator is being considered, is weighted with the probability of the outage occurring (with benchmark and/or historical forced outage rates assumed).

A survey to determine the VCR for electricity in Victoria was last conducted in 2007. AEMO applies an index to these survey results between survey periods. This ensures that the VCR value is updated to reflect current income and economic growth for the various identified sectors of the economy (Residential, Agricultural, Commercial, and Industrial), enabling the production of a headline figure reflecting a weighted average.

The index uses data from the Australian National Accounts: State Accounts data series, updated by the Australian Bureau of Statistics (ABS). The data for the 2008/09 year was released on 22 December 2009. The new data has been used to calculate the 2010 VCR numbers for Victoria.

Table 8-1 summarises the 2010 VCR results.

Table 8-1 – VCR value for Victorian electricity

Sector	Value (per MWh)
Residential	$16,326
Agricultural	$134,149
Commercial	$114,679
Industrial	$45,945
Headline	$60,178
Note: all figures are in $2009/10 (Dec $09)	

8.4 Electricity scenarios and the 10-year outlook

This section describes the supply scenarios created to enable a study of the electricity DSN in year 10 (see Chapter 7 for the results of this study), and the way they are expected to impact future generation and power flow patterns.

To model the system for this period of time, it is necessary to take a view about likely generation patterns in year 10. While demand can be forecast, and a central view taken (such as medium economic growth), this approach is not appropriate for generation. As the location of new generation can considerably affect the pattern of power flows and system constraints, a scenario-based planning approach has been adopted.

8.4.1 National Transmission Network Development Plan (NTNDP) scenarios

To ensure consistency between all AEMO planning documents and studies, a set of five National Transmission Network Development Plan (NTNDP) scenarios have been developed. These scenarios are described in a report to AEMO from consultants MMA titled “Future Developments in the Stationary Energy Sector: Scenarios for the Stationary Energy Sector, 2030”. This report is available on the AEMO web-site with other background information on the 2010 NTNDP.[37]

Using the inputs from the NTNDP scenarios, as well as preliminary market modelling results, AEMO has developed five scenarios specifically for the VAPR 10-year electricity outlook. These scenarios are designed to capture the limits of transmission infrastructure development that may be required, describe the potential location and type of new generation within Victoria as well as the potential changes in Victorian imports and exports.

[37] See http://www.aemo.com.au/planning/ntndp2010.html

The VAPR scenarios, which represent trends in the generation mix expected under the NTNDP scenarios, are not intended to be predications of the state of generation in 10 years, but do lie within the bounds of reasonable possibility. The VAPR scenarios also account for new electricity and gas connection enquiries from AEMO.

The NTNDP scenarios were developed with extensive consultation with a Stakeholder Reference Group (SRG) made up of industry experts with a diverse range of experiences and interests. The SRG members were invited to participate in a number of surveys, questionnaires and two workshops to draw out different perspectives, facilitate discussion, and test the robustness of the scenarios.

Each NTNDP scenario describes the Australian Stationary Energy sector in 2030. These descriptions then translate to a set of drivers that will impact the Victorian electricity DSN and the gas DTS, including through regional interchange.

8.4.2 The 10-year development study

The 10-year development study enables the study of the electricity DSN over the next ten years, and models the Victorian transmission network with a native maximum demand (MD) of 12,777 MW (summer 10% POE MD).

To meet the demand and power transfer levels between regions, approximately 2,000 MW of additional new generation will be required in Victoria by 2019/20 (see Table 8-2 for information about the supply-demand balance used to determine this additional generation).

In all the scenarios, at least 1,000 MW and 1,150 MW of installed wind power capacity (existing and new) was modelled in the South-West Corridor and Regional Victoria, respectively.

Two of the scenarios modelled up to 4,000 MW of installed wind power capacity (existing and new), with 2,000 MW in the South-West Corridor and 2,000 MW in Regional Victoria.

It is assumed that at least 8% of installed wind power capacity will be available for the summer MD.

Table 8-2 lists a summary of the supply scenarios used to assess Victorian electricity DSN requirements. The five mutually exclusive supply scenarios load different parts of the transmission network to assess the effects of different generator sizes and locations.

Table 8-2 – Electricity supply scenarios for the 10-year outlook (MW increases)

	Eastern Corridor		South-West Corridor		Greater Melbourne & Geelong		Regional Victoria		New Victoria	Import from NSW	Import from SA	Total
	Fuel	**MW**	**Fuel**	**MW**	**Fuel**	**MW**	**Fuel**	**MW**	**MW**	**MW**	**MW**	**MW**
Scenario 1 **Fast rate of change**	Gas	1,400	Wind	80	Gas/ DSP	500	Wind	60	**3,240**	-1,500	460	**2,000**
			Gas	1,000								
		(700)				(500)						**(1,200)**
Scenario 2 **Uncertain world**	Gas	0	Wind	80	Gas/ DSP	0	Wind	60	**1,640**	1,460	-1,000	2,000
	Coal	0	Gas	1,400								
Scenario 3 **Decentralised world**	Coal	-1,800	Wind	160	Gas/ DSP	1,160	Wind	160	**2,240**	0	0	**2,000**
	Gas	800	Gas	1,000			Gas	300				
(Gas DTS v1)		(400)				(800)	Solar	220				**(1,200)**
(Gas DTS v2)		(400)				(500)		(300)				**(1,200)**
Scenario 4 **Oil shock and adaptation**	Coal	800	Wind	160	Gas/ DSP	500	Wind	160	**1,920**	-720	1,000	**2,000**
	Gas	-1,800	Gas	1,900								
(Gas DTS)		(400)		(500)		(500)						**(1,400)**
Scenario 5 **Slow rate of change**	Gas	0	Wind	80	Gas/ DSP	100	Wind	60	**1,240**	0	960	**2,000**
			Gas	800								

8.4.3 Scenario 1 - Fast rate of change

Description at 30 years

Successful deployment of both centralised and decentralised supply-side technologies, combined with high demand-side participation (DSP), facilitates a rapid transformation of the sector to meet strong emission targets. Australia remains competitive on the global stage and reaps the benefit of strong international growth.

Internationally agreed CO2-emission (CO2-e) reduction targets of less than 450 ppm by 2050 have been achieved. Government and industry investment in low emissions technology such as carbon coal and sequestration (CCS) means that these technologies are cheaper than expected. Geothermal, solar and wind operate on a large scale. Coal and gas are fitted with CCS and continue to operate in traditional generation locations.

World-wide growth in LNG demand supports LNG production in Australia and gas prices in the northern States reach international parity.

Description at 10 years

Under this future, research and development into CCS and geothermal technologies have proceeded faster than expected and the technologies are clearly viable on a large scale. Coal generators in the Eastern Corridor will be preparing to fit CCS to existing generation and new and existing generators will be building new gas plants in the Eastern Corridor to take advantage of the carbon storage capability in the region.

New entry wind generation will have slowed down as proponents watch geothermal taking off with the first large scale geothermal plant built in South Australia in 2015.

LNG production in Australia has ramped up and gas prices in the northern States have doubled, limiting new gas generation in New South Wales and Queensland.

VAPR scenario

The VAPR scenario in a 'Fast rate of change' world may take the following shape:

- Substantial new gas generation in the Eastern Corridor, combined with no retirement of existing generators.
- Growth on the gas DTS from GPG generation in the Eastern Corridor.
- Rising imports from South Australia into Victoria from geothermal generation.
- Substantial exports into New South Wales from both Eastern Corridor generation and South Australia.
- Moderate growth in DSP and GPG on the gas DTS in the Greater Melbourne and Geelong region.

8.4.4 Scenario 2 - An uncertain world

Description at 30 years

Carbon policy uncertainty creates barriers for emerging demand and supply-side technologies. Strong international demand for Australia's resources drives high economic and population growth, resulting in high energy demand.

A target CO2-e concentration not exceeding 550 ppm by 2050 has been agreed internationally, but is constantly being reviewed and debated.

A high-risk premium is placed on capital investment in the electricity sector due to continuing carbon policy uncertainty. Low levels of investment in research and development results in slowed investment in new, low-emission electricity generation, and delays the anticipated retirement of older plant.

Deployment of new demand-side technologies is also muted and the cost of small-scale renewables remains high. Wind farms are tolerated, but local community resistance has begun to force the selection of more remote sites.

Domestic LNG production is limited as Australia struggles to capture its share of the international market, leading to low domestic gas prices across the eastern seaboard.

Description at 10 years

The low gas price and relatively strong industrial demand in the northern States have supported new gas generation in New South Wales and Queensland. The weak carbon target has not caused the retirement of existing coal generation. With no CCS on the immediate horizon there has been no new development in the Eastern Corridor.

After the completion of generation projects that were on the table in 2008-2010, there is little further investment in Victoria due to the uncertain investment environment, with the result that Victoria has become a stronger importer from the northern States.

New entry geothermal generation is still uncertain, and community resistance to local installation (a 'not in my backyard' or 'NIMBY' attitude) has slowed down the rate of new entry wind generation, leaving South Australia short of generation.

VAPR Scenario

The VAPR scenario in 'An uncertain world' may take the following shape:

- Substantial imports from New South Wales into Victoria.
- Moderate new investment in gas generation in the South-West Corridor.
- Substantial export from Victoria into South Australia.
- Little or no gas DTS growth.

8.4.5 Scenario 3 - A decentralised world

Description at 30 years

Demand-side technologies and distributed generation emerge as lower cost alternatives to new centralised supply-side options, such as geothermal generation or CCS. The emergence of fuel cells in homes, coupled with high uptake of commercial and industrial cogeneration and tri-generation, increases domestic demand for gas.

Moderate reduction targets aimed at restricting CO2-e concentration to less than 550 ppm have been implemented and met.

Domestic LNG production from coal seam gas manages to capture a reasonable share of international demand, but new gas supply discoveries in the domestic market keep gas prices low across the eastern seaboard.

New low-emission, baseload power sources, such as geothermal and CCS, have proven more expensive than first thought and there has not been large-scale uptake. The first large-scale geothermal plants were built in 2020, and the first CCS plants are yet to come. There has been strong growth in wind generation and small scale renewable generation.

Description at 10 years

Wind generation in both Victoria and South Australia has grown rapidly due to strong renewable and CO2-e targets and the lack of geothermal development.

In the Eastern Corridor there has been some retirement of brown coal as well as some conversion to GPG. There has been a strong focus on energy efficiency and demand-side initiatives including smart meters, solar water heaters, and photo-voltaic panels.

VAPR Scenario

The VAPR scenario in 'A decentralised world' may take the following shape:

- Substantial demand-side participation in the Greater Melbourne and Geelong region.
- Substantial new wind generation in both the south west and regional areas, as well as supporting gas peaking generation
- Less generation than currently exists in the Eastern Corridor, with some conversion from coal to gas, causing some gas DTS growth.
- Moderate demand for GPG in Melbourne and Geelong, and additional demand on the gas DTS.

8.4.6 Scenario 4 - Oil shock and adaptation

Description at 30 years

After reaching agreement on a global carbon emissions policy, the international economy is challenged by a global oil shortage, putting upward pressure on oil and gas prices and leading to low economic growth both internationally and domestically. Higher than expected CCS costs and fossil fuel prices lead to greater reliance on centralised renewable energy options.

CO2-e targets are moderate at 550 ppm by 2050. Demand-side initiatives and CCS have proven to be more costly than first anticipated, which has made meeting the CO2-e target more challenging.

Oil reserve shortages drive up international demand for LNG, and domestic LNG production has increased, causing gas price rises.

Description at 10 years

Increasing gas prices caused by LNG export demand produce a heavy reliance on geothermal and other renewable generation options to meet the growth in energy requirements. Gas peaking generation also increases to support increased intermittent wind generation in the south west and regional areas of Victoria.

The moderate CO2-e reduction causes some retirement and conversion of brown coal plant in the Eastern Corridor, leaving Victoria reliant on increasing geothermal generation in South Australia.

VAPR Scenario

The VAPR scenario in an 'Oil shock and adaptation' world may take the following shape:

- Substantial wind and gas generation in the South-West Corridor.
- Substantial geothermal and wind generation exports from South Australia to Victoria.
- Less generation than currently exists in the Eastern Corridor, with some conversion from coal to gas, causing some gas DTS growth.
- Moderate growth in DSP and GPG on the DTS in Greater Melbourne and Geelong.

8.4.7 Scenario 5 - Slow rate of change

Description at 30 years

Low domestic economic growth and population growth, driven by difficulties accessing capital, slows the rate of transformation of the Stationary Energy Sector. Australia moves further towards a service economy, with some manufacturing and energy-intensive industry moving off-shore.

Boosting economic activity is considered the key priority for government. To support the domestic coal industry, CCS research is supported but low demand growth slows this technology's rate of deployment.

Description at 10 years

Significant support for geothermal research enables the first large scale geothermal plant to be built in South Australia in 2016, leading to large exports to Victoria by 2018/19. The entry of geothermal generation to the renewable market has significantly slowed investment in wind generation. Geothermal generation proposals are also close to becoming committed in New South Wales.

The government support for CCS and the low CO2-e target has encouraged brown coal generators to remain operating, but there has been no new investment.

VAPR Scenario

The VAPR scenario in a 'Slow rate of change' world may take the following shape:

- Very little generation growth in Victoria.
- Substantial geothermal and wind generation exports from South Australia to Victoria.
- Little or no demand growth on the gas DTS.

- Little net power transfer between Victoria and New South Wales.

8.4.8 Electricity supply-demand balance 2019/20

Table 8-3 lists the supply-demand balance used for the 10-year outlook, setting out the levels of existing and committed generation, import and export, Victorian demand and the reserve figures used to determine the requirement for new generation.

Table 8-3 – Electricity supply-demand balance (MW) 2019/20

	Supply-demand source	Supply-demand (MW)
Demand	Victorian native demand (10% POE)	12,777
	Victorian minimum reserve level	665
	Total demand plus reserve level	**13,442**
Supply	Anglesea	156
	Bairnsdale	74
	Bogong	140
	Clover	26
	Dartmouth	153
	Eildon	120
	Energy Brix Complex	164
	Hazelwood	1,580
	Hume (Vic)	17
	Jeeralang	416
	Laverton North GT	310
	Loy Yang A	2,190
	Loy Yang B	965
	McKay Creek	160
	Mortlake	518
	Murray	1,500
	Newport	475
	Somerton GT	133
	Valley Power	270
	West Kiewa	66
	Yallourn	1,420
	Import from Tasmania	600
	Portland wind generation (132 MW)	11
	Waubra wind power generation (192 MW)	15
	Distribution connected wind power generation (104 MW)	8
	Distribution connected non-wind power generation	14
	Total supply	**11,453**

Supply-demand source	Supply-demand (MW)
Amount of additional new generation required	**1,989**

1. The combined minimum reserve level (MRL) for Victoria and South Australia is 615 MW. The minimum reserve level for South Australia is -50 MW (as per the 2009 Electricity Statement of Opportunities). These minimum reserve levels are assumed for 2019/20

2. Scheduled generation capacities are based on the summer 2018/19 figures from AEMO's 2008 Electricity Statement of Opportunities.

8.4.9 National transmission planning

The National Transmission Network Development Plan

In 2010, AEMO will publish its first National Transmission Network Development Plan (NTNDP). The NTNDP will provide AEMO's view of the efficient development of the national transmission grid for a planning horizon covering the next 20 years for a range of credible scenarios.

The NTNDP is intended to be a key planning resource for the electricity industry, and AEMO is seeking stakeholder views about how the NTNDP can best meet their needs.

2009 National Transmission Statement outcomes

In 2009, AEMO published the National Transmission Statement (NTS). This was a transitional document that replaced the Annual National Transmission Statement (ANTS) [38].

The NTS was published in two volumes:

- Volume 1 'National Grid 2030 for a Low Carbon Australia' was a vision statement, drawing on and providing a high-level analysis of the results from Volume 2.
- Volume 2 'Modelling and Analysis' provided a detailed analysis of historical NEM transmission network performance, emerging needs identified by the jurisdictional planning bodies (JPBs), and projected network performance based on market simulation.

The findings on Victorian electricity transmission planning have been incorporated into this year's VAPR, with particular emphasis on the scenarios that were developed (See Section 8.4.2).

8.5 Gas planning

AEMO's planning role

AEMO is the system operator and gas planner for Victoria's gas transmission network, the gas Declared Transmission System (DTS). In performing this role, AEMO undertakes its responsibility in accordance with the National Gas Rules (NGR). AEMO's identification and subsequent provision of information about potential constraints constitutes advice to the market, but does not impose an obligation on market participants to act.

[38] Previously published by the National Electricity Market Management Company (NEMMCO).

Planning criteria and scenario development

Information about gas planning updates for 2010 involves the following:

- Gas planning criteria.
- Gas scenario planning and scenario development.

Gas planning criteria

AEMO has reviewed and updated the gas planning criteria and gas scenarios (used to assess system constraints and propose possible gas transmission network developments) for each gas region for 2010. These updates build on the criteria used for the 2009 VAPR and also take into account emerging gas industry trends.

Gas scenario planning and scenario development

AEMO uses 5-year and 10-year outlook studies as a screening process to identify transmission constraints and possible augmentation options.

Identified constraints receive further, more detailed analyses that are beyond the scope of the VAPR, the results of which are published in Major System Augmentation Reports. Possible augmentation requirements within the 5-year outlook period are then prioritised.

The VAPR's 5-year outlook studies are based on a set of trigger events that give rise to the need for augmentation. The reduced certainty surrounding these events in the 10-year outlook studies, however, requires modelling that uses a scenario-planning approach.

The gas planning criteria, 5-year outlook studies, and 10-year outlook study scenarios reflect both current and possible future demand on the gas DTS, and have been developed in partnership with gas industry stakeholders. This approach facilitates prudent, early identification and exploration of potential system constraints and augmentation requirements.

As gas is both readily available and less greenhouse-gas intensive than other fossil fuels, it is likely that it will continue to be an attractive option for new entry generation. As a result, the studies also consider various possible locations for future generation of this type.

The 5-year outlook studies and 10-year outlook study scenarios also cover new patterns of physical gas flow through the gas DTS. In the past, Victorian gas supplied Victorian demand centres. However, new commercial drivers and the evolution of the gas transmission network have increased the demand for Victorian gas for export to other States.

Industry stakeholders have advised of:

- proposals to export larger amounts of gas through the Northern Zone, and
- the possibility of supplying gas from Longford to South Australia via Iona.

Both these proposals impact the Northern Zone and the scenario export considerations (which manifest as a focus on augmentations in the Northern Zone).

All gas scenarios at least consider:

- 1 in 20 peak demand conditions, and
- 25 TJ/d of demand from existing GPG plants during 1 in 20 peak demand conditions.

The scenarios also consider some or all of the following factors:

- new entry OCGT GPG (at different locations)
- new entry CCGT GPG (at different locations), and
- increased gas exports.

8.5.1 Planning for the 5-year outlook

To assess system constraints and propose possible gas transmission network developments for each gas zone, the 5-year gas planning criteria for the winter peak day considers:

- 1 in 20 winter demand
- 25 TJ/d demand from existing GPG
- 900 MW of new CCGT, and
- export of up to 28 TJ/d via Culcairn to New South Wales.

The 5-year outlook studies aim to meet target system pressure, and assume that Longford and BassGas provide the majority of supply, with gas from Iona meeting any further capacity requirements.

Liquefied Natural Gas (LNG) is used for peak shaving when supply from Longford, BassGas and Iona cannot maintain target system pressures. Under this planning approach, a requirement for LNG in excess of the 60 TJ/day assumed for within-day balancing purposes leaves no security margin and no redundancy in the LNG facility for at least part of the day, making curtailment highly likely (see Chapter 5 for more information about LNG and within-day balancing). Scenarios that consider enhanced northern export also impact LNG usage.

Four main triggers for recommended augmentations are as follows:

- System demand growth, which has historically been the main driver of gas DTS augmentations.
- New entry GPG, which can have the effect of accelerating system demand growth leading to the need for augmentations that would otherwise not be required as soon.
- Greater export, which is not strictly a trigger for augmentation but rather the consequence of evolving commercial and market outcomes.
- Other factors, such as operating conditions, gas velocity and the amount of injection.

Increased export capability through Culcairn was considered based on committed augmentations in the Northern Zone. See Chapter 9, for information about export capability through Culcairn, and for information about the findings of the 5-year outlook analysis and the triggers for augmentation.

The committed augmentations in the Northern Zone have been assumed to be operational in the 2010 winter for the purposes of this study.

8.5.2 Planning for the 10-year outlook

This section describes the demand and supply scenarios created to enable a study of the gas DTS over the next 10 years. To model the system for this period of time, it is necessary to take a view about likely demand and supply patterns in 10 years time. While system demand can be forecast, and a central view taken, this approach is not appropriate for GPG demand.

As the location of new GPG can considerably affect the pattern of gas flows and system constraints, a scenario-based planning approach has been adopted due to the range of possible sites for new GPG plant and possible network flows of gas under different demand and gas market conditions.

Furthermore, as combined system and GPG demand will exceed current supplies, supply increases (injections) are also assumed.

Four scenarios were developed that considered different locations for new GPG demand:

- The emphasis for Scenario 1 was new GPG demand in the Eastern Corridor.
- The emphasis for Scenario 2 was new GPG demand in the South-West Corridor.
- The emphasis for Scenario 3 was new GPG demand in Greater Melbourne and Geelong.
- The emphasis for Scenario 4 was new GPG demand in Regional Victoria.

The 10-year outlook also considered a further increase in export capability through Culcairn, beyond the increases considered in the 5-year outlook, as well as export to South Australia. These export scenarios are defined as Scenarios 5a-5d.

The NTNDP scenarios described in Section 8.4 form the basis for the 10-year gas planning scenarios. Table 8-2 shows how the NTNDP scenarios impact the expected electricity supply outlook, and quantifies the additional capacity expected to be provided by GPG. Not all the NTNDP scenarios, however, are expected to impact GPG demand, and one NTNDP scenario may potentially lead to two different GPG demand scenarios. With respect to the relationship between the NTNDP scenarios and the gas planning scenarios:

- Scenario 1 'Fast rate of change' had an emphasis on new generation in the Eastern Corridor and aligns with gas planning Scenario 1.
- Scenario 3 'Decentralised world' included new gas generation in Greater Melbourne and Geelong and Regional Victoria. One potential variation of this scenario aligns with Gas Planning Scenario 3 and the other potential variation of this scenario aligns with gas planning Scenario 4.
- Scenario 4 'Oil shock and adaptation' included substantial new gas generation in the South-West Corridor. This scenario aligns with the gas planning Scenario 2.
- Scenario 2 'Uncertain world' and Scenario 5 'Slow rate of change' both assumed that there would be no additional GPG demand on the gas DTS within the next 10 years.

The 10-year development studies

The 10-year outlook studies include a high and low system demand scenario, including other factors such as existing and new GPG demand and exports (which make up sub-scenario parameters).

The four triggers for augmentation for the 5-year outlook have also been used to characterise the findings of the 10-year outlook studies.

See Chapter 9 for information about the findings of the 10-year outlook analysis and the triggers for augmentation.

High system demand scenarios

The following assumptions were made for the 10-year study for high system demand:

- The current peak day system demand forecast for 2019 is 1,356 TJ/d. Allowing for 25 TJ/d of existing GPG demand, approximately 200 TJ/d export via Culcairn, and an additional GPG demand forecast of 186 TJ/d, gives a total peak day demand forecast for 2019 of approximately 1,767 TJ/d.
- Firm supplies forecast for 2014 are 1,518 TJ/d (excluding LNG), leaving the assumption that a further 249 TJ/d (approximately) will be available by 2019. For these screening studies this is

assumed to be supplied at Longford, given the high levels of non-firm forecast for 2014. See Chapter 5, Section 5.3.1, for more information.

- Existing GPG demand from GPG (OCGT) plant was considered given the level of GPG demand observed during the 2007 peak day.
- Taking the GPG demand forecast into account (see the 2009 VAPR Update, Section 1.1.6, for more information), it is assumed that between 1,200 MW and 1,400 MW of new GPG will be supplied from the gas DTS.
- Of the gas DTS-connected GPG, all scenarios include at least 500 MW of new CCGT in Greater Melbourne and Geelong, and an additional 400 MW of new CCGT in the Eastern Corridor, and 300-500 MW located in one of either the Eastern Corridor, Greater Melbourne and Geelong, South-West Corridor, or Regional Victoria.
- All CCGTs are assumed to run at 100% load factor during the modelled peak gas demand period.

Table 8-4 lists a summary of the high system demand scenario, sent out electricity at year 10 used to assess Victorian DTS augmentation requirements.

Table 8-4 – New CCGT assumptions for high system demand scenarios for the 10-year outlook (2019)

	Electricity sent out (MW)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Eastern Corridor (L)	700	400	400	400
Greater Melbourne and Geelong (M)	500	500	800	500
South-West (SW)	0	500	0	0
Regional (R)	0	0	0	300

Low system demand scenarios

The following assumptions were made for the 10-year study for low system demand:

- All CCGT GPG runs 24-hours per day, 7-days per week during the peak gas demand period.
- CCGT plant efficiency (sent-out electrical energy) is assumed to be 52%.

Scenario 5 – Low system demand with injection at Longford and no injection at Iona – was developed to test the system's capacity for export under low system demand conditions.

Table 8-5 lists the sub-scenarios considered for Scenario 5 as at year 10. The emphasis of these sub-scenarios is to consider the impact of export to New South Wales and South Australia in conjunction with different possible locations for new GPG.

Table 8-5 – Low system demand with injection at Longford and no injection at Iona (2019)

	Export to NSW (TJ/d)	Export to SA (TJ/d)	System Demand (TJ/d)	Existing GPG Sent Out Electricity (MW)	New GPG (MW) Scenario 5a	Scenario 5b	Scenario 5c	Scenario 5d
Eastern Corridor (L)	200	80	400	150	700	400	400	400
Greater Melbourne and Geelong (M)	200	80	400	150	500	500	800	500
South-West Corridor (SW)	200	80	400	150	0	500	0	0
Regional (R)	200	80	400	150	0	0	0	300

Long-term planning considerations

Long-term planning considerations include the following:

- New large GPG demand will significantly impact both gas and electricity transmission, with a range of factors determining whether GPG will be located near fuel sources or loads.
- Gas and electricity have different market processes and locational price signals. For example, investors may build new GPG close to gas supplies to:
- avoid complexity risk (e.g. operating in two complex markets rather than one), and/or
- use equity gas, rather than purchased gas, in situations where the investor also owns large gas reserves.
- New small GPG demand located close to load centres may enable the deferral of electricity network augmentation.
- The increased presence of wind power generation may increase the demand for GPG, the flexibility of which can compensate for wind power variability by providing frequency control ancillary services.
- Large GPG installations may place challenging demands on gas transmission network operations. Current methods of network operation are based on the use of linepack, underground and LNG storages, which do not ‘smooth’ demand. CCGT gas demand, however, has greater potential to reduce the effects of demand variation than most other gas loads. As a result, new approaches to gas transmission network operation may need to be developed to support GPG.

GPG demand for gas can be met by dedicated new transmission or by augmentation of the gas DTS, or both. For new GPG facilities located in or around:

- the Eastern and the South-West Corridor, dedicated new transmission is a more likely option, and
- Greater Melbourne and Geelong, augmentation of the gas DTS may be necessary.

See Chapter 7 for information about existing spare gas DTS capacity for GPG.

Whereas GPG in the Eastern and the South-West Corridor may be supplied via dedicated transmission, supply for GPG around Melbourne and Geelong is more likely to require gas DTS augmentation as well as:

- increased supply from Longford and/or Iona, and
- augmentation of the outer metropolitan ring and the building of new off-take points to move gas from the ring to GPG sites.

Given the proximity to urban areas, environmental issues and the acquisition of the necessary easements may also present significant issues.

8.6 Electricity and gas planning scenario overlaps

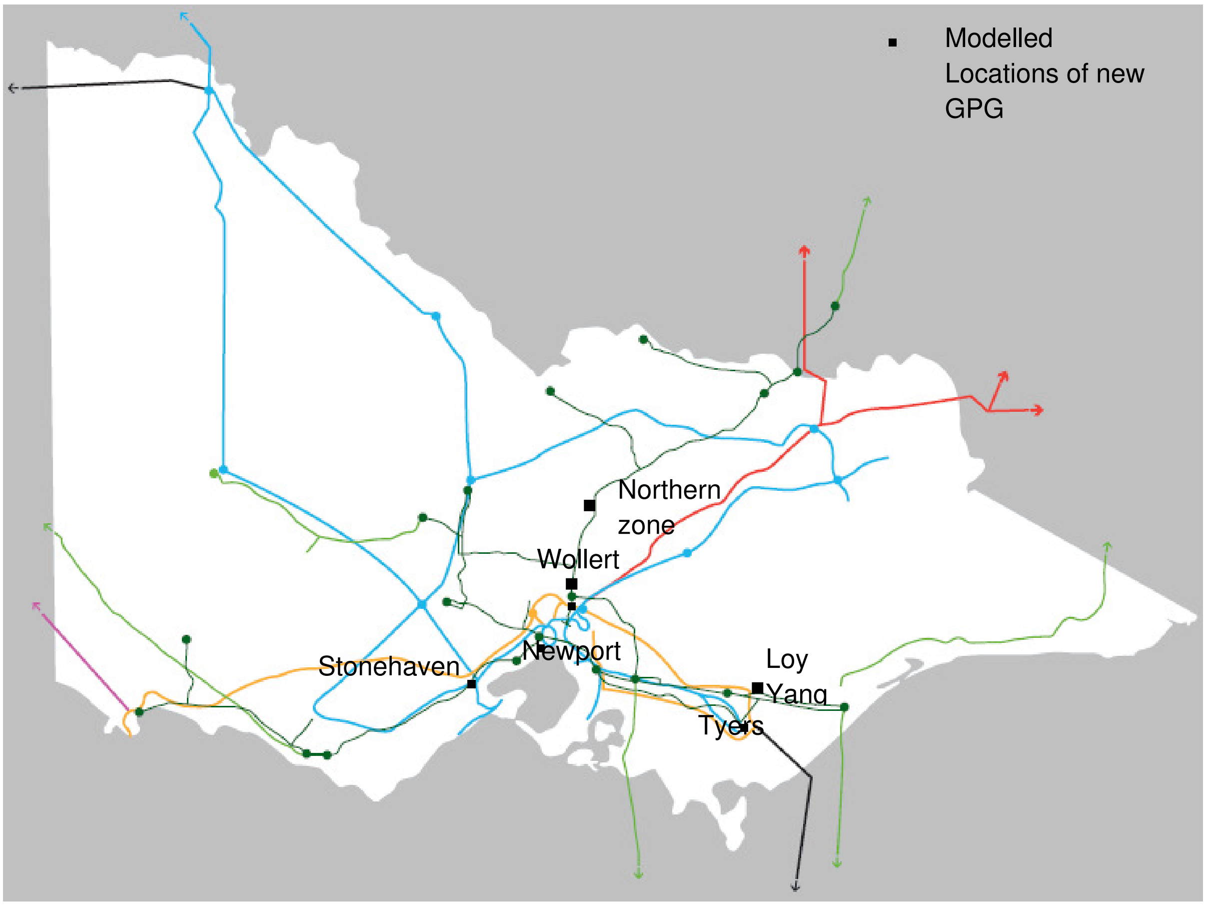
The 10-year outlook scenarios for both electricity and gas planning have been developed to ensure consistency.

The electricity supply scenarios do not differentiate between coal-fired generation and GPG (see Table 8-2), which allows for the location of new CCGTs identified in the gas scenarios, where:

- the Eastern Corridor is the same in both sets of scenarios
- Greater Melbourne and Geelong CCGTs are within the Greater Melbourne and Geelong electricity region, and
- Brooklyn-Geelong CCGTs can be within either the Greater Melbourne and Geelong or South-West Corridor electricity regions.

Figure 8-2 shows the possible locations for new CCGTs considered in the 10-year outlook scenarios. See the figure on the inside front cover for a legend and more detail about other locations.

Figure 8-2 – Possible new GPG locations considered in the 10-year outlook scenarios



Chapter 9 Transmission Development

This chapter presents information about existing and emerging limitations on the electricity Declared Shared Network (electricity DSN) and the gas Declared Transmission System (gas DTS). This includes plant outages and system capacity impacts, existing spare capacity, the status of major augmentations, and future planned developments for the forecast period (based on forecast Victorian energy and maximum demand (MD)), and the transmission network development options designed to alleviate them.

This information is presented by region, covering both electricity and gas in each case, to enable identification of specific transmission network development synergies.

In this chapter:

- Section 9.1 summarises identified electricity DSN constraints by region, covering a 5-year outlook and an outlook at year 10.
- Section 9.2 summarises identified gas DTS constraints by region, covering a 5-year outlook and an outlook at year 10.
- Section 9.3 lists the identified electricity DSN and gas DTS constraints by region (where relevant, identifying the potential impact, subject to the Regulatory Investment Test for Transmission (RIT–T), of continued high gas powered generation (GPG) demand on gas DTS constraint solution timings, and any development options currently being investigated [39].
- Section 9.4 lists electricity DSN impacts and considerations resulting from distribution network service provider planning.
- Section 9.5 outlines the SP AusNet Transmission asset renewal process and 10-year plan.
- Section 9.6 presents information about future gas transmission system developments (both proposed and commenced, and not necessarily linked to identified system constraints), and any significant new connections.
- Section 9.7 lists the potential impacts from specific gas plant outages.
- Section 9.8 lists specific gas plant outages by month for the 2010 planning year (sourced from the 2009 VAPR Update).

9.1 Electricity transmission development

9.1.1 Electricity Declared Shared Network constraints

This section summarises the electricity DSN constraints by Victorian electricity region:

- Eastern Corridor
- South-West Corridor
- Northern Corridor
- Greater Melbourne and Geelong, and

[39] Although electricity and gas regions are not precisely aligned, they share sufficient similarities to enable a common regional categorisation.

- Regional Victoria.

Each region's constraints and possible network solutions are presented in terms of the 5-year (years 1-5) and 10-year (year 10) outlooks. AEMO bases its constraint analysis on the energy and maximum demand (MD) forecasts presented in the 2009 VAPR, because the latest electricity forecasts (see Chapter 4 for more information) do not become available until late May.

The constraint analysis:

- assumes that the committed augmentations described in Chapter 3 will be in-service, as planned, and
- covers transmission constraints arising from transmission network capacity limitations.

Table 9-1 lists a summary of the network constraints for each Victorian region. The 10-year outlook's network solutions are only regarded as possible, and have not undergone rigorous economic justification.

