ATTACHMENT A1 - VICTORIAN GAS DTS MEDIUM TERM OUTLOOK

Summary

Introduction

This attachment to the 2011 GSOO provides medium-term Victorian gas demand and supply capability forecasts for the Victorian Declared Transmission System (DTS). These supplement or supersede the forecasts provided in the 2011 Victorian Annual Planning Report (VAPR)[1] that was published by the AEMO in June 2011.

The National Gas Rules (NGR) require that by 30 November each year, AEMO publishes a planning review covering the DTS. That review must assess the supply–demand outlook and the adequacy of gas system capacity, and provide additional information about maintenance plans, gas reserves, and gas pipeline developments.[2] The VAPR satisfies those requirements, but with two exceptions. The latest gas demand and supply-capability forecasts, and information about liquefied natural gas (LNG) usage for the following winter period are delayed until actual DTS operational data from the most recent winter becomes available.

In years prior to 2011, this supplementary information was published in a document known as the VAPR Update (VAPRU).[3] However, in 2011 this information is published in the following two documents:

- this 2011 GSOO, including this attachment entitled, Victorian Gas DTS Medium Term Outlook, and
- Victorian Gas System Adequacy for 2012, a document which is published only on the internet.[4]

Table A1-1 compares the content of these documents. The table emphasises that the Victorian Gas System Adequacy for 2012 document, as indicated by its title, focuses on information specific to 2012 gas system operations. On the other hand, this attachment provides forecasts for up to a 10-year outlook period.

This attachment also provides:

- a discussion of key Victorian and Australian Government energy policies that might impact gas demand, and
- results of the most recent gas customer demand survey.

Key messages regarding gas demand forecasts

In 2011, gas demand on the DTS, including gas demand for DTS-connected gas powered generation (GPG), is forecast to be 213 PJ.

In 2011, the largest demand segment on the DTS is known as the Tariff V segment, which covers residences and business customers with gas demand lower than 10 TJ/yr. This segment is forecast to consume nearly 58% of DTS gas demand. Commercial and industrial gas users with gas demand greater than 10 PJ/yr, known as the Tariff D market segment, are forecast to consume approximately 38% of gas demand in 2011. Gas demand for GPG is forecast to make up approximately 4% of total DTS gas demand.

In the medium growth scenario, total annual demand on the DTS is forecast to decline to a minimum of 205 PJ/yr in 2014. Demand is then projected to increase. Demand grows at an average rate of 1.5%/yr over the 10-year demand outlook period.

[1] AEMO. “2011 Victorian Annual Planning Report”. June 2011. Available http://www.aemo.com.au/planning/VAPR2011/vapr.html.

[2] See the National Gas Rules, Rule 323 for a full list of matters to be covered in annual planning reviews. Available http://www.aemc.gov.au/Gas/National-Gas-Tules/Current-Rules.html

[3] AEMO. “2010 Victorian Annual Planning Report Update”. Published 30 November 2010. Available http://www.aemo.com.au/planning/0400-0026.pdf.

[4] Available http://www.aemo.com.au/planning/planning_gas.html

Gas demand for GPG is forecast to increase by nearly five times over that period (medium scenario). Tariff V demand is forecast to grow with population and household income growth by an average of approximately 0.7%/yr. However, Tariff D demand is forecast to decline at an average rate of approximately 0.5%/yr.

The forecast gas demand growth on the DTS (1.5%/yr) is significantly less than the average 2%/yr forecast in last year's VAPR Update because of:

- greater global economic uncertainty
- the increasing certainty of carbon pricing commencing on 1 July 2012, and
- forecast downsizing of manufacturing plant operations or plant closures.

For example, Tariff D (larger commercial and industrial customers) demand is now forecast to reach 75 PJ/yr in 2020 compared with last year's forecast figure of 87 PJ/yr.

Key messages regarding gas supply capability forecasts

The available peak day supplies are sufficient to supply the 1-in-20 peak day demand throughout the five-year outlook period (2012 to 2016).

The capacity of the South West Pipeline limits Melbourne's access to gas supply from south-western Victoria.

The gas supply forecasts, which are based on information provided by gas producers, storage providers, and market participants, assume that there are no external factors that will prevent gas supplies to the Victorian gas market, should an event affecting supply occur in markets elsewhere.

Table A1-1 — Comparative content of Victoria-relevant AEMO gas planning documents

	2011 GSOO Chapter 5	Victorian Gas DTS Medium Term Outlook (2011 GSOO Attachment A1)	Victorian Gas System Adequacy for 2012 (internet publication only)
Gas demand forecasts			
Annual	20-year scenario-based projections for all of Victoria.	10-year high, medium, and low forecasts for the Victorian gas DTS only, and forecasts by System Withdrawal Zone (SWZ) for the medium economic growth case only.	
Monthly			Forecasts for each month in 2012 for the entire DTS and by SWZ.
Peak day	10-year scenario-based projections for all of Victoria.	10-year forecasts by DTS and by SWZ.	Forecasts for each month in 2012 for the entire DTS and by SWZ.
Peak hour		10-year forecasts by DTS and by SWZ.	Forecasts for each month in 2012 for the entire DTS and by SWZ.
Latest winter data	Not included.	Included in forecasting process.	Included in forecasting process.
Gas supply capability assessment and forecasts			
Annual	20-year scenario-based projections for all of Victoria.	5-year forecasts by injection point.	
Peak day	10-year scenario-based projections for all of Victoria.	5-year forecasts by injection point.	Forecasts for each month in 2012 by injection point.

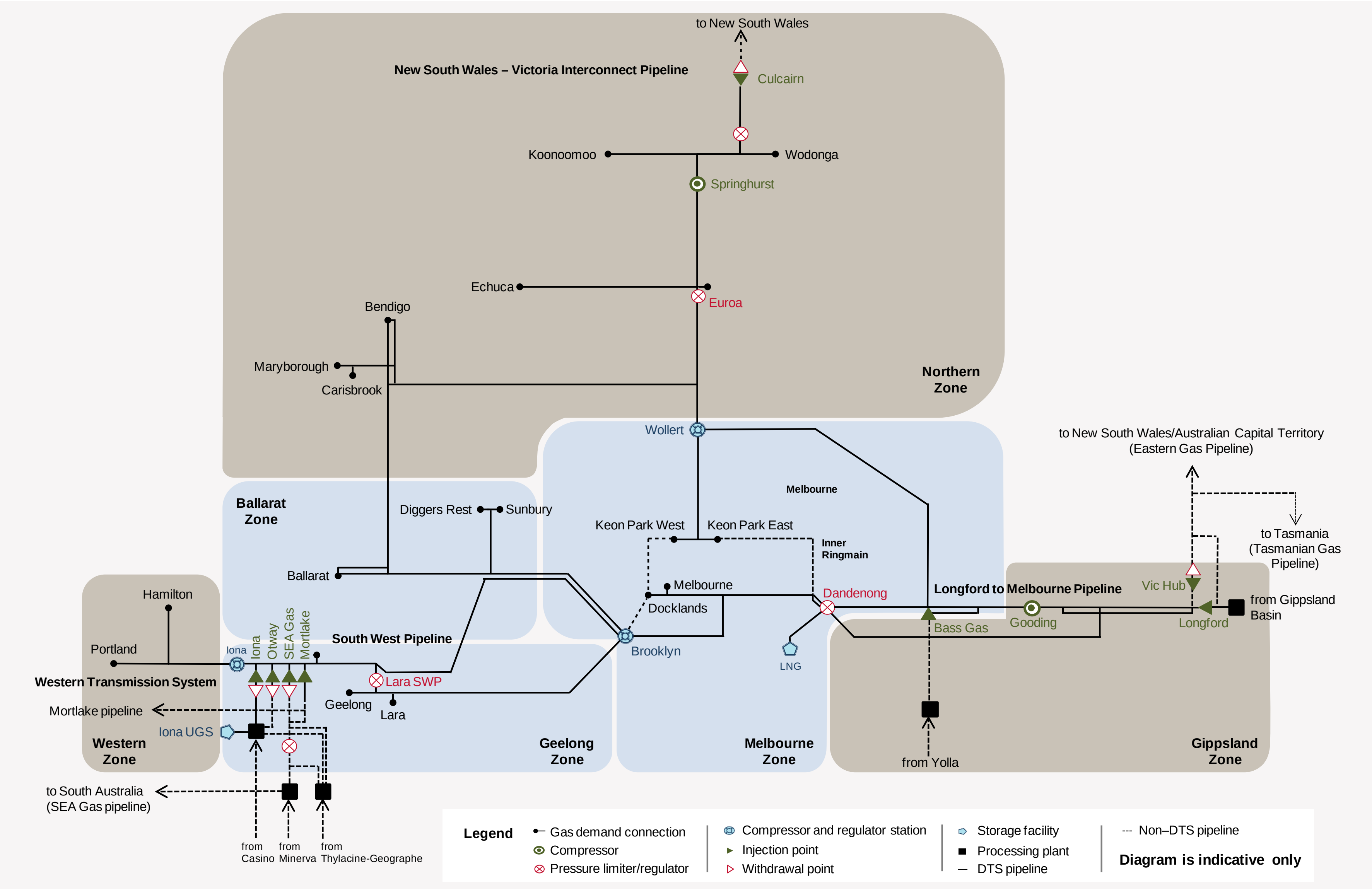
A1.1 Description of the Victorian gas Declared Transmission System and system withdrawal zones

Under the National Gas Rules, AEMO is required to publish demand forecasts for the Victorian gas Declared Transmission System (DTS) as a whole and for the following six defined regions known as system withdrawal zones (SWZs):

- Ballarat
- Geelong
- Gippsland
- Melbourne
- Northern, and
- Western.