Table 9-1 - Electricity transmission network constraint summary

	Constraint	Possible network solution	Trigger	Status
Eastern Corridor (see Section 9.3.1)				
Five-year outlook	Transient stability export limit	Braking resistor installation at Hazelwood Terminal Station	Increased export to New South Wales and/or South Australia	Identified for RIT-T assessment in 2010/11
	Hazelwood 500/220 kV transformer loading	500/220 kV transformer installation	Generation dispatch/new generation connected around the Latrobe Valley 220 kV area	Detailed assessment completed in 2009/10 with no justifiable solution – will re-assess at the time of additional generation around the Latrobe Valley 220 kV network
	Hazelwood-Loy Yang 500 kV line loading	Line installation and/or additional circuit breaker installation	Generation dispatch/new generation or increased import connected around the Latrobe Valley 500 kV area	Detailed assessment completed in 2009/10 with no justifiable solution – will re-assess at the time of additional generation around the Latrobe Valley 500 kV network, or additional import from Tasmania
Ten-year outlook	Latrobe Valley-Melbourne 500 kV line loading	Termination and circuit breaker upgrades, and line installation	Generation dispatch/new generation or increased import connected around the Latrobe Valley 500 kV and/or 220 kV area	Reassessment at time of increased generation around the Latrobe Valley 500 kV or 220 kV networks, or additional import from Tasmania
South-West Corridor (see Section 9.3.2)				
Five-year outlook	Moorabool-Heywood-Portland 500 kV line voltage unbalance	Installation of additional line transpositions on the Moorabool-Heywood-Portland 500 kV line	New generation connections along the Moorabool-Heywood 500 kV line	Identified for further assessment – dependant on new generation

	Constraint	Possible network solution	Trigger	Status
	Heywood 500/275/22 kV transformer loading	New 500/275/22 kV transformer and 500 kV bus-tie installation at Heywood Terminal Station	New generation/ increased bi-directional transfer between Victoria and South Australia	Undergoing detailed assessment as part of the VIC-SA joint feasibility study
Ten-year outlook	Insufficient connection points for possible wind farm and GPG connections	New connection point provision	New generation connections along the Moorabool-Heywood 500 kV line	Preparation of a new connection point provision is underway
	Moorabool-Heywood 500 kV line loading	New Moorabool-Heywood 500 kV line installation	New generation connections along the Moorabool-Heywood 500 kV line	Undergoing detailed assessment as part of the VIC-SA joint feasibility study
	Heywood-South East 275 kV line loading	New Heywood-South East 275 kV line installation	Increased bi-directional transfer between Victoria and South Australia	Undergoing detailed assessment as part of the VIC-SA joint feasibility study
	Voltage instability or collapse	Additional static VAr compensation (SVC)	New generation/ increased bi-directional transfer between Victoria and South Australia	Undergoing detailed assessment as part of the VIC-SA joint feasibility study
Northern Corridor (see Section 9.3.3)				
	Murray-Dederang 330 kV line loading	Series compensation, and/or a new Murray-Dederang 330 kV line installation	Increased import from New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)
	Eildon-Thomastown 220 kV line loading	Wind monitoring, line uprating, and/or series compensation on the Eildon-Thomastown 220 kV line	Increased import from New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)
Five-year outlook	Dederang-Mount Beauty 220 kV line loading	Wind monitoring installation or line uprating of the Dederang-Mount Beauty 220 kV line	Increased generation in the Eildon/Kiewa area	Detailed assessment completed in 2009/10 with no justifiable solution – will monitor with increasing generation in the Eildon/Kiewa area
	Dederang-South Morang 330 kV line loading	Line and series capacitor uprating, and/or a new Dederang-South Morang 330 kV line installation	Increased import from New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)
	Dederang 330/220 kV transformer loading	New 330/220 kV transformer installation at Dederang Terminal Station	Increased import from New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)

	Constraint	Possible network solution	Trigger	Status
Ten-year outlook	Voltage collapse at South Morang, Dederang, Wodonga and Jindera	Capacitor bank installation, and controlled series compensation at Dederang Terminal Station	Increased import from New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)
Greater Melbourne and Geelong (see Section 9.3.4)				
Five-year outlook	Eastern Metro 500/220 kV transformer and 220kV line loading	New 500/220 kV transformer installation at Rowville or Cranbourne Terminal Station	Increased demand in the Melbourne metropolitan area	Identified for further assessment
	South Morang 330/220 kV transformer loading	New or higher rated replacement 330/220 kV transformer or new 500/220 kV transformer installation at South Morang Terminal Station	Increased demand in the Melbourne metropolitan area	Detailed assessment commenced in 2009/10 with no justifiable solution reached – will finalise assessment with updated demand forecasts
	South Morang 500/330 kV transformer loading	New 500/330 kV or 500/220 kV transformer installation at South Morang Terminal Station	Increased export to New South Wales	Undergoing detailed assessment as part of the NSW-VIC feasibility study (focussing on the Snowy Mountains Scheme)
	Double circuit 220 kV line security in the south east metropolitan area	New circuit installation	Increased demand at Springvale, Heatherton, Malvern and Tyabb terminal stations and/or the facility to Western Port	Joint assessment with distribution business (DBs) commenced in 2009/10 with no justifiable solution reached – will finalise assessment with updated demand forecasts
	Rowville-Springvale 220 kV line loading	Conductor replacement or new Rowville-Springvale 220 kV circuit installation	Increased demand at Springvale and/or Heatherton terminal stations	Detailed assessment completed in 2009/10 with no justifiable solution – will monitor with increased load growth
	Metropolitan 220 kV line loading	Dynamic rating wind monitoring scheme installations around the Melbourne metropolitan area	Increased demand in the Melbourne metropolitan area	Detailed assessment completed in 2009/10 with wind monitoring scheme installation likely by around 2016 – will monitor with increased load growth
	Rowville 220 kV bus fault level	Bus support insulator replacements	Increased demand/ generation, particularly in the Rowville area	Bus support insulator replacements to take place in conjunction with terminal station refurbishment
Ten-year outlook	Rowville-Malvern 220 kV line loading	Line uprating	Increased demand at Malvern Terminal Station	Emerging constraint with no justifiable solution at this time – will monitor with increasing demand
	Thomastown-Ringwood 220 kV line loading	220 kV line cut-in at Ringwood	Increased demand in the Melbourne metropolitan area	Emerging constraint with no justifiable solution at this time – will monitor with increasing demand

	Constraint	Possible network solution	Trigger	Status
	South Morang-Thomastown 220 kV line overloading	220 kV line cut-in at South Morang	Increased demand in the Melbourne metropolitan area	Emerging constraint with no justifiable solution at this time – will monitor with increasing demand
	Voltage instability or collapse	Additional reactive power compensating plant installation	Increased demand in the Melbourne metropolitan area	Emerging constraint with no justifiable solution at this time – will monitor with increased load growth
	Fault levels	Operational arrangements, series reactor installation, switchgear replacement	Increased demand and/or generation, particularly in the Melbourne metropolitan area	Reassessment at the time of increased demand/generation in this area
Regional Victoria (see Section 9.3.5)				
Five-year outlook	Ballarat-Bendigo 220 kV line	Line uprating	Increased demand in Regional Victoria	Identified for RIT-T assessment in 2010/11
	Ballarat-Moorabool 220 kV line	Line uprating or new line installation	Increased demand in Regional Victoria	Identified for RIT-T assessment in 2010/11
	Geelong-Moorabool 220 kV line loading	Line uprating or replacement with new lines	Increased demand in the Geelong and Melbourne metropolitan area and/or generation in Regional Victoria or along the South-West Corridor	Identified for RIT-T assessment in 2010/11
Ten-year outlook	Bendigo-Fosterville-Shepparton 220 kV line loading	Line uprating, phase angle regulator, or new line construction	Increased demand in Regional Victoria	Reassessment at time of increased demand in this area
	Ballarat-Horsham 220 kV line loading	Line uprating or replacement with new lines	Increased generation in Regional Victoria	Reassessment at time of increased generation in this area
	Ballarat-Terang 220 kV line loading	Line uprating or replacement with new lines	Increased demand at Terang Terminal Station and/or increased generation in Regional Victoria	Reassessment at the time of increased generation in this area
	Moorabool-Terang 220 kV line loading	Line uprating or replacement with new lines	Increased demand at Terang Terminal Station and/or increased generation in Regional Victoria	Reassessment at the time of increased generation in this area
	Horsham-Red Cliffs 220 kV line loading	Line uprating or replacement with new lines	Increased generation in Regional Victoria	Reassessment at the time of increased generation in this area

	Constraint	Possible network solution	Trigger	Status
	Kerang-Wemen-Red Cliffs 220 kV line loading	Line uprating or replacement with new lines	Increased generation in Regional Victoria	Reassessment at the time of increased generation in this area
	Buronga-Red Cliffs 220 kV line loading	Line uprating	Increased generation in Regional Victoria	Reassessment at time of increased generation in this area
	Dederang-Glenrowan 220 kV line loading	Line uprating, phase angle regulator, or new line construction	Increased demand in Regional Victoria and/or increased import from New South Wales (focussing on the Snowy Mountains Scheme)	Reassessment at the time of increased demand/generation in this area
	Voltage instability or collapse	Additional reactive power compensating plant installation	Increased demand in Regional Victoria	Emerging constraint with no justifiable solution at this time – will monitor with increased load growth
	Fault levels	Operational arrangements, series reactor installation, switchgear replacement	Increased demand and/or generation, particularly in Regional Victoria	Reassessment at the time of increased demand/generation in this area

9.2 Gas transmission development

9.2.1 Declared Transmission System constraints

This section summarises the gas transmission constraints for Victoria, and presents identified gas DTS constraints, plant outages and system capacity impacts, current spare transmission system capacity, the status of major transmission system augmentations, and future planned developments for the forecast period (2010-2019) by Victorian gas region:

- Gippsland Zone
- Western Zone
- Northern Zone
- Melbourne and Geelong Zone, and
- Ballarat Zone.

Constraints are identified when a part of the gas DTS experiences lower pressures than the minimum pressure obligations required by the System Security Guidelines (SSG) or Distribution Business Connection Deeds. Constraints are grouped by gas region for augmentation within the next 5 and 10-years.

AEMO has modelled the gas DTS and produced possible network solutions for the constraints identified in each region. Other network solutions are always possible, and AEMO's modelling cannot be considered exhaustive.

Table 9-2 lists a summary of the gas DTS constraints, identified by modelling 1 in 20 peak day demand assuming all plant is available. See Section 9.3 for more information about each constraint.

Table 9-2 – Principal Transmission System constraint summary

	Constraint	Possible network solution	Trigger
Gippsland Zone (see Section 9.3.1)			
Five-year outlook	Warragul	Warragul branch pipeline duplication	Increased system demand Prior to winter 2012 (dependent on increased demand)
	Pakenham South	Pakenham South branch duplication The pipeline owner has indicated that duplication of the small diameter section of this lateral is being undertaken, and is expected to be complete by the end of May 2010	Increased system demand leading to high gas velocity on the branch pipeline
Ten-year outlook	Longford pipeline	Duplication upstream and downstream of Gooding to account for the limited pipeline capacity	Higher injections at Longford, new entry GPG (CCGT) and increased gas export
Western Zone (see Section 9.3.2)			
Five-year outlook	Western Transmission System	A new system injection point	Increased system demand and low or no injection coming from Iona Prior to winter 2014
Ten-year outlook	No constraints identified based on current demand forecast	Not applicable	Not applicable
Northern Zone (see Section 9.3.3)			
Five-year outlook	Shepparton/ Echuca Culcairn (exports)	Upgrade maximum allowable operating pressure (MAOP) to 8,800 kPa from Wollert to Euroa Wollert Compressor Station upgrade, and northwards compression at Springhurst A new compressor station at Euroa is required to further increase export capacity	Increased system demand, especially gas export of approximately 28 TJ/d export to New South Wales
Ten-year outlook	Culcairn (exports)	Pipeline duplication between Wollert to Barnawartha	Gas export of approximately 200 TJ/d
Geelong/Melbourne Zone (see Section 9.3.4)			
Five-year outlook	Maroondah Highway	Yarra Glen to Lilydale link	Increased system demand
	South West Pipeline	A new compressor station at Stonehaven	New entry GPG, gas export
Ten-year outlook	South West Pipeline	A new Rockbank to Wollert pipeline Pipeline duplication from Iona to Lara	Higher injections at Iona, new entry GPG (CCGT), and gas export to New South Wales
		Additional compression capability at Wollert to compress gas toward Iona A new compressor station at Rockbank to compress gas toward Iona	Gas export to South Australia

	Constraint	Possible network solution	Trigger
Ballarat Zone (see Section 9.3.5)			
Five-year outlook	Sunbury	Operate Wandong pressure limiter at high outlet pressure	Increased system demand and export to New South Wales Prior to winter 2010
		Tie over the Sunbury lateral to the BLP pipeline and Sunbury branch pipeline duplication	Increased system demand and export to New South Wales Prior to winter 2012
Ten-year outlook	No constraints identified based on current demand forecast	Not applicable	Not applicable

9.3 Regional transmission constraints

This section presents a combined view of transmission constraints by corresponding electricity and gas regions. Although electricity and gas regions are not precisely aligned, they share sufficient similarities to enable a common regional categorisation.

Table 9-3 – electricity and gas regions

Electricity region	Gas region
The Eastern Corridor	Gippsland Zone
The South-West Corridor	Western Zone
The Northern Corridor	Northern Zone
Greater Melbourne and Geelong	Melbourne and Geelong Zone
Regional Victoria	Ballarat Zone

9.3.1 The Eastern Corridor/Gippsland Zone

The Eastern Corridor and Gippsland Zone connect the greater Melbourne load centre to electricity generation in the Latrobe Valley and major gas supplies at Longford and VicHub (see Chapter 3 for more information about the Eastern Corridor and its electrical and gas layouts).

This review:

- involves constraints caused by issues within this region, and
- identifies constraint impacts and potential solutions to maintain the efficient transmission of electricity and gas.

Eastern Corridor – electricity 5-year outlook

The Eastern Corridor's 5-year outlook (years 1-5) includes the following constraints:

- A transient stability export limit.
- Hazelwood 500/220 kV transformer loading.
- Hazelwood-Loy Yang 500 kV line loading.

Transient stability export limit	
Background	Transient stability has been identified as limiting power flow in the Victoria to New South Wales direction and/or in the Victoria to South Australia direction under certain network operating conditions. Network constraints are invoked for system normal and various outage conditions to constrain export in preparation for a two-phase-to-ground fault on the Hazelwood-South Morang 500 kV line, resulting in the trip of a Hazelwood-South Morang 500 kV circuit
Potential impact	When binding under the existing constraint equations, power flow in the Victoria to New South Wales direction is limited to a maximum of 1,246 MW and a minimum of 281 MW. The export limit also impacts flows on the Basslink, Heywood-South East, Murraylink and Queensland-New South Wales (QNI) interconnectors and the combined set of constraint equations bound for more then 600 hours in the 2009 calendar year Binding of this constraint equation will only result in loss of load if there is insufficient generation in a particular region. This is more commonly associated with higher market prices due to the need to dispatch higher cost generation, rather then utilise cheaper generation in adjacent National Electricity Market (NEM) regions
Probability weighted constraint assessment	Due to the nature of this constraint, it is primarily results in generation rescheduling, as opposed to load reduction, and therefore has a small estimated value of less then $100,000 per annum in 2014/15
Possible constraint alleviation options	Installation of a 500 MW, 500 kV braking resistor at Hazelwood Terminal Station, at an indicative cost of $17 million, and/or installation of a static VAr compensator (SVC) at Dederang Terminal Station, at an indicative cost of $72 million
Economic evaluation of possible options	The market benefits associated with these proposed options are currently insufficient to justify augmentation
Conclusion	The market benefits associated with this constraint alone do not appear to justify the proposed augmentation. However, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the joint feasibility study between AEMO and ElectraNet on South Australian interconnection, and the New South Wales-Victoria interconnector upgrade feasibility study conducted by AEMO

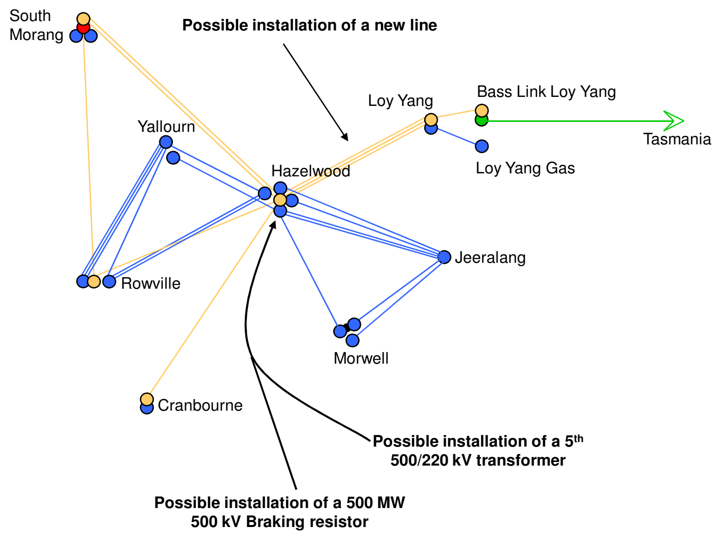
Hazelwood 500/220 kV transformer loading	
Background	The Hazelwood transformers are required for transferring power from generation connected at Hazelwood power station and the Jeeralang Terminal Station 220 kV switchyards to the 500 kV network. The flow through the Hazelwood 500/220 kV transformers is equal to the combined output of all of the generation, less the Morwell area load and the power used by the generator auxiliaries. There are four 500/220 kV transformers with a total capacity of 2,400 MVA. The transformers' loading is limited to 1,914 MVA, so that the outage of one transformer does not cause the loading on the remaining parallel transformers to exceed their short-term capacity The transformers' thermal capacity : requires the dispatch of generation of up to 400 MW (approximately) from generating units connected at the Hazelwood Power Station and Jeeralang Terminal Station 220 kV switchyards to be constrained, and leads to no reduction of generation at times of high summer demand, with transfer of Yallourn Generating Unit No.1 to the Yallourn 220 kV network via its alternative network connection

Potential impact	A reduction in generation dispatched via the Hazelwood 500/220 kV transformers may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria, New South Wales, South Australia and Tasmania. The dispatch of higher-cost plant replaces cheaper but constrained-off generation connected to the Hazelwood and Jeeralang 220 kV transmission networks With prior outage of a Hazelwood 500/220 kV transformer, up to 640 MW of generation may need to be constrained-off, with transfer of Yallourn Generating Unit No.1 to the Yallourn 220 kV transmission network via its alternative network connection Following outage of a Hazelwood 500/220 kV transformer, peak load reduction of approximately 20 MW is forecast during summer peak demand in the Melbourne area in 2013/14, increasing to approximately 230 MW in 2014/15. However, historical information suggests the probability of a Hazelwood 500/220 kV transformer being unavailable is less then 2%
Probability weighted constraint assessment	AEMO's 2010 assessment determined that the value of the constraint is approximately $500,000 in 2014/15
Possible constraint alleviation options	Installation of a fifth 500/220 kV transformer at Hazelwood Terminal Station, at an indicative cost is $36.4 million, and including replacement of four 220 kV circuit breakers at the Jeeralang Terminal Station to accommodate the increased fault level
Economic evaluation of possible options	The market benefits associated with this proposed option are currently insufficient to justify augmentation. AEMO expects that the market benefits of augmenting the network to alleviate this constraint will continue to fall as demand from Morwell increases
Conclusion	An option to remove the Hazelwood transformer constraint involves installing an additional Hazelwood 500/220 kV transformer and associated fault-level mitigation works with an indicative cost of $36.4 million. AEMO has assessed the cost-benefits in detail and considers that the market benefits of this option are currently insufficient and will continue to fall as demand from Morwell increases and addition of new generation in Victoria at locations other than Hazelwood, Jeeralang and Morwell connection points.

Hazelwood-Loy Yang 500 kV line loading	
Background	The three 500 kV lines between Hazelwood Terminal Station and Loy Yang Power Station are key components enabling access to generation at Loy Yang Power Station, and imports from Tasmania. Each line is connected with only one circuit breaker at one end, and with a more secure switching arrangement at the other end. A prior outage of a line or circuit breaker reduces the transfer capability from Loy Yang to Hazelwood
Potential impact	There is no constraint under system normal conditions. That is, with all three lines in service or in preparation for any single unplanned outage of these lines, the dispatch of generation or import from Tasmania is not constrained. However, with prior outage of a Hazelwood-Loy Yang line, the transfer from Loy Yang to Hazelwood needs to be reduced below 3,000 MW. This is in preparation of an additional unplanned outage that would leave only a single Hazelwood-Loy Yang line in service Following loss of a Hazelwood-Loy Yang 500 kV circuit, peak load reduction in the Melbourne area of approximately 100 MW may be required around 2012/13 to maintain system security. This increases to approximately 450 MW in 2014/15. However, historical information suggests the probability of a Hazelwood-Loy Yang circuit being unavailable is less then 1%
Probability weighted constraint assessment	AEMO's 2010 assessment determined that the value of the constraint will be approximately $500,000 in 2014/15
Possible constraint alleviation options	Two additional circuit breakers at Loy Yang and a new circuit breaker at Hazelwood at an indicative cost of $14 million A new (fourth) 500 kV line between Hazelwood and Loy Yang at an indicative cost of $55 million (excluding easement cost)
Economic evaluation of possible options	The market benefits of this option are currently insufficient to justify augmentation
Conclusion	AEMO has assessed the cost-benefits in detail and considers that the market benefits of this option are currently insufficient. AEMO will re-assess this constraint at the time of additional generation or import capability around the Latrobe Valley 500 kV area.

Figure 9-1 shows the schematic of the constraints identified during the Eastern Corridor's 5-year outlook.

Figure 9-1 – Transient stability export limit/Hazelwood transformer loading/Hazelwood-Loy Yang line loading



Eastern Corridor – electricity 10-year outlook

Table 9-4 lists each supply scenario's impact in terms of the Eastern Corridor's 10-year outlook (year 10). See Chapter 8, Section 8.4, for a detailed description of the supply scenarios.

Table 9-4 – Eastern Corridor supply scenario impacts (year 10)

Supply scenario	Impact
Scenario 1 (LV, increased export to NSW and increased import from SA)	Increased South Morang-Hazelwood 500 kV line and the Loy Yang-Hazelwood 500 kV line capacity will be required Increased transient stability limits will be required
Scenario 2 (Increased import from NSW and export to SA)	Increased transient stability limits will be required
Scenario 3 (Metro and Wind)	None
Scenario 4 (SW and increased import from SA and export to NSW)	Increased transient stability limits will be required
Scenario 5 (Increased import from SA)	Increased transient stability limits will be required

Table 9-5 lists the specific Eastern Corridor transmission network constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-5 – Eastern Corridor constraints (year 10)

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Inadequate Latrobe Valley-Melbourne 500 kV line thermal capacity	Upgrading terminations and circuit breaker thermal ratings at Hazelwood	To be costed	At the time approximately 800 MW of new Latrobe Valley generation is connected to the 500 kV network	Increased 500 kV and/or 220 kV generation in the Latrobe Valley, as modelled under Scenario 1

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Gippsland Zone – gas 5-year outlook

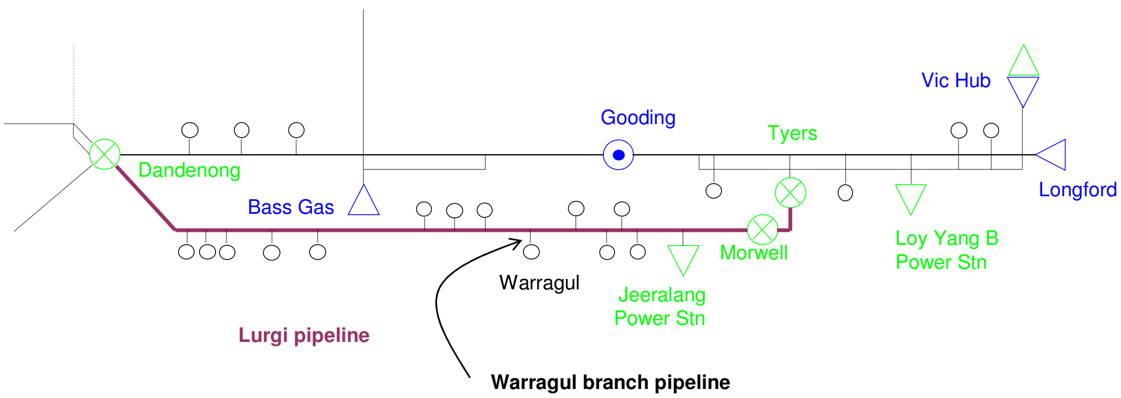
Gippsland's 5-year outlook (years 1-5) includes the following constraints:

- Warragul minimum connection pressure breach.
- Pakenham South excessive gas velocity.

Warragul minimum connection pressure breach	
Background	The Warragul branch pipeline connects to the Lurgi pipeline approximately 67 km east of the Dandenong City Gate (CG)
Issue	Assessments indicate that, with an increase in demand at Warragul, a breach in the minimum connection pressure will occur at Warragul under 1 in 20 peak day conditions in winter 2012
Solution	The solution to this constraint involves one of three options: a duplication of the 450 mm Lurgi pipeline, or a new compressor at the start of the Warragul branch pipeline, or duplication of the Warragul branch pipeline Based on current modelling, the preferred solution involves duplicating the 4.7 km, 100 mm diameter Warragul branch pipeline, using either 100 mm or 150 mm diameter pipe
Timing	Prior to winter 2012, based on a 1 in 20 peak day planning standard, depending on whether the expected load increase occurs
Trigger	Warragul demand growth

Figure 9- 2 shows the schematic of the Warragul constraint.

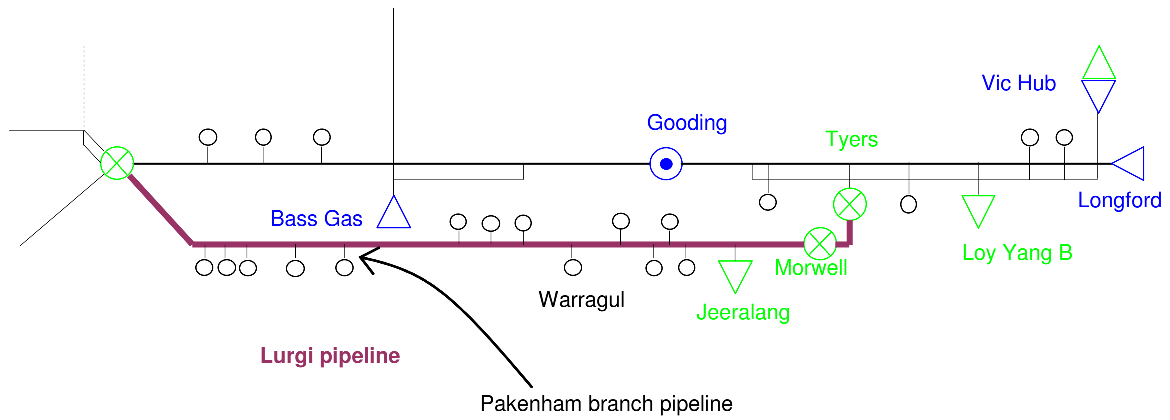
Figure 9- 2 – Warragul Lateral/Lurgi pipeline interconnection



Pakenham South excessive gas velocity	
Background	The Pakenham South lateral connects to the Lurgi pipeline approximately 28 km east of the Dandenong City Gate (CG)
Issue	Assessments indicate that, with a significant increase in demand in Pakenham, the smaller diameter section of the branch experiences excessively high gas velocity
Solution	The pipeline owner has indicated that duplication of the lateral is currently underway, and completion of the project is expected by the end of May 2010
Timing	Required prior to winter 2010 based on a 1 in 20 peak day planning standard
Trigger	Pakenham South demand growth, and high gas velocity

Figure 9- 3 shows the schematic of the Pakenham South constraint.

Figure 9- 3 – Pakenham Lateral/Lurgi pipeline interconnection



Gippsland Zone - gas 10-year outlook

Table 9-6 lists each supply scenario’s impact in terms of the Gippsland Zone’s 10-year outlook (year 10). See Chapter 8, Section 8.5, for a detailed description of the supply scenarios.

Table 9-6 – Gippsland Zone scenario impacts (year 10)

Supply scenario		Impact
Scenario 1 (LV)		Dandenong below minimum operating pressure
Scenario 2 (SW)		Dandenong below minimum operating pressure
Scenario 3 (M)		Dandenong below minimum operating pressure
Scenario 4 (R)		Dandenong below minimum operating pressure
Scenario 5 (exports)	**a**	No impact
	b	No impact
	c	No impact
	d	No impact

Table 9-7 lists the specific Gippsland zone constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-7 – Gippsland Zone constraints (year 10)

Constraint	Possible network solution	Indicative timing
Dandenong below minimum operating pressure with increased gas DTS demand	This constraint will occur as a result of Scenario 1, 2, 3, and 4. Possible network solutions include: duplicating the pipeline upstream and downstream of Gooding Compressor Station, and/or commissioning the Rockbank to Wollert pipeline to increase the pressure at Dandenong	At the time new GPG connects to the gas DTS in the Gippsland and Metropolitan area, and increased export to New South Wales to 200 TJ/d via Culcairn

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9.3.2 South-West Corridor/Western Zone

The South West Corridor links Greater Melbourne and Geelong to the localised high demand centre of Portland, and ultimately to South Australia (See Chapter 2 for more information about the South West Corridor and its electrical layout).

The Western Zone connects demand west of Iona to supplies at Iona and to the South West Pipeline (see Chapter 2 for more information about the Western Transmission System).

This review:

- involves constraints caused by issues within this region, and
- identifies constraint impacts and potential solutions to maintain the efficient transmission of electricity and gas.

South-West Corridor – electricity 5-year outlook

The South-West Corridor's 5-year outlook (years 1-5) includes the following constraints:

- Moorabool-Heywood-Portland 500 kV line voltage unbalance.
- Heywood 500/275/22 kV transformer loading.

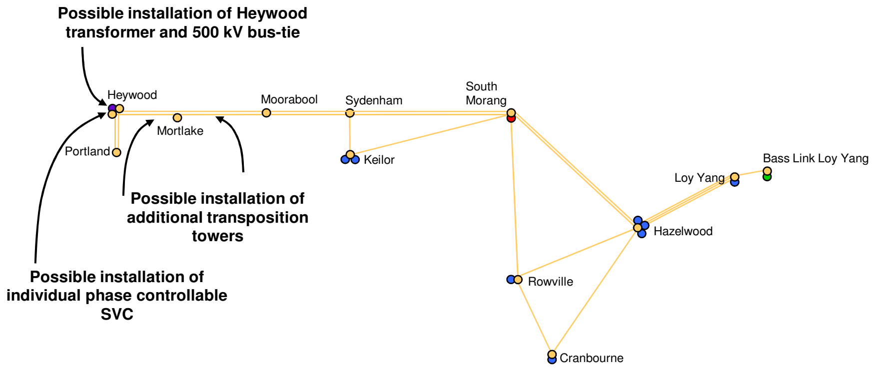
A detailed assessment of the constraints in the South-West Corridor is also being undertaken as part of the South Australia-Victoria joint feasibility study.

Mooraboool-Heywood-Portland 500 kV line voltage unbalance	
Background	The Moorabool-Heywood-Portland 500 kV lines currently have two evenly spaced transposition points. At each of these transpositions the three phases of each circuit are rotated to minimise the voltage unbalance between phases, caused by the mutual coupling between the two parallel circuits The existing lines were constructed in 1980 to supply the Portland aluminium smelter, and the transpositions were evenly spaced to adequately reduce the voltage unbalance caused by the mutual coupling between the two parallel Moorabool-Heywood-Portland 500 kV circuits AEMO has received a number of new generation connection applications in the South-West Corridor, including the new Mortlake GPG. As the level of voltage unbalance is associated with power flow magnitude and direction, the location and output of new generation connections have an impact
Potential impact	With installation of the Mortlake GPG and other proposed new connections, the level of voltage unbalance on the Moorabool-Heywood-Portland 500 kV lines can increase beyond the allowable limit defined in the National Electricity Rules (NER) during certain outage conditions
Probability weighted constraint assessment	Limiting the amount of voltage unbalance below expected levels is an NER requirement. Constraint equations to limit Mortlake generation under outage conditions, and so the level of voltage unbalance, have been developed for use in the National Electricity Market Dispatch Engine (NEMDE). If these constraint equations bind, the resulting value of constraint due to generation re-scheduling has not yet been calculated
Possible constraint alleviation options	1. Switched-capacitor with individual phase switching at Heywood or near Alcoa Portland 2. Static VAr Compensator (SVC) or Synchronous Static Compensator (STATCOM) 3. Additional transposition towers along the Moorabool-Heywood 500 kV lines
Economic evaluation of possible options	An economic evaluation of the possible options has not yet been conducted
Conclusion	AEMO has developed generation dispatch constraint equations to limit Mortlake generation during certain network outage conditions. When the Mortlake GPG is commissioned, these constraint equations will be available to be invoked to ensure the level of voltage unbalance remains within NER limits. Further assessment of the identified options is dependant on new generation connecting to these lines

Heywood 500/275/22 kV transformer loading	
Background	The two Heywood 500/275/22 kV transformers are important elements in the transfer of power between Victoria and South Australia The thermal capacity of these transformers may present a limitation at times of high transfer between the two regions for loss of the parallel transformer
Potential impact	A reduction in transfer capability between Victoria and South Australia may increase Victorian or South Australian market prices due to the need to dispatch higher-cost plant in place of reduced power transfers. With prior outage of a Heywood transformer, this may also lead to load reduction if demand exceeds available generation in a region
Probability weighted constraint assessment	The value of this constraint is negligible at present due to other constraints limiting the power transfer capability between Victoria and South Australia. However, if possible solutions to increase other transfer limiting constraints are implemented, the value of this constraint is expected to increase significantly over the period to 2014/15
Possible constraint alleviation options	A new (third) 500/275/22 kV transformer installation at Heywood Terminal Station, with an indicative cost of $33 million, individually or in combination with a 500 kV bus-tie installation at Heywood Terminal Station, which is still to be costed
Economic evaluation of possible options	AEMO will undertake a detailed assessment of the available network augmentation options and non-network solutions
Conclusion	AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the VIC-SA joint feasibility study

Figure 9-4 shows the schematic of the constraints identified during the South-West Corridor's 5-year outlook.

Figure 9-4 – Voltage unbalance and Heywood transformer loading



South-West Corridor – electricity 10-year outlook

Table 9-8 lists each supply scenario's impact in terms of the South -West Corridor's 10-year outlook (year 10). See Chapter 8, Section 8.4, for a detailed description of the supply scenarios.

Table 9-8 – South-West Corridor supply scenario impacts (year 10)

Supply scenario	Impact
Scenario 1 (LV, increased export to NSW and increased import from SA)	New generation (wind farm and gas-fired) connection points will be required New constraint equations for use in AEMO's dispatch process will be required to manage the anticipated 500 kV voltage unbalance between Moorabool and Portland. Resolving this issue in the longer term may require additional transposition points on the Moorabool-Heywood 500 kV lines, one or more static VAr compensators (SVC), or an alternative network solution A new (third) 275 kV power line from Heywood to South East (South Australia) will be required A new (third) 500 kV power line from Moorabool to Heywood will be required A new (third) 500/275 kV transformer at Heywood will be required New dynamic/static reactive support at or near Heywood will be required to control voltage stability
Scenario 2 (Increased import from NSW and export to SA)	As for scenario 1
Scenario 3 (Metro and Wind)	New generation (wind farm and gas-fired) connection points will be required New constraint equations for use in AEMO's dispatch process will be required to manage the anticipated 500 kV voltage unbalance between Moorabool and Portland. Resolving this issue in the longer term may require additional transposition points on the Moorabool-Heywood 500 kV lines, one or more static VAr compensators (SVC), or an alternative network solution
Scenario 4 (SW and increased import from SA and export to NSW)	As for scenario 1
Scenario 5 (Increased import from SA)	New generation (wind farm and gas-fired) connection points will be required New constraint equations for use in AEMO's dispatch process will be required to manage the anticipated 500 kV voltage unbalance between Moorabool and Portland. Resolving this issue in the longer term may require additional transposition points on the Moorabool-Heywood 500 kV lines, one or more static VAr compensators (SVC), or an alternative network solution A new (third) 500 kV power line from Moorabool to Heywood will be required A new (third) 275 kV power line from Heywood to South East (South Australia) will be required A new (third) 500/275 kV transformer at Heywood will be required New dynamic/static reactive support at or near Heywood will be required to control voltage stability

Table 9-9 lists the possible South-West Corridor transmission network constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-9 – South-West Corridor constraints (year 10)

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Insufficient connection points for possible wind farms and GPG	Providing suitable connection points as proposed under the new connection point provisions outlined in Chapter 3	Customer funded and project specific	At the time of wind farm and/or GPG connections	New generation connections to the Moorabool-Heywood 500 kV line, as modelled under Scenario 1, 2, 3, 4, and 5
Potential risk of loss of generation in excess of 2,000 MW for outage of a Moorabool-Heywood 500 kV line	A new (third) 500 kV double circuit line from Moorabool to Heywood	500	At the time of significant wind farm and/or GPG connections	New generation to the Moorabool-Heywood 500 kV line, as modelled under Scenario 4
Overloading of a 275 kV Heywood-South East line for outage of the parallel line	A new (third) 275 kV line from Heywood to South East (South Australia)	121	At the time of additional power transfer between South Australia and Victoria via Heywood	Increased bi-directional transfer due to increased import/export from/to South Australia via Heywood to the South East, as modelled under Scenario 2, 4 and 5
Voltage instability or collapse	A new 275/11 kV static VAr compensator (SVC) (one ±200 MVAr) or modern equivalent plant at Heywood	87	At the time of increased power transfer between South Australia and Victoria and increased wind generation in the South-West Corridor	Increased bi-directional transfer due to increased import/export from/to South Australia via Heywood to the South East, or new generation on the Moorabool-Heywood 500 kV line, as modelled under Scenario 1, 2, 4 and 5

Western Zone – gas 5-year outlook

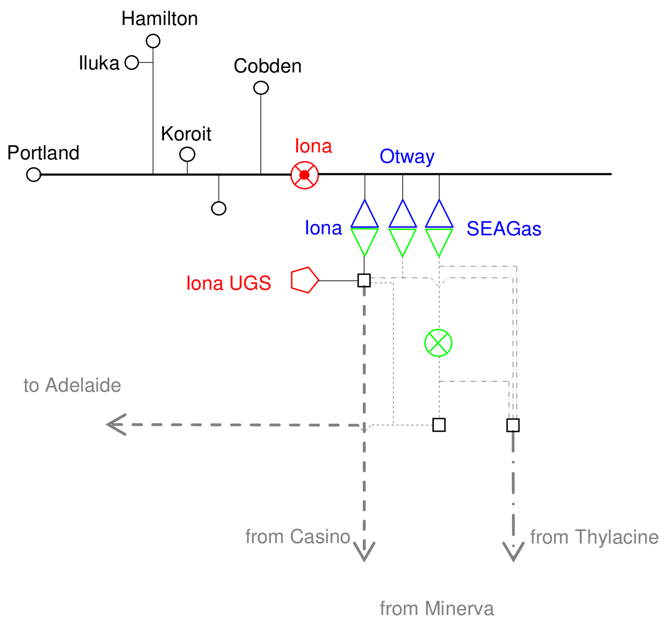
The Western Zone's 5-year outlook (years 1-5) includes the following constraints:

Western Transmission System minimum connection pressure breach.

Western Transmission System minimum connection pressure breach	
Background	The Western Transmission System (WTS) comprises 220 km of 150 mm diameter pipeline between the Iona City Gate and the Portland City Gate. It supplies Cobden, Hamilton, Koroit, Portland, and Warrnambool. New demand at Iluka has the potential to be as large as 1 TJ/d (approximately 6% of the current winter demand) Due to higher than average WTS demand growth, pressures at Portland and Hamilton may fall below the required minimum connection pressures if the pressure at Iona is not adequately maintained
Issue	Assessments indicate that, assuming the maintenance of minimum connection pressure at Iona, a breach in minimum connection pressure will occur at Portland under 1 in 20 peak day conditions in 2014
Solution	The solution to this constraint involves one of two options: upgrading the Iona Compressor Station, or creating a new system injection point south of Hamilton, to allow gas from the SEA Gas pipeline to be injected into the WTS These options will maintain minimum delivery pressures for the next 20 years, based on current demand forecasts. Based on current modelling, the preferred solution to this constraint involves a new system injection point. This option, though more cost-effective, also gives rise to: market issues relating to new gas supply arrangements, price, bidding and possibly shipping, and the need to determine just how much gas can be injected each day The effect of additional compression at Brooklyn is yet to be investigated
Timing	Prior to winter 2014, based on a 1 in 20 peak day planning standard
Trigger	No Iona injection and increased demand growth

Figure 9- 5 shows the schematic of the Western Transmission System.

Figure 9- 5– Western Transmission System



Western Zone – gas 10-year outlook

No constraints have been identified in the Western Zone for the 10-year outlook (year 10) based on the current demand forecasts and supply scenarios.

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9.3.3 Northern Corridor/Northern Zone

The Northern Corridor includes the Victorian side of the Victoria to New South Wales electrical interconnection (see Chapter 3 for more information about the Northern Corridor and its electrical layout), and is designed to enable import from New South Wales plus Murray generation of up to 1,900 MW [40]. Immediately following the loss of one of a number of critical transmission elements, operating solutions may be triggered that reduce import from New South Wales plus Murray generation levels to below 1,900 MW.