Figure A1-1 is an indicative drawing showing some features of the Victorian gas DTS and the location of SWZs.

Figure A1-1 — Diagram of Victorian gas DTS showing SWZ locations



A1.2 Government policies impacting Victorian gas demand

This section describes Victorian and Australian Government policies that might impact gas demand.

Table A1-2 provides an overview of eight policies, some of which are described in more detail in the following sections.

Table A1-2 — Key policies that might impact Victorian gas demand

Jurisdiction	Measure	Description of Impact on Gas Demand
National		
Clean Energy Future plan	Carbon price, energy efficiency, renewable energy.	Impact on generation merit order, price elasticity of demand by sector, and energy efficiency measures.
Energy Efficiency Opportunities Regulations (2006)	Assessment of energy efficiency opportunities from large energy users.	Energy savings; potential cogeneration and trigeneration opportunities.
Minimum Energy Performance Standards (MEPS)	MEPS for gas hot water heaters. Possible energy labelling for gas space heaters and cookers standards.	Gas appliance penetration and appliance efficiency.
Mandatory Disclosure (*Energy Efficiency Disclosure Act 2010*)	Residential and commercial energy performance when sold or leased (existing buildings).	Impacts gas use for space heating.
Federal Insulation Program 2009–10	Insulation subsidy for existing uninsulated dwellings.	Program ended in 2010, however ongoing impact on gas demand for space heating.
Renewable Energy Target (RET)	Targeted renewable energy production through certificate scheme – hot water eligible.	Significant impact via switch to solar hot water.
State		
Victorian Energy Efficiency Target (VEET) Phase Two	Retailers are required to meet targets mainly through energy efficiency measures.	Small impact on gas demand. Larger impact on electricity demand because of lighting upgrades.
6 Star Building Standards	Building standards for new dwellings.	Significant savings in gas space heating.

A1.2.1 Australian Government Clean Energy legislative package

On 8 November 2011, the Australian Government's Clean Energy Future plan[5] was passed into law. The legislation includes:

- putting a price on carbon pollution
- promoting innovation and investment in renewable energy
- improving energy efficiency, and
- creating opportunities in the land-use sector to cut carbon pollution.

Under the plan, Australia will reduce greenhouse gas pollution by at least five percent (compared with 2000 levels) by 2020, equivalent to removing 159 Mt/yr CO2-e from the atmosphere by 2020.

The bills confirmed a carbon tax is to be introduced by 1 July 2012 at a price of 23 $/t CO2-e, rising by 2.5%/yr plus inflation over the first three years before shifting to an emissions trading scheme from 1 July 2015.

A1.2.2 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target[6] (VEET) scheme commenced on 1 January 2009. It sets a target for energy savings, initially in the residential sector, and requires energy retailers to meet their own targets through energy efficiency activities such as providing households with energy saving products and services. The VEET scheme plays a role in achieving the Victorian Government's target of reducing Victoria's greenhouse gas emissions to 60% by 2050.

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 operates from 1 January 2009 to 31 December 2011.

On 24 May 2011 the Minister for Energy and Resources amended the Regulations to double the scheme target to 5.4 Mt/yr CO2-e for the second three-year phase beginning on 1 January 2012. Separately, the Minister announced that the scheme would be expanded from the residential to the business sector from the same date.

AEMO's forecasts incorporate a notional impact of the VEET scheme on residential gas demand. While the VEET scheme for some households might serve to increase residential gas demand, as these households substitute gas appliance use for comparable electricity appliance use, the net effect across all households is likely to reduce gas demand compared with a business-as-usual case.

A1.2.3 Energy Efficiency Opportunities regulations

The *Energy Efficiency Opportunities Act 2006* mandates that businesses with energy demand greater than 0.5 PJ/yr must report on energy savings opportunities with less than four year payback and report on implementation of these opportunities. The first phase of the Energy Efficiency Opportunities (EEO) program extended over the period 2006 to 2011. The second phase covering the period 2012 to 2017 is now being planned.

A report released in 2010 by the Department of Resources Energy and Tourism entitled "First Opportunities: A look at the results from 2006–2008[7] for the EEO program" noted that by 2009, EEO entities had identified energy savings of 67.7 PJ/yr. Of these identified savings, 61 PJ/yr had been, or were in the process of being implemented. Of these, 60% were expected to have a pay-back period of less than two years.

5 Available http://www.climatechange.gov.au/government/legislation.aspx.
6 Available http://www.esc.vic.gov.au/public/VEET/.
7 Available http://www.ret.gov.au/energy/efficiency/eeo/industry-sector/commercial/Pages/CommercialServices.aspx.

As part of the Australian Government's Clean Energy Future plan, the EEO program will be expanded.[8] This includes:

- extending base funding for the program out to 30 June 2017
- expanding the program to include energy transmission and distribution networks, and major greenfield and expansion projects, as recommended in the 2010 Prime Minister's Task Group on Energy Efficiency, and
- establishing a voluntary scheme for medium-sized energy users.

The Australian Government is working with industry on the implementation of the program.

A1.2.4 6 Star Standard

From 1 May 2011, the 6 Star Standard[9] was introduced in Victoria to align with the national energy efficiency measures in the Building Code of Australia – Volumes One and Two of the National Construction Code Series.

The 6 Star Standard applies to the thermal performance of a new home, home renovations, alterations, additions and relocations plus the requirement to install a solar water heater system or a rainwater tank for toilet flushing in new homes.

A1.2.5 Residential and commercial building mandatory disclosure

The Standing Council on Energy and Resources released the Regulatory Impact Statement for Residential Mandatory Disclosure[10] on 21 July 2011, detailing the options under consideration for implementing this legislation, and signalling the start of the public consultation process. The Victorian Government, as part of a nationwide process, is drafting the new disclosure rules for the benefit of potential buyers or tenants.

The law, also known as Environmental Performance Disclosure, is expected to be introduced into Victoria in 2012 for the residential sector. This means that people selling or leasing houses might be required to produce an energy efficiency rating performed by an accredited assessor.

From 1 November 2010 under the *Building Energy Efficiency Disclosure Act 2010*, commercial mandatory disclosure requires most sellers or lessors of office space of 2,000 or more square metres to obtain and disclose an up-to-date energy efficiency rating.[11] New commercial building standards and promotion of higher star ratings is promoting better energy performance investment in new and existing buildings. This will reduce gas demand for these buildings.

A1.2.6 Minimum Energy Performance Standards

Mandatory Minimum Energy Performance Standards (MEPS) and Energy Rating Labels[12] are implemented through a collaborative initiative called the Equipment Energy Efficiency Program involving representatives drawn from all jurisdictions in Australia and New Zealand.

There are currently no MEPS for gas space heaters and gas water heaters. The gas appliance labelling program is currently an industry voluntary scheme, but a review of the scheme is underway by the gas industry and governments.

[8] Available http://www.ret.gov.au/energy/efficiency/eeo/Pages/default.aspx.
[9] Available http://www.buildingcommission.com.au/www/html/2562-introduction-of-6-star.asp.
[10] Available http://www.ret.gov.au/Documents/mce/energy-eff/nfee/about/stage1.html.
[11] Available http://www.cbd.gov.au/LegalResponsibilities.aspx.
[12] Available http://www.energyrating.gov.au/.

A1.3 Demand forecast basis and methodology

A1.3.1 Definition of demand forecast terms

Forecast and actual data in this section pertain to gas days starting from 6:00 AM.

In this attachment, “system demand” includes:

- Tariff D customer demand: larger commercial and industrial customers nominally consuming more than10 TJ/yr of gas, and
- Tariff V customer demand: residential, small commercial, and industrial customers nominally consuming less than 10 TJ/yr of gas.

Excluded from the definition of system demand are:

- gas demand for GPG
- gas exports by pipeline to other states, and
- gas withdrawn at Iona for storage underground.

Distribution losses are included in the forecasts while losses from transmission pipelines are assumed to be zero.

Demand forecasts for this section were developed by the National Institute of Economic and Industry Research (NIEIR) using NIEIR’s state and energy industry based projection models.

A1.3.2 Economic growth scenarios

The gas demand forecasts in this chapter were prepared for high, medium and low economic growth scenarios[13] in conjunction with carbon prices in the core policy scenario modelled by Treasury in September 2011.[14] The economic forecasts used in this attachment were largely based on economic forecasts from KPMG prepared for AEMO in August 2011.[15]

A1.3.3 Demand forecast methodology and assumptions

This section outlines the methodology used to prepare the forecasts. Forecasts were prepared for the overall DTS and for each SWZ for the following aspects of demand:

- annual system demand
- annual demand for GPG
- peak day system demand, and
- peak hour system demand.

Annual demand forecast approach

The annual system demand forecasts are generated from econometric models using key forecast economic inputs including:

- Victorian gross state product
- state industry output projections, and
- projections of state population, dwelling stocks, real household disposable income, gas and electricity prices and consumer price index.

[13] These scenarios differ from those described and used in the main body of the GSOO.

[14] Australian Government, The Treasury. “Strong growth low pollution: modelling a carbon price," 21 September 2011. Available http://www.treasury.gov.au/carbonpricemodelling/content/update/Modelling_update.asp.

[15] KPMG. “Stage 2 Report: Update, A report to the Australian Energy Market Operator (AEMO), 15 September 2011”.