AEMO is currently undergoing a feasibility study to look at potential options to increase import from New South Wales into Victoria (focusing on the Snowy Mountains Scheme).

Northern corridor interconnector augmentations require joint planning between AEMO and Transgrid (the jurisdictional planning body for New South Wales).

The Northern Zone connects the compressor station at Wollert (just north of Melbourne) to the New South Wales interconnect. The main gas pipeline supplies laterals to Bendigo, Echuca, Koonoomoo and Wodonga. In recent years, all gas supply for this region has come via Wollert.

This review:

- involves constraints caused by issues within this region, and
- identifies constraint impacts and potential solutions to maintain the efficient transmission of electricity or gas.

Northern Corridor – electricity 5-year outlook

The Northern Corridor's 5-year outlook (years 1-5) includes the following constraints:

- Murray-Dederang 330 kV line loading.
- Eildon-Thomastown 220 kV line loading.
- Dederang-Mount Beauty 220 kV line loading.
- Dederang-South Morang 330 kV line loading.
- Dederang 330/220 kV transformer loading.

[40] The 1,900 MW level (with import from New South Wales plus Murray generation) assumes system normal conditions (all transmission elements in service) and an ambient temperature of 40ºC.

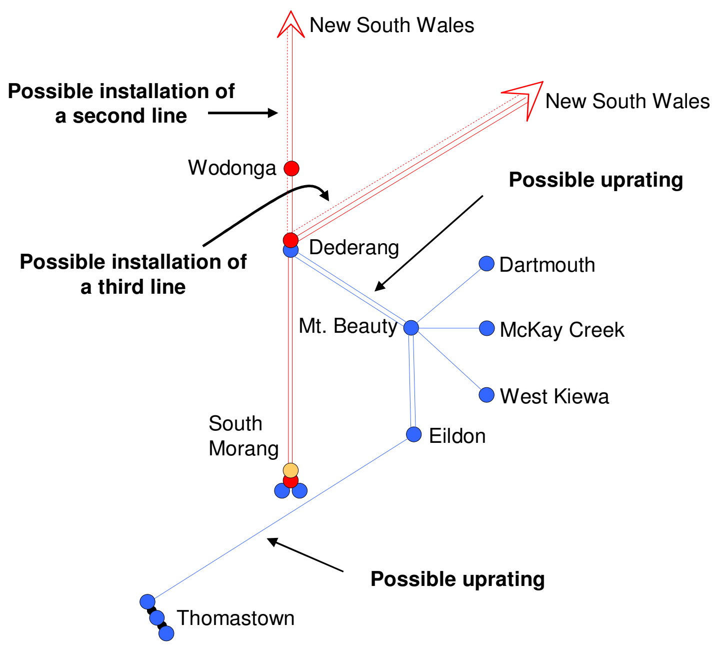
Murray-Dederang 330 kV line loading	
Background	The 330 kV transmission lines between Murray and Dederang are key components of the Victoria to New South Wales electrical interconnection. Loading on these lines defines the physical MW import from New South Wales plus Murray generation An outage of either line significantly reduces Victoria's: import from New South Wales plus Murray generation from 1,900 MW by approximately 550 MW, and export capability to New South Wales by approximately 400 MW
Potential impact	Reduced New South Wales import capability and Murray generation may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria, South Australia, and Tasmania. This may also lead to load reduction if demand exceeds available generation Reduced export capability to New South Wales may increase market prices in New South Wales and Queensland, and may also lead to load reduction in those regions if demand exceeds available generation
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less than $100,000 per annum for the period to 2014/15
Possible constraint alleviation options	Installation of a new (third) 330 kV power line from Murray to Dederang at an indicative cost of $153 million (excluding easement cost). This option is subject to obtaining the necessary easement Installation of a new (second) 330 kV line from Dederang to Jindera at an indicative cost of $86 million (excluding easement cost). This option requires widening of the existing easement between Dederang and Jindera. Uprating transmission lines in New South Wales will also be required
Economic evaluation of possible options	The market benefits associated with these options are currently insufficient to justify augmentation
Conclusion	The market benefits associated with these options are currently insufficient to justify augmentation. However, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the Victoria-New South Wales (focussing on the Snowy Mountains Scheme) feasibility study

Eildon-Thomastown 220 kV line loading	
Background	The Eildon-Thomastown 220 kV line is a key component of the connection of Southern Hydro generation, and the Victoria to New South Wales interconnection. The line's thermal capacity presents a constraint on Victorian import from New South Wales, Murray generation, and Southern Hydro generation, which can arise during prior outage of a Dederang-South Morang 330 kV line. In combination with several other constraints, a prior outage of a Dederang-South Morang line restricts power transfers in the New South Wales (including Murray generation) to Victoria direction to approximately 1,200 MW
Potential impact	An import capability reduction and constraint on Murray and Southern Hydro generation may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria, South Australia and Tasmania. The dispatch of higher-cost plant would be in place of the cheaper but constrained-off Murray and Southern Hydro generation plant. This constraint may also lead to load shedding if demand exceeds available generation
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less than $100,000 per annum for the period to 2014/15
Possible constraint alleviation options	Installation of a dynamic line rating wind monitoring scheme, at an estimated cost of $1.75 million Uprating the Eildon-Thomastown 220 kV line to 75ºC operation, at an estimated cost of $44 million
Economic evaluation of possible options	The market benefits associated with this option are insufficient to justify augmentation
Conclusion	The market benefits associated with these options are currently insufficient to justify augmentation. However, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the Victoria-New South Wales (focussing on the Snowy Mountains Scheme) feasibility study

Dederang-Mount Beauty 220 kV line loading	
Background	The Dederang-Mount Beauty 220 kV line is a key component for the connection of Kiewa/Eildon area generation and the Victoria to New South Wales interconnector. Loading of the line impacts Kiewa/Eildon area generation and export from Victoria to New South Wales. The recent removal of obsolete reactors (line traps), previously used for the old communications network that has since been upgraded, has increased the line terminations rating to the point that the conductor is now the limiting plant item
Potential impact	A reduction in Kiewa/Eildon area hydroelectric generation may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria and elsewhere in the National Electricity Market (NEM). The dispatch of higher-cost plant would be in place of the cheaper but constrained-off Murray and Southern Hydro generation plant
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is approximately $300,000 in 2014/15
Possible constraint alleviation options	Uprating of the Dederang-Mount Beauty 220 kV line (subject to feasibility)
Economic evaluation of possible options	The market benefits associated with this option are insufficient to justify significant augmentation. In particular, if less hydroelectric generation is available from the Kiewa area, there will be no constraint on this line during periods of import from or low export to New South Wales
Conclusion	AEMO has assessed the cost-benefits in detail and considers that the market benefits of this option are currently insufficient to justify augmentation. AEMO will re-assess this constraint at the time of the additional generation in the Eildon/Kiewa area

Figure 9-6 shows the schematic of the constraints identified during the Northern Corridor's 5-year outlook (featuring the Murray-Dederang 330 kV lines, and the Eildon-Thomastown and Dederang-Mount Beauty 220 kV lines).

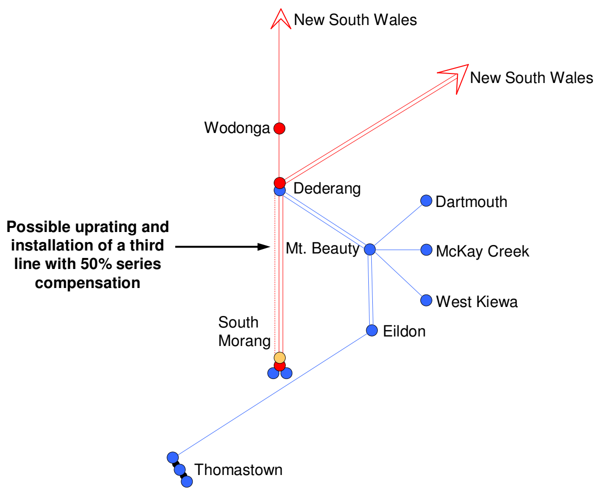
Figure 9-6 – Murray-Dederang 330 kV lines/Eildon-Thomastown and Dederang-Mount Beauty 220 kV lines



Dederang-South Morang 330 kV line loading	
Background	The Dederang-South Morang 330 kV lines are key components of the Northern Victorian transmission network and the Victoria to New South Wales interconnector. With all plant in service, the Dederang-South Morang thermal constraint does not normally limit Victorian import from New South Wales, since the Murray-Dederang 300 kV lines are the more critical constraint With prior outage of a South Morang-Dederang line, a number of overlapping Victorian import constraints apply. These include a voltage collapse and thermal loading on the Dederang 330/220 kV transformers and the Eildon-Thomastown 220 kV line See also the constraint reviews in this section for the Dederang 330/220 kV Transformers and the Eildon-Thomastown 220 kV line
Potential impact	An import capability reduction from New South Wales and Murray generation may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria, South Australia, and Tasmania. This may also lead to load shedding if demand exceeds available generation An export capability reduction to New South Wales may increase market prices in New South Wales and Queensland, and may also lead to load shedding in those regions if demand exceeds available generation
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less than $100,000 per annum for the period to 2014/15
Possible constraint alleviation options	Uprate both Dederang-South Morang 330 kV lines to 82^{O}C operation, and uprate series compensation to match the line rating at an indicative cost of $7 million Install a third Dederang-South Morang 330 kV line, with 50% series compensation to match the existing lines, at an indicative cost of $330 million (excluding easement costs)
Economic evaluation of possible options	The market benefits associated with this option are insufficient to justify augmentation
Conclusion	The market benefits associated with these options are currently insufficient to justify augmentation. However, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the Victoria-New South Wales (focussing on the Snowy Mountains Scheme) feasibility study

Figure 9-7 shows a schematic of the constraints identified during the Northern Corridor's 5-year outlook (featuring the Dederang-South Morang 330 kV lines).

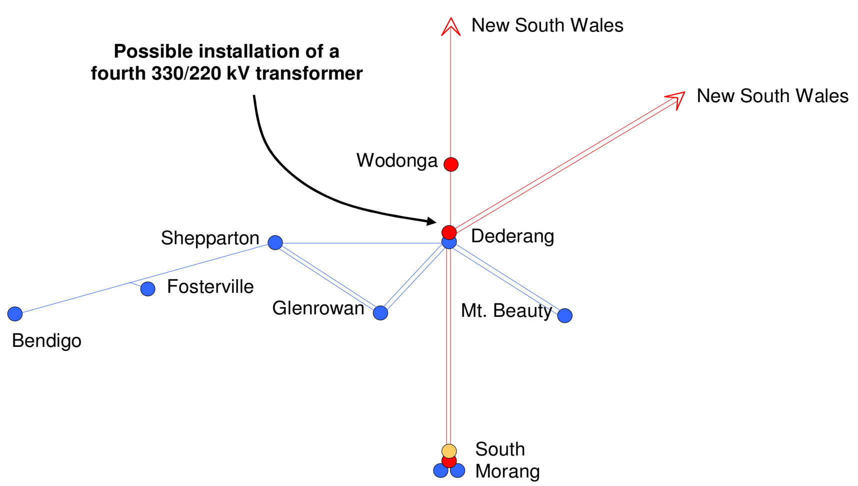
Figure 9-7 – Dederang-South Morang 330 kV lines



Dederang 330/220 kV transformer loading	
Background	The three Dederang 330/220 kV transformers are an important source of supply to Northern Victoria and also carry a portion of Victorian import from New South Wales and Murray generation The thermal capacity of these transformers presents a limitation on import from New South Wales and Murray generation, which may be reduced to (approximately): anywhere between 100 MW and 1,500 MW, depending on Eildon/Kiewa area generation, with the prior outage of one Dederang transformer, and 1,200 MW, with all plant in service and no Eildon/Kiewa area generation With more than approximately 50% of the Eildon/Kiewa area generation dispatched, transfer levels from New South Wales (including Murray generation)) to Victoria nominally increase to 1,900 MW
Potential impact	A reduction in import from New South Wales and Murray generation may increase Victorian market prices due to the need to dispatch higher cost plant in Victoria, South Australia and Tasmania. With prior outage of a Dederang transformer, this may also lead to load shedding if demand exceeds available generation. The dispatch of higher-cost plant replaces the cheaper but constrained-off Murray generation plant
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less than $100,000 per annum for the period to 2014/15
Possible constraint alleviation options	Installation of a fourth 330/220 kV transformer at Dederang at an estimated cost of $22 million
Asset replacement program coordination	As part of asset refurbishment works, SP AusNet plans to replace the existing 330/220 kV No.1 transformer at Dederang in 2016
Economic evaluation of possible options	The level of energy at risk does not economically justify the identified works
Conclusion	The market benefits associated with this option are currently insufficient to justify augmentation and AEMO expects the issue can be economically managed until completion of SP AusNet's asset refurbishment works. However, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the Victoria-New South Wales (focussing on the Snowy Mountains Scheme) feasibility study

Figure 9-8 shows a schematic of the constraints identified during the Northern Corridor's 5-year outlook (featuring the Dederang 330/220 kV transformers).

Figure 9-8 – Dederang 330/220 kV transformers



Northern Corridor – electricity 10-year outlook

Table 9-10 lists each supply scenario's impact in terms of the Northern Corridor's 10-year outlook (year 10). See Chapter 8, Section 8.4, for a detailed description of the supply scenarios.

Table 9-10 – Northern Corridor supply scenario impacts (Year 10)

Supply Scenario	Impact
Scenario 1 (LV, increased export to NSW and increased import from SA)	Increased capacity between Dederang and Mount Beauty will be required
Scenario 2 (Increased import from NSW and export to SA)	Increased network element capacities at and around Dederang, to enable increased New South Wales import, will be required Additional reactive plant at Wodonga or Dederang will be required to prevent voltage collapse
Scenario 3 (Metro and Wind)	No impact
Scenario 4 (SW and increased import from SA and export to NSW)	No impact
Scenario 5 (Increased import from SA)	No impact

Table 9-11 lists the possible Northern Corridor transmission network constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-11 – Northern Corridor constraints (year 10)

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Voltage Collapse at South Morang, Dederang, Wodonga and Jindera	Installing a second 150 MVAr capacitor bank at Wodonga	9	At the time of increased import or export from New South Wales or Snowy	This constraint will occur as a result of Increased import from / export to New South Wales, as modelled under Scenarios 1 and 2
	Upgrading the existing static series compensation on the South Morang-Dederang 330 kV lines to fully controlled series compensation (FACTS)	35	At the time of increased import or export from New South Wales or Snowy	
	A new 330/11 kV static VAr compensator (one +200/-120 MVAr) or modern equivalent plant	72	At the time of increased import or export from New South Wales or Snowy	

Northern Zone – gas 5-year outlook

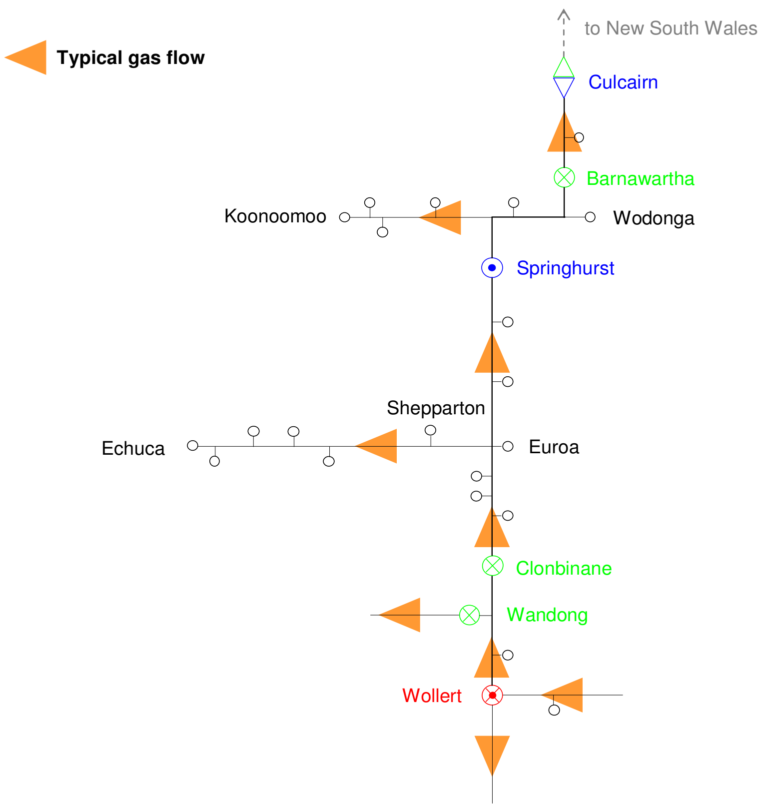
The Northern Zone's 5-year outlook (years 1-5) includes the following constraints:

Culcairn demand (exports).

Culcairn (exports)	
Background	There is limited capacity to enable exports to New South Wales via the New South Wales Interconnect at Culcairn, on days of high system demand
Issue	Background issues include the following: • Northern Zone 1 in 2 peak day demand has increased by approximately 34% since 1999, from76 TJ/d to approximately 100 TJ/d, reducing the ability to export gas to New South Wales. In an average year, 10 TJ/d can be exported via Culcairn for approximately 340 days per year • Northern Zone import-to-export mode changes take advance planning of a day or more (see Chapter 3, Section 3.7.5, for more information)
Solution	The pipeline owner is augmenting the system by: • increasing the maximum allowable operating pressure (MAOP) from Wollert to Euroa to 8,800 kPa • installing 2 Centaur 50 compressors at Wollert Compressor Station, and • modifying the Springhurst Compressor Station to enable it to compress gas northwards The augmentations, referred to as the Northern Expansion, will increase export capacity to 28TJ/d on a 1 in 20 peak day in 2010
Timing	Currently under construction
Trigger	Increased export of gas to New South Wales via Culcairn

Figure 9-9 shows a schematic of the Wollert to Euroa pipeline and the New South Wales interconnect (Culcairn).

Figure 9-9 – Wollert to Euroa pipeline and the New South Wales interconnect (Culcairn)



Northern Zone expansion and export capability through Culcairn

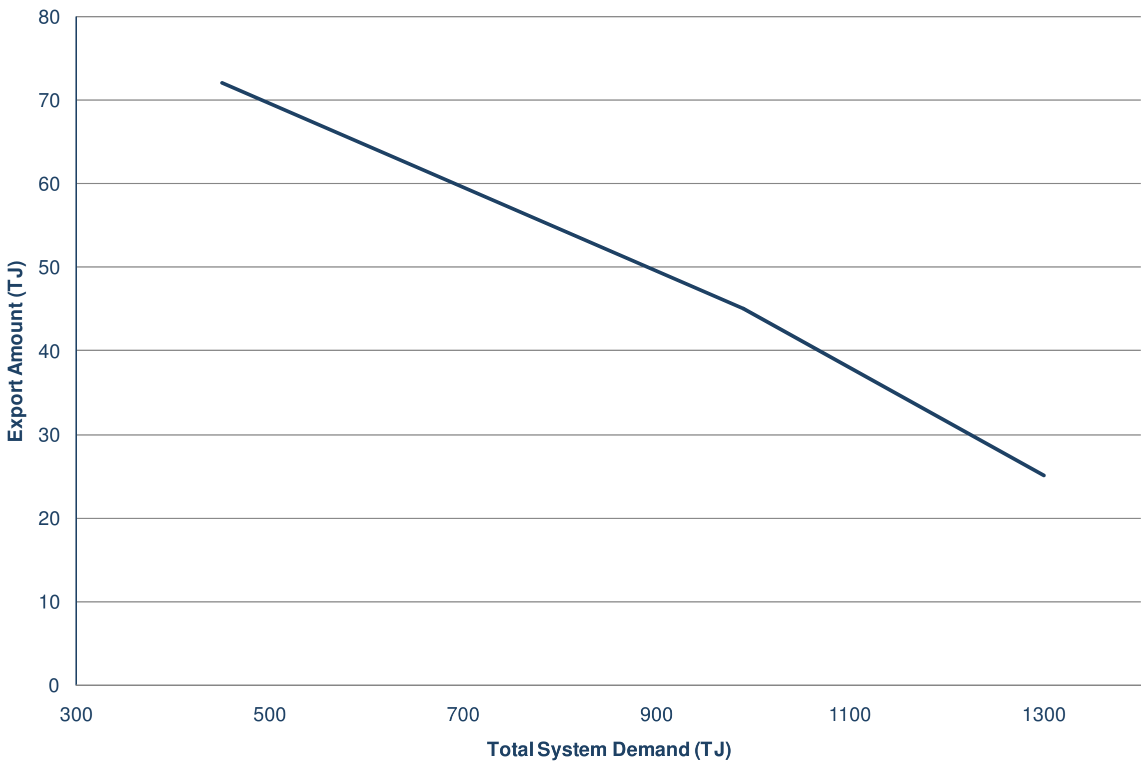
The export capacity to New South Wales varies, depending on the total system demand and gas DTS operating conditions, such as beginning-of-day conditions and the target minimum pressure at Culcairn (which is 6,000 kPa).

AEMO carried out modelling on the export capability through Culcairn to determine the relationship between export and other system factors, and particularly total gas DTS system demand.

AEMO's results show that exports of approximately 28 TJ/d through Culcairn under 1 in 20 peak day conditions are achievable in 2010 assuming that the Northern zone expansion is complete, with gas DTS operating boundaries stretched to their minimum limits at the Wollert Compressor Station, Springhurst Compressor Station, Wandong Regulator and Dandenong City Gate.

Figure 9-10 shows the relationship between Northern Zone exports and total gas DTS system demand after augmentation, which demonstrates that export capacity increases as system demand decreases.

Figure 9-10 – Northern Zone export vs total system demand



Prior to the Northern Expansion becoming operational, approximately 30-45 TJ/d of LNG is required to maintain system linepack under 1 in 20 peak day demand conditions. The availability of this linepack under these conditions is also impacted by gas exports. Usable system linepack within the Longford, Dandenong and Wollert section of the gas DTS will decrease when gas is exported through Culcairn (for example, for every 1 TJ of export through Culcairn, system linepack decreases by approximately 2.5 TJ).

Once the Northern Expansion is complete, introducing more usable linepack, the LNG required to maintain system linepack will decrease. However, LNG injection remains the most effective way to compensate for falling linepack, and exports of 28 TJ/d on a 1 in 20 winter peak day will still require LNG injections.

The export capability to New South Wales through Culcairn will decrease with system demand growth if there are no further Northern Zone augmentations.

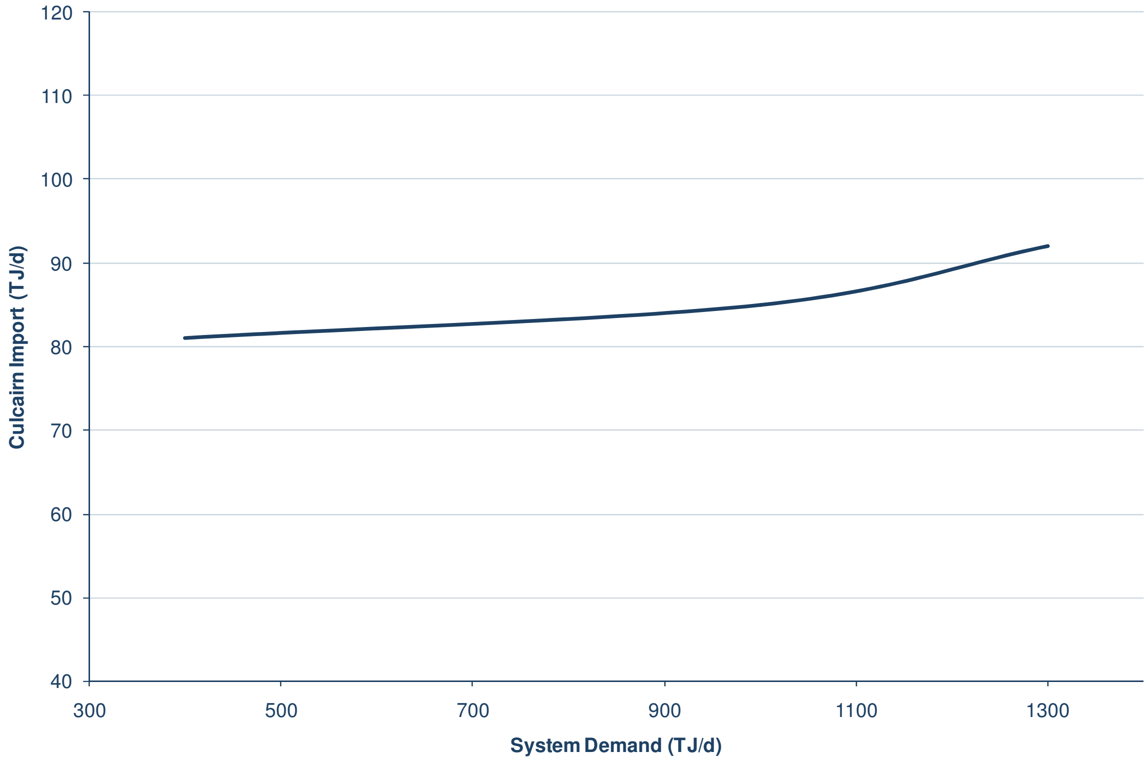
Import capability through Culcairn

AEMO carried out modelling on the import capability through Culcairn to provide information on the relationship between import and other system factors, and particularly total gas DTS system demand.

The import capacity via Culcairn varies depending on the total system demand and gas DTS and Moomba to Sydney Pipeline (MSP) operating conditions. For example, the maximum import capacity depends on the full availability of the MSP compressor located at Young and import capacity may be limited when ambient temperature exceeds 30°C due to design limitations at the Springhurst Compressor Station.

Figure 9-11 illustrates the import capacity trend with the Young and Springhurst compressors compressing southwards.

Figure 9-11 – Import capacity trend



Northern Zone – gas 10-year outlook

Table 9-12 lists each supply scenario's impact in terms of the Northern Zone's 10-year outlook (year 10). See Chapter 8, Section 8.5, for a detailed description of the supply scenarios.

Table 9-12 - Northern Zone scenario impacts (year 10)

Supply scenario		Impact
Scenario 1 (LV)		Culcairn drops below minimum operating pressure
Scenario 2 (SW)		Culcairn drops below minimum operating pressure
Scenario 3 (M)		Culcairn drops below minimum operating pressure
Scenario 4 (R)		Culcairn drops below minimum operating pressure
Scenario 5 (exports)	**a**	Culcairn drops below minimum operating pressure
	b	Culcairn drops below minimum operating pressure
	c	Culcairn drops below minimum operating pressure
	d	Culcairn drops below minimum operating pressure

Table 9-13 lists the specific Northern Zone constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-13 – Northern Zone constraints (year 10)

Constraint	Possible network solution	Indicative timing
Culcairn drops below minimum operating pressure with increased export demand via Culcairn	This constraint will occur as a result of Scenarios 1, 2, 3, 4, and 5 Possible network solutions include: duplication of the Wodonga pipeline from Wollert to Barnawartha Limiting Culcairn exports	When current system can no longer meet export requirements.

9.3.4 Greater Melbourne and Geelong/Melbourne and Geelong Zones

Greater Melbourne and Geelong form the Victorian transmission network's major electricity and gas demand centre (see Chapter 3 for more information about the Greater Melbourne and Geelong region and its electrical and gas layouts). Electrical power flows into the area, mainly from the Latrobe valley and the Northern Corridor, and limitations can occur as a result of transferring power from the 500 kV ring to the inner 220 kV mesh, and in some cases along 220 kV lines.

The Melbourne and Geelong Zone gas supply flows into the area primarily from Gippsland, as well as from Iona (at times of peak demand).

This review:

- involves constraints caused by issues within this region, and
- identifies constraint impacts and potential solutions to maintain the efficient transmission of electricity or gas.

Greater Melbourne and Geelong – electricity 5-year outlook

The Greater Melbourne and Geelong 5-year outlook (years 1-5) includes the following constraints:

- Eastern metro 500/220 kV transformers and 220 kV line loading.
- South Morang 330/220 kV transformer loading.
- South Morang 500/330 kV transformer loading.
- Double circuit 220 kV line security in the south east metropolitan area.
- Rowville-Springvale 220 kV line loading.
- Metropolitan 220 kV line rating.
- Rowville 220 kV bus fault level.
- Metropolitan 220 kV network voltage stability.

Eastern metro 500/220 kV transformers and 220 kV line loading	
Background	The eastern metro tie transformers at Cranbourne, Rowville and South Morang limit electricity supply from the 500 kV and 330 kV electricity transmission networks to the eastern metropolitan area of Melbourne In particular, the Cranbourne 500/220 kV transformer and two 220 kV lines from Rowville to East Rowville supply the load to the connection points at the Cranbourne, East Rowville and Tyabb Terminal Stations and the Western Port (JLA) sub-station in the south eastern metropolitan area A prior outage of the Cranbourne 500/220 kV transformer can limit the load supplied to these connection points at times of high load
Potential impact	Overloading of the Cranbourne transformer only occurs during peak demand conditions and if a critical network element is out of service. Following an outage of the Cranbourne transformer (or another credible contingency), the Rowville-East Rowville 220 kV lines can be overloaded, requiring the load supplied to the Cranbourne, East Rowville and Tyabb Terminal Stations, and the JLA sub-station to be constrained With all plant in service, load reduction is not required to maintain the loading of the transformers and lines within their thermal capacities Following a critical network outage, peak load reduction is forecast during summer peak demand at the Cranbourne, East Rowville and/or Tyabb terminal stations and/or the JLA sub-station of approximately 150 MW in 2013/14, increasing to approximately 250 MW in 2014/15 Under system normal conditions, a Rowville A1 500/220 kV transformer overload is forecast during summer peak demand by approximately 2014/15, requiring a peak load reduction at Springvale, Heatherton, Malvern and/or Richmond of approximately 25 MW Following a critical network outage during summer peak demand, load reduction at Springvale, Heatherton, Malvern and/or Richmond is forecast to be approximately 300 MW in 2010/11, 500 MW in 2012/13 and 700 MW in 2014/15 Further to this, following an outage of the Rowville A1 transformer (or a credible contingency), the A2 transformer at Rowville and the transformers at Cranbourne and South Morang can be overloaded and load supplied to Templestowe and Ringwood may also need to be constrained to avoid overloading the Thomastown-Templestowe and Thomastown-Ringwood 220kV transmission lines Despite the forecast peak load reduction levels, both the Cranbourne and Rowville transformers remain within their short-term ratings, so generation rescheduling and/or demand curtailment is restricted to a few hours during an unplanned network outage
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of the Cranbourne transformer constraint is less then $100,000 per annum The value of the Rowville transformer constraint is approximately $500,000 in 2014/15
Possible constraint alleviation options	A second 500/220 kV transformer at Cranbourne with an indicative cost of $56 million and any fault level mitigation works A second 500/220 kV transformer at Rowville, Ringwood or Templestowe and an upgrade of the Rowville-East Rowville and Cranbourne-East Rowville 220 kV lines with an indicative cost between $45 million and $143 million, plus any fault level mitigation works Non-network solutions (demand-side participation and/or new generation)
Economic evaluation of possible options	AEMO will undertake a detailed assessment of the available network augmentation options and non-network solutions
Conclusion	AEMO has identified that further assessment of the cost-benefits and timing of the potential solutions is required

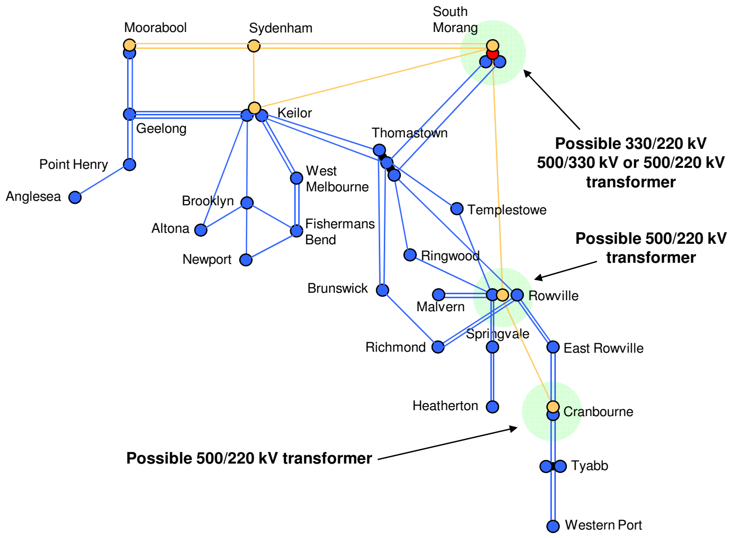
South Morang 330/220 kV transformer loading	
Background	The South Morang 330/220 kV transformers form part of the New South Wales to Victoria interconnector and metropolitan tie transformers With all plant in service, the South Morang 330/220 kV thermal constraint does not limit Victorian imports from New South Wales and Murray generation. With prior outage of a South Morang 330/220 kV transformer, imports from New South Wales and Murray generation are reduced to approximately 1,500 MW
Potential impact	Reduced imports from New South Wales and Murray generation may increase Victorian market prices due to the need to dispatch higher-cost plant in Victoria, South Australia and Tasmania. The dispatch of higher-cost plant replaces the cheaper but constrained-off Murray generation plant. With prior outage of a South Morang 330/220 kV transformer, this may also lead to load reduction if demand exceeds available generation

South Morang 330/220 kV transformer loading	
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less then $100,000 per annum
Possible constraint alleviation options	A new (third) 330/220 kV transformer at South Morang at an indicative cost of $24 million and any fault level mitigation works A new 500/220 kV transformer at South Morang, with an indicative cost of $45 million plus any fault level mitigation works Replacement of 330/220 kV transformers at South Morang with higher rated transformers Non-network solutions (demand-side participation and new generation)
Asset replacement program coordination	SP AusNet plans to replace the existing 330/220 kV No.1 transformer at South Morang in 2010 and the No.2 transformer around 2017. As part of this asset refurbishment AEMO will assess the cost-benefits of replacing the existing 330/220 kV transformers with higher rated transformers
Economic evaluation of possible options	AEMO will undertake a detailed assessment of the available network augmentation options and non-network solutions
Conclusion	AEMO has commenced detailed assessment of the cost-benefits. Assessment of this constraint will be finalised with the updated demand forecasts and AEMO will continue to coordinate with SP AusNet regarding their asset replacement program

South Morang 500/330 kV transformer loading	
Background	The South Morang 500/330 kV transformer forms part of the New South Wales to Victoria interconnector. Power flow through the South Morang transformer can limit Victorian export capability to New South Wales under low Victorian demand conditions, such as overnight when Victorian base load generation is supporting high export to New South Wales
Potential impact	Overloading of the South Morang 500/330kV transformer can occur during low demand conditions, with all plant in service. NEMDE currently utilises pre-contingent constraints to avoid overloading this transformer at times of high export to New South Wales. In the 2009 calendar year this constraint was identified as limiting Victoria to New South Wales export for approximately 480 hours Reduced export capability to New South Wales may increase market prices due to generation rescheduling in New South Wales and Queensland, and may also lead to load reduction in those regions if demand exceeds available generation
Probability weighted constraint assessment	AEMO's 2010 assessment estimates the value of this constraint is less then $100,000 per annum as the constraint is historically associated primarily with generation rescheduling, as opposed to load reduction
Possible constraint alleviation options	A new (second) 500/330 kV transformer at South Morang at an indicative cost of $46 million plus any fault level mitigation works A new 500/220 kV transformer at South Morang at an indicative cost of $45 million plus any fault level mitigation works Non-network solutions (demand-side participation and new generation)
Economic evaluation of possible options	The market benefits associated with these options are currently insufficient to justify augmentation
Conclusion	As the market benefits associated with these options are currently insufficient to justify augmentation, AEMO will assess this constraint in detail in conjunction with other interconnector limitations as part of the Victoria-New South Wales (focussing on the Snowy Mountains Scheme) feasibility study

Figure 9-12 shows a schematic of the constraints identified during the Greater Melbourne and Geelong Corridor's 5-year outlook (featuring the metro transformers).

Figure 9-12 – Metro transformers



Double circuit 220 kV line security in the south east metropolitan area	
Background	Radially-configured double-circuit 220 kV lines supply the Springvale, Heatherton, Malvern and Tyabb Terminal Stations, and the JLA sub-station. Failure of one or more of the radial lines' towers can cause considerable loss of supply to any one of these areas United Energy Distribution (UED) forecasts that a new terminal station in the Dandenong area, supplied from the 220 kV network, may be needed as early as 2020. A new transmission line is proposed to address security of supply and to provide a connection point for the new terminal station
Potential impact	An unplanned outage of any of these double-circuit lines will result in total loss of supply to the relevant terminal station. A Rowville-Springvale line tower failure can result in over 900 MW of load shedding for an extended period of time. However, a portion of load can be supplied from nearby terminal stations via emergency distribution network rearrangements taking anywhere from minutes to hours to implement
Probability weighted constraint assessment	AEMO's 2010 estimate of the value of this potential loss of load is approximately $58 million over 30 years, reduced to $36 million by utilisation of existing emergency arrangements. AEMO is in discussions with distribution businesses to determine the value of any additional limitations on supplying future load growth in the south eastern metropolitan area
Possible constraint alleviation options	An overhead 220 kV line from Cranbourne Terminal Station to Heatherton Terminal Station at an indicative cost of $80 million, subject to procuring an easement for overhead line construction A 220 kV underground cable from Cranbourne Terminal Station to Heatherton Terminal Station at an indicative cost of up to $673 million, including 10 km of tunnelling A 220 kV underground cable between Heatherton and Malvern terminal stations with an indicative cost of $370 million, including 8 km of tunnelling Option 1 secures Springvale and Heatherton area loads against double-circuit line outages and establishes a new Dandenong Terminal Station to securely supply the rapidly growing Dandenong area load Options 2 and 3 supply less than 85% of peak load at Springvale and Heatherton Terminal Stations during a Rowville-Springvale double-circuit outage, but do not supply the new Dandenong Terminal Station
Economic evaluation of possible options	AEMO is in discussions with distribution businesses to determine the relative market benefits, including the assessed value of possibly being able to procure an overhead line easement immediately, due to community developments utilising currently undeveloped land
Conclusion	AEMO proposes further joint planning with distribution businesses to identify all the options and to undertake a detailed assessment of the constraint and market benefits. An initial joint planning consultancy study has now been completed so further joint planning can continue

Rowville-Springvale 220 kV line loading	
Background	Springvale and Heatherton Terminal Stations are supplied at 220 kV by a radial double-circuit line from Rowville Terminal Station. In recent years, installation of a wind monitoring scheme and a line upgrade has increased the line capability. Expected increases in load growth in the Springvale and Heatherton areas will lead to further increases in loading of the Rowville-Springvale 220 kV line for the forecast period and beyond
Potential impact	The Rowville-Springvale line's ability to supply the Springvale and Heatherton loads is expected to reach its thermal limit as soon as 2012/13 Following an outage of a Rowville-Springvale 220 kV circuit (to avoid overloading the parallel circuit), during the equivalent of a summer: 10% POE maximum demand (MD) and 1.2 m/s wind speed, approximately 3 MWh of load is at risk in 2014/15, and 5% POE MD and 1.2 m/s wind speed, approximately 19 MWh of load is at risk in 2012/13, increasing to approximately 70 MWh in 2014/15
Probability weighted constraint assessment	AEMO's constraint value estimate is negligible within the forecast period to 2014/15

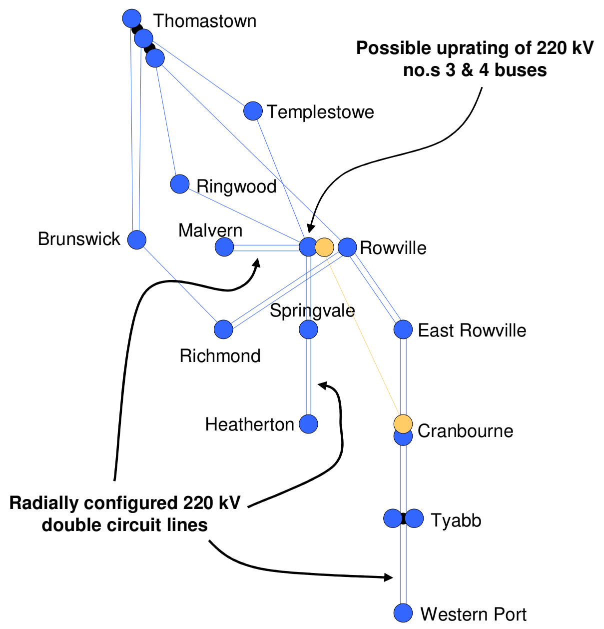
Rowville-Springvale 220 kV line loading	
Possible constraint alleviation options	All of the network options referred to in the 5-year outlook constraint issue involving double circuit 220 kV line security in the south east metropolitan area Replacement of a Rowville-Springvale circuit with high capacity (high temperature) conductors Demand-side management and/or new generation connected to Springvale and/or Heatherton Terminal Station
Economic evaluation of possible options	The market benefits associated with these options are insufficient to justify network augmentation
Conclusion	AEMO has assessed the cost-benefits in detail and considers that the market benefits of these potential options are currently insufficient to justify augmentation. AEMO will re-assess this constraint a the time of increased load at the Springvale and/or Heatherton terminal stations

Metropolitan 220 kV line loading	
Background	Most of the terminal stations in the Melbourne metropolitan area are supplied from 220 kV transmission lines. The loading on these lines is forecast to increase with increased load growth in the metropolitan area, and the outage of one or more is likely to overload the parallel transmission circuit or the remaining transmission circuit connected to the terminal stations at times of both high demand and high ambient temperature Transmission line thermal capabilities increase with wind speed due to the cooling effect of the wind over the conductor. Wind monitoring stations at appropriate locations help determine real-time wind speeds so that they can be combined with already monitored real-time ambient temperatures to calculate real-time thermal capabilities
Potential impact	An outage of a 220 kV transmission line in the metropolitan area may require up to a 160 MW (approximately) load reduction in the Melbourne metropolitan area. The location and amount of load reduction depends on the location of the outage and the ambient temperature
Probability weighted constraint assessment	AEMO's 2010 assessment estimates that the value of this constraint is approximately $7,000 in 2010/11, increasing to approximately $145,000 in 2018/19
Possible constraint alleviation options	1. Install wind monitoring schemes for the identified transmission lines to take advantage of higher wind speeds on hot summer days, and better utilisation of the existing assets, at an indicative cost of $0.35 million per monitoring station unit 2. Uprating and/or replacing a number of 220 kV transmission lines 3. Demand-side options and/or connection of new local generation at a number of terminal stations in the metropolitan area
Economic evaluation of possible options	The market benefits assessment shows that installing wind monitoring schemes for the identified 220 kV transmission lines is a likely option in around 2016 if achievable with one additional monitoring station
Conclusion	AEMO completed a detailed assessment of the possible options and considers that installation of a wind monitoring scheme is a likely option to address a number of thermal line constraints. AEMO will monitor the 220 kV line loading with increasing Melbourne metropolitan load growth, with the likely result being installation of a new wind monitoring station by around 2016.

Rowville 220 kV bus fault level	
Background	Rowville Terminal Station is connected to the 500 kV and 220 kV transmission networks in Melbourne's south east metropolitan area. Its roles include: • switching 500 kV and 220 kV lines to the Latrobe Valley, and in the metropolitan (500 kV and 220 kV) rings • supplying bulk power between these rings via its two 1,000 MVA 500/220 kV transformers, and • supplying bulk power to a number of directly-connected terminal stations Rowville Terminal Station usually operates with its four 220 kV buses connected as two groups, with: • buses 1 and 2 tied, and • buses 3 and 4 tied The two groups are tied via remote 220 kV terminal stations and the 500 kV network. Rowville 220 kV fault levels have increased with power system development over time, with bus 1-2 fault levels leading bus 3-4 fault levels Buses 1-2 and connected plant were augmented to be capable of withstanding the increased the fault levels caused by connection of the second Rowville 500/220 kV transformer. Under a particular network switching configuration, fault levels where previously reported as approaching the fault level withstand capability of the No.3 and No.4 220 kV bus bars at Rowville After a detailed assessment, however, SP AusNet has since advised that the fault withstand capability of these busbars, including supports and foundations, are sufficient to meet the forecast fault levels for the foreseeable future This revised fault withstand capability is subject to replacement of a small number of bus support insulators in addition to SP AusNet's asset refurbishment planned for this station
Potential impact	Plant is operated, as planned; within its fault withstand capability. At times of high demand and generation, and with increased levels of Victorian generation, the existing fault ratings may require network reconfiguration, increasing the probability of constraining generation and/or load shedding following an unplanned transmission element outage
Probability weighted constraint assessment	AEMO has not undertaken a probability weighted assessment of the options to alleviate the plant limitations identified, as an option with negligible costs now exists
Possible constraint alleviation options	Replacement of bus support insulators at negligible cost Interim switching to reduce the fault level prior to implementation of Option 1
Asset replacement program coordination	SP AusNet plans to replace a number of 220 kV switch bays at Rowville Terminal Station from 2010-2013. AEMO is coordinating with SP AusNet to ensure that the replacement plant's ratings are increased and to minimise the cost of the long-term option
Economic evaluation of possible options	Due to the negligible cost, in addition to SP AusNet's asset refurbishment works, AEMO considers the replacement of additional bus support isolators is economically justified
Conclusion	AEMO will continue to consult with SP AusNet to ensure 220 kV switch bay replacements, including bus support insulators, are adequately rated to withstand the forecast fault levels

Figure 9-13 shows a schematic of the constraints identified during the Greater Melbourne and Geelong Corridor's 5-year outlook (featuring the Double circuit 220 kV line security in the south east metropolitan area/Rowville-Springvale 220 kV line loading/wind monitoring schemes/Rowville 220 kV bus fault level).

Figure 9-13 – Double circuit 220 kV line security in the south east metropolitan area/Rowville-Springvale 220 kV line loading/wind monitoring schemes/Rowville 220 kV bus fault level



Greater Melbourne and Geelong – electricity 10-year outlook

Table 9-14 lists each supply scenario's impact in terms of the Greater Melbourne and Geelong 10-year outlook (year 10). See Chapter 8, Section 8.4, for a detailed description of the supply scenarios.

Table 9-14 - Greater Melbourne and Geelong supply scenario impacts (year 10)

Supply scenario	Impact
Scenario 1 (LV, increased export to NSW and increased import from SA)	Increased network element capacities around the major power inflows to Rowville, South Morang, Keilor, and Moorabool will be required. At some locations, security of supply also becomes an issue Other requirements include: new terminal stations for 220/66 kV transformation; upgraded reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Increased South Morang 500/330 kV transformation capacity will be required
Scenario 2 (Increased import from NSW and export to SA)	Increased network element capacities around the major power inflows to Rowville, South Morang, Keilor, and Moorabool will be required. At some locations, security of supply also becomes an issue Other requirements include: new terminal stations for 220/66 kV transformation; upgraded reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Additional South Morang 330/220 kV transformation, and increased Thomastown-South Morang 220 kV line capacity, will be required
Scenario 3 (Metro and Wind)	Increased network element capacities around the major power inflows to Rowville, South Morang, Keilor, and Moorabool will be required. At some locations, security of supply also becomes an issue Other requirements include: new terminal stations for 220/66 kV transformation; upgraded reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management

Supply scenario	Impact
Scenario 4 (SW and increased import from SA and export to NSW)	Increased network element capacities around the major power inflows to Rowville, South Morang, Keilor, and Moorabool will be required. At some locations, security of supply also becomes an issue Other requirements include: new terminal stations for 220/66 kV transformation; upgraded reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Increased South Morang 500/330 kV transformation capacity will be required
Scenario 5 (Increased import from SA)	Increased network element capacities around the major power inflows to Rowville, South Morang, Keilor, and Moorabool will be required. At some locations, security of supply also becomes an issue Other requirements include: new terminal stations for 220/66 kV transformation; upgraded reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management

Table 9-15 lists the possible Greater Melbourne and Geelong transmission network constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-15 – Greater Melbourne and Geelong constraints (year 10)

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Outage of a Rowville-Malvern 220 kV line and overloading of the parallel line	Uprating the Rowville-Malvern 220 kV line to 82ºC	16	At the time of significant permanent load transfer from Richmond to Malvern	This constraint will occur as a result of increased demand at Malvern Terminal Station, as modelled under all scenarios
	Cut-in Rowville-Richmond 220 kV lines at Malvern Terminal Station	30	Feasibility in respect to fault levels to be investigated	
Outage of Rowville-Ringwood 220 kV line overloads the Thomastown-Ringwood 220 kV line	Cut-in existing Thomastown-Templestowe 220 kV line at Ringwood.	5	At the time of significant increased Melbourne metropolitan area load, estimated to be approximately 2015	This constraint will occur as a result of increased demand in the Melbourne metropolitan area, as modelled under all scenarios
Outage of a South Morang-Thomastown 220 kV line and overloading of the parallel line	Cut into the existing Rowville-Thomastown 220 kV line into the South Morang 220 kV bus to form a third South Morang-Thomastown 220 kV line	8	At the time of increased power transfer from New South Wales	This constraint is caused by increased Melbourne metropolitan area demand and/or increased import from New South Wales, as modelled under all scenarios
	Cut into the existing Eildon-Thomastown 220 kV line into the South Morang 220 kV bus to form a fourth South Morang-Thomastown 220 kV line	7	At the time of increased power transfer from New South Wales	
Unable to maintain network voltage levels and voltage stability	A 220 kV switched shunt capacitor at Cranbourne	7.3	At the time of increased Melbourne metropolitan load	This constraint will occur on a locational basis due to increased demand in the Melbourne metropolitan area, as modelled under all scenarios
	Dynamic reactive power plant			
	Power factor correction at the point of connection by the connected parties			
Increase in fault	Operational arrangements		Needs driven	This constraint will

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
levels	Series reactor installation Switchgear replacement			occur due to increased demand and/or new generation in the Melbourne metropolitan area

Melbourne and Geelong Zone – gas 5-year outlook

The Melbourne and Geelong Zone 5-year outlook (years 1-5) includes the following constraints:

- South West Pipeline (SWP) and system capacity.

South West Pipeline (SWP) and system capacity	
Background	The commissioning of the BLP pipeline has increased system capacity from Iona to Brooklyn. However, with increased demand from new GPG and increased export to Culcairn, greater deliverability and system linepack will be required AEMO's modelling indicates that a Stonehaven compressor will increase system capacity by approximately 46 TJ/d under normal operating conditions, but will only marginally increase system linepack, which is insufficient for peak day requirements. However, at different operating conditions, this increase in capacity can vary
Issue	Insufficient system capacity and linepack will result in the curtailment of demand
Solution	Based on current modelling, a preferred solution to this constraint involves constructing a compressor station at Stonehaven A new Centaur 50 compressor at Stonehaven will increase SWP capacity by approximately 46TJ/d. However, the available SWP capacity depends upon the system's operating pressure
Timing	Timing of the new compressor station is contingent upon the timing and location of a major new GPG connection to the gas DTS, together with increased export requirements through Culcairn Based on currently available information, modelling shows the solution is likely to be required by winter 2012
Trigger	Triggers include: the commissioning of a new GPG; exports of gas to New South Wales via Culcairn; increased existing GPG demand; and increased system demand during peak times

Figure 9-14 shows the range of SWP capacities, based on pressure at Iona and demonstrates the SWP capacity with and without operation of a Stonehaven compressor. Figure 9-14 also shows the SWP capacity at three different gas DTS demand levels: 1200 TJ/d, 1293 TJ/d and 1307 TJ/d.

Figure 9-14 – South West Pipeline capacities with the addition of a compressor at Stonehaven

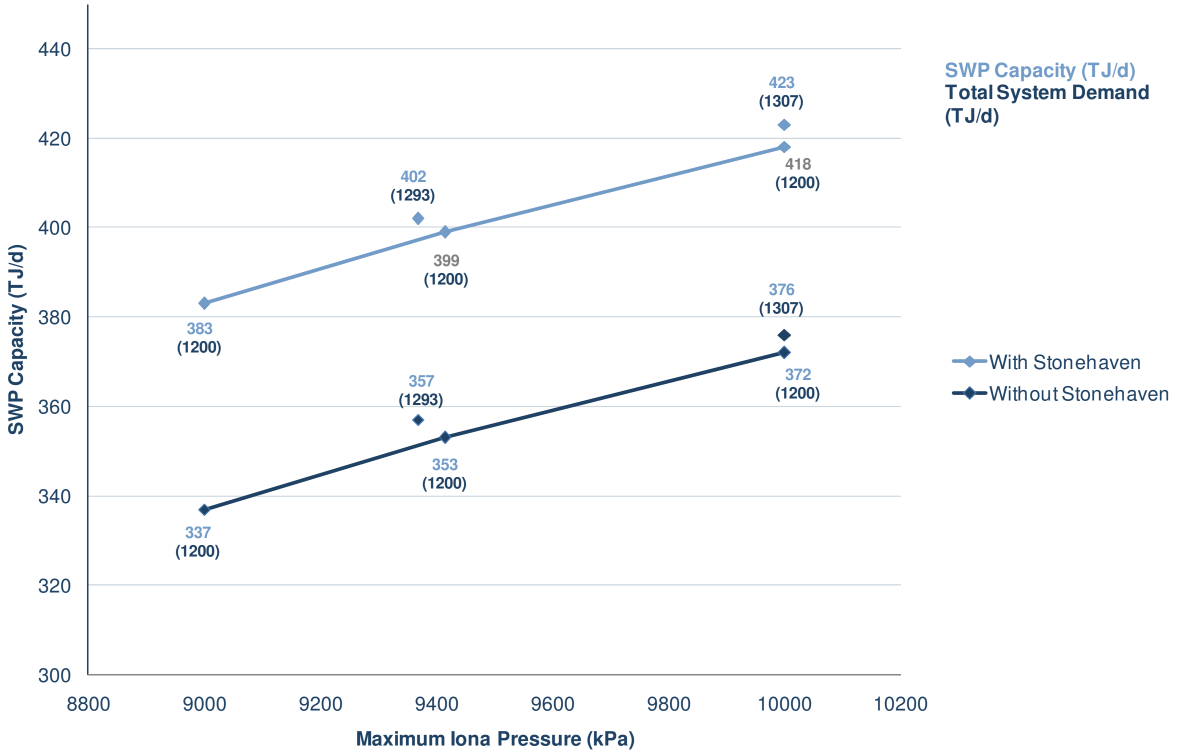
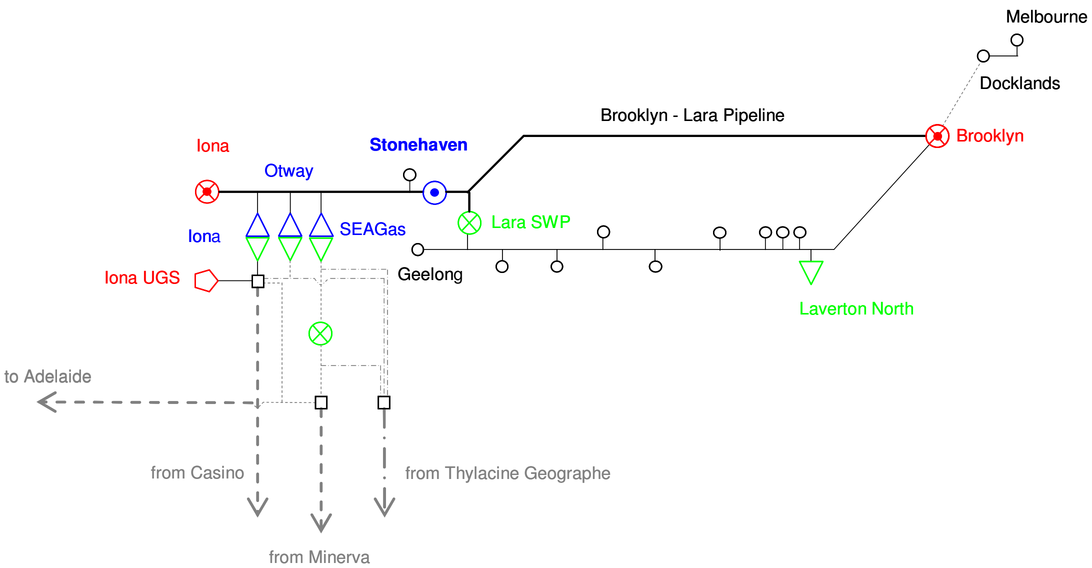


Figure 9-15 shows the schematic of the South West Pipeline (Stonehaven).

Figure 9-15 – South West Pipeline (Stonehaven)



Melbourne and Geelong Zone – gas 10-year outlook

Table 9-16 lists each supply scenario's impact in terms of the Melbourne and Geelong Zone 10-year outlook (year 10). See Chapter 8, Section 8.5, for a detailed description of the supply scenarios.

Table 9-16 – Melbourne and Geelong Zone supply scenario impacts (year 10)

Supply scenario		Impact
Scenario 1 (LV)		South West Pipeline capacity is constrained by its maximum operating pressure
Scenario 2 (SW)		South West Pipeline capacity is constrained by its maximum operating pressure
Scenario 3 (M)		South West Pipeline capacity is constrained by its maximum operating pressure
Scenario 4 (R)		South West Pipeline capacity is constrained by its maximum operating pressure
Scenario 5 (exports)	**a**	Brooklyn to Lara Pipeline City Gate (CG) inlet pressure below minimum operating pressure
	b	Brooklyn to Lara Pipeline City Gate (CG) inlet pressure below minimum operating pressure
	c	Brooklyn to Lara Pipeline City Gate (CG) inlet pressure below minimum operating pressure
	d	Brooklyn to Lara Pipeline City Gate (CG) inlet pressure below minimum operating pressure

Table 9-17 lists the specific Melbourne and Geelong Zone constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-17 – Melbourne and Geelong Zone constraints (year 10)

Constraint	Possible network solution	Indicative timing
South West Pipeline capacity is constrained by its maximum operating pressure while flowing from Iona to Melbourne, and its minimum pressure while flowing from Melbourne to Iona	This constraint will occur as a result of Scenarios 1, 2, 3, 4	
	Commissioning the Rockbank to Wollert pipeline [1] Duplication of the pipeline between Iona and Stonehaven Duplication of the pipeline between Stonehaven and Lara	When Iona injects more than 400 TJ/d and/or when new GPG (CCGT) connects to the DTS in the Gippsland and Metropolitan area
	Installation of a compressor station at Rockbank to compress gas towards Iona Upgrade of a Wollert compressor to enable gas compression toward Iona	When a large amount of flow from Melbourne to Iona is required (e.g. 80TJ/d export to South Australia)
Brooklyn to Lara Pipeline City Gate (CG) inlet pressure below minimum operating pressure with increased export to South Australia	This constraint will occur as a result of Scenario 5 Possible network solutions include: duplicating the pipeline upstream and downstream of Gooding Compressor Station, and commissioning the Rockbank to Wollert pipeline, and a new compressor at Wollert compressing gas towards Iona	At the time new GPG connects to the gas DTS, and increased export to New South Wales to 200 TJ/d and South Australia to 80 TJ/d

1. Under certain operating conditions (e.g. high injection from Iona and low injection from Longford on a low demand day), the Rockbank to Wollert link is required. This requirement supports commissioning of the link as soon as possible (within 5 years).

9.3.5 Regional Victoria/Ballarat Zone

Regional Victoria forms an electrical area of long distance, lower-capacity lines that deliver energy to provincial cities and regional load centres (see Chapter 2 for more information about Regional Victoria and its electrical layout). Regional Victoria's lines provide a path for energy imported from New South Wales to the main demand centre of Greater Melbourne and Geelong. This path runs parallel to the Northern Corridor, which carries the bulk of that energy. Regional Victoria also provides links to South Australia via the Murraylink HVDC interconnector at Red Cliffs. As a consequence, limitations in the area not only arise from load growth at its terminal stations, but also from the bulk transfer of energy across the region under certain system conditions.

The Ballarat Zone connects the Bendigo lateral to Brooklyn via the Bendigo lateral. This allows gas supply to this region to flow from Brooklyn at times of peak demand.

This review:

- involves constraints caused by issues within this region, and
- identifies constraint impacts and potential solutions to maintain the efficient transmission of electricity or gas.

Regional Victoria – electricity 5-year outlook

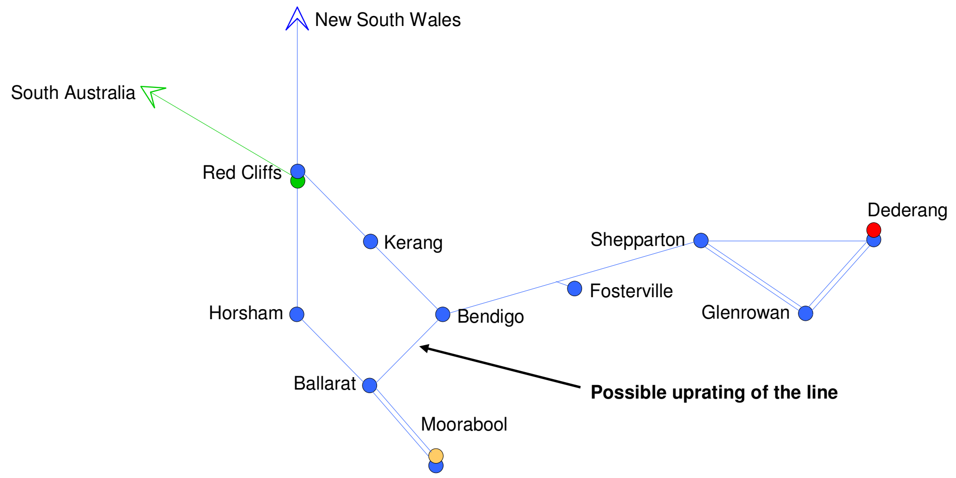
The Regional Victoria 5-year electricity outlook (years 1-5) includes the following constraints:

- Ballarat-Bendigo 220 kV line loading.
- Ballarat-Moorabool 220 kV line loading.
- Moorabool-Geelong 220 kV line loading.

Ballarat-Bendigo 220 kV line loading	
Background	The Ballarat -Bendigo 220 kV line forms one of the main supply routes into North Western Victoria and South Australia, via the Murraylink DC interconnector at Red Cliffs, and on to South Western New South Wales Loading of the line presents a thermal constraint during system normal conditions in preparation for loss of the Ballarat-Horsham 220 kV line or the Bendigo-Fosterville-Shepparton 220 kV line The impact of this constraint will increase with load growth in North Western Victoria. A wind monitoring scheme for this line is currently being installed and will reduce the impact of the constraint
Potential impact	Given the simultaneous occurrence of peak demand and high ambient temperatures, an unplanned transmission circuit outage of either the Ballarat-Horsham 220 kV line or the Bendigo-Fosterville-Shepparton 220 kV line may require load reduction in North Western Victoria to prevent thermal overload of the Ballarat-Bendigo 220 kV line During peak summer demand, forecast load reduction is approximately 50 MW in 2010/11, 70 MW in 2010/13, and 70 MW in 2014/15
Probability weighted constraint assessment	AEMO's 2010 constraint assessment estimates that the value of this constraint is $5 million in 2014/15
Possible constraint alleviation options	Uprating the Ballarat-Bendigo 220 kV line to 75°C operation at an estimated cost of $28 million
Economic evaluation of possible options	The market benefits associated with this constraint show that a detailed assessment of the constraint is required
Conclusion	AEMO will perform a detailed assessment of the constraint and possible solutions while ensuring completion of the new wind monitoring scheme to utilise increased line capability during high wind conditions

Figure 9-16 shows a schematic of the constraints identified during the Regional Victoria 5-year outlook (featuring the Ballarat-Bendigo 220 kV line).

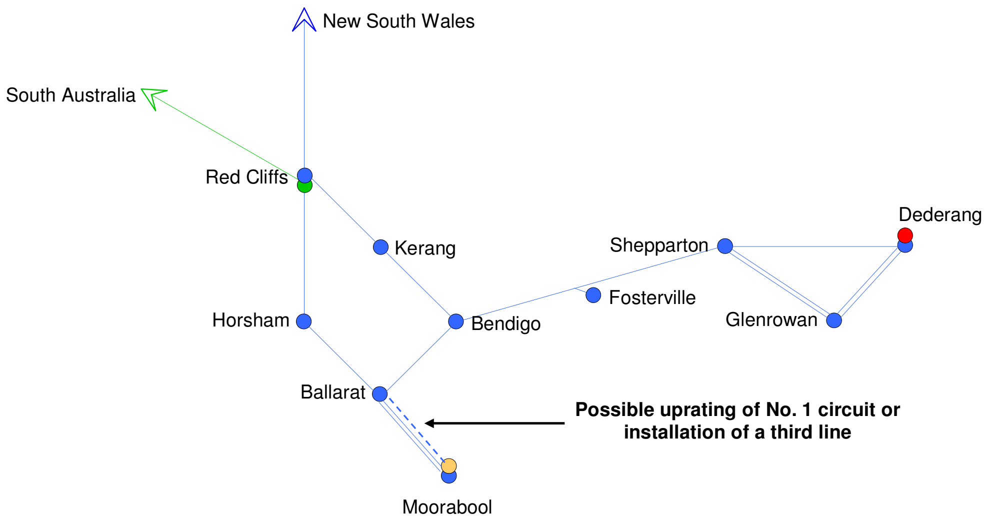
Figure 9-16 – Ballarat-Bendigo 220 kV line



Ballarat-Moorabool 220 kV line loading	
Background	The two Moorabool-Ballarat 220 kV circuits form one of the main supply routes into North Western Victoria. These circuits also form part of the supply into South Australia, via the Murraylink DC interconnector at Red Cliffs, and into South Western New South Wales A wind monitoring scheme, commissioned in September 2006, allows additional thermal line capacity to be utilised at times of increased wind, thereby reducing any thermal limitation in the short term. However, increased load growth, above the level of any new local generation, has led to increased line loading over time
Potential impact	Given the simultaneous occurrence of high demand in North Western Victoria and high ambient temperatures, a single unplanned transmission circuit outage can result in export to South Australia (via Murraylink) falling to zero, and a reduction of export to (or an increase in import from) New South Wales, and load reduction in North Western Victoria During peak summer demand, forecast load reduction is approximately 40 MW in 2010/11, 60 MW in 2010/13, and 80 MW in 2014/15
Probability weighted constraint assessment	AEMO's 2010 constraint assessment estimates that the value of this constraint is $5 million in 2014/15
Possible constraint alleviation options	Uprating the Moorabool-Ballarat No. 1 circuit to 75°C operation, at an estimated cost of $23.4 million Uprating the Moorabool-Ballarat No. 1 circuit to 82°C operation, at an estimated cost of $25.6 million (or $5 million after option 1) Installing a third Moorabool-Ballarat circuit, at an estimated cost of $21 million (the new line will be strung on the existing Moorabool-Ballarat No.2 line)
Economic evaluation of possible options	The market benefits associated with this constraint show that a detailed assessment of the constraint is required
Conclusion	AEMO will perform a detailed assessment of the constraint and possible solutions

Figure 9-17 shows a schematic of the constraints identified during the Regional Victoria 5-year outlook (featuring the Ballarat-Moorabool 220 kV line).

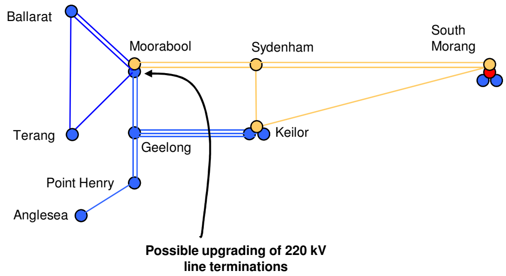
Figure 9-17 – Ballarat-Moorabool 220 kV line



Geelong-Moorabool 220 kV line loading	
Background	Loads at Geelong Terminal Station and the Point Henry Smelter are supplied by two Geelong-Moorabool 220 kV circuits, three Geelong-Keilor 220 kV circuits, and local generation from the Anglesea Power Station Due to the large demand at Geelong and Point Henry, the 220 kV circuits are heavily loaded and may reach their thermal limit during high demand high temperature conditions or during an outage of one of the parallel circuits
Potential impact	During peak summer demand, under system normal conditions the forecast load reduction (at the Geelong Terminal Station or the Point Henry Smelter) is approximately 150 MW in 2014/15
Probability weighted constraint assessment	AEMO's 2010 constraint assessment estimates that the value of this constraint is $1.5 million in 2014/15
Possible constraint alleviation options	Uprating the Geelong-Moorabool 220 kV line terminations to match the conductor rating, at an estimated cost of $5 million New double circuit Geelong-Moorabool 220 kV line installation (with a conductor temperature of 82°C), at an estimated cost of $21 million
Economic evaluation of possible options	The market benefits associated with this constraint show that a detailed assessment is required and that replacement of line terminations is justifiable
Conclusion	AEMO will perform a detailed assessment of the constraint and possible solutions

Figure 9-18 shows a schematic of the constraints identified during the Regional Victoria 5-year outlook (featuring the Geelong-Moorabool 220 kV line).

Figure 9-18 – Geelong-Moorabool 220 kV line



Regional Victoria – electricity 10-year outlook

Table 9-18 lists each supply scenario's impact in terms of the Regional Victoria 10-year outlook (year 10). See Chapter 8, Section 8.4, for a more detailed description of the supply scenarios.

Table 9-18 – Regional Victoria supply scenario impacts (year 10)

Supply scenario	Impact
Scenario 1 (LV, increased export to NSW and increased import from SA	Increased line capacities in the loop running parallel to the Northern Corridor (Moorabool to Dederang via Bendigo) will be required. Other requirements include: new terminal stations to meet load growth; improved reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Increased line capacities (specifically involving the No.1 Moorabool-Ballarat 220 kV and Mount Beauty-Dederang 220 kV lines) will be required
Scenario 2 (Increased import from NSW and export to SA)	Increased line capacities in the loop running parallel to the Northern Corridor (Moorabool to Dederang via Bendigo) will be required. Other requirements include: new terminal stations to meet load growth; improved reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Increased line capacities (specifically involving the No.1 Moorabool-Ballarat 220 kV and Mount Beauty-Dederang 220 kV lines) will be required
Scenario 3 (Metro and Wind)	Increased line capacities in a number of 220 kV lines in Western and South Western Victoria will be required. Other requirements include: new terminal stations to connect wind farms and meet load growth; improved static and dynamic reactive support to maintain voltage stability and voltage levels within limits; and improved fault-level management
Scenario 4 (SW and increased import from SA and export to NSW)	Increased line capacities in the loop running parallel to the Northern Corridor (Moorabool to Dederang via Bendigo) will be required. Other requirements include: new terminal stations to meet load growth; improved reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management Increased line capacities (specifically involving the No.1 Moorabool-Ballarat 220 kV and Mount Beauty-Dederang 220 kV lines) will be required
Scenario 5 (Increased import from SA)	Increased line capacities in the loop running parallel to the Northern Corridor (Moorabool to Dederang via Bendigo) will be required. Other requirements include: new terminal stations to meet load growth; improved reactive support to maintain voltage levels within limits and to prevent voltage collapse; and improved fault-level management

Table 9-19 lists the possible Regional Victoria transmission network constraints (and the possible network solutions) resulting from each supply scenario.

Table 9-19 – Regional Victoria constraints (year 10)

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Bendigo-Fosterville-Shepparton lines overload for numerous outages [1]	Uprating the Bendigo-Shepparton 220 kV line to 90ºC	25	Approximately 2017 or at the time of increased import from New South Wales	This constraint will occur as a result of increased demand in regional Victoria and/or increased import from New South Wales, as modelled under all scenarios
	Installing a phase angle regulating transformer on the Bendigo-Shepparton 220 kV line	46		
	A new double circuit Bendigo-Shepparton 220 kV line – conductor temperature 82ºC	183		
Ballarat-Horsham 220 kV line overload for numerous outages [1]	Uprating the Ballarat-Horsham 220 kV line terminations to match the conductor rating	1.2	At the time of increased generation in Regional Victoria (Scenario 3)	This constraint will occur as a result of increased generation in Regional Victoria, as modelled under Scenario 3
	A new double circuit Ballarat-Waubra-Horsham-Redcliffs 220 kV line – conductor temperature 82ºC	694		
	A new Ballarat-Horsham Cliffs 500 kV line – initially operating at 220 kV			
Ballarat-Terang 220 kV line overload for outage of the Moorabool-Terang line	Uprating the Ballarat-Terang 220 kV line's conductor temperature to 82ºC	70	At the time of increased generation in Regional Victoria (Scenario 3)	This constraint will occur as a result of increased generation in Regional Victoria, as modelled under Scenario 3
	A new double circuit Ballarat-Terang 220 kV line – conductor temperature 82ºC	180	At the time of increased generation in Regional Victoria (Scenario 3)	
Moorabool-Terang 220 kV line overload for outage of the Ballarat-Terang line	Uprating the Moorabool-Terang 220 kV line's conductor temperature to 82ºC	70	At the time of increased generation in Regional Victoria (Scenario 3)	This constraint will occur as a result of increased generation in Regional Victoria, as modelled under Scenario 3
	A new double circuit Moorabool-Terang 220 kV line – conductor temperature 82ºC	205		

Constraint	Possible network solution	Cost estimate ($M)	Indicative timing	Trigger
Horsham-Red Cliffs 220 kV line overload for numerous outages [1]	Uprating the Horsham-Red Cliffs 220 kV line terminations to match conductor rating	1.2	At the time of increased generation in Regional Victoria (Scenario 3)	This constraint will occur as a result of increased generation in Regional Victoria, as modelled under Scenario 3
	A new double circuit Horsham-Red Cliffs 220 kV line – conductor temperature 82ºC	270		
	A new Horsham-Red Cliffs 500 kV line – initially operating at 220 kV			
Kerang-Wemen-Red Cliffs 220 kV line overload for numerous outages [1]	A new double circuit Kerang-Wemen-Red Cliffs 220 kV line – each of the circuit rating 800 MVA	230	At the time of increased generation in Regional Victoria (Scenario 3)	This constraint will occur as a result of increased generation in regional Victoria, as modelled under Scenario 3
	A new Kerang-Wemen-Red Cliffs 500 kV line – initially operating at 220 kV			
Dederang-Glenrowan 220 kV line overload for outage of a parallel circuit	Installing a phase angle regulating transformer on the Bendigo-Shepparton 220 kV line	46	Approximately 2016 or at the time of increased import from New South Wales	This constraint will occur as a result of increased demand in regional Victoria and/or increased import from New South Wales, as modelled under all scenarios
	A new double circuit Dederang-Glenrowan 220 kV line – each circuit rated at 800 MVA	240		
Lack of network reactive support and voltage control in Regional Victoria	Shunt static capacitors		Needs driven	This constraint will occur as a result of increased demand in regional Victoria and/or with increased wind generation in Regional Victoria, as modelled under all scenarios
	Dynamic reactive power plant (1 or 2 units, with a second unit only required for Scenario 3)	36 to 73	At the time of increased generation in Regional Victoria (Scenario 3)	
Increase in fault levels	Operational arrangements		Needs driven	This constraint will occur as a result of increased demand and/or increased generation in Regional Victoria, as modelled under all scenarios
	Series reactor installation			
	Switchgear replacement			

Outages of the Darlington Point-Balranald 220 kV line, Balranald-Buronga 220 kV line, Buronga-Red Cliffs 220 kV line, Ballarat-Bendigo 220 kV line, Bendigo-Kerang 220 kV line, Ballarat-Waubra-Horsham 220 kV line or Eildon-Thomastown 220 kV line

Ballarat Zone – gas 5-year outlook

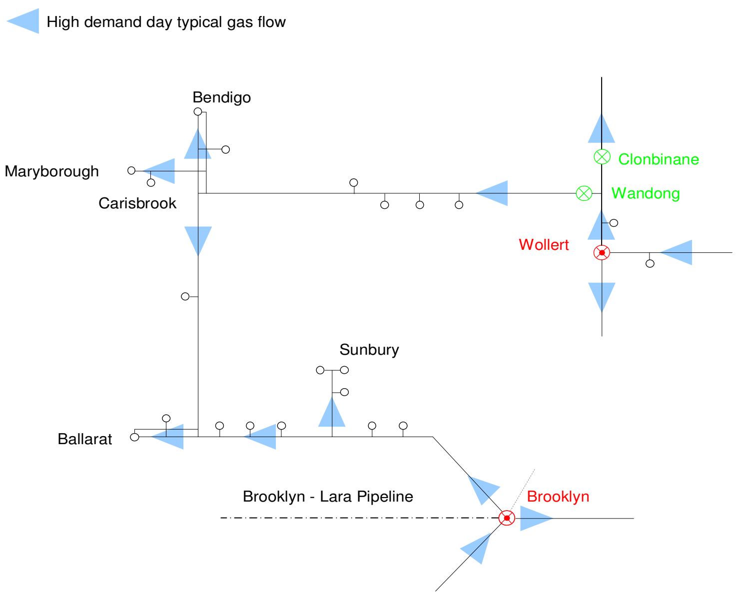
The Ballarat Zone gas 5-year outlook (years 1-5) includes the following constraints:

- Sunbury minimum connection pressure breach.