Other factors taken into account when preparing the forecasts include:

- a survey of major industrial users on planned expansions or reductions including gas cogeneration (see Section A1.3.5)
- market information obtained from media reports
- federal and state government energy policies, as described in Section A1.2, and
- standard weather conditions. Victorian gas demand is highly sensitive to weather variations and therefore, gas demand forecasts are based on standard weather conditions (refer to Attachment 2 of the 2009 VAPR Update for the methodology).[16]

The econometric models generate annual demand forecasts for the industrial, commercial, and residential sectors, and for each major industry group.[17] The forecasts are adjusted with demand variation information from the major gas customer survey and market information, and policies that might influence gas demand.

The annual system demand forecast by SWZ is generated by analysing historical Tariff D demand by industry sector and historical Tariff V demand to determine heating and non-heating loads in each SWZ.

Peak day system demand forecast approach

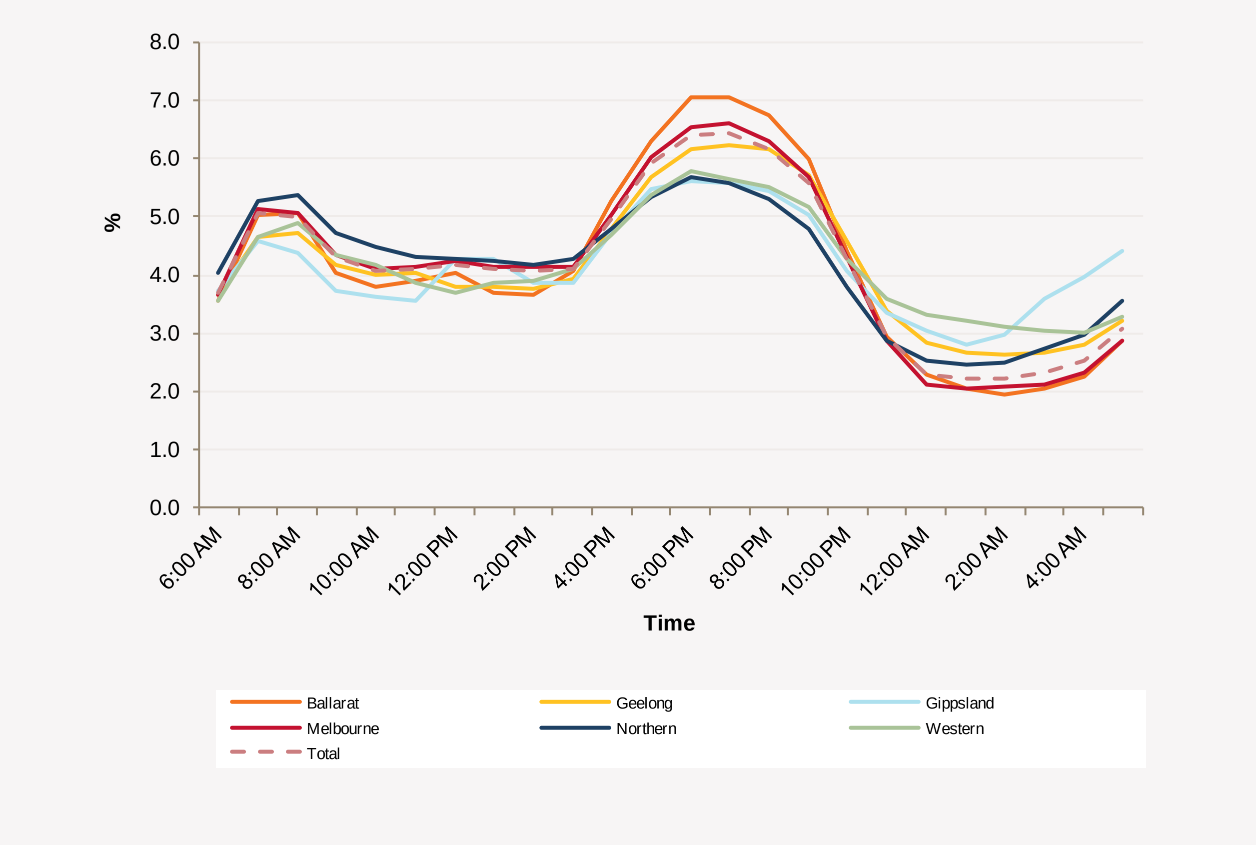
The peak day system demand forecast is determined by applying load factors[18] to the average daily demand, derived from the annual demand forecasts. Peak day forecasts are calculated for Tariff D and V separately, which are then added together to provide the DTS system demand forecast.

16 Available http://www.aemo.com.au/planning/0400-0003.pdf. June 2009.
17 As defined by the Australian and New Zealand Standard Industry Classifications (ANZSIC).
18 Defined as the ratio of the average daily demand to the peak day demand.

Peak hour system demand forecast approach

Winter peak day hourly demand profiles for each SWZ and the total system are shown in Figure A1-2. Demand peaks at around 8:00 AM and again at around 6:00 PM primarily because of residential demand.

Figure A1-2 — Winter peak day hourly demand profiles, by SWZ



The peak hour system demand forecasts for each SWZ are produced by applying the proportion of gas used in the peak hour on a selection of high demand days in the previous winter to the peak day forecasts. The growth rates are assumed to be the same as for the peak day forecasts.

Peak hour system demand forecasts are prepared for 1-in-2 and 1-in-20 peak day weather standards.

The peak hour demand forecasts in each SWZ are unlikely to coincide. Peak hour demand in some SWZs will occur in the morning while in others it will occur in the evening. Evening peaks associated with residential gas heating usually occur between 6:00 PM and 7:00 PM. Morning peaks due to heating, hot water and industry start-up usually occur between 7:00 AM and 8:00 AM.

A1.3.4 Differences between these forecasts and GSOO Chapter 5 projections

The Victorian gas demand forecasts published in this attachment were prepared using similar methodologies as were used to produce Victorian gas demand projections published in Chapter 5. However, there are several key differences between the two sets of forecasts and projections, as outlined below:

- The demand forecasts in this attachment cover gas demand on the DTS only, whereas the projections published in Chapter 5 cover the entire state of Victoria.
- The forecasts of gas demand for GPG published in this attachment cover DTS-connected gas powered generators only. Victorian gas demand projections published in Chapter 5 also cover Victorian gas powered generators that are outside the DTS.
- The forecasts published in this attachment incorporate an analysis of winter gas demand data up to 31 August 2011. Victorian gas demand projections published in Chapter 5 incorporate demand data up to 31 May 2011.
- The demand forecasts in this attachment were prepared based on carbon prices in the core policy scenario[19], starting from 1 July 2012, which was published by the Australian Treasury in September 2011. The modelling for demand projections published in Chapter 5 use the carbon pricing projections described in Chapter 1 that assume that carbon pricing starts on 1 July 2013.
- The demand forecasts in this attachment incorporate the latest information regarding plant downsizing or closures forecast by a number of large industrial gas customers. These supersede what is presented in Chapter 5.

A1.3.5 Gas customer survey

In May 2011, NIEIR undertook a survey of 190 Victorian industrial and commercial gas customers. The survey sought information regarding their recent and future gas demand in order to assess gas demand trends. This section provides a high-level overview of the survey responses.

Many survey respondents expressed some uncertainty regarding their responses. In developing the forecasts for Tariff D demand, NIEIR evaluated the 2011 survey information against the 2010 responses, other economic information, and publicly available information.

[19] See note 14 in this attachment.

Survey response rate

Table A1-3 shows the number of returned surveys by industry segment.

Of the 190 customers surveyed, 99 responded, including 14 of the top 20 gas customers. The whole survey group consumed approximately 70 PJ of gas in 2010. The share of Tariff D segment gas consumed by the responding customers was 71%.

Table A1-3 — 2011 gas customer survey response rate, by industry segment

Industry segment	Number of surveys sent out	Response rate (%)	Response rate in terms of 2010 gas demand (%)
Accommodation / cafe / restaurant, cultural, recreational, and personal services	3	0	0
Agriculture	6	17	14
Basic & fabricated metal products manufacturing	12	67	81
Chemicals, petroleum, coal manufacturing	21	67	63
Finance, insurance, property & business services	3	0	0
Food, beverages, tobacco manufacturing	59	42	60
Government administration, defence, education, health, and community services	23	43	66
Non-metallic minerals manufacturing	26	85	89
Textiles, clothing and footwear manufacturing	9	44	35
Transport, storage, and communication services	3	33	62
Transport and other machinery equipment manufacturing	9	67	86
Wood and paper, wood products, and paper product manufacturing	16	44	79
Total or overall %	**190**	**52**	**71**

Survey results summary

Table A1-4 shows the aggregated forecast gas demand of responding Tariff D customers.

A number of industrial consumers intend to close or downsize by the end of 2012 and this leads to decreasing demand in 2011 and 2012.

Gas demand is forecast to increase in 2013 due to the operation of some cogeneration plants.