	Sunbury minimum connection pressure breach
Background	Demand in the Ballarat Zone is growing much faster than average, particularly on the Sunbury lateral due to increased demand at Sunbury, Diggers Rest, Sydenham and Caroline Springs. This has the potential to cause minimum pressure breaches at Sunbury The latest CTM peak day data shows a 13% increase in demand (from 60 TJ to 68 TJ) in the Ballarat Zone.
Issue	Assessments indicate that a minimum connection pressure breach will occur at Sunbury under 1 in 20 peak day conditions in winter 2010
Solution	• Increasing the Wandong Regulator pressure to approximately 4,800-5,200kPa, and/or • connecting the Sunbury branch onto the South West Pipeline, and • duplicating the Sunbury lateral
Timing	Prior to winter 2010 to increasing the Wandong Regulator pressure to approximately 4,800-5,200 kPa Prior to 2012 for duplicating the Sunbury lateral
Trigger	High Sunbury system demand growth and export to New South Wales from 2010

Figure 9-19 shows a schematic of the Ballarat and Sunbury laterals.

Figure 9-19 – Ballarat and Sunbury



Ballarat Zone – gas 10-year outlook

No constraints have been identified in the Ballarat Zone for the 10-year outlook (year 10) based on the current demand forecasts and supply scenarios.

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9.4 Distribution network service provider planning

AEMO uses load forecasts provided by distribution network service providers (DNSPs) in its electricity DSN planning.

In undertaking augmentation planning, AEMO:

- accounts for DNSP plans for existing and new connection points, and
- addresses the impact that DNSP plans have on electricity DSN planning in its constraint assessments.

The general impact distribution load growth has on the electricity DSN is addressed by modelling this growth at connection points. This also tends to account for the impact that preferred network solutions have on connection asset constraints (for example, installing additional transformation at existing connection points), which are not explicitly addressed by the VAPR.

Table 9-20 lists the planned connection modifications from the 2009 Transmission Connection Planning Report, and the potential shared transmission network impacts and considerations.

Table 9-20 – Distribution network service provider planning impacts

Location / terminal station	Preferred network solution	Electricity DSN impacts and considerations
Altona 66 kV	Install additional transformation capacity and reconfigure 66 kV exits in 2019	Fault levels may increase (220 kV and 66 kV)
Ballarat 66 kV	Install a third Ballarat 150 MVA 220/66 kV transformer in 2019	Contingency plans exist to reduce supply interruptions due to Ballarat 220/66 kV transformer outages. Distribution (66 kV) transfers of up to 20 MVA to Brooklyn and 10 MVA to Horsham may be made Installing a third Ballarat 220/66 kV transformer reduces or eliminates the need for these contingency plans. However, this will not affect electricity DSN augmentation, as AEMO does not consider these contingency plans in its transmission constraint valuation
Bendigo 66 kV and 22 kV	Install two new 75 MVA 230/22 kV transformers by 2013, separating 66 kV and 22 V points of supply and transferring load from the existing (230/66/22 kV) transformation	Increased Bendigo load, leading to the additional Bendigo Terminal Station transformer installation, and fault levels with the planned reconfiguration, are being monitored.
Brunswick 66 kV	Establish a new 66 kV supply point with two 225 MVA 220/66 kV transformers in approximately 2012. This enables off-loading of the West Melbourne and Richmond Terminal Stations	The transfer of load from the western and eastern metropolitan areas to the northern metropolitan area may impact electricity DSN augmentation timings and preferences
Cranbourne 66 kV	Install a fourth Cranbourne 150 MVA 220/66 kV transformer in 2014	This will supply most new south-eastern growth corridor load from the Rowville A2 and Cranbourne A1 500/220 kV transformers. Timings allow for 150 MVA of 66 kV load transfers within two hours to East Rowville, Tyabb and Heatherton Terminal Stations. Fault levels are likely to increase (220 kV and 66 kV)
East Rowville 66 kV	Install a fourth 150 MVA 220/66 kV transformer in late 2011	Fault levels may increase (220 kV). Timings allow for load transfers within two hours of 60 MVA to Ringwood and 65 MVA to Springvale Terminal Stations via 66 kV networks, and 20 MVA via 22 kV networks

Location / terminal station	Preferred network solution	Electricity DSN impacts and considerations
Fishermans Bend 66 kV	Implement a 66 kV bus tie normally open/auto-close control so all three transformers can be in service in 2017/18	Fault levels likely to increase (220 kV and 66 kV)
Geelong 66 kV	Install a fourth 150 MVA 220/66 kV transformer in late 2010	Fault levels may increase (220 kV and 66 kV)
Keilor 66 kV	Rearrange 66 kV lines in 2011 so all five 150 MVA 220/66 kV transformers can be normally in service, connected to two 66 kV bus groups, within fault ratings	The Keilor 220 kV terminal station switching configuration and flows under normal and various abnormal conditions are being reviewed
Morwell 66 kV	Install a fourth Morwell 165 MVA 220/66 kV transformer in 2013 based on power station outputs of 50 MVA at Morwell and nil at Bairnsdale	Thermal and fault-level impacts in the Hazelwood 220 kV area may require action if an additional Morwell transformer is installed
Red Cliffs 66 kV	Establish Wemen Terminal Station with 235/66 kV transformers in early 2011, transferring Red Cliffs 66 kV load there, and to Red Cliffs 22 kV buses	The electricity DSN 220 kV lines supplying Red Cliffs may require thermal and/or voltage control changes to retain reliability
Richmond 66 kV	Transfer load to the new Brunswick 66 kV connection point from 2012 to 2015. Additional transformation is provided at Brunswick instead of at the Richmond Terminal Station by 2014/15	Metropolitan 220 kV ring loading and fault levels will be affected by this change
Ringwood 22 kV	Install new 220/22 kV transformers at Ringwood in 2010/11, replacing existing assets	The 220/22 kV transformer’s requirements may impact the possible switching (as part of the Ringwood Terminal Station refurbishment project) of the Rowville-Templestowe 220 kV circuit at the Ringwood Terminal Station
Ringwood 66 kV	Development of an extra 150 MVA transformer at Ringwood (5th) or Templestowe (4th), new Ringwood 66 kV capacitor banks, or a new terminal station at either Coldstream or Doncaster in 2016	AEMO will review the requirements and feasibility of the new termination stations and associated electricity DSN supply requirements, including easements
South Morang 66 kV	Install a third 220/66 kV 225 MVA transformer at South Morang in 2019	AEMO will review the requirements to accommodate the new 220/66 kV transformer at South Morang
Terang 66 kV	Install an additional 220/66 kV transformer at Terang in 2019 – timing may be deferred subject to embedded generation at Terang	Fault levels likely to increase (e.g. 220 kV and 66 kV)
Tyabb 66 kV	Install a third 220/66 kV transformer at Tyabb in 2016/17	The Tyabb 220 kV switchyard needs to be reconfigured with additional 220 kV circuit breakers to accommodate a new Tyabb transformer
Wemen 66 kV	Establish a 220/66 kV terminal station at Wemen with a first transformer in 2010 and a second transformer in 2014	Wemen 220 kV connection on the existing Kerang-Red Cliffs 220 kV line, approximately 61 km from Red Cliffs Terminal Station No significant impact on the electricity DSN
West Melbourne 22 kV	Transfer load to the new Brunswick 66 kV connection point in 2015	Metropolitan 220 kV ring loading and fault levels will be affected by this change
West Melbourne 66 kV	Transfer load to the new Brunswick 66 kV connection point in 2012	Metropolitan 220 kV ring loading and fault levels will be affected by this change
Wodonga 66 kV	SPI Electricity is negotiating network support arrangements for 2013 with a new Wodonga power station proponent. Install a third 345/66 kV transformer at Wodonga in around 2017/18	The Wodonga 330 kV switchyard needs to be reconfigured with additional 330 kV circuit breakers to accommodate a new Wodonga transformer

9.5 SP AusNet asset replacement and refurbishment plan

This section outlines SP AusNet's transmission asset renewal process and provides a list of asset renewal projects planned for the next 10-year period.

The asset renewal plan is based on asset condition and performance information as well as other factors that affect the life of the assets, where the asset life is defined as that period of time that an asset continues to be of technical and economic use.

Plans for asset renewal also examine efficiencies for the entire planning period by integrating them with the augmentation plans. This approach optimises outage requirements and resource utilisation.

Asset renewal objectives

The objective of asset renewal is to achieve sustainable outcomes in the following areas:

- Health, safety and environment.
- Network performance and community impact due to network outages.
- Minimising asset life cycle costs through the consideration of capital, operational and maintenance costs.
- Physical security of assets.
- Compliance with codes, licences, contracts, industry standards and other obligations.

Asset renewal options

The following options are considered in the asset renewal evaluation:

- Replace upon Failure is only employed in circumstances where asset failure has an insignificant or no impact on network performance, health, safety and the environment, and where the asset has a short procurement and installation lead-time.
- Asset Renewal on Condition or Performance is employed to optimise the lifecycle cost of the asset with due consideration to health, safety and environmental factors as well as the community cost based on the performance of the asset. This strategy requires sufficient asset condition and performance monitoring to predict failure of the respective plant with sufficient lead-time to enable renewal prior to failure.
- Renewal by Asset Class is employed when a class of asset has either a higher than acceptable failure rate or exhibits a greater degree of deterioration than other types of assets. This approach avoids network performance deterioration due to multiple asset class-related failures.
- Renewal on a Bay-by-Bay (or Scheme/Network) Basis is employed when all primary plant and equipment within a specific bay or scheme of a station is being replaced. This strategy is often adopted for terminal station renewals.
- Replacement of Whole Station in Existing Location (Brownfield) is employed when all assets are replaced as part of a single, coordinated project within the existing station or location (normally when station assets are approaching the end of their life and there are advantages in station reconfiguration).
- Replacement of Whole Station in New Location (Greenfield) is employed for the construction of a replacement station on a new site. It is a more expensive strategy than works within an existing station (due to the need to procure new land, establish key infrastructure, and to relocate associated lines), and can usually only be justified on the basis of the existing infrastructure's

inadequacy or poor condition, or (possibly) when replacement works cannot occur without a sustained supply disruption due to the existing site's limitations.

SP AusNet 10-year asset renewal plan

The SP AusNet 10-year plan (in calendar years) covers major asset renewal projects where the cost is forecast to exceed $5 million. Projects already committed are not included in this plan. The description of the scope of work in the table below only covers the main plant items.

The project commitment and completion dates are indicative timings only, as the projects are yet to be approved. A higher degree of uncertainty is being placed on projects in the 6-10 year period. The cost estimates provided are also indicative at this stage and may vary significantly due to factors like outage requirements to implement the project.

The plan is subject to change based on the results of further analysis, asset failures necessitating a reprioritisation of projects, and regulatory revenue decisions.

Table 9-21 – SP AusNet 10-year asset renewal plan (cost estimates are in $2010)

Project Name	Location	Scope of Work Summary	Cost Estimate ($M)	Likely Commitment Date	Likely Completion Date
Years 1 to 5					
HWPS Switch Bay Replacement - Stage 2	HWPS	Replace 4 x 220 kV Switch Bays, Refurbish Bushings of selected CBs	10	2010	2012
DDTS 220kV Switch Bays	DDTS	Replace 5 x 220 kV Switch bays	10	2010	2012
KTS Transformer Replacement	KTS	Replace with 2 x 150 MVA 220/66 kV Transformers	13	2010	2012
ROTS 220kV Switch Bays	ROTS	Replace 7 x 220 kV Switch Bays	17	2010	2013
HOTS Switch Bays	HOTS	Replace 4 x 220 kV and 5 x 66 kV Switch bays	12	2010	2013
GNTS Switch Bays	GNTS	Replace 7 x 220 kV Switch Bays and 6 x 66 kV Switch Bays	17	2012	2014
RTS Rebuild	RTS	Replace with 3 x 225 MVA 220/66 kV Transformers, with 9 x 220 kV Switch Bays, new 66 and 22kV stations	98	2010	2015
WMTS Rebuild	WMTS	Replace 3 x 150MVA 220/66 kV Transformers, 7 x 220 kV Switch Bays, 16 x 66 kV Switch Bays and 22 kV Switch Bays	65	2011	2016
GTS Transformer Replacement	GTS	Replace 2 x 150 MVA 220/66kV Transformers	13	2012	2015
SMTS Transformer Replacement - Stage 1	SMTS	Replace 1 x 700 MVA 330/220 kV Transformer	15	2013	2015
BETS-KGTS Line Communications	BETS-KGTS Line	Replace PLC with OPGW	5	2014	2015
RWTS Replacement - Stage 2	RWTS	Replace 9 x 220 kV and 8x 66 kV Switch Bays	21.5	2014	2015
Years 6 to 10					

Project Name	Location	Scope of Work Summary	Cost Estimate ($M)	Likely Commitment Date	Likely Completion Date
DDTS Transformer Replacement	DDTS	Replace 1 x 340 MVA 330/220 kV Transformer	10	2014	2016
BETS Transformer Replacement	BETS	Replace 1 x 150 MVA 220/66 kV Transformers	6.5	2014	2016
TTS Transformer Replacement	TTS	Replace 1 x 150 MVA 220/66kV Transformers	7	2014	2016
GNTS Transformer Replacement	GNTS	Replace 1 x 150 MVA 220/66kV Transformer	9	2014	2016
KGTS-RCTS Line Communications	KGTS-RCTS Line	Replace with OPGW	10	2015	2016
HTS Rebuild	HTS	Replace 2 x 150 MVA 220/66 kV Transformers, 2 x 220 kV Switch Bays and 8 x 66 kV Switch Bays	25	2015	2017
SVTS Switch Bays	SVTS	Replace 15 x 66 kV and 4 x 220 kV Switch Bays	18	2015	2017
Waubra TS-HOTS Line Communications	Waubra TS-HOTS Line	Replace with OPGW	5	2016	2017
FBTS Synchronous Condenser	FBTS	Refurbish SCO or replace with SVC or other reactive plant retaining existing service levels	33	2016	2018
HWPS Switch Bays - Stage 3	HWPS	Replace 19 x 220 kV Switch Bays	38	2016	2018
RCTS Transformers and Switch Bays	RCTS	Replace with 2 x 35 MVA 220/66/22 kV Transformers and 3 x 22 kV Switch Bays	8	2016	2018
TSTS Synchronous Condenser	TSTS	Refurbish SCO or replace with SVC or other reactive plant retaining existing service levels	33	2016	2018
TSTS Transformer Replacement	TSTS	Replace 1 x 150 MVA 220/66 kV Transformer	6.5	2016	2018
MLTS 500kV Switch Bays	MLTS	Replace 8 x 500 kV CBs	16	2017	2018
SMTS Transformer Replacement - Stage 2	SMTS	Replace 1 x 700 MVA 330/220 kV Transformer	15	2017	2019
ERTS Switch Bays	ERTS	Replace 2 x 220 kV and 16 x 66 kV Switch bays	36	2017	2019

9.6 Gas - future developments

This section provides details about transmission system developments that are not necessarily linked to the regional gas DTS constraints identified in Section 9.3.

9.6.1 Compressor strategy

APA Group has completed upgrade of 2850 kW compressor packages at Gooding and Brooklyn to dry seals and installed a new dry seal 3500 kW compressor package at Brooklyn. Two dry seal 4500 kW compressor packages are being commissioned at Wollert in 2010 and further work is under review at Brooklyn (see Table 9-22). The upgrade work is subject to the APA Group Access Arrangement. Table 9-22 lists the proposed upgrades to specific compressors.

Table 9-22 – Compressor upgrades (proposed and committed)

Station	Compressor	Nature of upgrade	Expected completion
Brooklyn	BCS13 and BCS14	Two new 3,500 kW dry seal compressors to replace the 850 kW BCS6 and BCS8, and the 950 kW BCS7 and BCS9 compressors (proposed)	Under review
	BCS11	Relocation of existing BCS11 2,850 kW compressor (proposed). BCS10 to be removed	Under review
Wollert	WCS4 and WCS5	Two new 4,500 kW dry seal compressors to replace the 850 kW WCS1 and WCS3, and the 950 kW WCS2 compressors (proposed)	2010
	WCS6	A new 4,500 kW dry seal compressor to meet increasing demand (proposed) The proposed Wollert upgrades are linked to the Ballarat Zone constraint located at Shepparton/Echuca See Section 9.3.1 for more information	2015
Springhurst	SCS1	Reconfigure existing 4,500 kW dry seal compressor for northward compression (proposed)	2010
Euroa	ECS1	One new 4,500 kW dry seal compressor (proposed)	2011/2012

9.6.2 New connections

There have been a series of enquiries, including a number of potentially large loads in the Latrobe Valley, regarding new supplies to various locations within the gas DTS. As none of these enquiries are regarded as being firm, no detailed analysis has been undertaken.

9.7 Plant outages and system capacity

Table 9-23 lists the potential high-level impacts from specific gas plant outages involving entire facilities.

Table 9-23 – Gas plant outage impacts

Plant	Outage impact
Brooklyn CS	Constrains summer transport to Iona to less than 45 TJ/d. During winter, the compressor configuration, power and redundancy minimises supply risks to Geelong and Ballarat
Gooding CS	Limits Longford injections to approximately 760 TJ/d
LNG facility	Decreases the ability to maintain system linepack, potentially leading to curtailment
SCADA/Communication system	Requires the implementation of manual operation, reducing control effectiveness and impacting operational schedules
Springhurst CS	Decreases the import capacity at Culcairn from 50 TJ/d to 35 TJ/d if Young compressor station is not operating and from 92 TJ/d to 60 TJ/d if Young compressor station is not operating
Wollert CS	Decreases the capacity from Wollert to Culcairn, further limiting gas exports to New South Wales

Maintenance schedules

Annual maintenance schedules are generally the same from year-to-year. As a result, AEMO expects the maintenance schedule for 2009 to apply for the forecast period. See Section 9.8 for more information about scheduled maintenance and outages for 2010, including the impact of scheduled cyclical plant maintenance and outages on system capacity for 2010.

9.8 Planned maintenance (monthly planning review 2010)

Under the National Gas Rules (NGR), AEMO is responsible for coordinating transmission pipeline owner and storage provider maintenance planning, to ensure system security is not threatened due to the unavailability of pipeline equipment. As a result, maintenance and outages are planned to minimise gas transport disruptions, and to ensure 1 in 20 peak day system demand requirements. The same principles apply to other planned works, such as system augmentations and new connections (or both).

In terms of scheduled maintenance outages for 2010 (unless otherwise identified), AEMO reviewed:

- APA Group’s planned gas DTS equipment maintenance and LNG plant outages, and
- supply and UGS maintenance.

9.8.1 Maintenance and plant outages for 2010

Table 9-24 lists the gas DTS maintenance schedules, infrastructure, and plant outages for 2010. See also Section 9.6 for information about compressor upgrades (proposed and committed).

Table 9-24 – DTS maintenance schedules, infrastructure, and plant outages, 2010

Infrastructure	Description, role and required maintenance
Brooklyn Compressor Station	**Description:** One 850 kW compressor (Unit 8), one 950 kW compressor (Unit 9), two 2,850 kW compressors (Units 10 and 11), and one 3,500 kW compressor (Unit 12) **Primary Role:** Provides compression to the Brooklyn-Corio pipeline (and ultimately the South West Pipeline (SWP)) and the Brooklyn-Ballarat-Bendigo pipeline **Maintenance required:** With increased production of gas from the Otway fields, it is expected that Otway gas, rather than Longford gas, will be used to replenish the UGS. As a result, there will be less compression at Brooklyn to replenish the UGS. There will, however, be increased Brooklyn compression to supply the GPG at Laverton North Units 8 and 9 will be out of service for maintenance during January and February, respectively. Units 10 and 11 will be out of service during September and April, respectively. Unit 12 will be out of service for March. These outages are not expected to cause a transmission constraint. Ongoing consultation between AEMO and APA Group should enable maintenance to be carried out whilst minimising the risk to system security Brooklyn Unit 10 is a standby machine and will only be operated if Unit 11 or Unit 12 has failed
Gooding Compressor Station	**Description:** Four 2,850 kW compressors (Units 1, 2, 3 and 4). For normal winter operation, up to three compressors are operated simultaneously. One compressor is available as a standby in case of failure **Primary Role:** Provides compression to the Longford-Melbourne pipeline **Maintenance required:** Normal annual maintenance (making alternate compressors unavailable for up to four weeks at a time) from January-April. As the works are to occur when Gooding compression is unlikely to be required, this outage is not expected to cause a transmission constraint
Iona Compressor Station	**Description:** Two 298 kW reciprocating compressors (Units 1 and 2) **Primary Role:** Provides compression to the WTS from the SWP **Maintenance required:** Alternate units will be out of service for one week in November. During this period, a standby compressor failure will limit Iona withdrawals to approximately 25 TJ/d to maintain a pressure of approximately 4,500 kPa at Iona and ensure supply to the WTS
Springhurst Compressor Station	**Description:** One 4,550 kW compressor (Unit 1) **Primary Role:** Provides compression for imports via the New South Wales interconnect **Maintenance required:** This compressor will be out of service for general maintenance during May. This normally reduces interconnect import capacity from 50 TJ/d to 35 TJ/d, when the Young compressor is not operating. APA Group proposes to upgrade the station to allow compression northwards. See Chapter 3 for more information about anticipated import levels via the New South Wales interconnect for 2009
Wollert Compressor Station	**Description:** Two 850 kW compressors (Units 1 and 3) and one 950 kW compressor (Unit 2). Up to two units are operated in winter with one on standby, minimising the risk of transmission constraints. APA Group is installing two new 4500 kW compressor packages at Wollert to replace the wet seal Saturn compressors, and to increase export capacity to Culcairn **Primary Role:** Provides compression to the Wollert-Wodonga pipeline and assists supply to the New South Wales interconnect at Culcairn. Exports to New South Wales are generally not possible without Wollert compression **Maintenance required:** Alternate units will be out of service for four weeks each for annual maintenance from January-March. This is not expected to further restrict export capacity

In addition to compressor maintenance, general compressor station maintenance is also scheduled to take place at different times of the year. This maintenance:

- does not normally require extensive equipment outages
- has a rapid recall period (usually four hours), and
- does not represent a major risk to gas transport and system security.

Liquefied Natural Gas plant maintenance

Table 9-27 summarises LNG facility maintenance schedules for 2010. Taking plant redundancy into account, maintenance and works have been scheduled to minimise supply risks throughout the period.

The LNG facility has a maximum vaporisation capacity of 180 t/h, requiring three vaporisers, three pumps, and one boil-off compressor to be available. Failure of either a pump or a vaporiser can reduce capacity by 17% (to 44%). The LNG firm contracted rate is for 100 t/h for 16 hours, providing up to 87 TJ/d. This provides for plant redundancy in case of an outage of one pump and one vaporiser (see Chapter 5, Section 5.3.4 to 5.3.7, for more information about LNG storages).

The facility will undergo general maintenance in February and May. The recall period (usually four hours) minimises the risk to system security. Annual vaporiser maintenance requires each unit to be out of service for four weeks during low demand periods. During this period, the vaporisation capacity will be reduced to 56% (when Vaporiser C is unavailable), and 83% (when either Vaporiser A or B is unavailable).

Boil-off compressor maintenance does not affect vaporisation.

9.8.2 Supply and Underground Gas Storage maintenance

Table 9-25 lists supply and UGS infrastructure maintenance schedules. Table 9-26 and Table 9-27 list monthly planned maintenance for the compressor stations and LNG facility, respectively.

Table 9-25 – Supply and UGS infrastructure maintenance schedules for 2010

Infrastructure	Planned Maintenance
The Longford plant	Maintenance is scheduled to occur during the lower demand summer period. In addition, Esso and BHP Billiton will undertake maintenance activities required for the Kipper, Tuna and Turrum projects, including the installation of the newest platform in Bass Strait, Marlin B While final scheduling is not confirmed, some of these activities are currently planned for Winter and Spring 2010. AEMO and Exxon-Mobil work jointly to plan Longford plant maintenance
The UGS facility	The commissioning of a second Iona gas processing train is expected to occur in August 2010, but may be delayed due to high gas demand in August or a project delay. This will require a five day shutdown. No other capacity restrictions are expected
VicHub	Limited maintenance is planned
SEA Gas	Limited maintenance is planned
BassGas	Maintenance is scheduled for October 2010. This will require a five day shutdown

Infrastructure	Planned Maintenance
Pipeline Inspection	The following pipeline inspection (pigging) works are scheduled: Iona Paaratte 150 mm pipeline (2010) Paaratte-Allansford 150 mm pipeline (2010) Allansford-Portland 150 mm pipeline (2010) Metropolitan Ring main 450 mm pipeline (summer 2009/10) Wollert-Wodonga 300 mm pipeline (summer 2009/10) Keon Park-Wollert 600 mm pipeline (summer 2009/10) Brooklyn-Corio 350 mm pipeline (summer 2009/10) The exact timing of these works will depend on resource availability and suitable flow and pressure conditions. As pigging is carried out on a live pipeline, there is no effect on pipeline capacity. Pigging runs are not always successful, and may need to be rerun under different conditions to enable collection of reliable data.
Third party projects	Occasionally, bodies such as VicRoads or Melbourne Water request APA Group to make pipeline alterations. Under these circumstances, APA Group and AEMO work jointly to determine the appropriate timing of the work to ensure that peak demand can be met.

Table 9-26 – APA Group planned maintenance and outages, July 2010-June 2011 [1]

	Brooklyn Compressor Station	Gooding Compressor Station	Iona Compressor Station	Springhurst Compressor Station	Wollert Compressor Station
July					
August					
September	Unit 10				
October					
November			Units 1 & 2		
December					
January	Unit 9	Unit 1			
February	Unit 8	Unit 2			Unit 2
March	Unit 12	Unit 3			Unit 3
April	Unit 11	Unit 4			Unit 1
May				Unit 1	
June					

1. Only accounting for major maintenance and outages with a recall time longer than 24 hours

Table 9-27 – APA Group planned maintenance and outages – LNG facility, July 2010 - June 2011 [1]

	LNG facility unavailable	Vaporiser unavailable	Boil-off compressor unavailable	Pump unavailable
July				
August				
September				
October		Unit A		
November		Unit B		
December				
January				
February	Total facility		Unit B	
March				
April			Unit A	
May	Total facility			
June				

1. Only accounting for major maintenance and outages with a recall time longer than 24 hours

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E1 Comparison of Previous Forecasts and Actual Demand Data

E1.1 Historical information

Victorian electricity consumption

Annual electricity consumption in Victoria has grown by around 730 GWh per annum over the 10 years from 1999/00-2008/09. Table E 1-1 shows the historical Victorian electricity energy consumption from 1997/98-2008/09. Data prior to 1 July 1999 was obtained from SP AusNet's Historical Information System (HIS). Data from 1 July 1999 is based on the operational data published by NEMMCO (now AEMO). The non-scheduled energy shown includes energy supplied by Victorian wind generation data, sourced from electricity distribution businesses, and by generation from the small hydro plants at Clover and Rubicon.

Table E 1-1 – Historical annual electricity consumption

Financial year	Scheduled energy (GWh)	Non-scheduled energy (GWh)	Native energy (GWh)
1997/98	43,275	62	43,337
1998/99	44,861	62	44,923
1999/00	45,991	115	46,106
2000/01	47,035	115	47,150
2001/02	46,892	136	47,028
2002/03	48,474	211	48,685
2003/04	49,434	362	49,795
2004/05	49,822	357	50,180
2005/06	50,791	355	51,146
2006/07	51,561	417	51,978
2007/08	52,379	399	52,778
2008/09	51,590	620	52,209

Historical Victorian maximum demand

Victorian summer maximum demand (MD) has increased by approximately 243 MW per annum over the 10 years from 1999/00-2008/09 and winter MD has increased by around 148 MW per annum over the same period.

Table E 1-2 shows the summer MD and the non-scheduled generation at the time of the MD from 1997/98.

Table E 1-2 – Historical summer maximum demand

Financial year	Summer scheduled MD (MW)	Non-scheduled generation (MW)	Summer native MD (MW)
1997/98	7,213	22	7,235
1998/99	7,584	22	7,606
1999/00	7,832	40	7,872
2000/01	8,088	40	8,128
2001/02	7,618	43	7,661
2002/03	8,202	46	8,248
2003/04	8,572	61	8,633
2004/05	8,512	54	8,566
2005/06	8,730	58	8,788
2006/07	9,062	72	9,134
2007/08	9,818	60	9,878
2008/09	10,566	57	10,623
2009/10	9,918	225	10,143

Table E 1-3 shows the winter MD and the non-scheduled generation at the time of the MD from 1997.

Table E 1-3 – Historical winter maximum demand

Calendar year	Winter scheduled MD (MW)	Non-scheduled generation (MW)	Winter native MD (MW)
1997	6,404	12	6,416
1998	6,662	12	6,674
1999	6,672	23	6,695
2000	7,086	23	7,109
2001	7,118	23	7,141
2002	7,312	39	7,351
2003	7,488	45	7,533
2004	7,436	90	7,526
2005	7,764	46	7,810
2006	7,863	36	7,899
2007	8,351	84	8,435
2008	8,037	56	8,093
2009	8,108	70	8,178

Table E 1-4 lists the summer days with the highest average temperatures from 1999/00-2009/10 and their corresponding MD for the day. Most of these days fell on weekends or public holidays when demand was lower than on normal business weekdays.

Table E 1-4 – Historical hottest day average temperature by year

Financial year	Date	Daily native MD (MW)	Average temperature (℃)	Comments
1999/00	Thu 3-Feb-00	7,618	33.4	Load shedding
2000/01	Thu 11-Jan-01	7,434	32	Christmas-New Year holiday, reduced load
2001/02	Fri 15-Feb-02	7,617	29.3	Friday, reduced load
2002/03	Sat 25-Jan-03	7,460	35.5	Saturday, reduced load
2003/04	Tue 30-Dec-03	7,381	32	Christmas-New Year holiday, reduced load
2004/05	Wed 26-Jan-05	7,432	30.1	Australia Day, reduced load
2005/06	Sun 22-Jan-06	8,075	34.6	Sunday, reduced load
2006/07	Sun 10 Dec 06	7,580	31.7	Sunday, reduced load
2007/08	Sun 1 Jan 08	7,475	34.6	Christmas-New Year holiday, reduced load
2008/09	Fri 30 Jan 09	10,400	35.4	No significant effect
2009/10	Mon 11 Jan 10	10,278	31.1	Holiday period, reduced load

Daily and annual load profiles

Figure E 1-1 shows the daily load profiles for the Victorian region for the 2009 winter MD and the 2009/10 summer MD.

Figure E 1-1 – Summer and winter MD, 2009/10

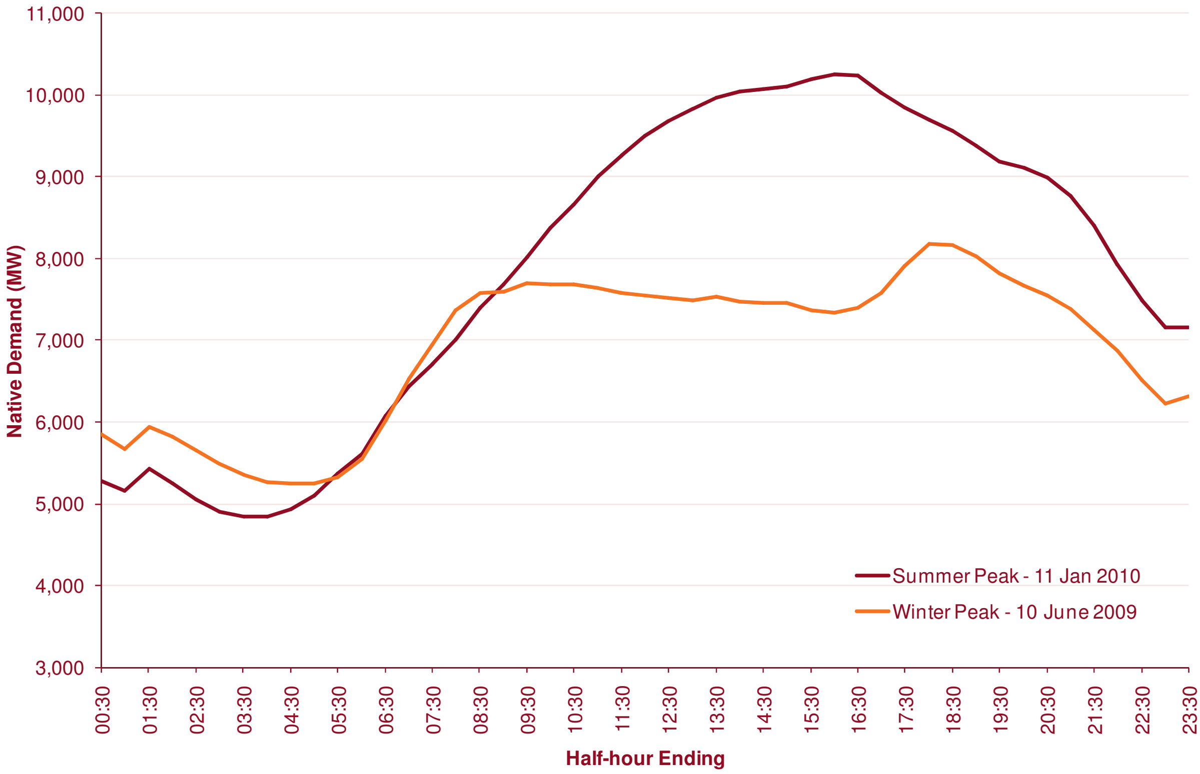
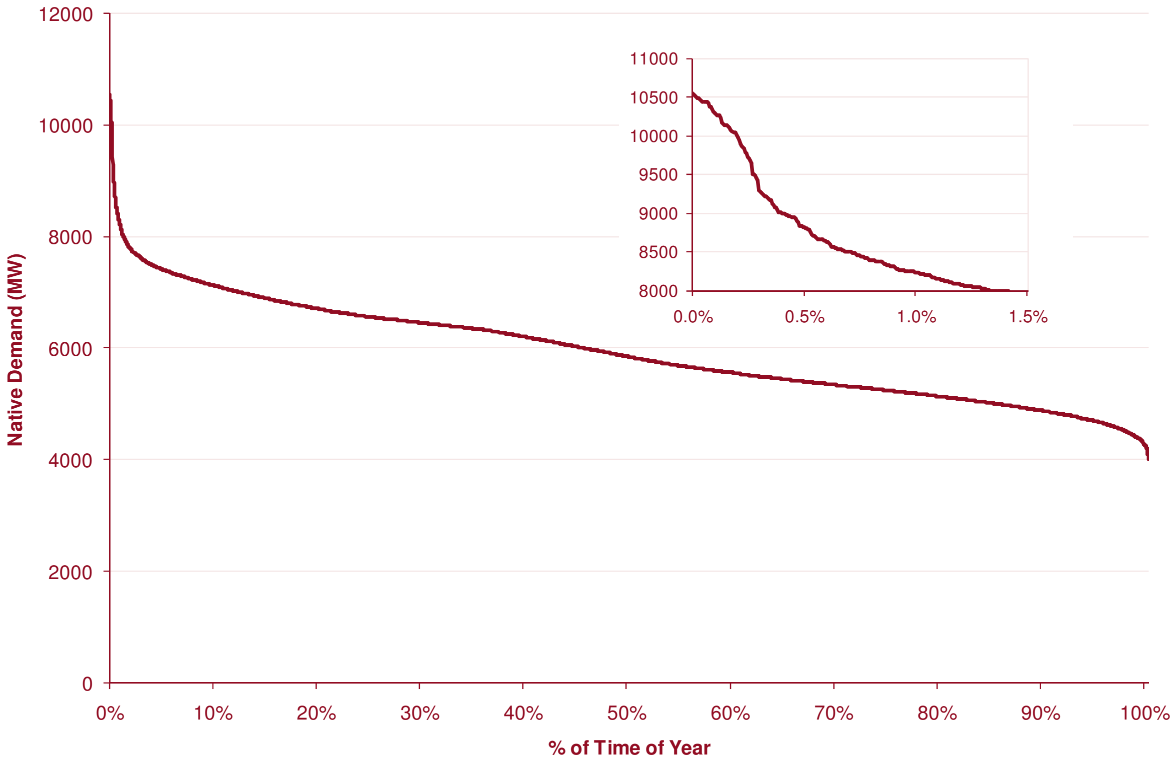


Figure E 1-2 shows the annual load duration curve characteristic for Victorian native demand over the 2008/09 financial year.

Figure E 1-2 – Load duration curve, 2008/09



Comparison of the 2010 VAPR forecasts with historical demand

Table E 1-5 compares the historical and forecast annual average growth rates for energy consumption and summer and winter MD in Victoria. The historical growth rates for summer and winter MD, adjusted to 10% probability of exceedence (POE) conditions, are shown for comparison. The historical average annual growth rates of Australian gross domestic product (GDP), Victorian gross state product (GSP) and Victorian population, and the projections used in the 2009 and 2010 VAPR are also shown.

Table E 1-5 – Summary of annual average growth rates

Outlook period	Australian GDP	Victorian GSP	Victorian populatio n	Annual energy	Summer 10% POE MD	Winter 10% POE MD
Historical growth rates – actual (adjusted summer and winter 10% POE)						
2000/01 to 2009/10	2.9%	2.8%	1.4%	1.4%	2.8%	2.1%
2010 VAPR growth rates – medium energy scenario and summer and winter 10% POE forecasts						
2010/11 to 2014/15	3.4%	2.5%	1.4%	0.8%	2.6%	1.3%
2014/15 to 2018/19	2.5%	2.5%	1.3%	0.9%	2.1%	1.4%
2009 VAPR growth rates – medium energy scenario and summer and winter 10% POE forecasts						
2010/11 to 2014/15	2.8%	2.0%	1.3%	0.8%	2.2%	0.7%
2014/15 to 2018/19	3.5%	3.1%	1.2%	1.2%	1.8%	1.4%

First five-year period

The Victorian population has grown an average of 1.7% over the past three years, and this growth is expected to continue at a similar rate for the near future. The projected growth rate in GSP is slightly lower relative to historical rates of growth. This reduced rate of GSP growth and the announced smelter reduction cause the decrease in the growth of energy use over the first five years of the outlook period compared to the historical rates of growth.

The projected summer 10% POE MD growth rate is reduced relative to the historical growth rate. Summer MD can be considered in two portions: a non-temperature sensitive portion (or base load), mainly arising from industrial and commercial demand, and a temperature sensitive portion, mainly arising from air-conditioning use. Base load summer demand and annual energy use have the same drivers, so demand is expected to grow at a slower rate than historically, in line with projected GSP growth.

The temperature sensitive portion of the summer MD is assumed to continue to grow, but at a slower rate than over the last five years. This reflects the assumption that during extreme temperature events consumers will continue to use their existing air-conditioners at the same rate as they did in the past, but that new air-conditioner sales will slow.

Winter 10% POE MD growth over the first five years of the outlook period is projected to be lower than it was in the past decade. This reduction is again caused by the smelter reductions, which have a larger impact on the winter peak demand than on the summer peak demand.

Second five-year period

Over the latter part of the forecast period, from 2014/15-2018/19, the economic indicator growth rates are projected to be lower than they were over the last decade. The lower energy and demand growth rates (versus historical growth rates) forecast for this later period result from the increasing number of policies designed to reduce energy use in Victoria, and the introduction of a price on carbon emissions from 2013/14.

Comparison of actual energy and maximum demand with 2009 VAPR forecasts

Table E 1-6 lists the 2009/10 native summer MD, which was 10,118 MW, and occurred at 4:00 pm on Monday, 11 January 2010. AEMO's forecasts are produced on a native basis, and assume no demand-side participation (DSP) and no load shedding, enabling calculation of an estimated native demand corrected for DSP.

Table E 1-6 – 2009/10 summer maximum demand

Date and time	Scheduled demand (MW)	Non-scheduled generation (MW)	Native maximum demand (MW)	DSP (MW)
11/01/2010 16:00	9,892	225	10,118	135

The 2009 VAPR forecast medium 10% POE MD was 10,346 MW. This was:

- higher than the estimated 2009/10 summer native MD of 10,253 MW, and
- lower than the backcast of 10,425 MW (reflecting the higher than previously forecast economic recovery).

The 2009 native winter MD of 8,178 MW occurred on 10 June 2009. This was lower than the backcast winter 10% POE MD of 8,327 MW.

Estimated annual electricity consumption over 2009/10, using actual data up to the end of April 2010, is projected to be 51,870 GWh. This is slightly lower than the high economic growth scenario forecast in the 2009 VAPR as shown in Table E 1-7, due to an earlier than previously forecast economic recovery.

Table E 1-7 – 2009/10 electricity annual energy versus 2009 VAPR forecasts

	Actual	2009 VAPR high growth scenario	2009 VAPR medium growth scenario	2009 VAPR low growth scenario
2009/10 Energy (GWh)	51,870	52,068	51,291	50,047
Difference		-198 GWh (-0.4%)	579 GWh (1.1%)	1,823 GWh (3.5%)

Forecast model assessment

AEMO's summer and winter MD forecasts are prepared using a simulation model, which produces forecast probability distributions for the range of possible MD outputs. These forecast probability distributions reflect variability in demand due to the timing and severity of weather effects and randomness in consumer behaviour. As this methodology explicitly forecasts demand distributions, rather than point forecasts of peak demand, it is not valid to associate a particular POE demand to a POE temperature, as a range of drivers can cause a particular demand level. For this reason AEMO no longer publishes reference temperatures.

To assess the accuracy of the demand forecasts, the simulation model is used to produce demand distributions for past years using actual historical economic outcomes. Accuracy statistics can then be derived from these backcast, or ex-post, demand distributions and the actual demand outcomes.

Table E 1-8 lists the accuracy statistics assessment of the 2009 and 2010 summer MD model. The accuracy statistics were calculated using the actual observed MD and the expected MD, approximated by the ex-post forecast 50% POE demand estimates over the period 1996/97-2009/10.

Accuracy metrics rely on the assumption of a sufficient sample size. In a small sample like this one (11 peaks), statistics can be misleading, and it is recommended that caution be exercised when interpreting these statistics and making conclusions about the relative accuracy of the model.

Table E 1-8 - Accuracy statistics of the summer maximum demand models

Measure	VAPR 2010	VAPR 2009	Difference
Root Mean Square Error (RMSE)	318 (MW)	314 (MW)	4 (MW)
Mean Absolute Error (MAE)	223 (MW)	189 (MW)	34 (MW)
Mean Absolute Percentage Error (MAPE)	2.5%	2.2%	0.3%
Theil Inequality Coefficient	0.02	0.02	0
Bias Proportion	0.01	0.03	-0.02
Variance Proportion	0.122	0.135	-0.013
Covariance Proportion	0.864	0.839	0.025

The Root Mean Square Error is a commonly used measure of the difference between expected and observed values. The estimate here suggests that the average difference between observed MD and implied 50% POE MD is approximately 318 MW.

The Mean Absolute Error measures the difference in expected and observed values.

The Mean Absolute Percentage Error measures the difference in expected and observed values as a proportion of the observed value.

The Theil Inequality Coefficient provides a measure of how well a time series of estimated values compares to a corresponding time series of observed values. The closer the coefficient is to zero, the better the forecast method.

The Bias Proportion measures how far the mean of the expected values is from the mean of the observed values.

The Variance Proportion measures how far the variance of the expected values is from the variance of the observed values.

The Covariance Proportion measures the remaining unsystematic difference.

Expected values are considered good when the bias and variation proportion are small.

In addition to these statistics, excess percentage metrics were calculated using the entire implied POE distribution of MD over the period 1996/97-2009/10. Over a 10-year period, (on average) one MD is expected to exceed a 10% POE level. Extending this logic further, (on average) two MDs are expected to exceed a 20% POE level over a 10-year period. This logic applies across the whole probability distribution.

Figure E 1-3 shows the number of MD events expected over a 13-year period for each POE level. It also shows the number of MD events observed over the 13-year period for each POE level. The MD events broadly track the expected number of MDs for most of the probability spectrum.

Figure E 1-3 – Number of maximum demand events in the period 1996/97-2009/10

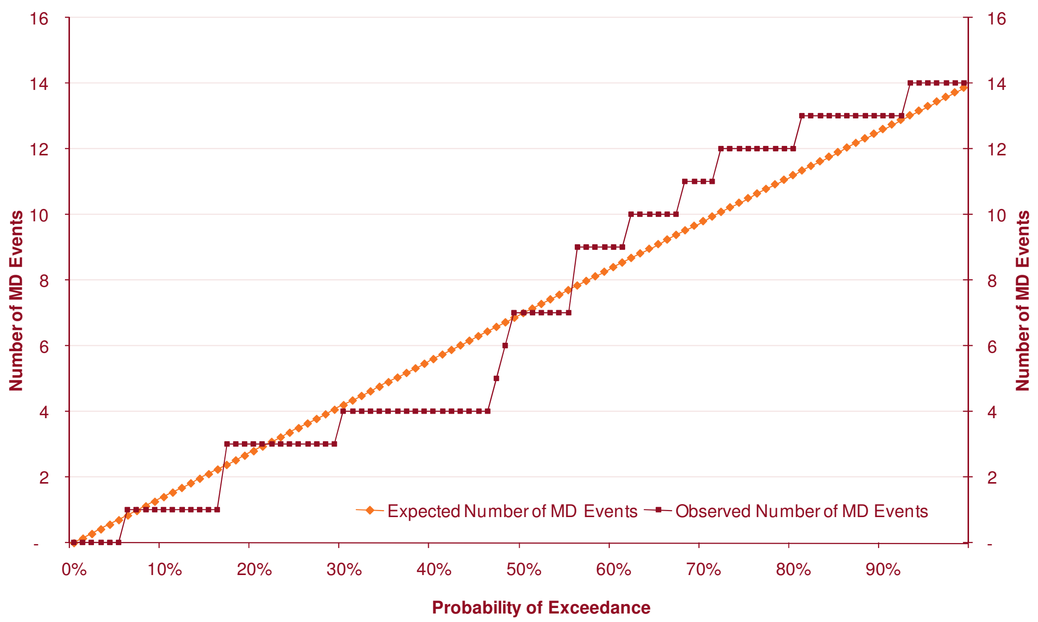
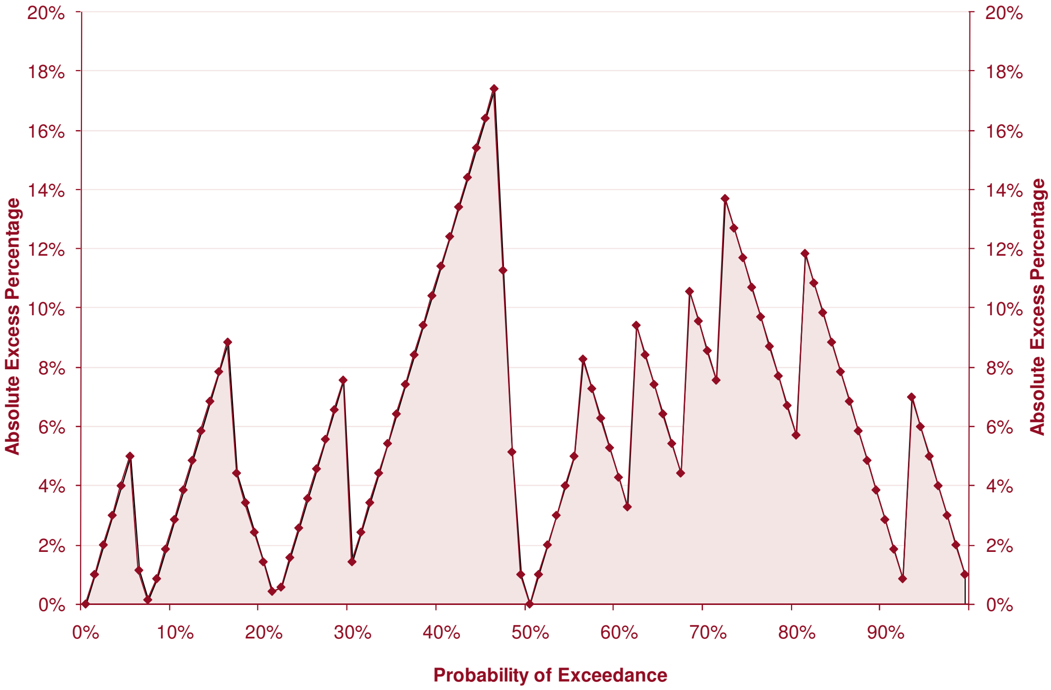


Figure E 1- 4 is an alternative way of visualizing this information. It shows the deviation between the observed and expected number of MD events as a proportion of the expected number of events.

Figure E 1- 4 – Excess percentage in the period 1996/97-2009/10



E2 Victorian Economic Forecasts

This appendix presents the Victorian economic outlook for the next 10 years. AEMO engaged KPMG Econtech to prepare the economic projections for a medium (or most probable), high (or optimistic) and low (or pessimistic) economic growth scenario. These projections were prepared in March 2010.

E2.1 Economic forecasts

Table E2-1 lists:

- actual Victorian Gross State Product (GSP) growth for the period from 2006/07-2008/09
- estimated GSP growth for 2009/10, and
- KPMG Econtech's projected Victorian GSP growth for the next 10 years for the medium, high and low economic growth scenarios.

Victorian GSP growth was 2.0% in 2008/09 and is forecast to be 1.6% in 2009/10.

Table E2-1 – Victorian GSP projections, KMPG Econtech

Year	Medium	High	Low
2006/07	2.7%	2.7%	2.7%
2007/08	2.9%	2.9%	2.9%
2008/09	2.0%	2.0%	2.0%
2009/10	1.6%	2.6%	2.1%
2010/11	2.5%	3.0%	2.0%
2011/12	2.5%	2.1%	1.7%
2012/13	1.7%	3.2%	2.4%
2013/14	2.6%	4.2%	2.7%
2014/15	3.3%	4.0%	2.1%
2015/16	3.1%	3.2%	1.3%
2016/17	2.4%	2.5%	0.8%
2017/18	1.8%	2.6%	2.1%

Table E2-2 lists KPMG Econtech's projections of population growth for the medium, high and low economic growth scenarios.

Table E2-2 – Victorian population projections, KMPG Econtech

Year	Medium	High	Low
2006/07	1.8%	1.8%	1.8%
2007/08	1.6%	1.6%	1.6%
2008/09	1.7%	1.7%	1.7%
2009/10	1.5%	1.6%	1.3%
2010/11	1.4%	1.6%	1.1%
2011/12	1.3%	1.5%	1.0%

Year	Medium	High	Low
2012/13	1.3%	1.6%	1.0%
2013/14	1.4%	1.6%	1.0%
2014/15	1.4%	1.7%	1.0%
2015/16	1.4%	1.6%	1.0%
2016/17	1.3%	1.6%	0.9%
2017/18	1.3%	1.6%	0.9%

Victorian GSP growth over recent years has been underpinned by strong population growth, solid growth in private consumption expenditure, and high levels of private business investment and construction expenditures. Under the medium economic growth scenario for 2010/11, Australian GDP is forecast to be 2.7%, and Victorian GSP is forecast to be 2.5%.

E3 Major Government Energy Policies and Initiatives

This appendix provides a list of current and recent major government energy policies, and identifies the extent to which the electricity forecasts reflect those policies and any related assumptions that have been made. Government policies that were announced but are not yet implemented have been identified and any related assumptions clearly outlined.

E3.1 Carbon Pollution Reduction Scheme

On 15 December 2008, the Australian Government released its White Paper on the Carbon Pollution Reduction Scheme (CPRS). The White Paper followed the Green Paper, which was released in July 2008 and canvassed options for the scheme's design.

The CPRS is a 'cap and trade' scheme, which caps the total amount of annual greenhouse gas emissions through the issue of permits.

Under the scheme, significant emitters of greenhouse gases must acquire a permit for every tonne of gas emitted in a particular year. Entities obliged to acquire permits will be able to trade them, placing a price on emissions.

In short, the key points from the White Paper were as follows:

- The Australian Government has committed to a medium-term target range to reduce Australia's greenhouse gas emissions by between 5% and 15% below 2000 levels by 2020, and a long-term goal of reducing emissions to 60% below 2000 levels by 2050.
- The price of permits will be capped at $40/t carbon dioxide equivalent (CO2-e) emissions, with the cap imposed for the first five years of the scheme, rising in real terms by 5% each year beyond 2015.
- Coverage of the scheme is around 75% of Australia's emissions, involving mandatory obligations for around 1,000 entities.
- Revenue generated from the auction of permits will be used to assist households and businesses to adjust to the economic impact of the CPRS.
- Around 25% of total permits will be issued free to 'emissions-intensive trade-exposed industries' (EITEs) at the scheme's commencement, increasing to around 45% by 2020.
- The coal industry is classified as a 'strongly affected industry' and will receive compensation under the Electricity Sector Adjustment Scheme (ESAS).
- A scheme regulator will be established and given a high level of operational independence to implement the emissions trading legislation and apply it to individual cases.

On 4 May 2009, the Prime Minister announced amendments to the CPRS including:

- a delay in the start date, from mid-2010 to mid-2011
- fixed price permits (at $10 per tonne CO2-e emissions) for the first year of the scheme
- a commitment to a more ambitious target of 25% of 2000 levels by 2020 if a global agreement on emissions reductions is reached
- an increase in assistance to EITEs, and

- recognition of various voluntary emission reduction activities.

In November 2009, a number of further amendments to the CPRS were announced, including:

- permanently including assistance to EITE, and
- a total of $1.5 billion in transitional assistance to the coal sector over five years.

After several unsuccessful attempts, the legislation has now been shelved until after the 2013 election due to uncertainty relating to the major emitters, China, the United States and India. As a result, the 2010 forecast assumes that the CPRS is introduced in mid-2013 with a permit price of $10 per tonne CO2-e emissions.

Table E 3-3 lists the assumed permit prices.

Table E 3-3 – Carbon permit prices ($/tonne CO2-e)

Year	Assumed trajectory
2011/12	0.0
2012/13	0.0
2013/14	10.0
2014/15	34.3
2015/16	35.7
2016/17	37.1
2017/18	38.6
2018/19	40.1
2019/20	41.7

In the first year of the scheme, the permit prices were set to the fixed permit price of $10/tonne CO2-e. From 2014/15, the permit prices grow by 4% per annum.

Renewable Energy Target

The Australian Government is committed to expanding its Mandatory Renewable Energy Target (MRET) scheme, which includes a legislated target of 9,500 GWh of electricity from renewable sources in 2010, to create a national Renewable Energy Target (RET) scheme, which includes a target of 45,000 GWh by 2020. The aim of the expanded scheme is to have the equivalent of at least 20% of Australia's electricity supply generated from renewable sources by 2020.

Draft amendment regulations for the national RET scheme were released for comment in December 2008, with the following design elements:

- A dual linear ramp-up of annual targets from 2010 rising to 45,000 GWh in 2020.
- Targets maintained at 45,000 GWh from 2020-2024.
- Targets ramped down from 45,000 GWh in 2025 to 23,000 GWh in 2030 when the scheme terminates.
- All existing projects eligible under the current MRET scheme to be eligible under the national RET scheme.
- The same eligibility criteria to apply under the national RET scheme as under the current MRET including:
  - solar water heaters with a 10-year deeming period through to the end of the scheme, and
  - native forest wood waste eligible subject to current MRET restrictions.

- Unlimited banking allowed.
- Projects able to create Renewable Energy Certificates (RECs) from date of accreditation until scheme termination.
- The fixed (un-indexed) shortfall REC penalty price to be set at a level marginally above the projected peak REC price.
- A multiplier is to be applied for RECs created by micro-generation units including photovoltaic (PV) systems, small wind turbine systems, and micro-hydro systems, such that:
  - from 2009/10 every 1 MWh of deemed generation from micro-generation units will earn five RECs
  - the multiplier of five RECs for every 1 MWh of deemed generation will remain until 2011/12, after which it ramps down to zero in 2015/16, and
  - the multiplier applies only to the first 1.5 kW of a micro-generation system's capacity.

In April 2009, the Council of Australian Governments (COAG) announced an agreement on the design of the national RET scheme to achieve a 20% share of renewables, or 45,000 GWh, in Australia's electricity mix by 2020. Changes from the original COAG agreement draft included the:

- annual target of 45,000 GWh, which will now be extended from 2020 until 2030 when the scheme ends, and
- REC penalty price, which will be increased from the current MRET penalty price of $40/MWh to $65/MWh.

The national RET scheme legislation passed on 20 August 2009.

Assumptions used

KPMG Econtech developed forecasts of semi-scheduled, non-scheduled, and exempt generation required to met the national RET scheme in April 2010.

In developing the electricity annual energy and maximum demand (MD) forecasts, NIEIR considered the impact the national RET scheme will potentially have on retail electricity prices as well as solar hot water heater installations and micro-generation system installations and usage. Installation of solar hot water heaters and micro-generation systems reduces native demand by displacing demand required to be supplied by the transmission system, and in the case of micro-generation systems, may also contribute generation to the grid.

In the medium growth scenario, it is assumed the energy impacts from micro-generation systems derive from a native energy reduction of around 6 GWh in 2010/11, rising to 29 GWh by 2019/20. The majority of micro-generation is assumed to be in the form of photovoltaic systems. Their impact is assumed to rise during the summer MD from 4.5 MW in 2009/10 to 21 MW in 2019/20, and to be negligible during winter MDs.

The impact of the national RET scheme on solar hot water heater installation was considered along with other initiatives designed to decrease electricity use in water heating (see Section E3.6 for more information).

E3.2 Minimum energy performance standards

Lighting

In November 2009, a Minimum Energy Performance Standard (MEPS) for lighting was introduced, requiring most incandescent light bulbs and some low voltage halogen bulbs to be removed from sale. The MEPS is initially set at a minimum of 15 lumens/watt. Incandescent bulbs have an efficiency of approximately 7 lumens/watt. The more efficient bulbs that meet the MEPS, including compact fluorescent lamps (CFLs), already have a substantial market share, and some major grocery chains have (apart from decorative types) already stopped selling incandescent lamps.

For the medium growth scenario, it was assumed that the additional reduction in annual electricity consumption due to the MEPs for lighting will be around 142 GWh per annum for the first three years of the scheme, decreasing to around 28 GWh for the following five years.

The winter MD in Victoria generally occurs between 6 and 7 pm, and is associated with increased lighting load from the residential sector. The forecasts assume that the winter MD will decrease by approximately 30 MW in 2010, but by only 5 MW by 2016.

The impact of the MEPs for lighting on summer peaks is assumed to be negligible, as the summer MD commonly occurs between 3 and 4 pm, when lighting is not as significant.

Air conditioners

The MEPS for air conditioning is to be increased from 2010. A recent NIEIR survey, however, found that many of the available air conditioning units in the most common residential unit size already meet or exceed the proposed 2010 target. In addition, the way that manufacturers meet MEPS tends to mean that overall efficiency improvements, in MWhs, translate into lower peak performance improvements. NIEIR's projections of the impact of air conditioner MEPS take these two factors into account, as well as the increased market penetration of air-conditioning units and behavioural changes towards their use.

In the medium growth scenario, the impact on annual electricity consumption is expected to be minor, starting at 5 GWh per annum in 2010/11, increasing to 56 GWh in 2019/20. The impact on the summer MD is assumed to start at 7 MW in 2010/11, increasing to 75 MW in 2019/20.

Standby power

A target of one watt is planned for all appliance and equipment standby power usage by 2012. Under the medium growth scenario, NIEIR estimated the reduction in annual electricity consumption will start at around 51 GWh in 2011/12, increasing to 212 GWh in 2019/20. The impact on summer and winter MD was assumed to be in the order of 6 MW starting from 2012.

E3.3 Federal insulation program

As part of the Australian Government's Energy Efficient Homes Package, Australian homeowners and renters received financial assistance to install ceiling insulation in uninsulated homes or homes with ceiling insulation of negligible effectiveness. The program originally supported installation of ceiling insulation up to the value of:

- $1,600 through the Homeowner Insulation Program, or
- $1,000 through the Low Emission Assistance Plan for Renters.

Following advice received from Dr. Allan Hawke in the Review of the Administration of the Home Insulation Program, the Government decided not to proceed with the insulation component of the Renewable Energy Bonus Scheme (REBS), which is assumed to have no impact on future energy consumption reduction.

E3.4 Advanced Metering Infrastructure

The Advanced Metering Infrastructure (AMI) policy intends to deliver interval or smart meters to all Victorian households. The Victorian Government approved the roll-out of smart meters in early 2006 to consumers with an annual energy consumption of less than 160 MWh. The smart meters replace residential and small-to-medium business customer meters that only record total consumption and are subject to quarterly manual readings.

The roll-out started in 2009, with approximately 2.5 million smart meters to be installed throughout Victoria over four years. Smart meters are intended to provide Victorian consumers with information enabling them to better manage their electricity consumption.

Assumptions

AMI is likely to deliver energy reduction and reduced peak loads across Victoria. Time-of-use tariffs, incorporating some form of peak power pricing and direct load control (DLC), are also assumed to affect the peak demand forecasts. The assumed effects are conservative, partly because some customers will have opted not to switch tariffs or implement DLC.

NIEIR based their estimates of the impact of AMI on trials in other regions. Trialled consumer responses were mixed, with reductions in residential load varying from 4% to 10%. For the medium growth scenario, NIEIR assumed a reduction of 6% of residential load, starting at 165 GWh in 2012/13, increasing to 396 GWh in 2015/16.

Reductions in peak load are more difficult to make, as this largely depends on customer willingness to shift to peak pricing tariffs and responsiveness to pricing events. The summer peak response, estimated by NIEIR for the medium energy scenario, starts at 27 MW in 2011/12, increasing to 57 MW in 2014/15. The medium energy scenario winter peak response is slightly more pronounced, starting at 41 MW in 2012, increasing to 101 MW in 2015.

E3.5 Victorian Energy Efficiency Target or Energy Saver Incentive

The Victorian Energy Efficiency Target (VEET) scheme, which commenced on 1 January 2009, sets energy savings targets. Starting with the residential sector, the VEET scheme requires energy retailers to meet their own targets through energy efficiency activities, such as providing households with energy saving products and services, at little or no cost.

The VEET scheme plays an important role in achieving the Victorian Government's target of reducing household greenhouse gas emissions by 10% of 2000 levels by 2010, and Victoria's overall emissions to 60% of 2000 levels by 2050.

The scheme operates by making large Victorian electricity and gas retailers (known as relevant entities) legally liable for contributing to energy efficiency measures by acquiring and surrendering Victorian energy efficiency certificates (VEECs). A penalty will be imposed on entities that fail to surrender sufficient VEECs to meet their liability.

Under the VEET scheme, accredited persons are eligible to create VEECs for prescribed activities undertaken at residential premises. Each VEEC created represents one tonne of carbon dioxide equivalent (CO2-e) emissions reduced by a prescribed activity.

The Victorian Energy Efficiency Target Act 2007 (VEET Act) provides for the VEET scheme to operate in three-year phases, with new scheme targets and prescribed activities set for each phase. The first phase of the VEET scheme will operate from 1 January 2009 to 31 December 2011.

Assumptions

When estimating the VEET scheme's impact on annual and peak Victorian electricity consumption, NIEIR assessed the additional impacts from the VEET scheme as opposed to business as usual (BAU), such as the penetration of low-flow shower heads and CFLs. Some VEET scheme activities are accounted for by other measures, including MEPS for lighting and air-conditioning, various hot water initiatives, and the Australian Government's insulation program. The VEET scheme impact determined by NIEIR includes only those activities not likely to be affected by other measures.

For the medium growth scenario, NIEIR forecast a reduction in annual energy consumption due to the VEET scheme activities starting at 18 GWh in 2010/11, increasing to 99 GWh by 2014/15. The impact on summer and winter peak demand is forecast to be negligible.

E3.6 Hot water initiatives

The range of initiatives affecting electric water heating over the forecast period includes:

- an Australian Government rebate to replace electric storage hot water systems with solar or heat pump hot water systems, available from February 2009 until June 2013
- Victorian rebates for the installation of solar hot water or heat pumps, and for replacing peak electric water heaters with high efficiency gas water heaters
- replacement of electric resistance water heaters with gas or solar water heaters, which is an eligible VEET scheme activity
- solar hot water and heat pump installations, which are eligible for RECs under the national RET scheme
- the Victorian 5-star building standard, which requires the installation of a solar water heater or plumbed water tank in new residences
- hot water management, particularly regulations and incentives for installation of low-flow shower heads
- a national program to substantially phase out electric resistance water heating by restricting assess to these heaters in new homes and as existing water heater replacements (except when exempt), and
- CPRS impacts on electricity and gas prices.

NIEIR forecast that by 2020 most electric resistance hot water units will be replaced in Victoria, except in some apartments where replacement will not be feasible. Commercial and industrial heat pump penetration will reduce hot water heating loads in sectors. Hot water energy use will also be reduced by improved hot water management in shower heads, dishwashers and washing machines.

For the medium growth scenario, NIEIR estimates that the reduction in annual energy use from these initiatives will be around 57 GWh per year from 2010/11, reaching 578 GWh by 2019/20. The impact on the summer and winter MD is estimated to be negligible.

E3.7 Other initiatives

Feed-in tariffs

Feed-in tariffs (FITs) provide a guaranteed price for electricity produced by small generation systems that export electricity to the grid. A gross FIT provides a guaranteed price for all electricity generated, and a net FIT provides a guaranteed price for electricity exported to the grid.

A premium net FIT of $600/MWh was introduced in Victoria on 1 November 2009 for solar PV systems up to 3.2 kW. The standard retail net FIT applies to other renewable power systems, such as wind, hydro, and biomass used by households and businesses with capacities up to 100 kW.

NIEIR included the impact of FITs in their analysis of micro-generation systems under the national RET scheme (see Section E3.1).

Residential building standards - 5-star and proposed 6-star

The current 5-star standard in Victoria covers the building shell and the requirement to install either a solar hot water system or a rain water tank. The 5-star standard was introduced in 2004/05. Through a COAG process in April 2009, the Australian, State and Territory Governments have agreed to move towards a 6-star residential standard by 2012. NIEIR only included a small impact for the proposed 6-star building standard in its forecasts.

E3.8 Policy summary

The various policies and initiatives will reduce annual electricity energy and MD. The CPRS and the national RET scheme will impact usage by changing electricity prices. The national RET scheme and the other measures discussed also impact electricity usage by:

- changing the stock of appliances (due to the MEPS, VEET, hot water initiatives, and the phasing out of incandescent lightbulbs)
- reducing the need for energy (due to new building standards)
- introducing time-of-day pricing that consumers can see and respond to (due to AMI or smart meters), and
- displacing electricity delivered by the transmission network (due to feed-in-tariffs, national RET scheme incentives for solar water heaters and PVs).

NIEIR estimated the impacts of these measures in terms of annual electricity energy and MD, keeping in mind that several of the measures are not mutually exclusive. Impact estimates are problematic, given that some are new measures without historical precedent, and others have had a large range of impacts. As a result, AEMO has accounted for the uncertainties in these estimates by using the lower and upper ends of the range of impacts for the high and low economic growth scenarios, respectively.

Figure E 3-1 shows the impact each policy and initiative has had on Victorian annual electricity consumption in the medium growth scenario.

Figure E 3-1 – Policy impact on native energy forecasts, medium growth scenario

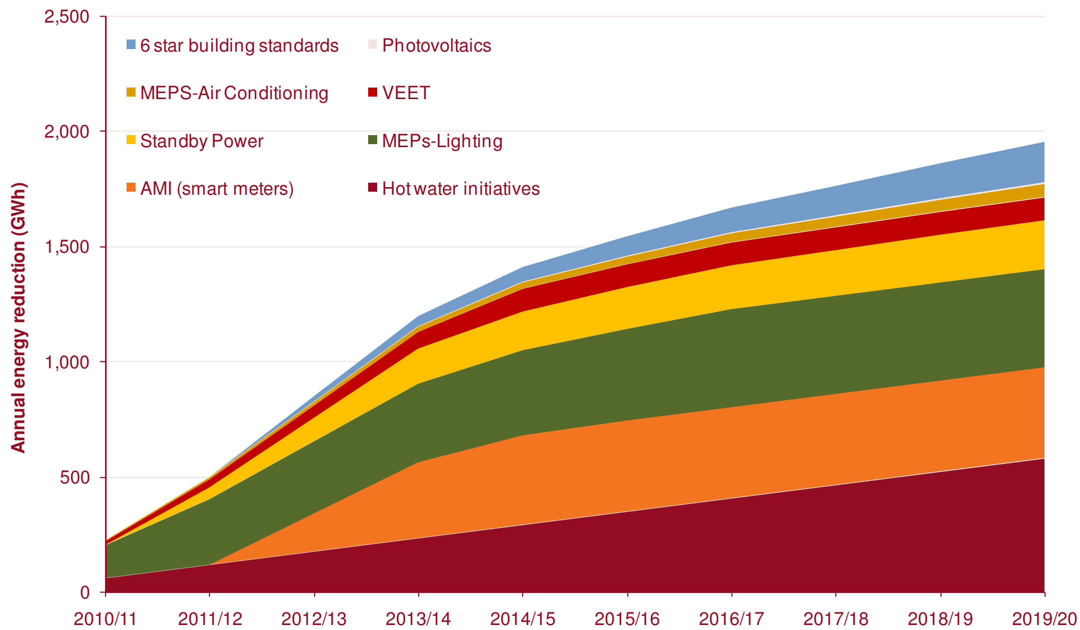
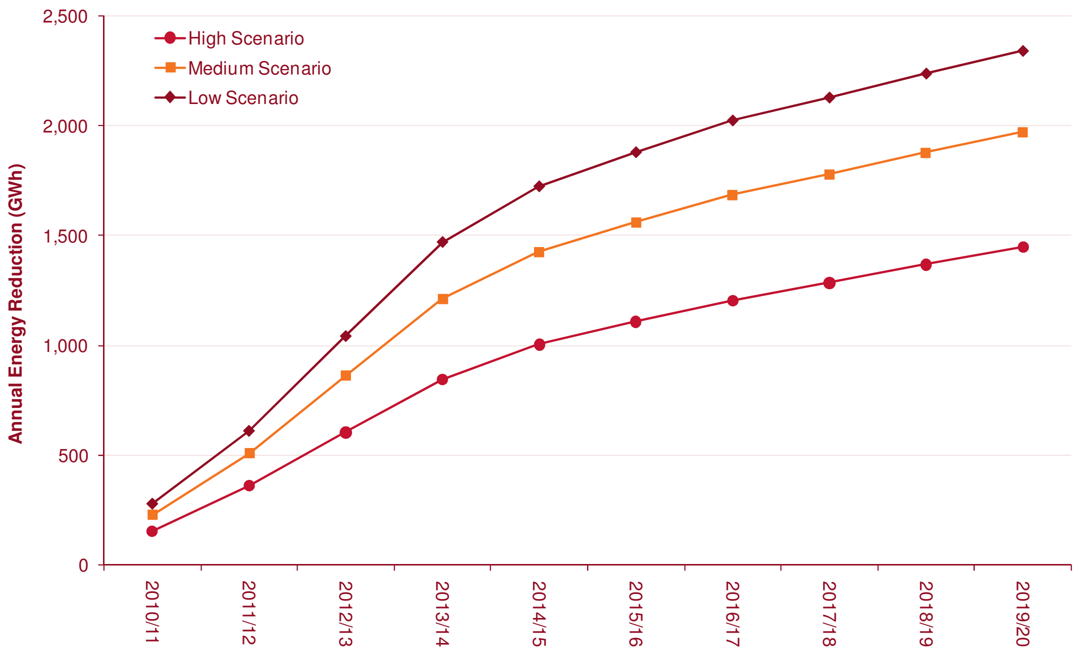


Figure E 3-2 shows the overall annual energy reduction assumed in each growth scenario.

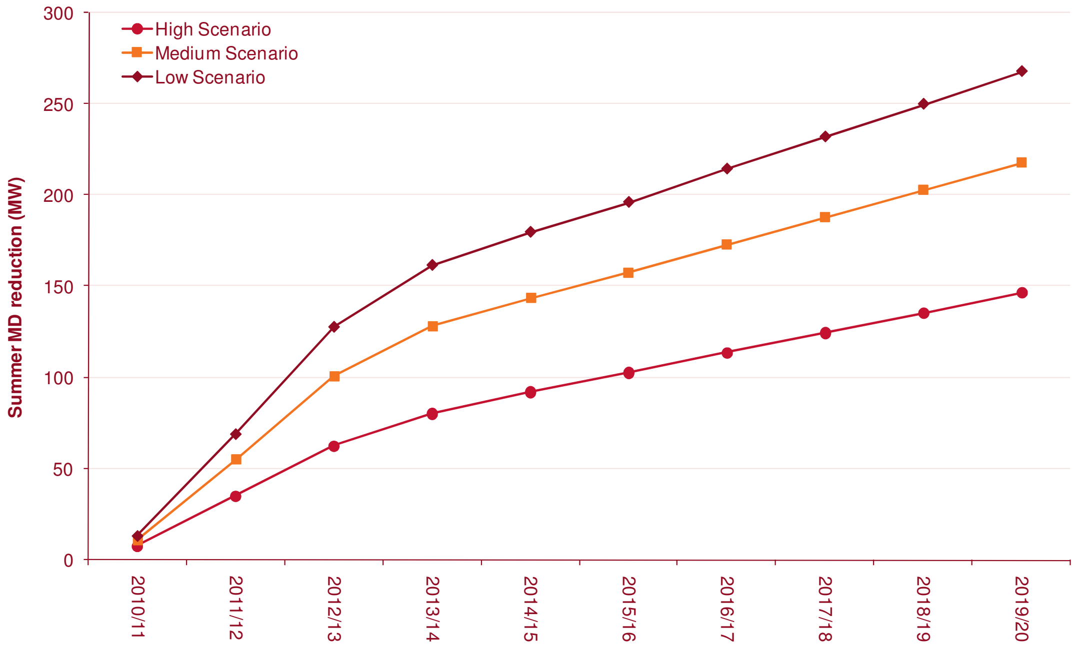
Figure E 3-2 – Policy impact on native energy forecasts



Estimating the energy policy impacts on MD is particularly challenging because it is difficult to predict how households will operate appliances and equipment during peak periods, and how appliances and equipment will perform. For this reason, the range between the scenarios is reasonably wide and the impact assumed in the high growth scenario is conservative.

Figure E 3-3 shows the impact of the policies on the summer MD under the high, medium and low growth scenarios.