Table A1-4 — Responding customers' forecasts of annual gas demand (aggregated)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Annual demand (TJ)	73,043	72,403	71,565	72,647	73,144	73,316	73,305	73,191	73,451	73,714
Year-to-year change (%/yr)	n/a	-0.9	-1.2	1.5	0.7	0.2	0.0	-0.2	0.4	0.4

A1.4 Demand forecasts

This section presents forecasts of demand for gas supplied through the DTS, including forecasts of:

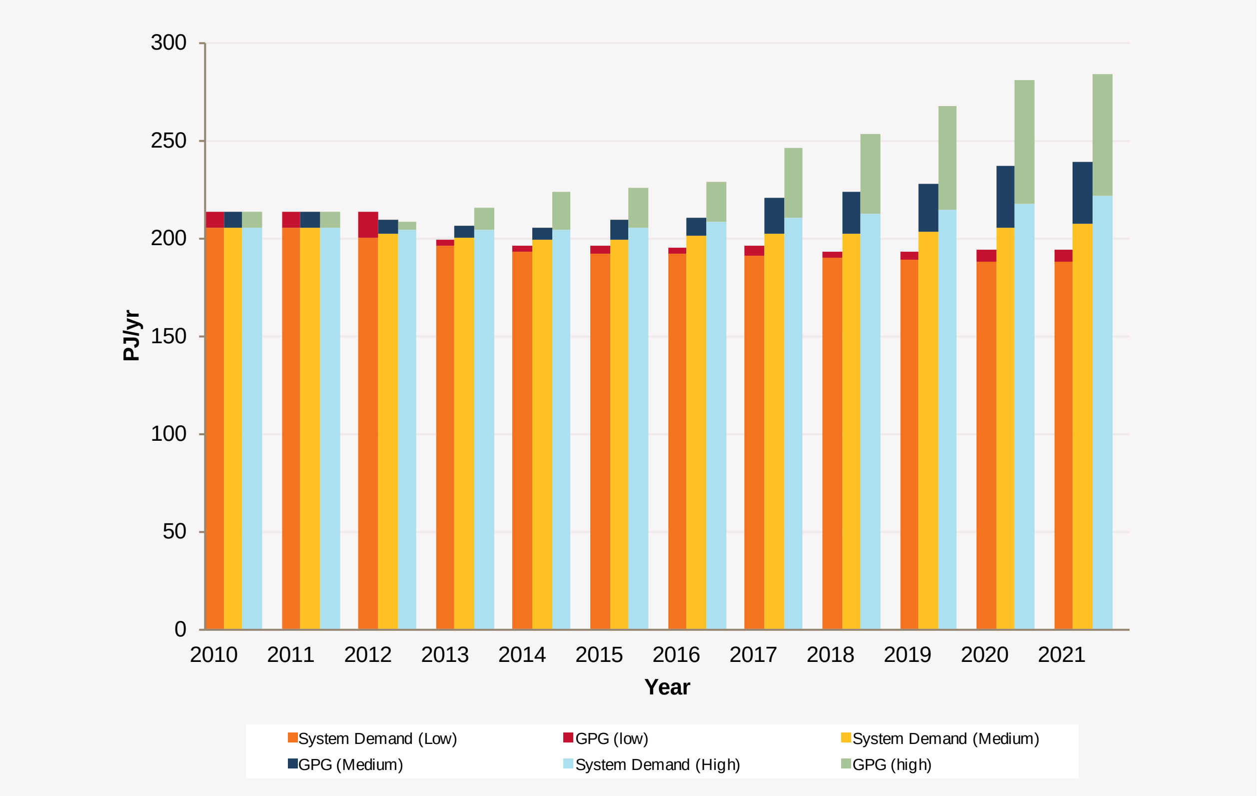
- annual system plus DTS-connected GPG demand for all economic growth scenarios
- annual system demand for all scenarios
- annual system demand by SWZ for the medium scenario
- annual DTS-connected GPG demand for all scenarios
- 1-in-2 and 1-in-20 peak day system demand for the medium scenario
- 1-in-2 and 1-in-20 peak day system demand by SWZ for the medium scenario
- peak hour system demand by SWZ for the medium scenario, and
- gas exports to other states.

A1.4.1 Annual system plus DTS-connected GPG forecast

Figure A1-3 and Table A1-5 show annual system plus DTS-connected GPG demand forecast for the low, medium and high economic growth scenarios.

Over the period 2012 to 2021, demand increases by 14% in the medium scenario.

Figure A1-3 — Annual system plus DTS-connected GPG forecast, all scenarios[20]



[20] 2010 figures are based on actual data.

Table A1-5 — Annual system plus DTS-connected GPG demand forecast, all scenarios (PJ/yr)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr) 2012-2021
High	213	217	215	224	226	229	246	253	268	281	284	3.0
Medium	213	209	206	205	209	211	221	224	227	236	239	1.5
Low	213	205	199	196	196	195	196	193	193	194	194	-0.6
Last year's forecast												**2011-2020**
High	219	226	227	259	254	282	293	298	298	313	n/a	4.0
Medium	218	221	221	246	234	253	257	255	250	261	n/a	2.0
Low	216	216	212	232	217	231	230	225	218	227	n/a	0.6

A1.4.2 Annual system demand forecast (excluding GPG)

Table A1-6 shows forecast annual system demand (Tariff D plus Tariff V) for the low, medium, and high economic growth scenarios.

In the medium economic growth case, annual system demand falls from 205 PJ in 2011 to a minimum of 199 PJ in 2014. Annual system demand is then forecast to increase to 207 PJ in 2021.

Tariff D forecast demand (consumers using more than 10 TJ/yr) declines from 82 PJ in 2011 to a minimum of 75 PJ in 2018.

Factors influencing Tariff D demand include:

- building cycle sensitivities
- increased competition from overseas imports in the manufacturing sector
- gas powered cogeneration and trigeneration by commercial and industrial customers, and
- responses to future carbon costs in the energy sector.

Tariff V forecast demand (consumers using less than 10 TJ/yr) remains constant at 123 PJ from 2011 to 2014 and then increases to 131 PJ in 2021.

Tariff V demand is driven by population growth, employment levels and household income, and is mitigated by improved gas appliance efficiency, increased reverse-cycle air conditioner usage for heating, and reduced water heating demand due in part to lower water use.

Table A1-6 — Annual system demand forecast (excluding GPG), all scenarios (PJ/yr)

	2011[a]	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's system demand forecast												**2012-2021**
High	205	204	204	204	206	208	210	212	214	218	221	0.9
Medium	205	202	200	199	199	201	202	202	203	205	207	0.2
Low	205	200	196	193	192	192	191	190	189	188	188	-0.7
This year's system demand forecast by market segment (medium growth scenario)												**2012-2021**
Tariff D	82	79	77	76	76	76	76	75	75	75	76	-0.5
Tariff V	123	123	123	123	124	125	126	127	128	130	131	0.7
Last year's system demand forecast by market segment (medium growth scenario)												**2011-2020**
Tariff D	85	86	86	86	86	87	87	87	87	87	n/a	0.3
Tariff V	123	125	127	128	128	128	129	130	131	132	n/a	0.8
Total	**208**	**211**	**213**	**214**	**214**	**215**	**216**	**217**	**218**	**219**	**n/a**	**0.6**

a. The calculations for the year 2011 involve eight months of weather-normalised, actual metering data, to the end of August 2011, and then forecasts for the rest of 2011.

Comparison with last year's annual system demand forecasts, medium growth scenario

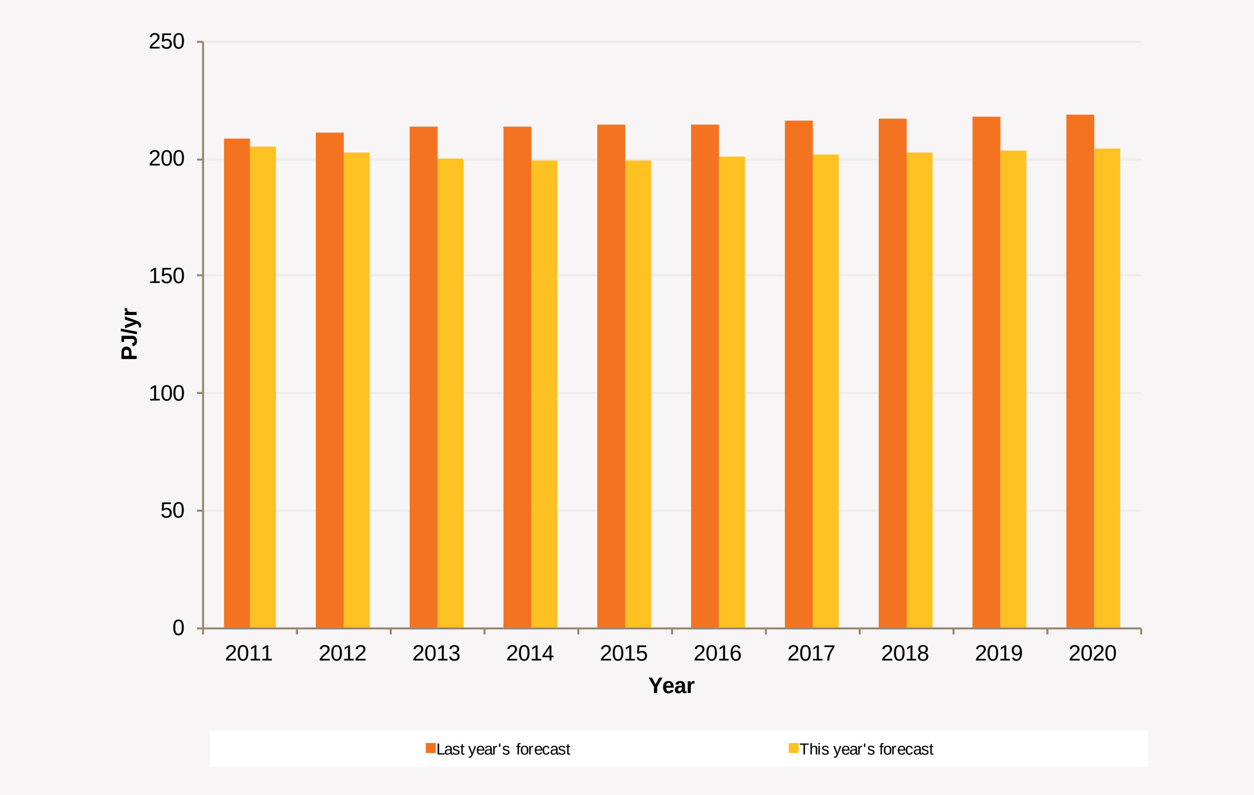
Table A1-6 and Figure A1-4 compare this and last year's forecasts for the medium economic growth scenario.

For the medium economic growth scenario, cumulative demand over the period 2011 to 2020 compared with last year's forecast:

- for Tariff D, is now forecast to be 11% lower
- for Tariff V, is now forecast to be 2% lower, and
- for total system demand, is now forecast to be 6% lower.

The lower Tariff D demand forecast reflects forecast manufacturing plant downsizing or closures.

Figure A1-4 — Comparison of annual system demand forecast, medium scenario (excluding GPG)



Annual system demand forecast by SWZ for the medium scenario

Table A1-7 shows annual system demand forecasts by SWZ in the medium economic growth scenario.

The growth rate differences between the six SWZs are primarily because of differences in how the demand is distributed between Tariff D and V, and the different growth rates that are forecast for these two market segments.

SWZs with higher Tariff D demand relative to Tariff V demand (i.e. Geelong and Western) have a negative growth rate, while those with a larger proportion of Tariff V demand (i.e. Northern and Ballarat) have positive growth rates.

This reflects the forecast downsizing of a few industrial companies because of slower growth in the Victorian manufacturing sector and future carbon costs. On the other hand, Tariff V demand is projected to grow as population grows.

Table A1-7 also compares this year's annual system demand gas forecasts with those published in the 2010 VAPR Update. This year's forecast averages 14 PJ/yr lower over the period 2012 to 2020.

Table A1-7 — Annual system demand forecast by SWZ, medium scenario (PJ/yr)

SWZ	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's forecast												**2012-2021**
Ballarat	8.8	8.8	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.1	9.3	0.6
Geelong	23.8	24.0	22.7	22.7	22.7	22.7	22.6	22.5	22.4	22.5	22.6	-0.7
Gippsland	14.5	14.2	14.5	14.1	14.1	14.2	14.2	14.3	14.3	14.4	14.6	0.3
Melbourne	135.5	132.9	131.7	131.4	131.6	132.6	133.5	133.9	134.8	135.9	137.3	0.4
Northern	17.7	17.7	17.6	17.4	17.5	17.6	17.7	17.8	17.9	18.0	18.2	0.3
Western	4.8	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.8	0.0
Total System Demand	**205**	**202**	**200**	**199**	**199**	**201**	**202**	**202**	**203**	**205**	**207**	**0.3**
Last year's forecast												**2011-2020**
Ballarat	9.0	9.1	9.2	9.3	9.3	9.3	9.4	9.4	9.5	9.6	n/a	0.7
Geelong	23.4	23.9	24.0	24.1	24.0	24.1	24.2	24.3	24.3	24.3	n/a	0.4
Gippsland	14.8	14.7	15.4	14.9	14.9	14.9	14.8	14.8	14.7	14.7	n/a	-0.1
Melbourne	138.2	140.1	140.8	141.1	141.3	141.9	142.9	143.7	144.4	145.1	n/a	0.5
Northern	18.2	18.5	19.1	19.8	19.8	19.8	19.9	20.0	20.0	20.1	n/a	1.1
Western	4.7	4.8	4.9	4.9	4.9	4.9	4.9	4.9	5.0	5.0	n/a	0.7
Total System Demand	**208**	**211**	**213**	**214**	**214**	**215**	**216**	**217**	**218**	**219**	**n/a**	**0.6**

A1.4.3 Annual forecast of gas demand for DTS-connected GPG

Figure A1-5 and Table A1-8 show this year's annual forecast of gas demand for DTS-connected GPG.

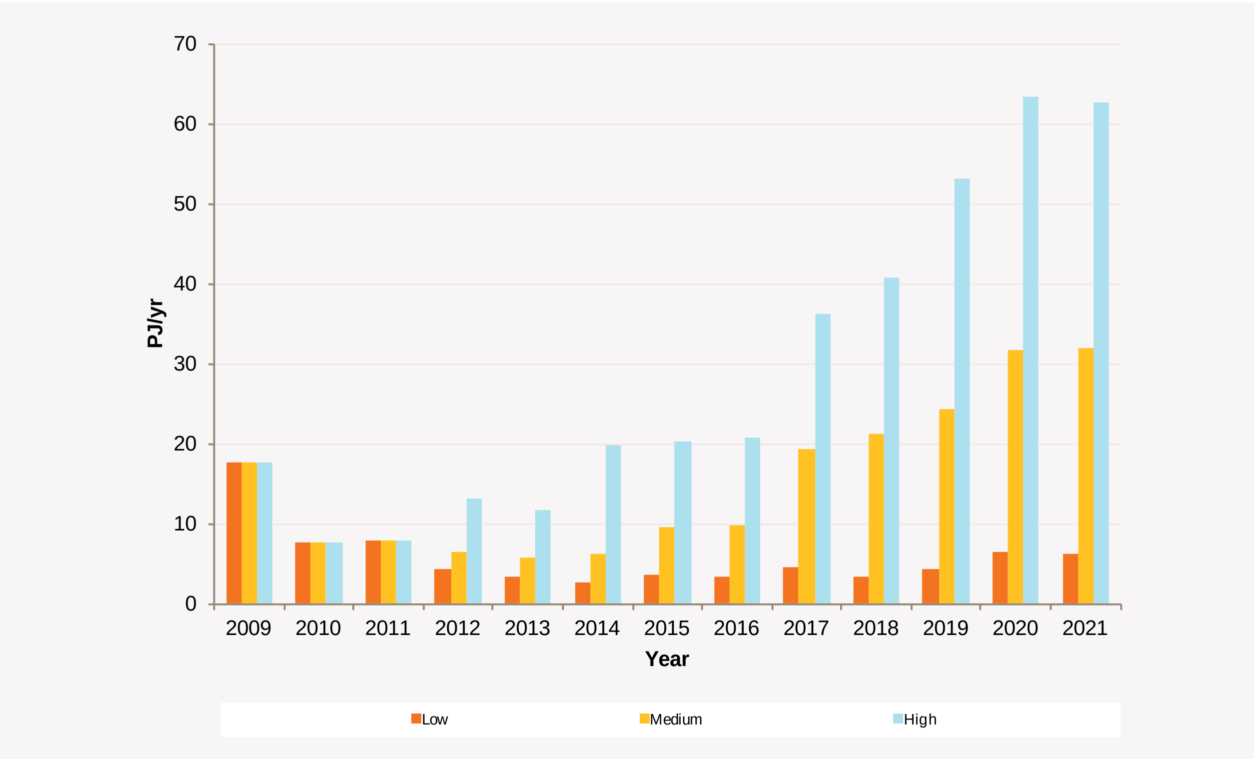
In the medium economic growth scenario, gas demand for GPG is forecast to be 7.9 PJ/yr in 2011, down from 9.5 PJ/yr in 2010. Gas demand for GPG then falls to 6.4 PJ/yr in 2012 and 5.8 PJ/yr in 2013, which is lower than the 2010 forecast. This is because of the forecast assumption that new GPG plant located outside the DTS will supply the majority of electricity demand growth.

GPG demand is then forecast to increase in 2014 and beyond, because of the forecast assumption that existing coal power stations will be gradually replaced because of the carbon price and contract for closure policies, as described below. By 2021, total gas demand for DTS-connected GPG is forecast to be 31.9 PJ/yr, or about four times the demand forecast for 2011.

The underlying assumptions of the DTS-connected GPG demand forecasts have been updated, compared with those used for the 2010 VAPR, to include the impacts of the following recent developments:

- A carbon price, assumed to commence on 1 July 2012, is forecast to increase gas demand for GPG located in Victoria, both on and off the DTS.
- The Australian Government is pursuing contracts for closure of around 2,000 MW of high-emission coal-fired electricity generation capacity by 2020.
- Stage 1 of the Mortlake Power Station (two 282 MW open cycle gas turbines located off the DTS) is assumed to commence commercial operation by the end of 2011.
- Other planned and publicly announced GPG projects plan to source gas without adding to demand on the DTS.

Figure A1-5 — Annual DTS-connected GPG demand forecast, all scenarios[21]



[21] 2009 and 2010 figures are based on actual data.

Table A1-8 — Annual DTS-connected GPG demand forecast, all scenarios (PJ/yr)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's forecast												**2012-2021**
High	7.9	13.1	11.7	19.9	20.3	20.9	36.2	40.9	53.2	63.5	62.6	25.9
Medium	7.9	6.4	5.8	6.2	9.5	9.9	19.3	21.3	24.3	31.8	31.9	16.8
Low	7.9	4.3	3.4	2.7	3.7	3.4	4.6	3.4	4.3	6.5	6.3	-2.5
Last year's forecast												**2011-2020**
Medium	9.5	10.1	7.5	32.5	20.1	38.2	40.3	37.9	32.0	42.1	n/a	18.0

A1.4.4 Winter peak day system demand forecasts

Winter peak day system demand forecasts are prepared for the medium economic growth scenario only. They exclude withdrawals from Iona, GPG demand, and export demand.

Winter peak day system demand is sensitive to weather conditions, with increased heating load expected on colder winter days. The peak day forecasts are presented for the following two weather standards (see Section A1.3.3):

- **1-in-2 peak day**: This 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)
- **1-in-20 peak day**: This 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 A1-6 and Table A1-9 show weather-normalised 1-in-2 and 1-in-20 peak day system forecasts for the period 2012 to 2021.

The actual peak day system demand in 2011 was 1,147 TJ/d, which occurred on 7 June. This compares to last year's 1-in-20 forecast of 1,326 TJ/d.