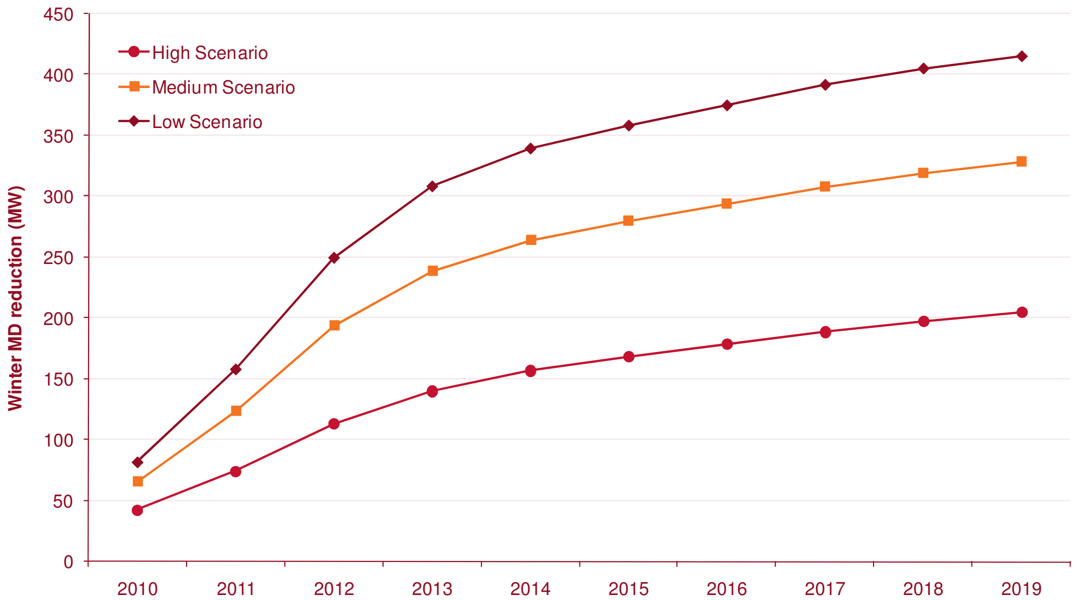
Figure E 3-3 – Policy impact on summer maximum demand



The estimated policy impact on high growth scenario winter peak demand is also quite conservative, with the reduction reaching around 200 MW, but is more pronounced than the impact on the summer peak. This is because of the larger impact of lighting efficiency at the time of the winter peak, typically around 6 pm, rather than the 3 pm summer peak.

Figure E 3-4 shows the policy impacts on the winter MD under the high, medium and low growth scenarios.

Figure E 3-4 – Policy impact on winter maximum demand



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E4 Terminal Station Demand Forecasts (2009/10-2018/19)

AEMO prepares load forecasts for points of connection within the electricity Distributed Shared Network (the electricity DSN) in Victoria. Table E 4-1 and Table E 4-2 list the average active power 1 year in 2 (50% POE) and 1 year in 10 (10% POE) maximum demand (MD) forecast for summer and winter, respectively.

This appendix provides forecasts for each Victorian terminal station. The Terminal Station Demand Forecasts 2009/10-2018/19, a detailed report including reactive power demand, is available from the AEMO website.

A new report with forecast updates will be published in September 2010.

Table E 4-1 – Summer maximum demand forecasts by terminal station

		2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Terminal station	POE	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Altona West 66kV	10	174.7	179.5	185.0	191.6	197.6	203.8	210.2	216.8	208.0	231.1
	50	166.6	171.1	176.4	182.7	188.4	194.4	200.4	206.7	198.4	220.3
Altona/Brooklyn 66 kV	10	296.6	298.0	307.5	311.6	317.5	323.8	330.1	336.4	360.8	367.2
	50	287.9	289.5	298.9	303.1	308.8	315.0	321.1	327.3	351.3	357.6
Ballarat 66 kV	10	176.1	179.5	185.3	188.6	191.7	195.1	198.4	201.7	204.6	207.5
	50	169.3	172.6	178.2	181.3	184.4	187.6	190.8	194.0	196.7	199.5
Bendigo 22 kV	10	59.9	67.9	69.6	81.6	83.5	85.4	87.5	89.5	91.5	93.6
	50	52.9	60.0	61.5	72.1	73.8	75.5	77.3	79.1	80.9	82.7
Bendigo 66 kV	10	185.2	187.0	190.2	184.7	187.8	191.1	194.3	197.6	201.2	204.9
	50	171.5	173.2	176.1	171.0	173.9	177.0	179.9	183.0	186.3	189.7
Brooklyn 22 kV	10	65.7	66.9	68.2	69.5	70.9	72.3	73.7	75.2	73.4	74.8
	50	65.4	66.6	67.9	69.2	70.5	71.9	73.3	74.8	73.0	74.4
Brooklyn-SCI 66 kV	10	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2
	50	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2
Brunswick 22 kV	10	99.0	100.9	102.6	104.2	105.9	107.8	109.8	111.8	113.8	115.9
	50	92.3	94.0	95.6	97.1	98.7	100.5	102.3	104.2	106.1	108.0
Cranbourne 66 kV	10	371.7	383.4	417.6	439.1	461.7	484.6	508.4	534.3	562.0	591.3
	50	350.3	361.2	393.3	413.5	434.8	456.4	478.8	503.2	529.3	556.9
East Rowville 66 kV	10	515.3	530.9	536.1	556.9	578.0	596.4	614.0	633.8	654.9	676.3
	50	481.4	495.8	500.1	519.5	539.1	556.3	572.7	591.2	610.8	630.9
Fishermans Bend 66 kV	10	255.7	270.5	281.0	290.3	299.6	309.7	320.0	330.3	339.7	346.7
	50	243.4	257.4	267.4	276.3	285.1	286.7	304.5	314.3	323.3	330.0
Geelong 66 kV	10	434.8	450.6	465.5	481.1	490.0	500.9	512.0	520.7	530.9	539.6
	50	426.8	442.6	457.5	473.1	482.0	492.9	504.0	512.7	522.9	531.6
Glenrowan 66 kV	10	110.7	112.4	114.2	116.9	119.6	122.4	125.3	128.3	131.3	134.4
	50	104.4	106.1	107.7	110.3	112.9	115.5	118.2	121.0	123.8	126.8
Heatherton 66 kV	10	339.7	346.2	354.9	361.6	368.0	372.8	376.6	381.5	386.6	391.5
	50	321.4	327.3	335.2	341.4	347.4	351.9	355.4	359.9	364.7	369.3

		2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Terminal station	POE	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Heywood 22 kV	10	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
	50	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
Horsham 66 kV	10	88.4	90.5	92.2	93.3	94.4	95.5	96.6	97.8	98.9	99.9
	50	86.4	88.5	90.2	91.3	92.4	93.5	94.6	95.8	96.9	97.9
Keilor 66 kV	10	625.1	654.1	676.1	698.0	720.0	740.4	758.6	777.4	796.6	807.1
	50	593.1	620.6	641.5	662.2	683.1	702.5	719.8	737.8	756.0	765.9
Kerang 22 kV	10	11.7	11.8	11.9	12.1	12.2	12.3	12.4	12.6	12.7	12.8
	50	11.3	11.4	11.5	11.7	11.8	11.9	12.0	12.2	12.3	12.4
Kerang 66 kV	10	57.9	59.5	60.9	61.9	62.9	64.2	65.2	66.2	67.4	68.7
	50	56.9	58.5	59.9	60.9	61.9	63.2	64.2	65.2	66.4	67.7
Loy Yang 66 kV	10	24.0	24.1	24.1	24.2	24.3	24.3	24.4	24.5	24.6	24.6
	50	23.6	23.6	23.7	23.8	23.8	23.9	24.0	24.1	24.1	24.2
Malvern 22 kV	10	39.7	40.0	40.7	41.2	41.7	42.1	42.4	42.7	43.1	43.5
	50	36.7	36.9	37.5	37.9	38.4	38.7	39.0	39.3	39.7	40.0
Malvern 66 kV	10	176.5	181.4	187.8	193.0	198.0	202.1	204.5	207.6	210.8	213.9
	50	163.3	167.7	173.5	178.2	182.8	186.6	188.7	191.5	194.5	197.3
Morwell/Loy Yang 66 kV	10	455.6	466.3	477.2	494.1	511.5	529.6	548.3	567.7	587.8	608.6
	50	430.3	440.4	450.7	466.6	483.1	500.1	517.8	536.1	555.0	574.7
Mount Beauty 66 kV	10	34.6	34.9	35.2	35.6	36.1	36.6	37.1	37.6	38.1	38.6
	50	32.6	32.9	33.2	33.6	34.1	34.5	35.0	35.5	35.9	36.4
Red Cliffs 22 kV	10	41.2	42.3	43.2	44.0	44.9	45.7	46.6	47.5	48.5	49.4
	50	39.0	40.1	40.9	41.7	42.5	43.3	44.1	45.0	45.9	46.8
Red Cliffs 66 kV	10	170.8	176.9	141.1	143.9	146.9	149.8	152.5	155.3	158.1	161.1
	50	165.1	170.9	136.3	139.1	141.9	144.8	147.3	150.0	152.8	155.6
Richmond 22 kV	10	77.6	79.2	80.4	81.6	82.9	84.1	85.4	86.7	87.9	89.2
	50	71.8	73.3	74.5	75.6	76.8	77.9	79.1	80.2	81.4	82.6
Richmond 66 kV	10	574.5	590.5	604.0	616.2	627.5	638.3	648.9	659.9	670.9	682.0
	50	531.4	546.2	558.6	569.9	580.3	590.3	600.1	610.2	620.4	630.6
Ringwood 22 kV	10	99.7	101.9	104.8	107.5	110.3	112.9	115.5	118.3	121.2	124.1
	50	93.3	95.3	98.0	100.5	103.1	105.6	108.0	110.6	113.3	116.0
Ringwood 66 kV	10	521.2	534.2	549.7	571.0	593.0	615.2	637.9	661.9	687.0	713.1
	50	489.8	502.0	516.4	536.4	557.1	578.0	599.4	622.0	645.6	670.1
Shepparton 66 kV	10	301.0	305.6	312.8	317.4	321.5	325.6	329.7	334.0	338.3	342.7
	50	286.0	290.6	297.8	302.4	306.5	310.6	314.7	319.0	323.3	327.7
South Morang 66 kV	10	235.7	247.5	258.9	273.0	287.6	301.3	315.8	331.0	347.0	363.9
	50	222.4	233.5	244.2	257.6	271.3	284.3	297.9	312.3	327.4	343.3
Springvale 66 kV	10	477.8	491.6	512.4	523.1	532.8	541.3	547.7	555.6	564.0	572.1
	50	441.6	454.0	472.8	482.6	492.0	499.2	504.9	512.2	519.9	527.2
Templestowe 66 kV	10	344.8	349.7	357.5	365.3	373.0	379.9	386.4	393.5	400.8	408.2
	50	321.9	326.3	333.5	340.7	347.9	354.3	360.3	366.9	373.8	380.7
Terang 66 kV	10	195.3	200.7	205.6	209.4	212.9	216.2	219.5	222.9	226.4	229.6
	50	192.3	197.5	202.4	206.1	209.5	212.8	216.1	219.4	222.9	226.0
Thomastown	10	268.7	275.7	281.8	290.5	300.0	308.1	316.5	325.2	334.1	343.3

		2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Terminal station	**POE**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
1&2 66 kV	50	253.5	260.1	265.8	274.1	283.0	290.7	298.6	306.8	315.2	323.9
Thomastown 3&4 66 kV	10	268.6	275.5	282.5	292.3	301.7	307.5	313.3	319.3	325.3	331.5
	50	253.4	259.9	266.5	275.7	284.7	290.1	295.6	301.2	306.9	312.8
Tyabb 220 kV	10	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
	50	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
Tyabb 66 kV	10	265.5	271.3	281.9	290.2	298.2	304.1	309.0	315.0	321.5	327.7
	50	244.7	249.8	259.4	266.9	274.2	279.6	283.9	289.5	295.4	301.0
Wemen 66 kV	10	0.0	0.0	51.8	54.4	56.3	57.7	58.9	59.7	60.5	61.2
	50	0.0	0.0	50.1	52.6	54.4	55.8	56.9	57.7	58.5	59.2
West Melbourne 22 kV	10	96.9	105.8	110.0	114.2	118.5	122.8	127.1	131.5	135.9	140.4
	50	91.5	99.8	103.8	107.8	111.8	115.8	119.9	124.1	128.2	132.4
West Melbourne 66 kV	10	483.9	500.1	516.5	538.3	554.8	571.2	587.7	604.4	621.4	638.5
	50	456.3	471.5	487.0	507.6	523.2	538.6	554.2	569.9	585.9	602.0
Wodonga 22 kV	10	33.6	34.7	35.7	36.8	37.9	39.0	40.2	41.4	42.6	43.9
	50	31.7	32.7	33.7	34.7	35.7	36.8	37.9	39.0	40.2	41.4
Wodonga 66 kV	10	68.6	69.3	69.9	71.0	72.0	73.0	74.1	75.2	76.3	77.4
	50	64.7	65.3	66.0	66.9	67.9	68.9	69.9	70.9	72.0	73.0
Yallourn 11 kV	10	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.2	7.3	7.4
	50	6.3	6.3	6.4	6.5	6.5	6.6	6.7	6.8	6.9	7.0

Table E 4-2 – Winter maximum demand forecasts by terminal station

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Terminal station	**POE**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Altona West 66kV	10	142.0	140.1	144.1	148.3	153.6	158.2	163.0	168.1	173.2	163.3
	50	138.9	137.0	140.9	145.1	150.3	154.8	159.5	164.5	169.5	159.8
Altona/Brooklyn 66 kV	10	296.8	309.5	311.6	320.5	323.9	329.1	332.8	338.4	344.0	367.8
	50	293.5	306.2	308.2	317.1	320.5	325.6	329.3	334.9	340.4	364.0
Ballarat 66 kV	10	163.9	166.2	168.8	173.6	176.2	178.6	181.3	183.8	186.4	187.9
	50	163.9	166.2	168.8	173.6	176.2	178.6	181.3	183.8	186.4	187.9
Bendigo 22 kV	10	37.2	38.5	44.4	45.4	54.1	55.3	56.6	57.8	59.1	60.5
	50	37.2	38.5	44.4	45.4	54.1	55.3	56.6	57.8	59.1	60.5
Bendigo 66 kV	10	134.9	136.6	138.2	140.4	135.0	137.2	139.4	141.6	144.0	146.4
	50	134.9	136.6	138.2	140.4	135.0	137.2	139.4	141.6	144.0	146.4
Brooklyn 22 kV	10	60.7	60.0	61.1	62.2	63.3	64.5	65.6	66.9	68.1	66.2
	50	60.4	59.7	60.8	61.9	63.0	64.2	65.3	66.6	67.8	65.8
Brooklyn-SCI 66 kV	10	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
	50	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
Brunswick 22 kV	10	87.3	88.0	89.4	90.7	91.9	93.1	94.5	95.9	97.3	98.7
	50	83.9	84.6	86.0	87.2	88.3	89.5	90.8	92.2	93.5	94.9
Cranbourne 66 kV	10	247.6	266.9	284.7	290.2	296.8	303.6	310.1	317.1	324.4	331.7
	50	236.1	254.8	271.6	276.7	282.9	289.4	295.6	302.3	309.2	316.2

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Terminal station	**POE**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
East Rowville 66 kV	10	400.3	409.2	408.3	417.2	428.5	440.4	451.3	463.7	476.6	489.6
	50	385.4	393.7	393.0	401.3	412.1	423.5	433.8	445.8	458.1	470.6
Fishermans Bend 66 kV	10	201.5	221.9	234.5	240.7	253.0	263.0	273.3	283.7	286.2	300.5
	50	195.7	215.5	227.8	233.9	245.8	255.5	265.5	275.6	285.8	291.9
Geelong 66 kV	10	351.2	363.2	378.4	392.1	405.6	413.5	423.0	432.4	440.1	448.7
	50	351.2	363.2	378.4	392.1	405.6	413.5	423.0	432.4	440.1	448.7
Glenrowan 66 kV	10	109.4	110.2	111.0	112.2	113.5	114.7	116.0	117.3	118.5	119.9
	50	103.2	103.9	104.7	105.9	107.0	108.2	109.4	110.6	111.8	113.1
Heatherton 66 kV	10	255.6	260.6	266.1	268.9	274.1	279.7	284.1	289.7	295.4	301.1
	50	248.2	252.8	258.0	260.6	265.6	271.0	275.3	280.7	286.3	291.8
Heywood 22 kV	10	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
	50	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
Horsham 66 kV	10	68.8	70.5	71.8	73.1	74.0	74.7	75.6	76.4	77.2	78.0
	50	68.8	70.5	71.8	73.1	74.0	74.7	75.6	76.4	77.2	78.0
Keilor 66 kV	10	462.6	474.0	497.8	515.8	532.0	549.0	564.4	577.6	591.3	605.3
	50	453.6	464.7	488.0	505.6	521.6	538.2	553.3	566.3	579.7	593.4
Kerang 22 kV	10	11.1	11.2	11.3	11.4	11.6	11.7	11.8	11.9	12.0	12.1
	50	11.1	11.2	11.3	11.4	11.6	11.7	11.8	11.9	12.0	12.1
Kerang 66 kV	10	50.0	51.1	52.6	53.7	54.8	55.8	56.9	58.0	59.1	60.4
	50	50.0	51.1	52.6	53.7	54.8	55.8	56.9	58.0	59.1	60.4
Loy Yang 66 kV	10	32.5	32.7	32.8	32.9	33.0	33.1	33.2	33.4	33.5	33.6
	50	31.9	32.0	32.1	32.2	32.3	32.4	32.6	32.7	32.8	32.9
Malvern 22 kV	10	34.5	34.7	35.2	35.5	36.0	36.6	37.1	37.7	38.3	38.9
	50	33.5	33.7	34.1	34.3	34.9	35.5	35.9	36.5	37.1	37.7
Malvern 66 kV	10	126.6	129.9	133.4	135.1	137.9	140.7	143.2	145.4	147.7	149.9
	50	122.8	126.0	129.3	130.9	133.5	136.3	138.7	140.9	143.0	145.2
Morwell/Loy Yang 66 kV	10	426.8	430.4	434.1	439.5	445.1	450.7	456.4	462.2	468.1	474.0
	50	403.2	406.6	410.0	415.2	420.5	425.8	431.2	436.6	442.1	447.7
Mount Beauty 66 kV	10	53.0	53.3	53.7	54.2	54.6	55.1	55.6	56.1	56.6	57.1
	50	50.0	50.3	50.6	51.1	51.5	52.0	52.5	53.0	53.4	53.9
Red Cliffs 22 kV	10	21.9	22.9	23.7	24.2	24.7	25.2	25.7	26.2	26.7	27.3
	50	20.8	21.8	22.6	23.1	23.6	24.1	24.6	25.1	25.6	26.2
Red Cliffs 66 kV	10	103.1	111.5	93.4	96.0	98.7	101.4	103.1	104.7	106.3	108.0
	50	100.3	108.5	90.9	93.4	96.0	98.6	100.3	101.9	103.4	105.1
Richmond 22 kV	10	62.6	64.5	65.7	66.7	67.8	68.8	69.9	70.9	72.0	73.0
	50	60.2	62.1	63.2	64.2	65.2	66.2	67.2	68.2	69.2	70.2
Richmond 66 kV	10	431.8	445.5	457.2	466.6	476.4	485.7	494.8	504.2	513.6	523.1
	50	415.6	428.8	440.0	449.0	458.4	467.4	476.2	485.2	494.3	503.4
Ringwood 22 kV	10	75.8	77.5	79.4	81.2	83.4	85.5	87.7	90.0	92.3	94.7
	50	72.2	73.8	75.6	77.3	79.3	81.4	83.4	85.6	87.8	90.1
Ringwood 66 kV	10	374.1	382.2	390.8	403.2	416.8	431.0	445.3	460.4	476.0	492.2
	50	355.3	362.8	370.9	382.6	395.5	408.9	422.4	436.7	451.5	466.8

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Terminal station	**POE**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Shepparton 66 kV	10	203.2	207.4	210.8	215.5	218.8	221.7	224.6	227.6	230.7	233.8
	50	203.2	207.4	210.8	215.5	218.8	221.7	224.6	227.6	230.7	233.8
South Morang 66 kV	10	119.9	192.3	199.8	208.0	215.8	223.6	230.0	236.7	243.5	250.6
	50	113.1	183.0	190.1	198.0	205.4	212.8	219.0	225.3	231.8	238.5
Springvale 66 kV	10	355.5	361.6	372.6	382.0	389.5	397.5	403.9	411.9	420.1	428.2
	50	344.7	350.4	360.9	369.8	377.0	384.8	390.9	398.7	406.6	414.5
Templestowe 66 kV	10	278.0	283.5	287.5	291.9	297.4	302.9	308.0	313.6	319.2	325.0
	50	266.2	271.4	275.2	279.4	284.5	289.8	286.7	300.0	305.4	310.9
Terang 66 kV	10	180.8	186.9	190.8	195.0	198.2	200.7	203.4	206.2	209.0	211.8
	50	180.8	186.9	190.8	195.0	198.2	200.7	203.4	206.2	209.0	211.8
Thomastown 1&2 66 kV	10	253.4	185.5	189.2	192.4	196.1	200.2	203.2	206.2	209.3	212.4
	50	242.5	176.8	180.4	183.5	187.0	190.9	193.7	196.6	199.5	202.5
Thomastown 3&4 66 kV	10	210.4	223.4	229.1	234.4	242.0	249.4	253.4	257.4	261.6	265.8
	50	203.3	215.9	221.3	226.5	233.9	241.0	244.8	248.7	252.7	256.8
Tyabb 220 kV	10	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2
	50	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2
Tyabb 66 kV	10	217.8	205.9	210.0	212.0	215.9	220.1	223.4	227.5	231.7	235.9
	50	211.4	199.7	203.6	205.4	209.2	213.2	216.4	220.4	224.5	228.5
Wemen 66 kV	10	0.0	0.0	27.0	28.7	29.7	30.5	31.2	31.8	32.1	32.5
	50	0.0	0.0	26.3	27.9	28.9	29.7	30.3	30.9	31.2	31.6
West Melbourne 22 kV	10	86.5	90.5	94.8	98.7	102.7	106.8	110.8	115.0	119.1	123.3
	50	83.2	87.0	91.1	94.9	98.8	102.7	106.6	110.5	114.5	118.6
West Melbourne 66 kV	10	359.1	377.4	390.8	404.6	422.4	436.3	450.0	463.9	478.0	492.1
	50	345.7	363.3	376.2	389.5	406.6	420.0	433.3	446.6	460.1	473.8
Wodonga 22 kV	10	29.0	29.9	30.8	31.7	32.7	33.7	34.7	35.7	36.8	37.9
	50	27.4	28.2	29.1	29.9	30.8	31.8	32.7	33.7	34.7	35.7
Wodonga 66 kV	10	53.7	54.2	54.8	55.5	56.3	57.1	57.9	58.7	59.5	60.4
	50	50.7	51.2	51.7	52.4	53.1	53.9	54.6	55.4	56.2	57.0
Yallourn 11 kV	10	4.3	4.3	4.4	4.4	4.5	4.6	4.6	4.7	4.7	4.8
	50	4.1	4.1	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.5

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E5 Energy Supply Technology

E5-1 New supply technologies

Victoria is a world leader in advanced brown coal utilisation research. Currently, 'clean coal' technologies are in a developmental stage and have been receiving significant government support through taxation concessions and grants. They are yet to demonstrate commercial viability in their own right, however, or to contribute significant amounts to Victorian electricity supplies. If widely adopted, they will have important implications for transmission investment by preserving the central role of the Latrobe Valley as an energy source.

Similarly, distributed generation technologies, if commercially successful, have the potential to reduce the concentration of generation that has dominated electricity transmission network topology to date.

Table E 5-1 lists the energy supply technologies in which Australia currently plays a significant international research and development role.

Table E 5-1 – Energy supply technology

Supply technology	Australian relevance
Advanced brown coal utilisation	Australia has large reserves of cheap brown coal. Coal of this type is used in only a few countries so there is limited international research and development to support its long term use. Research is focused on coal drying and gasification processes to increase the efficiency of electricity production and cut greenhouse gas emissions
Geo-sequestration	Technology to remove carbon dioxide (CO_2) from power station exhaust gas or natural gas and return it to long term underground storage is a possible key to low emission use of fossil fuels. Local geology is central to the performance of sequestration sites. Identifying, characterising and evaluating potentially suitable geologic structures to identify viable CO2 storage locations is vital to the development of this technology
Hot dry rocks	This is one of the more speculative (less proven) base load renewable electricity generation options. Australia's hot dry rock resource is among the best in the world, although much is distant from energy markets. Domestic geology determines accessibility and potential
Photovoltaic (PV)	Australia has world-leading research in this technology. Australia's climate, settlement patterns, and electricity use profile offer a supportive environment for uptake. However, despite decades of development, the delivered price of PV devices remains non-competitive for mainstream energy supply, although it fills a significant niche market
Remote area power supply systems	Australia has technology leadership in small integrated systems for remote settlements and industries (for example mine sites)
Solid oxide fuel cells	Australia has world-leading fuel-cell technology. Fuel cells can utilise natural gas and offer significant potential for moving to more distributed electricity generation. However, this is an inherently capital intensive technology, which requires fuel supply to distributed locations
Solar tower electricity	Listed company Enviromission Limited is planning the first large scale application of this technology at a site north of Mildura. Solar heating will be used to generate rapid airflow through a high tower, producing 200 MW of electricity from internal wind turbines at its base

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G1 System Capacity

This appendix presents information about the operational (and other) factors that affect system capacity.

G1-1 Operational factors affecting system capacity

Beginning-of-day linepack

Linepack is the pressurised gas stored in transmission pipelines. Gas Declared Transmission System (gas DTS) linepack varies considerably throughout the day, as it is drawn down in the first half of the gas day to balance a fairly constant hourly injection rate with the evening peak demand. Linepack reaches a minimum by 10 pm (approximately). Overnight, injections exceed demand and linepack is replenished until the start of the morning peak at around 6 am (approximately).

Demand forecast error

Daily demand forecast errors occur due to changes in the weather, large loads varying from the initial forecast (such as gas powered generation (GPG)), and forecast model errors.

When actual demand is:

- higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system capacity, and
- lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the Exxon-Mobil plant at Longford.

Delivery pressures

Delivery or supply pressure drives gas through a pipeline. The higher the pressure, then the higher the average level of linepack and effective system capacity.

Injection profiles

For operational reasons, gas production plants generally operate at a fairly constant injection rate. Varying the injection rate to reflect demand throughout the day, however, can increase gas transport capacity. In particular, an injection profile with a higher injection rate during the first half of the day can increase gas transport capacity by over 4%. See Appendix G 4 for more information about injection profiles.

Gas sources that can be injected for short periods at times of high demand, such as Liquefied Natural Gas (LNG), can greatly assist overall system capacity.

Demand profiles (temporal distribution)

During winter, peaking demand in the morning and evening (due to temperature sensitive load) draws down system linepack. More severe demand profiles, including the presence of spike loads such as GPG, will deplete linepack at a faster rate.

Spatial distribution of demand

System capacity is modelled using forecast load distribution across the system. If a specific load is located close to an injection point, the gas transport capacity is higher than if the load is located further away.

G1-2 Other factors affecting system capacity

Other factors affecting system capacity include:

- heating values and the specific gravity of injected gas at each injection point
- ground and ambient air temperatures
- minimum and maximum operating pressure limits at critical points throughout the system, and
- the power and efficiency of compressor stations.

G2 Modelling Methodology

This appendix provides an overview of the methodology and assumptions attaching to the use of the Gregg Engineering Winflow and WinTran software modules.

G2-1 AEMO determines system capacity using a calibrated gas transmission system model (specifically, the Gregg Engineering WinFlow (steady state) and WinTran (transient) software modules).

Table G2-1 lists the standard modelling assumptions.

Table G2-1a sample set of conditions for determining system capacity.

AEMO's gas transmission system model is regularly calibrated using actual winter metered gas injections and withdrawals on selected high and moderate-demand days. Regular model calibration refines the model to ensure that it accurately simulates the observed pressures and flows throughout the gas Declared Transmission System (gas DTS). AEMO and APA Group have thoroughly checked this model, revising the pipe lengths and diameters to ensure it is as accurate as possible.

System capacity is normally modelled as the maximum daily flow that can be sustained over several days given a defined set of operating conditions. System capacity is a function of many factors (see Appendix G1). As a result, a set of conditions and assumptions must be applied in any system capacity assessment.

To better reflect real-world conditions, the adequacy of the system to meet peak demand has been modelled using typical beginning-of-day linepack and surprise cold weather. This methodology is used in the assessment of constraints in Chapter 7.

G2-2 Interpreting modelled capacities

Modelled capacities are subject to uncertainty because they depend on forecast inputs, assumed operating parameters, operating conditions, and a mathematical representation of the system. Uncertainties in modelled capacities are estimated at approximately 1% for high-capacity runs (for example, Longford's capacity to inject gas) but can be up to 10% for small capacities, such as the New South Wales Interconnect's export capacity, or the capacity of a lateral pipeline.

Modelled maximum capacities can only be realised with reliable demand forecasting and operating conditions (on the day) that are similar to the model's assumptions. Extreme high demand days that test system capacity are often also surprise cold days, where scheduling is not optimum and maximum capacities cannot be realised. On peak days, the level of linepack and the beginning-of-day operating conditions are also critical.

G2-3 Modelling assumptions

Table G2-1 lists the standard modelling assumptions.

Table G2-1 – System (GREGG) network modelling assumptions

Capacity model for gas transmission system	
Network modelling assumptions and conditions	**Notes**
Heating value: 38.7 MJ/m^3 and specific gravity: 0.61	Victorian gas standard properties
Gas delivery temperature above 2℃	Gas Quality Regulations requirement
Longford injections at flat hourly profile	Normal operating condition
Maximum pressure at Longford 6,750 kPa	To conform to normal operating practice and pipeline licence requirements
VicHub injections at flat hourly profile	Normal operating condition
New South Wales injection at Culcairn at flat hourly profile	Normal operating condition
Iona and SEA Gas injection at flat hourly profile	Normal operating condition
Iona maximum and minimum pressures	As per pipeline licences, operating agreements and practice
Minimum pressure at Culcairn	Operating agreement pressure requirement
Maximum allowable operating pressure (MAOP) and delivery pressures in connection and Service Envelope Agreements are not infringed	Service Envelope Agreement and Connection Deed requirements. For example, a minimum 3,100 kPa at the Dandenong City Gate
Load profiles calculated by AEMO	Calculated from historical flow data for each custody transfer meter (CTM)
Load distribution as per AEMO forecasts	Based on historical CTM data
Supply to Horsham pipeline at Carisbrook	Carisbrook to Horsham pipeline modelled with demands at Ararat, Stawell and Horsham (connected in 1998)
Supply to Murray Valley (Chiltern Valley-Koonoomoo)	New pipeline commissioned 1998
Transmission UAFG determined at Longford	Calculated from calibrated model data
New South Wales gas flow from north to south	Information provided for the VAPR indicates imports of gas at Culcairn during winter
BOC liquefaction operating, let down gas operating	Full supply to this customer is normally required
Beginning -of-day (BOD) and end-of-day (EOD) linepack are equal	For capacity modelling, mining of linepack is not allowed
Beginning-of-day linepack 20 TJ below target	Used for lateral constraint modelling
APA Group pipeline, regulator and compressor assets and operating conditions as specified in Service Envelope Agreement	Agreement between APA Group and AEMO 20 November 2006
BOD and EOD pressures similar at key network locations	Required for System Security
Regulators, compressors, and valves are set to reflect operational guidelines	Required to reflect operational and system security requirements
LNG contracted vaporisation rate 100 t/h for 16 hours	For peak shaving purposes to support critical system pressures, LNG is effective only up to 10 pm. As a result, only 11 hours LNG is assumed, equivalent to 60 TJ

Table G2-2 lists the planning assumptions for probabilistic mass-balance modelling.

Table G2-2 – Probabilistic mass-balance modelling base-case assumptions

Probabilistic mass-balance modelling assumptions and conditions	Notes
GPG consumption	The GPG profiles used are normalised profiles. The model scales up the historic GPG profile to meet the annual

Probabilistic mass-balance modelling assumptions and conditions	Notes
	quantity while accounting for the actual maximum output capability of the GPG plant
Winter period only	The modelling covers the high demand period between May and September. The use of LNG for supply-demand balancing is not expected to be required outside this period
Effective degree day (EDD)	Uses actual daily EDD data between 1970 and 2009
Annual demand	The system demand profiles used are normalised profiles. The model scales up the historic system demand profile to meet the annual quantity
Winter period only	The modelling covers the high demand period between May and September. The use of LNG for supply-demand balancing is not expected to be required outside this period
VicHub injections at flat hourly profile	Normal operating condition
New South Wales injection at Culcairn at flat hourly profile	Normal operating condition
Iona and SEA Gas injection at flat hourly profile	Normal operating condition
Iona maximum and minimum pressures	As per pipeline licences, operating agreements, and practice

Table G2-3 lists the planning assumptions for deterministic mass-balance modelling.

Table G2-3 – Deterministic mass-balance modelling base case assumptions

Deterministic mass-balance modelling assumptions and conditions	Notes
System demand	1 in 20 peak day
System demand profile	78.8% demand 6 am to 10 pm
GPG demand profile	90% demand 6 am to 10 pm
Forecasting error	6% under actual demand at 6 am schedule
GPG forecasting error	15% under actual demand at 6 am schedule
BOD system linepack	10 TJ below target
Supply reschedules	Effective 10 am, 2 pm, 6 pm, 10 pm

LNG is critical for maintaining system pressures. The planning standard for LNG reflects the need to maintain redundancy in the LNG plant. This is consistent with the firm, contracted, LNG-vaporisation capacity. The contracted LNG capacity is 100 t/h for 16 hours and provides 87 TJ/d. Only 60 TJ/d of LNG is effective for peak shaving purposes before 10 pm, which is an important peak day planning assumption.

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G3 Within-day Balancing

This appendix presents information about the application of the mass-balance model in terms of analysing within-day balancing requirements, the management of linepack depletion, and the application of probabilistic and deterministic modelling for forecasting Liquefied Natural Gas (LNG) requirements.

G3-1 Mass-balance model

Figure G 3-1 shows a deterministic mass-balance model representation of hourly supply and demand on a gas day. This model treats the gas transmission system as a storage tank that holds linepack. Excepting local transmission constraints, the model is a simple but useful representation of the system.

This type of model can be used in the peak day supply-demand and load duration curve supply-demand analysis, as well as the LNG simulation models to estimate LNG requirements.

To ensure the reliability of the results, the models have been tuned to match usable linepack and LNG usage with a range of representative scenarios that were developed using a calibrated computer model of the transmission system.

G3-2 Within-day balancing

Figure G 3-1 also shows within-day supply, demand and usable linepack. However, as within-day balancing is affected by pipeline capacity and the usable system linepack, an examination of hourly supply and demand becomes critical.

In this figure, the left axis applies to supply and demand, and the right axis applies to usable system linepack. The amount of usable system linepack varies from day-to-day, depending on operating conditions. In this example, beginning-of-day (BOD) usable linepack is set at 140 TJ.

In this figure:

- Daily supply typically follows a flat injection profile over a 24-hour period (injection plants running most efficiently at a constant rate) excepting for reschedules as shown in
- Figure G 3-1. An initial forecast at the beginning-of-day determines the rate of injection, which is then kept relatively constant for the rest of the day. With the introduction of the new 6 am gas day, within-day adjustments have become possible with rescheduling at 10 am, 2 pm, 6 pm, and 10 pm. AEMO is examining operational data to assess if this is helping to eliminate some forecast error, and potentially reducing LNG requirements.
- Demand varies considerably through the day, increasing in the morning and evening due to gas heating, cooking, and hot water loads, and decreasing overnight due to commerce and industry demand reductions, and reduced heating in homes. Any additional demand from gas powered

generation (GPG) is usually more concentrated in the first half of the gas day, increasing the daytime swing in demand, and tending to draw down system linepack.

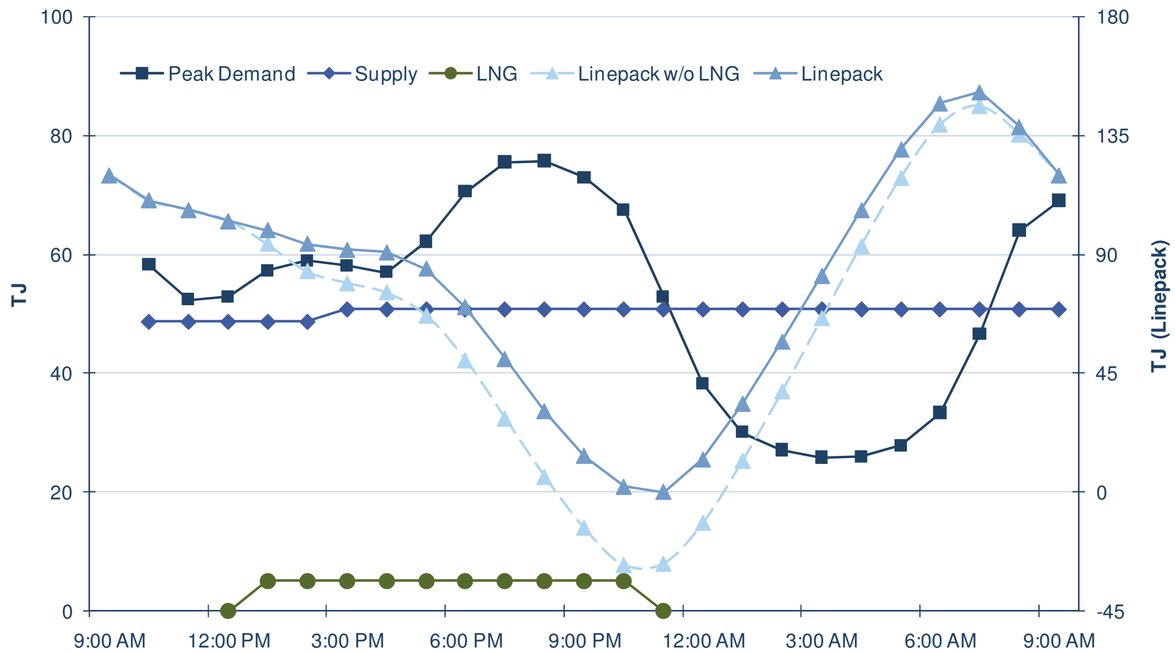
- A typical day's system linepack profile results from an imbalance in the hourly supply and demand levels. Although the aim is for supply to match demand over 24 hours, this may not occur. System linepack falls to a minimum at around 10 pm, and is rebuilt for the following morning.
- The dashed linepack projection falls to a negative value, indicating there is insufficient usable linepack. LNG is scheduled to compensate. Capable of being injected at short notice (and in close proximity to the point of demand), LNG is used:
  - for within-day balancing (because it is the fastest way to supply gas to the gas Declared Transmission System (gas DTS), and
  - to maintain system pressures when predictions have system linepack falling to a minimum.