The 1-in-2 and 1-in-20 peak day system demand forecasts grow at average rates of 0.5%/yr over the 10-year demand outlook period (see Table A1-9). These peak day system demand growth rates exceed the annual system demand growth rate (medium scenario), which is forecast to grow at an average rate of 0.2%/yr (see Table A1-6). This is because of the temperature-sensitive component of residential gas demand, which increases with population growth rather than in response to other economic factors.

Figure A1-6 also shows the 1-in-2 peak day forecast provided by gas distribution participants (gas distributors). These forecasts are only slightly higher than AEMO's 1-in-2 peak day forecasts.

Figure A1-6 — Winter peak day system demand forecast, medium scenario

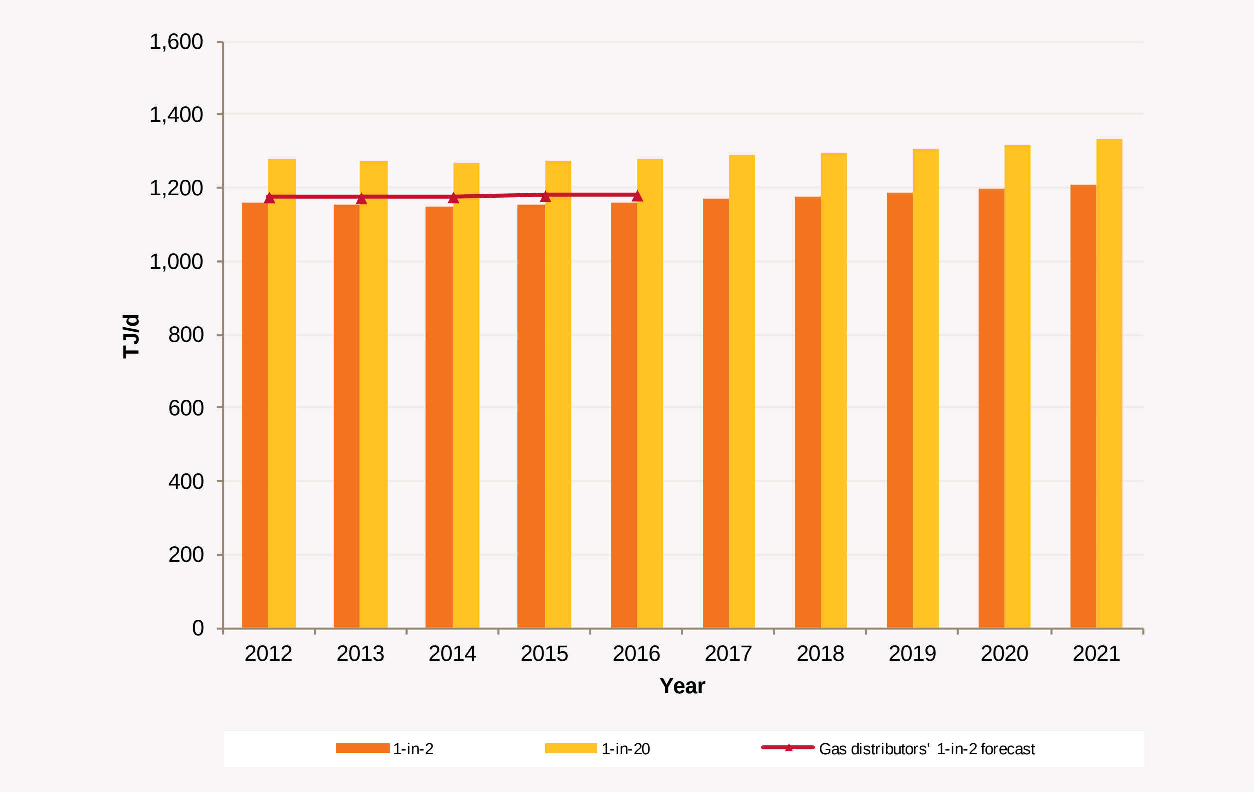


Table A1-9 also compares the current forecast with the forecasts prepared for the 2010 VAPR Update. Over the 10-year demand outlook period, peak day system demand is now forecast to grow at a lower rate than was forecast in the 2010 VAPR Update due to the lower forecast Tariff D peak day demand.

Table A1-9 — Winter peak day system demand forecast, medium scenario (TJ/d)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's forecast												**2012-2021**
1-in-2	n/a	1,162	1,155	1,151	1,155	1,163	1,170	1,177	1,185	1,196	1,210	0.5
1-in-20	n/a	1,280	1,273	1,269	1,274	1,282	1,291	1,298	1,308	1,320	1,336	0.5
Last year's forecast												**2011-2020**
1-in-20	1,326	1,346	1,361	1,366	1,369	1,373	1,382	1,391	1,398	1,406	n/a	0.7

Winter peak day system demand forecasts by SWZ for the medium scenario

Table A1-10 and Table A1-11 list the 1-in-2 and 1-in-20 peak day system demand forecasts by SWZ.

The figures shown for the year 2011 are the actual 2011 peak day system demand that has been weather-normalised for 1-in-2 and 1-in-20 conditions.

As was explained for the annual system demand forecasts (see Section A1.4.2), the differences in the peak day growth rates between the SWZs are because of the different proportions of Tariff D and Tariff V demand in the SWZs, and the different growth rates forecast for these market segments over the outlook period.

Table A1-10 and Table A1-11 also include the 1-in-2 and 1-in-20 peak day system demand forecasts published in last year's 2010 VAPR Update.

Table A1-10 — 1-in-2 winter peak day system demand forecast by SWZ, medium scenario (TJ/d)

SWZ	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's forecast												**2012-2021**
Ballarat	60	60	60	60	60	61	61	62	62	63	63	0.6
Geelong	111	111	108	108	108	108	108	108	108	109	110	-0.1
Gippsland	65	64	65	64	64	64	65	65	65	66	67	0.5
Melbourne	814	808	803	801	804	811	816	821	829	836	847	0.5
Northern	101	101	101	100	101	101	102	103	103	104	105	0.5
Western	18	18	18	18	18	18	18	18	18	18	18	0.1
System demand	**1,169**	**1,162**	**1,155**	**1,151**	**1,155**	**1,163**	**1,170**	**1,177**	**1,185**	**1,196**	**1,210**	**0.5**
Last year's forecast												**2011-2020**
Ballarat	62	64	65	65	65	65	66	66	67	67	n/a	0.9
Geelong	108	111	112	112	112	113	113	114	114	114	n/a	0.6
Gippsland	66	67	69	68	68	68	68	68	68	68	n/a	0.3
Melbourne	827	855	861	865	867	869	876	881	887	893	n/a	0.9
Northern	101	105	107	109	109	110	110	111	111	112	n/a	1.2
Western	19	19	20	20	20	20	20	20	20	20	n/a	0.6
System demand	**1,183**	**1,221**	**1,234**	**1,239**	**1,241**	**1,245**	**1,253**	**1,260**	**1,267**	**1,274**	**n/a**	**0.8**

Table A1-11 — 1-in-20 winter peak day system demand forecast by SWZ, medium scenario (TJ/d)

SWZ	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth (%/yr)
This year's forecast												**2012-2021**
Ballarat	67	67	67	67	67	68	68	69	69	70	71	0.6
Geelong	120	120	117	117	117	117	117	117	118	118	119	-0.1
Gippsland	70	69	70	68	69	69	69	70	70	71	72	0.5
Melbourne	900	894	889	888	891	898	906	910	919	927	939	0.5
Northern	111	111	111	110	111	111	112	113	113	115	116	0.5
Western	19	19	19	19	19	19	19	19	19	19	19	0.2
System demand	**1,287**	**1,280**	**1,273**	**1,269**	**1,274**	**1,282**	**1,291**	**1,298**	**1,308**	**1,320**	**1,336**	**0.5**
Last year's forecast												**2011-2020**
Ballarat	71	72	73	73	73	73	74	74	75	75	n/a	0.6
Geelong	118	120	121	122	121	122	123	123	123	124	n/a	0.6
Gippsland	72	72	75	73	74	73	73	74	74	74	n/a	0.3
Melbourne	933	947	954	958	961	964	971	978	983	989	n/a	0.6
Northern	112	114	117	119	119	120	120	121	122	122	n/a	1.0
Western	20	21	21	21	21	21	21	21	21	22	n/a	1.1
System demand	**1,326**	**1,346**	**1,361**	**1,366**	**1,369**	**1,373**	**1,382**	**1,391**	**1,398**	**1,406**	**n/a**	**0.7**

A1.4.5 Peak hour system demand forecasts

Table A1-12 shows 1-in-2 and 1-in-20 peak hour system demand forecasts by SWZ for the medium economic growth scenario.

The highest growth rates are seen in the Melbourne and Gippsland SWZs, while peak hour system demand declines in the Geelong SWZ.

Note that it is not appropriate to add up peak hour demand for each SWZ because all SWZs are not expected to coincide.

Table A1-12 — Peak hour system demand forecast by SWZ, medium scenario (TJ/hr)

	SWZ	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average annual growth 2012-2021 (%/yr)
1-in-2 peak hour	Ballarat	4.1	4.1	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.3	4.3	0.5
	Geelong	6.5	6.6	6.4	6.3	6.4	6.4	6.4	6.4	6.4	6.4	6.5	-0.2
	Gippsland	3.7	3.6	3.7	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.8	0.6
	Melbourne	52.0	51.5	51.2	51.1	51.3	51.8	52.0	52.4	52.9	53.3	54.0	0.5
	Northern	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.3	6.4	0.5
	Western	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0
	System Demand	**Peak hour demand for individual SWZs might not occur at the same time.**											
1-in-20 peak hour	Ballarat	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	0.5
	Geelong	7.1	7.1	6.9	6.9	6.9	6.9	6.9	6.9	6.9	7.0	7.0	-0.2
	Gippsland	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.1	0.6
	Melbourne	57.4	57.0	56.7	56.5	56.8	57.3	57.6	58.0	58.5	59.1	59.9	0.6
	Northern	6.7	6.7	6.7	6.7	6.7	6.7	6.8	6.8	6.9	6.9	7.0	0.5
	Western	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0
	System Demand	**Peak hour demand for individual SWZs might not occur at the same time.**											

A1.4.6 Forecasts of gas export to other states

Export points from the Victorian DTS are located at Culcairn, VicHub and Iona.

At Culcairn, during the nine months to the end of September 2011, there were consistent net exports to New South Wales totalling 6.7 PJ. This compares to net exports of 1.5 PJ for the previous year to the end of September 2010.

Chapter 7 projects a reduction in exports from Victoria over the long term. This modelling is based on the physical capabilities of the network and projected reserves development only and excludes consideration of commercial positions.

Exports at VicHub[22] can be delivered to either New South Wales or Tasmania; however, interstate export via VicHub is currently negligible. Following the commissioning of large gas powered generators in both of those states in recent years, exports to New South Wales or Tasmania from VicHub might be required at times when gas cannot be supplied to these units from other sources.

A1.5 Gas supply sources and capability forecasts

This section describes individual gas supply sources and presents gas supply forecasts for the period 2012 to 2016. This includes annual and peak day supplies of gas transported through the DTS. Supplies are those available to the Victorian gas market, whether used or not.

The gas supply forecasts, which are based on information provided by gas producers, storage providers, and market participants, assume that there are not likely to be any external factors preventing gas supplies reaching the Victorian gas market, should an event affecting supply occur in markets elsewhere.

The following two classifications of gas supply are used for planning purposes[23]:

- “Available” supply is the aggregate contracted maximum daily quantities available to the market through commercial arrangements between market participants and gas producers or storage providers.
- “Prospective” supply is subject to participants offering gas on the gas day, might depend on interconnecting pipeline operating conditions and contracts, and is therefore is a less certain source of supply than that classified as available.

A1.5.1 Individual gas supply sources, injection points, and supply forecasts

The following describes the facilities where gas is injected into the DTS. Forecasts of available and prospective supply have been provided by participants. The annual supply forecast by SWZ and injection point is shown in Table A1-13. Peak day supply forecast data is shown in Table A1-14. Additional facility information is provided in Chapter 4.

Gippsland SWZ

The BassGas, Longford, and VicHub injection points are located in the Gippsland SWZ where gas can be injected into the Longford to Melbourne Pipeline (LMP) component of the DTS. The rate of gas injection might be limited by the capacity of the LMP, as described in Section A1.6.1.

BassGas injection point

The BassGas injection point is located at the Lang Lang gas plant in West Gippsland. It is the DTS injection point that allows gas produced from the offshore Yolla gas field and processed at the Lang Lang gas plant to flow into the LMP. Participants have advised that the winter peak day available supply from BassGas is 65 TJ/d for the outlook period. The participants have indicated no prospective supply.

[22] See Section A1.5.1 for a description of the VicHub injection point.

[23] See the National Gas Rules, Rule 323. Available http://www.aemc.gov.au/Gas/National-Gas-Rules/Current-Rules.html.

Longford injection point

The Longford plant, located near Sale in South Gippsland, processes gas from the Gippsland Basin and injects it into the DTS via the Longford metering station and LMP. The Longford plant has historically been the largest producer of gas for the Victorian market.

For 2012, participants have advised that the winter peak day available supply from Longford is 854 TJ/d. Table A1-14 shows that over the outlook period there is a small decrease in the available supply and a small increase in prospective supply.

VicHub injection point

The VicHub injection point, located near the Longford plant and metering station, has a DTS injection point for gas flowing from the Eastern Gas Pipeline into the LMP. Participants have advised that available supply for winter 2012 is 85 TJ/d. Over the outlook period, there is a small decrease in the available supply before decreasing to 20 TJ/d in 2016. The participants have indicated no prospective supply.

Geelong SWZ

The Iona, Mortlake, Otway, and SEA Gas injection points are located near the township of Port Campbell in south-west Victoria in the Geelong SWZ. Gas can be injected into the South West Pipeline (SWP) component of the DTS. Injection might be limited by the capacity of the SWP, as described in Section A1.6.2.

Iona injection point

Iona gas processing and storage facilities are described in Chapter 4.

As shown in Table A1-14, participants have advised that winter peak day available supply from Iona is 492 TJ/d in 2012, potentially increasing to 550 TJ/d by 2016.

Participants have furthermore advised that Iona has a winter peak day plant processing and injection capacity of approximately 520 TJ/d for 2012, however not all of this capacity is classified as available and participants have not indicated that there is any prospective supply.

Iona plant processing and injection capacity could potentially be increased to 600 TJ/d from 2014 onwards depending on augmentation of the SWP.[24]

Mortlake injection point

A new Mortlake injection point was installed in 2010 and will allow gas from the pipeline supplying the Mortlake Power Station to be injected into the DTS via the SEA Gas connection point. However, no available or prospective supply capacity has been advised for this injection point.

Otway injection point

The Otway gas plant is described in Chapter 4. Gas from the Otway plant can be injected into the DTS through the Otway, SEA Gas or Iona injection points.

Participants have advised that winter peak day available supply at the Otway injection point is 188 TJ/d for 2012. No prospective supply has been advised.

[24] This is the updated plant capacity provided by the participant in September 2011. It differs from the plant capacity that was used in Chapter 4 and used in the modelling described in Chapter 7.

SEA Gas injection point

The SEA Gas injection point is the DTS injection point for gas from the offshore Minerva gas field, the Otway gas plant, and the Mortlake pipeline. From this injection point, gas can be injected into the DTS, the SEA Gas pipeline (for export to South Australia), or into the underground gas storage facility at Iona.

Participants have advised that the winter peak day available supply from the SEA Gas injection point is 87 TJ/d for 2012 (see Table A1-14). Additional supply from SEA Gas could be available to the DTS depending on market conditions, however the participants have not advised any prospective supply.

Northern SWZ – Culcairn injection point

The Culcairn injection point in New South Wales is located in the Northern SWZ on the New South Wales – Victoria Interconnect pipeline. Participants have advised that supplies of 60 TJ/d will be available in 2012, and an additional 1.5 TJ/d should be classed as prospective. For 2013 onwards, the prospective quantity of supply to Victoria increases to 5 TJ/d.

However, given that the Interconnect pipeline can flow in either direction, some participants indicate that gas might, at times, be exported to New South Wales.

Melbourne SWZ - Dandenong injection point

The Dandenong injection point is located near the Dandenong LNG storage facility, which is in the Melbourne SWZ.

The Dandenong LNG storage facility liquefies and stores LNG that might be used as a source of gas on high demand days and at other times including maintaining system security in the event of a sustained supply or transmission failure. The LNG system security reserve level requirement was reviewed, and as mentioned in the 2010 VAPR Update, it is no longer necessary for AEMO to hold a security reserve of LNG.

The existing LNG tank has a storage capacity of 12,400 tonnes (680 TJ).[25] Approximately 10,135 tonnes (555 TJ) is available to gas market participants while 2,265 tonnes (125 TJ) is contracted to third party customers.

For developing forecasts, the assumptions involving the LNG storage facility include:

- the LNG tank will be full or nearly full at the start of each winter, and
- vaporising capacity of up to 100 t/hr will be available over 16 hours for peak shaving.[26] This capacity equates to the vaporisation of 87 TJ/d, reflecting the contracted available rate for the outlook period.

Normally, LNG is not scheduled from the beginning-of-day, but is included in a reschedule later in the day.[27] For within-day balancing purposes, LNG only effectively supports DTS pressure when injected by 10:00PM on the day it is required.

Given that LNG for peak shaving is only available over 11 hours, rather than the contracted time of 16 hours, peak day planning assumes that 60 TJ/d of LNG can be delivered for within-day balancing.[28] After 10:00PM, further LNG injections only serve to increase the linepack for the following 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 t/d, or 2.7 TJ/d.

[25] Participants advise (as at September 2011) that 1 tonne of LNG has an energy equivalent of 54.8 GJ.
[26] This is based on the participant's firm LNG rate, which allows for an outage of one of three pumps and one of three vaporiser units.
[27] LNG can be scheduled from the beginning-of-day.
[28] The LNG used at a rate of 100 t/hr over an 11 hour period (11:00AM- 10:00PM) is 1,100 tonnes (60TJ).