Under favourable conditions, the profiling of injections at Iona has reduced the volume of LNG required, but LNG is still a critical supply source on high-demand days.

Normally, LNG is not introduced until later in a gas-day, once demand forecasts and system linepack projections are firm. However, LNG may still be present in the first schedule issued for the day. See Chapter 5, Section 5.3.5, for more information about LNG scheduling.

Breaches of system security are most likely to occur in the late evening (around 10 pm to 11 pm), when system linepack normally reaches a minimum.

Figure G 3-1 – Within-day supply, demand and usable linepack



G3-3 Managing linepack depletion

Operational factors leading to a depletion of usable system linepack include:

- extreme demand
- high demand with an extreme profile
- lower than planned BOD system pressures (meaning low BOD linepack, usually due to a colder than forecast morning leading into a cold day)
- demand from GPG, where this demand is usually concentrated in the first half of the gas day
- GPG forecast error, where demand turns out to be materially higher than forecast due to changes in National Electricity Market (NEM) schedules, including reschedules due to forced outages
- system demand forecast error, where demand turns out to be materially higher than forecast, usually due to colder weather than the original morning forecast
- supply problems when a producer or storage provider has not been able to meet scheduled injection rates, particularly in the first half of the gas day, and
- pipeline constraints.

In practice, some combination of these events can occur on any gas day, causing uncertainty in the projections for the rest of the day, including the likelihood and magnitude of LNG use.

Methods for mitigating the impact of these events include the following:

- The use of non-uniform supply injection profiles that more closely resemble the demand profile to support system linepack. In practice, this involves a higher than average injection rate for the first half of each gas day so that, say, 55% of the scheduled daily quantity is injected in the first 12 hours.
- Overnight rescheduling to increase supply if the linepack target is not going to be met, including, if necessary, scheduling LNG vaporisation before 9 am.
- Use of a higher end-of-day (EOD) linepack target during periods of high demand. This is not always possible because higher linepack levels increase the probability of having to back-off supplies when demand turns out to be lower than expected.
- Use of zonal EOD linepack targets, for example, by way of separate targets for the South West Pipeline and the Longford pipeline.
- Improved demand forecasting performance for very high demand days (which is difficult, given weather forecasting errors).
- Participant awareness of the within-day impact of GPG, particularly if the level of demand is higher than AEMO is advised at BOD. Market participants, as GPG agents, need to work closely with their clients and AEMO to improve the reliability and timeliness of their forecasts.
- Building a security margin in supply schedules to provide for greater linepack depletion, where possible.

G3-4 Probabilistic and deterministic modelling for forecasting LNG requirements

AEMO uses two measures for the forecast period, which involve forecasting LNG requirements during:

- peak days using deterministic modelling, and
- winters using probabilistic modelling, based on outcomes from simulations applying the full range of weather conditions.

The probabilistic and deterministic modelling methodologies both model the transmission system as the existing system including the BLP pipeline.

Deterministic modelling (peak day LNG requirement)

AEMO uses deterministic mass-balance modelling to establish when system capacity will be reached on a peak day. The model, which assesses 1 in 20 peak day capabilities:

- treats the system like a simple storage tank, simulating the operation of the gas DTS over a 24-hour period
- calculates system linepack over the day, using specific supply and demand inputs to determine the LNG required for within-day balancing, and
- applies the 6 am to 6 am gas day, taking into account the system demand profile, demand forecast error, injection rescheduling, and usable system linepack (determined via system modelling).

Deterministic modelling cases

AEMO assesses three cases, which include the:

- 1 in 20 peak winter day base case (for severe, 1 in 20 year weather conditions), which is the planning standard used for assessing the adequacy of gas supplies and transmission system capacity
- 1 in 20 peak winter day base case with GPG (for severe, 1 in 20 year weather conditions). The 1 in 20 peak day with GPG, which is the planning standard used for assessing the adequacy of gas supplies and transmission system capacity, and
- 1 in 2 peak winter day with GPG (for milder, 1 in 2 year weather conditions). The 1 in 2 peak day represents the more probable outcome, with the addition of GPG resulting in the same total demand as a 1 in 20 peak day, but with a ‘peakier’ demand profile.

Probabilistic modelling (winter LNG requirement)

AEMO uses a probabilistic mass-balance model to establish future LNG usage for within-day balancing over a whole winter. As with deterministic modelling, probabilistic modelling assesses system security by calculating LNG use, and considers probability distributions for weather taken from the last 30 years, taking into account the warming trend, and adjusted for the latest weather standard, level of demand, demand profile, and BOD linepack.

Probabilistic modelling is also used to determine the potential for GPG and industrial curtailment on high demand days by simulating:

- the impact of the most frequent events driving LNG use, which are system linepack depletion, severe demand profiles, forecast errors, and winter GPG

- daily supply and demand over each winter (for 175 years), taking into account demand forecast errors, demand profile variation, BOD system linepack variation, and GPG and industrial demand curtailment (when required), and
- a full range of weather conditions (historical EDD adjusted for a warming trend).

The modelling of winter capabilities:

- takes a mass-balance approach to model daily LNG use
- generates random values to simulate variable operating conditions and events
- models gas use every day of the period May to September (LNG is assumed not to be in use outside this period)
- assumes LNG is used to manage system linepack deficits and peak shaving
- assumes the aggregate capacity from non-LNG sources has been reached
- assumes normal GPG assumptions, and

applies the 6 am to 6 am gas day, injection rescheduling, and system linepack.

G4 Dependence of Pipeline Capacity on Delivery Pressure and Injection Profile

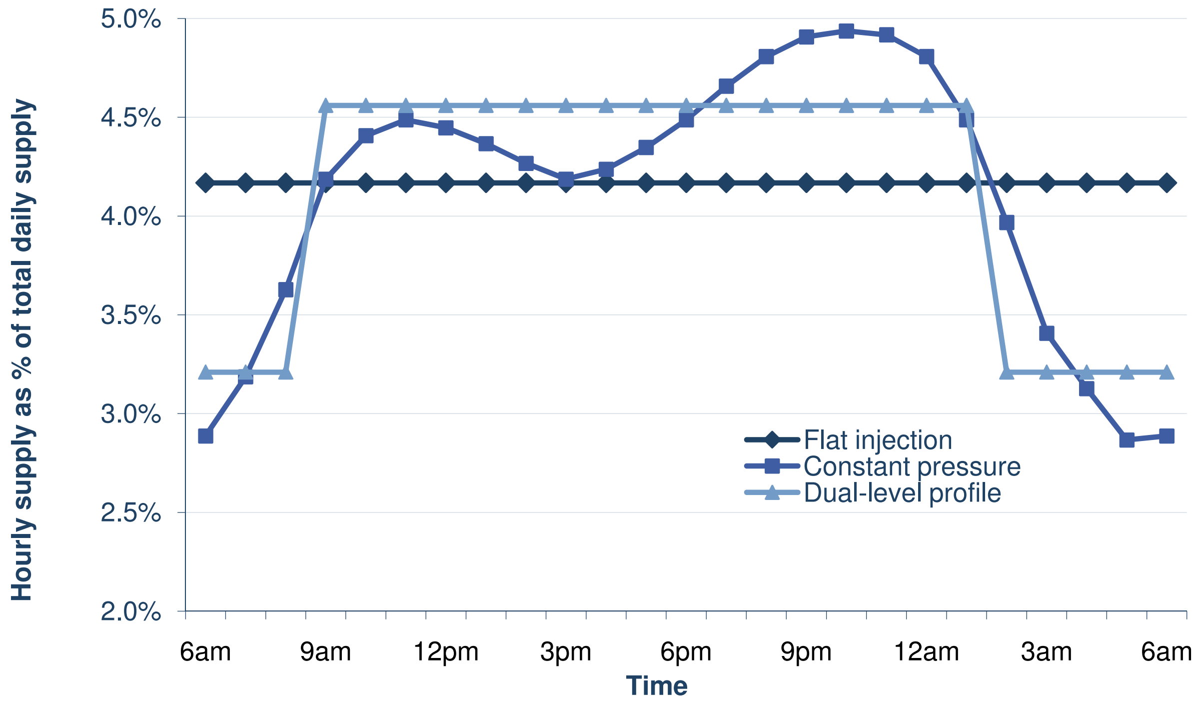
This appendix presents information about pipeline capacity dependence on injection pressure, injection profile, load profile and load distribution, and the variables that can determine a pipeline's transport capacity.

G4-1 Injection profiles

Usual injection flow rates are constant throughout the day, with variations due to rescheduling. Under these conditions, the pressure varies throughout the day. If a constant delivery pressure can be maintained, however, pipeline transport capacity increases by almost 5%.

Figure G 4-1 shows the curved injection profile that occurs as a result of a constant delivery pressure (charting each hour's demand as a percentage of the total demand for the day). Higher injection rates during the daytime, with compensating lower rates overnight, maximise system capacity. Alternatively, an increase of approximately 4% in pipeline transport capacity can be achieved using a 2-step injection profile (dual-level profile).

Figure G 4-1 – Injection profiles



G5 Compressor Requirements

This appendix presents information about compressor requirements, and includes information about compressor availability and the requirements for meeting expected system demand each month, the level of compressor redundancy, and the difference between the number of units available and the number of units required.

Table G 5-1 lists the:

- compressor availability and requirements for meeting expected system demand each month
- level of compressor redundancy, and
- difference between the number of units available and the number of units required.

The Brooklyn compressor station comprises three Centaur compressors (2 x 2,850 kW and 1 x 3,500 kW), and two Saturn compressors (850 kW and 950 kW). Their requirement and availability are shown separately, as only the Centaurs are used to compress gas to Iona for Underground Gas Storage (UGS) withdrawal. During winter, if compressors are required to compress gas to Geelong and/or Ballarat, Centaur and Saturn compressors are used in appropriate combinations. The table also shows the scheduled compressor maintenance, and can be read in conjunction with the maintenance tables in Chapter 9, Section 9.8.2.

Table G 5-1 – Compressor requirement and availability July 2010 to June 2011

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Gooding Compressor Station												
4 Centaurs @ 2,800 kW												
Available	4	4	4	4	4	4	3	3	3	3	4	4
Required	3	3	3	3	2	0	0	0	0	2	2	3
Redundant	1	1	1	1	2	4	3	3	3	1	2	1
Maintenance	-	-	-	-	-	-	1	1	1	1		
Brooklyn Compressor Station												
2 Centaurs (C) @ 2,850 kW and 3,500 kW 1												
Available	2	2	2	2	2	2	2	2	1	1	2	2
Required	1	1	1	0	0	0	0	0	0	0	0	1
Redundant	1	1	1	2	2	2	2	2	1	1	2	1
For TRUenergy GS Withdrawal												
Available				2	2	2	2	2	1			
Required				2	2	2	2	2	1			
Redundant				0	0	0	0	0	0			
Maintenance	-	1	-	-	-	-	-	-	1	1	-	-
2 Saturns (S) @ 850 kW and 950 kW												
Available	2	2	2	2	2	2	1	1	2	2	2	2
Required	2	2	2	1	0	0	0	0	0	0	1	2
Redundant	0	0	0	1	2	2	1	1	2	2	1	0
Maintenance	-	-	-	-	-	-	1	1	-	-	-	-

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Wollert Compressor Station												
3 Saturns @ 850 kW												
Available	3	3	3	3	3	3	3	2	2	2	3	3
Required	2	2	2	2	2	2	2	2	2	2	2	2
Redundant	1	1	1	1	1	1	1	0	0	0	1	1
Maintenance	-	-	-	-	-	-	-	1	1	1	-	-
Springhurst Compressor Station												
1 Centaur @ 4,500 kW												
Available	1	1	1	1	1	1	1	1	1	1	0	1
Required	0	0	0	0	0	0	0	0	0	0	0	0
Redundant	1	1	1	1	1	1	1	1	1	1	0	1
Maintenance	-	-	-	-	-	-	-	-	-	-	1	-
Iona Compressor Station												
2 Caterpillars @ 300 kW												
Available	2	2	2	2	1	2	2	2	2	2	2	2
Required	1	1	1	1	1	1	1	1	1	1	1	1
Redundant	1	1	1	1	0	1	1	1	1	1	1	1
Maintenance	-	-	-	-	1	-	-	-	-	-	-	-

1. Only two Centaur compressors are shown on the basis that Unit 10 (wet-seal compressor) is used as a backup only when dry-seal compressors (Unit 11 and 12) are not available

Glossary

Definitions, abbreviations and terminal station names

Definition	Description
1 in 2 peak day	Most probable peak day gas demand forecast, with a 50% probability of exceedence. This is expected, on average, to be exceeded once in 2 years (also known as the 50% peak day).
1 in 20 peak day	Peak day gas demand forecast for severe weather conditions, with a 5% probability of exceedence. This is expected, on average, to be exceeded once in 20 years (also known as the 95% peak day).
AEMC	Australian Energy Market Commission.
AER	Australian Energy Regulator.
AEST	Australian Eastern Standard Time (see also EDST).
AMDQ	Authorised Maximum Daily Quantity.
Annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity and demand and other planning information.
APD	Portland Aluminium (customer owned station).
APS	Anglesea Power Station.
APT	Australian Pipeline Trust (formerly Eastern Australian Pipeline Limited).
ATS	Altona Terminal Station
Augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Australian Pipeline Trust (formerly Eastern Australian Pipeline Limited)	Owner and operator of the Moomba to Sydney pipeline (and laterals).
Authorised Maximum Daily Quantity	In respect of a customer, the maximum daily quantity of gas, expressed in GJ/day, which is authorised by AEMO to be withdrawn by or on behalf of that customer from the transmission system, in accordance with the allocation of authorised MDQ under clauses 5.3.2, 5.3.3 and 5.3.4 of the MSOR.
Back-off	A forced reduction in gas injections.
BassGas	A new project, sourcing gas from the Bass Basin for supply to the gas DTS, and injected at Pakenham.
BATS	Ballarat Terminal Station.
Beginning-of-day linepack	Beginning-of-day linepack (BOD LP) is equal to the end-of-day linepack from the previous gas day.
BETS	Bendigo Terminal Station.
Bid stack	Incremental gas quantities by injection point offered by market participants and stacked in price order.
BLTS	Brooklyn Terminal Station.
BOC	BOC Gases Australia Limited.
BOC Gases Australia Limited.	The BOC plant, situated next to GasNet in Dandenong, liquefies natural gas for storage in GasNet’s LNG tank.
BOD LP	Beginning-of-day linepack.
BOM	Bureau of Meteorology.
Brownfield	A tract of land developed for industrial purposes, polluted, and then abandoned.
BTS	Brunswick Terminal Station.
CAGR	Compound average growth rate.
CBTS	Cranbourne Terminal Station.
CCGT	Combined Cycle Gas Turbine. A type of GPG.

Central dispatch	The process managed by AEMO for the dispatch of scheduled generating units and other services in accordance with Clause 3.8 of the NER.
Coincident peak day demand	Gas used by a given customer or a group of customers on the day of maximum system usage in a given year or month.
Compound average growth rate	The year-over-year growth rate over a specified period of time.
Connection asset	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).
Connection asset constraint	A constraint applying to an asset connecting the electricity transmission network to the distribution network.
Connection point	A gas delivery point, transfer point, or receipt point.
Constraint (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
Constraint (gas)	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
Constraint value estimate	An electricity transmission network constraint's expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example increased fuel cost).
Consumer	See customer.
Contestable augmentation	An electricity transmission network augmentation for which the capital cost is reasonably expected to exceed $10 million and that 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. An event affecting the power system that is likely to involve an electricity generating unit's or transmission element's failure or removal from service.
CPI	Consumer Price Index.
Credible contingency	Any planned or forced outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults.
Critical contingency	The specific forced or planned outage that has the greatest potential to impact on the electricity transmission network at any given time.
CTM	Custody Transfer Meter.
Culcairn	The gas transmission network interconnection point between Victoria and New South Wales.
Curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
Custody Transfer Meter	A meter installed at a connection point to measure gas withdrawn from or injected into a transmission system.
Customer	Any party who purchases gas and consumes gas at particular premises. Customers can deal through retailers or may choose to become market participants in their own right, and take on the retailing functions themselves.
DB	Distribution business.
DD	Degree Day.
DDTS	Dederang Terminal Station.
Degree Day	A commonly used temperature model for predicting gas demand for area/space heating.
Delivery point	The point on a pipeline gas is withdrawn from for delivery to a customer or injection into a storage facility.
Demand-side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).
Demand-side participation	The act of voluntarily shedding electrical load by prior arrangement.
Demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
Distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.

Distribution pipeline	Pipelines for the conveyance of gas that: • have a maximum allowable operating pressure of 515 kPa or less, or • where the maximum operating pressure is greater than 515 kPa, and are uniquely identified as a distribution pipeline in a distributor's access arrangement.
Distributor	The owners of the distribution pipelines that transport gas from the transmission pipelines to the consumer or customer.
DNSP	Distribution network service provider.
DPS	Dartmouth Power Station.
DSP	Demand-side participation.
DTS	Declared Transmission System (gas)
DSN	Declared Shared Network (electricity)
EAPL	East Australian Pipeline Limited.
EAPR	Electricity Annual Planning Report.
East Australian Pipeline Limited	The former operator of the Moomba to Sydney pipeline.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
EDD	Effective Degree Day.
EDST	Eastern Daylight Savings Time (see also AEST).
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. EDD is used to model the daily gas demand-weather relationship.
EGP	Eastern Gas Pipeline.
EHV	Extra high voltage.
End-of-day linepack	End-of-day linepack (EOD LP) is measured at the end of a gas day at 6 am. EOD LP is equal to the beginning-of-day linepack (BOD LP) for the next gas day.
EOD LP	End-of-day linepack.
EPS	Eildon Power Station.
ERTS	East Rowville Terminal Station.
ESC	Essential Services Commission.
Ex-ante	Before the event.
FBTS	Fishermans Bend Terminal Station.
FCAS	Frequency control ancillary service.
FEED	Front-End Engineering and Design.
Firm capacity	Guaranteed or contracted capacity to supply gas.
Flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
Forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
Front-End Engineering and Design	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.
FVTS	Fosterville Terminal Station (customer-owned substation).
Gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
Gas quality excursion	Breach of gas quality limit (as determined by the Gas Quality Guidelines).
Generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as 'used in station load').
Generator-terminal basis	Refers to the demand for electricity as measured at the generator terminals. This measure includes generator auxiliary loads.
GJ	Gigajoule. An SI unit, 1 GJ equals 1x109 Joules.

GNTS	Glenrowan Terminal Station.
GPG	Gas powered generation.
Greenfield	Land (as a potential industrial site) not previously developed or polluted.
GRP	Gross regional product.
GSP	Gross state product.
GTS	Geelong-terminal Station.
GWh	Gigawatt hours.
HDD	Heating Degree Day. See Degree Day.
Heating Degree Day	See Degree Day.
HOTS	Horsham Terminal Station.
HTS	Heatherton Terminal Station.
HVDC	High-voltage direct current.
HWPS	Hazelwood Power Station.
HWTS	Hazelwood Terminal Station.
HYTS	Heywood Terminal Station.
Injection	The physical injection of gas into the transmission system.
Interconnect (The)	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
JLA	Western Port (customer-owned substation).
JLTS	Jeeralang Terminal Station.
k	Thousand.
KGTS	Kerang Terminal Station.
km	Kilometres.
kPa	Kilopascal. A unit for measuring gas pressure.
KTS	Keilor Terminal Station.
kV	Kilovolts.
Lateral	A pipeline branch.
Let-down gas	Gas released from the BOC plant (during the liquefaction processes) into the high pressure distribution system.
Limiter	A regulator installed in a pipeline to reduce pressure and remove the need for heaters at downstream off-takes.
Linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
Liquefied Natural Gas	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.
LNG	Liquefied Natural Gas.
Load shedding	Disconnection of electricity customer load.
Longford Hub	Interconnection hub for the EGP, DTS, TGP pipelines and Gippsland gas supplies.
LOR	Lack of Reserve.
LRA	Long-run average.
LY	Loy Yang Substation (customer-owned substation).
LYPS	Loy Yang Power Station.
M	Million.
MAOP	Maximum allowable operating pressure.
Market customer	A gas customer who is a market participant.
Market participant	A party who is eligible, by registration with AEMO, to trade gas on the spot market by submission of nominations and 'inc/dec' offers to AEMO in accordance with the MSOR.

Maximum allowable operating pressure	The maximum pressure at which a pipeline is licensed to operate.
Maximum daily quantity	Maximum daily quantity of gas supply or demand.
Maximum hourly quantity	Maximum hourly quantity of gas supply or demand.
MBTS	Mount Beauty Terminal Station.
MD	Maximum demand.
MDQ	See Maximum daily quantity.
Meter	A device that measures and records volumes and/or quantities of electricity or gas.
Meter ID number	The number attaching to a daily metered site with annual gas consumption greater than 10,000 GJ or an MHQ greater than 10 GJ, which are assigned as Tariff D in the AEMO meter installation register. See also Tariff D.
Metering	The act of recording electricity and gas data (such as volume, peak, quality parameters etc) for the purpose of billing or monitoring quality of supply.
Metering data	The data obtained from a metering installation, including energy data.
Metering Identification Registration Number (MIRN)	The unique gas supply withdrawal point identifier (daily metered sites and CTMs). See meter ID number.
Metropolitan ring-main	The 450 mm, distributor–owned pipeline from Dandenong to Keon Park to West Melbourne.
MHQ	Maximum hourly quantity.
MIRN	See Metering Identification Registration Number (MIRN).
MKPS	McKay Creek Power Station.
MLTS	Moorabool Terminal Station.
MMt/a	Million, million tonnes per annum.
MPS	Morwell Power Station.
Mt/a	Million tonnes per annum.
MTS	Malvern Terminal Station.
MVA	Megavolt amperes.
MVAr	Megavolt amperes reactive.
MW	Megawatts.
MWh	Megawatt hours.
MWTS	Morwell Terminal Station.
National Electricity Market	The wholesale market for electricity supply in the Australian Capital Territory and the states of Queensland, New South Wales, Victoria, Tasmania and South Australia.
National Institute of Economic and Industry Research	A private economic research, consulting, and training group.
Natural gas	A naturally occurring hydrocarbon composed of between 95 and 99% methane (CH4), the remainder predominantly being ethane (C2H6).
NCAS	Network control ancillary service.
NEM	National Electricity Market.
NEMMCO	National Electricity Market Management Company.
NER	National Electricity Rules.
NGR	National Gas Rules
NIEIR	See National Institute of Economic and Industry Research.
Non-coincident peak day demand	A given customer's (or group of customers') gas demand peak day. This does not necessarily occur at the same time as the system demand peak day.
Non-contestable augmentation	Electricity transmission network augmentations that are not 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. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
NPSD	Newport Power Station.

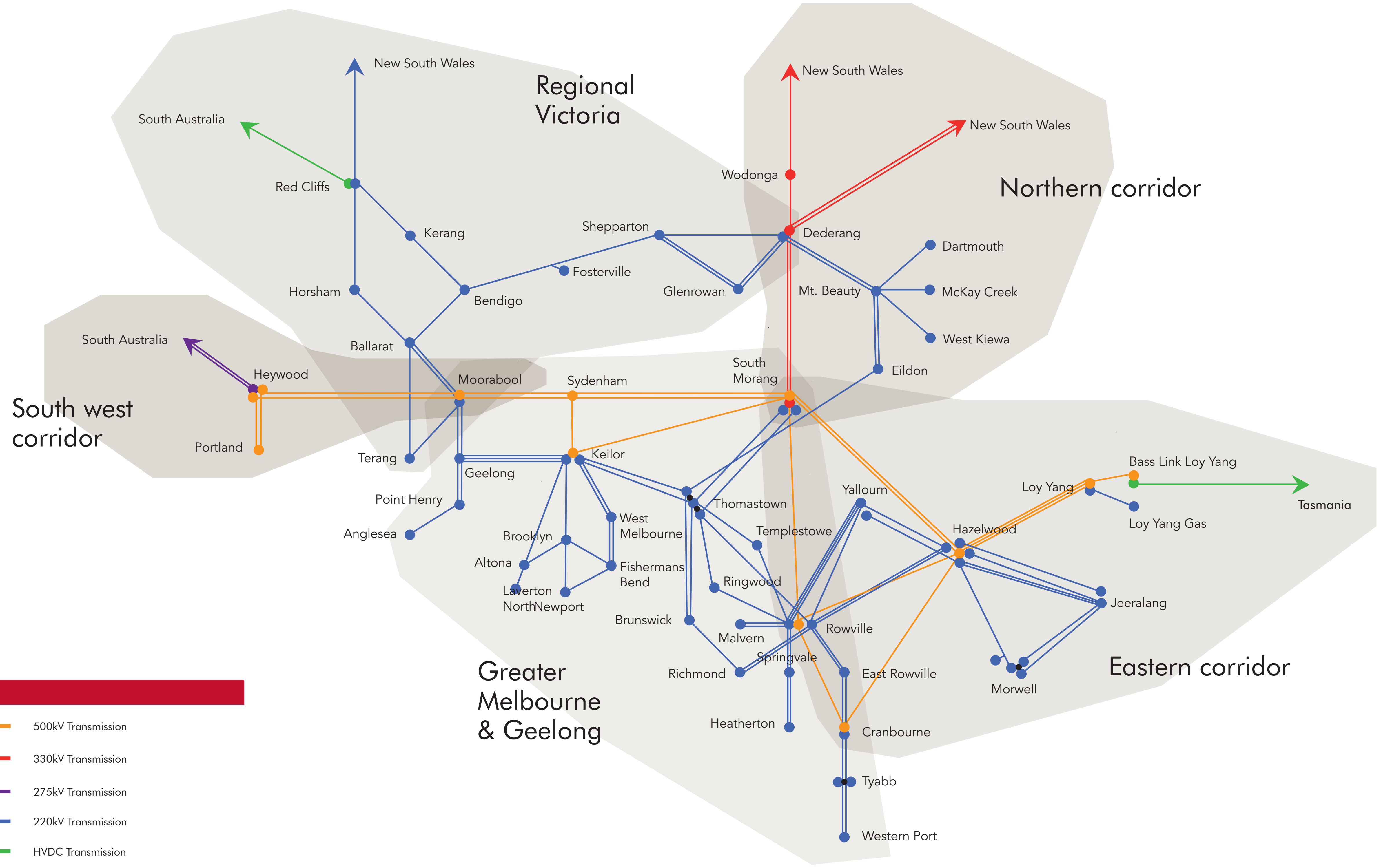
NPV	Net present value.
OCGT	Open cycle gas turbine. A type of GPG.
Otway Hub	The interconnection hub for the SWP, WTS and SEA Gas pipelines, the UGS, and the on-shore and offshore Otway Basin supplies.
Participant	A person registered with AEMO in accordance with the MSOR (Victorian gas industry).
Peak day profile	The hourly profile of injection or demand occurring on a peak day.
Peak flow rate	The highest hourly flow rate of gas or MHQ passing a particular point in the system under normal conditions (as determined by AEMO) in the immediately preceding 12-month period or, if gas has passed a particular point in the system for a period of less than 12 months, the highest hourly flow rate which in the reasonable opinion of AEMO is likely to occur in respect of that system point under normal conditions for the following 12-month period.
Peak shaving	Meeting a demand peak using injections of vaporised LNG.
Petajoule	Petajoule (PJ), SI unit, 1 PJ equals 1x1015 Joules. Also PJ/yr or petajoules per year.
Pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
Pipeline injections	The injection of gas into a pipeline.
Pipeline throughput	The amount of gas that is transported through a pipeline.
PJ	Petajoule.
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.
POE	Probability of Exceedence.
Post-contingent	The timeframe after a power system contingency occurs.
Pre-contingent	The timeframe before a power system contingency occurs.
Declared Transmission System	Owned by GasNet and operated by AEMO, the Declared Transmission System (gas DTS) serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, Geelong, and extending to Port Campbell.
Declared Transmission System constraint	A constraint on the Declared Transmission System (gas DTS). See also Constraint (gas).
Prior outage conditions	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage.
Probability of Exceedence	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% POE maximum demand figure will, on average, be exceeded only 1 year in every 10.
PTH	Point Henry (customer-owned substation).
RCTS	Red Cliffs Terminal Station.
Retailer	Those selling the bundled product of energy services to the customer.
ROTS	Rowville Terminal Station.
RTS	Richmond Terminal Station.
RWTS	Ringwood Terminal Station.
Satisfactory operating state	Operation of the electricity transmission network such that all plant is operating at or below its rating (whether the continuous or (where applicable) short-term rating).
Scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the MSOR, for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
SEA Gas Interconnect	The interconnection between the SEA Gas pipeline and the gas DTS at Iona.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
Secure operating state	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a ‘satisfactory’ state.
Sent-out basis	A measure of demand and energy at the connection point between the generating system and the electricity transmission network. The measure includes consumer load, and transmission and distribution losses.

Shoulder season	The period between low (summer) and high (winter) gas demand, it includes calendar months April, May, October, and November.
SHTS	Shepparton Terminal Station.
SMTS	South Morang Terminal Station.
SOO (AEMO)	Statement of Opportunities.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
Spike loads	A short duration peak in gas demand.
SRMC	Short-run marginal cost.
Statement of Opportunities	The Statement of Opportunities published annually by AEMO.
Storage facility	A facility for storing gas, including the LNG storage facility and the Iona UGS.
Summer	In terms of the electricity industry, December to February of a given fiscal year.
Surprise event	An event that can occur within the day for which, in order to operationally balance the system, AEMO may need to change the schedule of gas injections and/or withdrawals issued at the start of the gas day (due to a change in forecast weather, for example).
SVC	Static Var compensator.
SVTS	Springvale Terminal Station.
SWP	South West Pipeline.
SWZ	System withdrawal zone.
System capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • load distribution across the system • hourly load profiles throughout the day at each delivery point • heating values and the specific gravity of injected gas at each injection point • initial linepack and final linepack and its distribution throughout the system • ground and ambient air temperatures • minimum and maximum operating pressure limits at critical points throughout the system, and • powers and efficiencies of compressor stations.
System coincident peak day	The day of highest system demand (gas). See also system demand.
System constraint	See Declared Transmission System (DTS) constraint.
System demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes GPG demand, exports, and gas withdrawn at Iona.
System injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
System normal constraint	A constraint that arises even when all electricity plant is available for service.
System withdrawal point	A gas DTS connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
System withdrawal zone	Part of the gas DTS that contains one or more system withdrawal point/s and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
SYTS	Sydenham Terminal Station.
t/d	Tonnes per day.
t/h	Tonnes per hour.
t/m	Tonnes per month.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption > 10,000 GJ or MHQ > 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).

Tariff order	The Tariffs and Charges Order made under section 48A of the Gas Industry Act and any Tariffs and charges that are approved under an access arrangement.
Tariff V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users.
Tasmanian Gas Pipeline	The pipeline from VicHub (Longford) to Tasmania.
TBTS	Tyabb Terminal Station.
Terajoule	Terajoule (TJ). An SI unit, 1 TJ equals 1x1012 Joules.
TGP	Tasmanian Gas Pipeline.
TGTS	Terang Terminal Station.
TJ	Terajoule.
TJ/d	Terajoules per day. See also Terajoule.
TNSP	Transmission network service provider.
TOC	Transmission Operations Centre (formally VNSC).
Transmission	Long haul transportation of gas via high pressure pipelines.
Transmission customer	A customer that withdraws gas from a transmission delivery point.
Transmission delivery point	A point on the gas DTS at which gas is withdrawn from the transmission system and delivered to a transmission customer or injected into a storage facility.
Transmission pipeline	A pipeline that is not a distribution pipeline.
Transmission pipeline owner	A person who owns or holds under a lease a transmission pipeline that is being or is to be operated by AEMO.
Transmission system	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
TSTS	Templestowe Terminal Station.
TTS	Thomastown Terminal Station.
UAFG	Unaccounted for gas.
UGS	Underground Gas Storage.
Unaccounted for gas	The difference between metered injected gas supply and metered and allocated gas at delivery points. UAFG comprises gas losses, metering errors, timing, heating value error, allocation error, and other factors.
Underground Gas Storage	The Underground Gas Storage (UGS) facility at Iona.
Unserved energy (USE)	The amount of energy that cannot be supplied because there is insufficient generation to meet demand.
USE	Unserved energy.
Value of Lost Load	VoLL is a price cap applied to dispatch prices. The value of VoLL, which is set by the reliability panel, is currently $10,000 per MWh.
VCR	Value of Customer Reliability.
VENCorp	Victorian Energy Networks Corporation.
VicHub	The interconnection between the EGP and the gas DTS at Longford, facilitating gas trading at the Longford hub.
VoLL	Value of Lost Load.
VPGS	Valley Power Gas Station.
Western Transmission System (WTS)	Western Transmission System. The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the gas market and the gas DTS.
Winter	In terms of the electricity industry, June to August of a given calendar year.
WKPS	West Kiewa Power Station.
WMTS	West Melbourne Terminal Station.
WOTS	Wodonga Terminal Station.
WTS	See Western Transmission System.
YPS	Yallourn Power Station.

ELECTRICITY NETWORK

Victorian shared electricity transmission network
topological representation



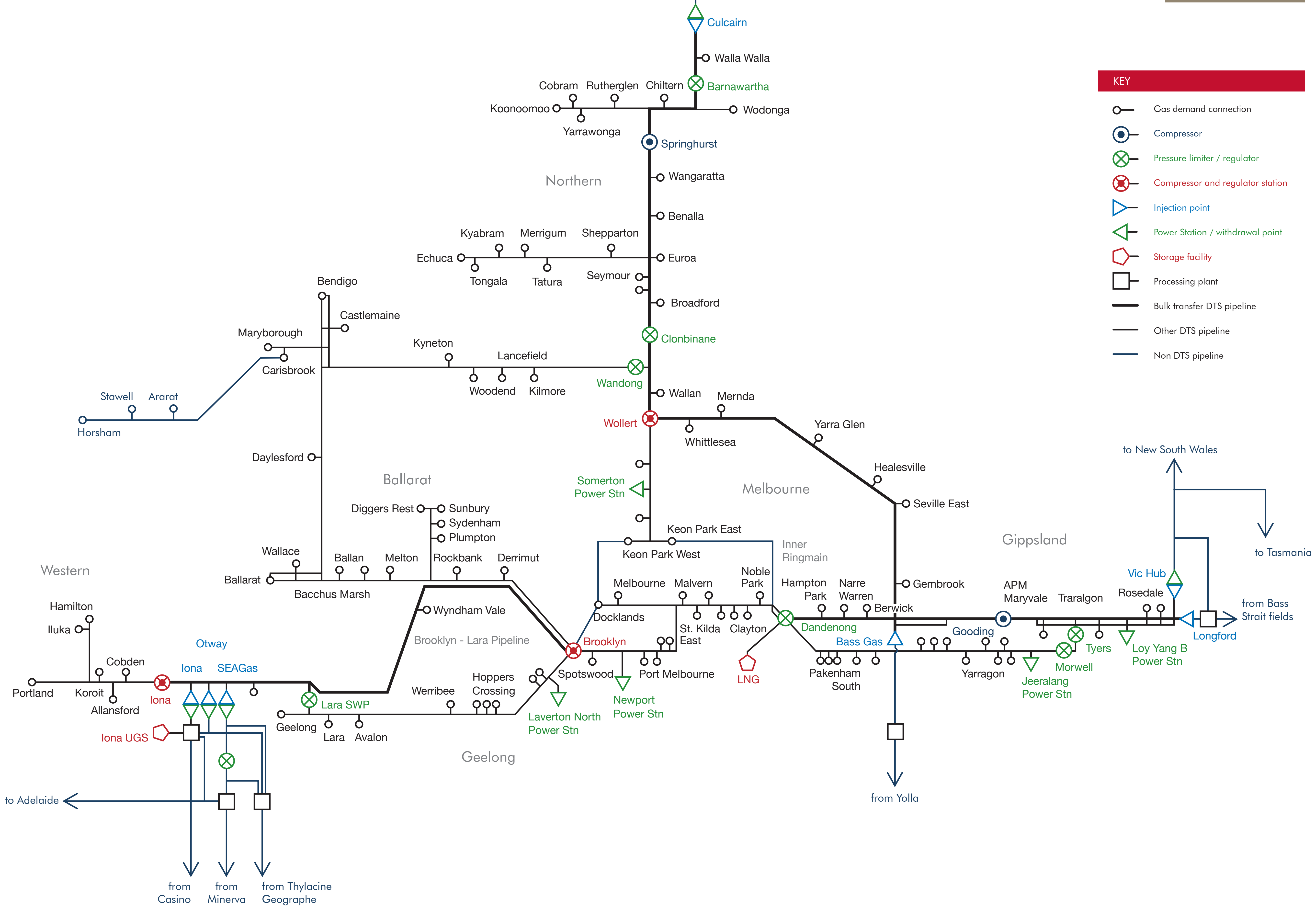
KEY

- 500kV Transmission
- 330kV Transmission
- 275kV Transmission
- 220kV Transmission
- HVDC Transmission
- Switching Station / Node (500, 330, 275, 220, 66kV and HVDC)
- Switching Stations with tie transformer(s) between multiple voltages
- Regional boundary point

GAS NETWORK

Victorian gas transmission network
topological representation

GAS NETWORK



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