A1.5.2 Other supply augmentations

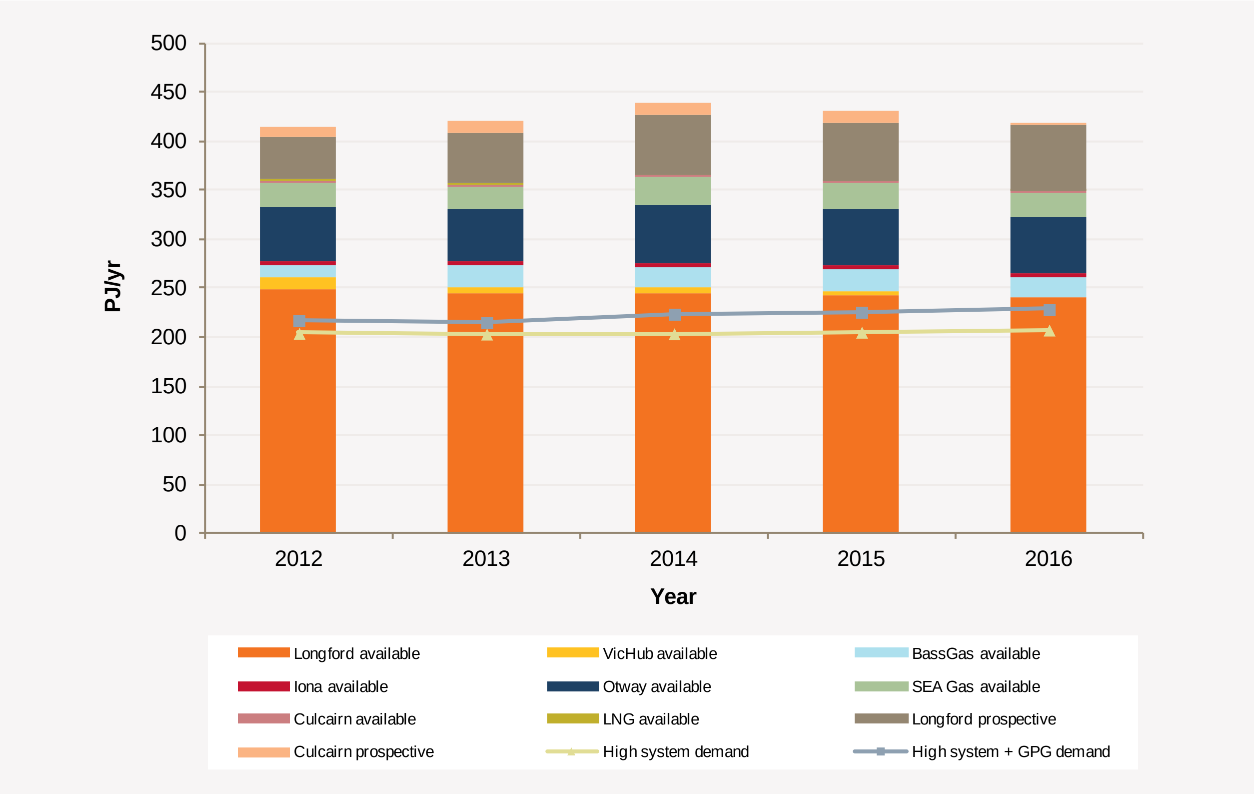
For other committed and proposed supply augmentation projects, please refer to Chapter 6. Completed augmentations are described in Chapter 4.

A1.5.3 Annual supply forecast by SWZ and injection point compared with demand

Figure A1-7 and Table A1-13 summarise forecast annual available and prospective supplies by SWZ and injection point. This data was provided by participants (see Section A1.5.1). Available plus prospective supply ranges from 415 to 438 PJ/yr over the outlook period.

Figure A1-7 also shows forecast annual demand (system as well as DTS-connected GPG) for the high economic growth scenario.[29] Forecast available supply exceeds annual system-plus-GPG demand throughout the outlook period for all scenarios.

Figure A1-7 — Annual supply forecast compared with high scenario demand forecast



[29] Demand in the high scenario is greater than demand in the medium and low scenarios.

Table A1-13 also shows last year's annual gas supply forecasts for 2012. Compared with that forecast, available supply for 2012 has decreased by 4.1 PJ/yr and total available plus prospective supply has decreased by 33.8 PJ/yr. This data has been provided by participants.

Table A1-13 — Annual supply forecast by SWZ and injection point (PJ/yr)

System Withdrawal Zone	Injection Point	2012 (2010 VAPRU)	2012	2013	2014	2015	2016
Gippsland	Longford available	226.2	250.4	244.5	244.9	243.4	241.4
	Longford prospective	77.2	43.5	51.8	60.8	58.8	67.8
	VicHub available	6.6	10.8	6.8	5.6	3.4	0.0
	VicHub prospective	0.0	0.0	0.0	0.0	0.0	0.0
	BassGas available	16.8	11.7	22.3	20.7	23.3	21.1
	BassGas prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Gippsland available	249.6	272.9	273.6	271.2	270.1	262.5
	Gippsland available plus prospective	**326.8**	**316.4**	**325.5**	**332.0**	**328.9**	**330.3**
Geelong	Iona available	5.6	4.9	4.4	4.4	4.0	4.0
	Iona prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Otway available	73.0	55.4	53.3	58.7	57.4	56.6
	Otway prospective	6.0	0.0	0.0	0.0	0.0	0.0
	SEA Gas available	29.5	25.2	23.0	28.5	26.0	23.8
	SEA Gas prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Geelong available	108.1	85.5	80.7	91.6	87.4	84.4
	Geelong available plus prospective	**114.1**	**85.5**	**80.7**	**91.6**	**87.4**	**84.4**
Northern	Culcairn available	6.8	2.0	2.0	2.0	2.0	2.0
	Culcairn prospective	0.5	10.5	11.8	11.8	11.8	1.8
	Northern available plus prospective	**7.3**	**12.5**	**13.8**	**13.8**	**13.8**	**3.8**
Melbourne	LNG available	0.5	0.5	0.5	0.5	0.5	0.5
Total available		365.0	360.9	356.8	365.3	360.0	349.4
Total prospective		83.7	54.0	63.6	72.6	70.6	69.6
Total available plus prospective		**448.7**	**414.9**	**420.4**	**437.9**	**430.6**	**419.0**

A1.5.4 Winter peak day supply forecast by SWZ and injection point

Figure A1-8 and Table A1-14 summarise forecast winter peak day available and prospective supplies by SWZ and injection point. This data was provided by participants (see Section A1.5.1).

Figure A1-8 also shows forecast 1-in-2 and 1-in-20 peak day system demand (excluding GPG). Available supply exceeds peak day system demand; however, this comparison ignores transmission pipeline constraints. A more complete picture of supply capability including pipeline constraints is discussed in Section A1.6 and Section A1.7.

Figure A1-8 — Winter peak day supply forecast compared with medium scenario demand

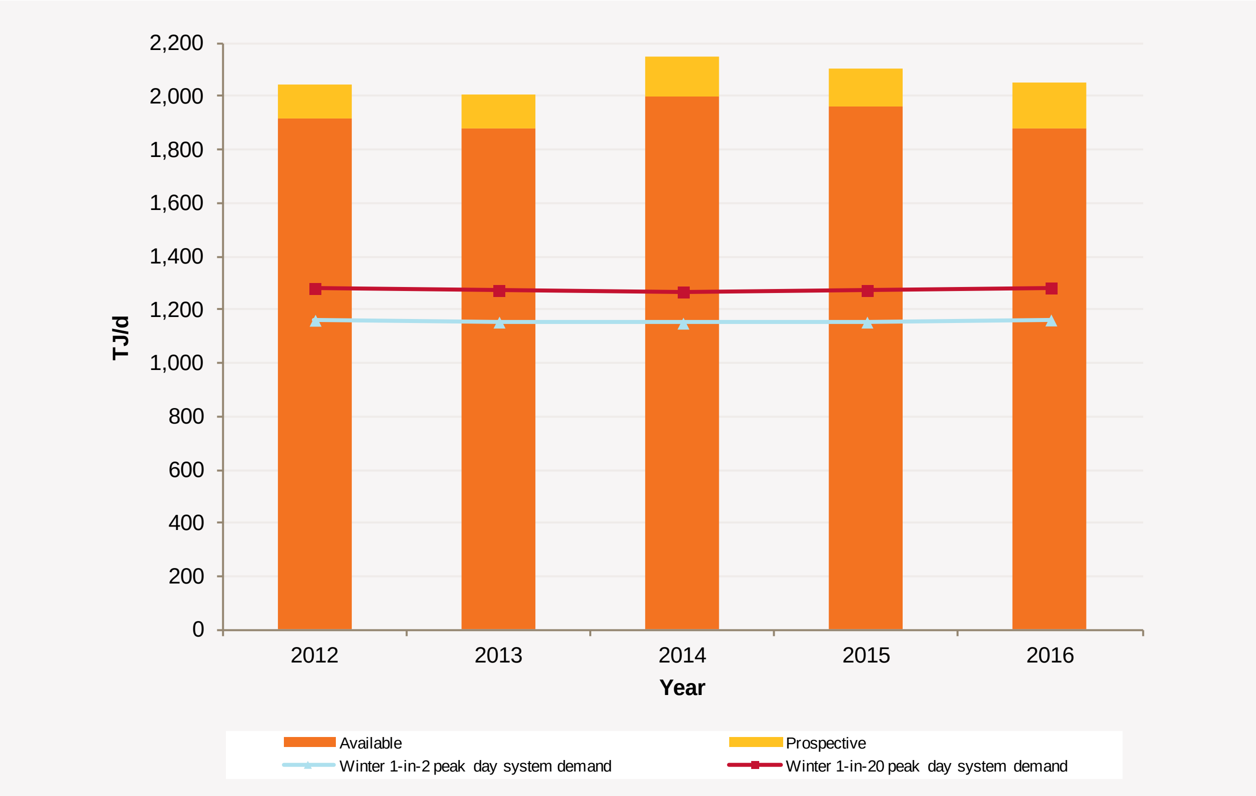


Table A1-14 also includes last year's peak day gas supply forecasts for 2012. Compared with that forecast, available supply for 2012 has decreased by 23 TJ/d and total available plus prospective supply has decreased by 92 TJ/d. This data has been provided by participants.

Table A1-14 — Winter peak day supply forecast by SWZ and injection point (TJ/d)

System Withdrawal Zone	Injection Point	2012 (2010 VAPRU)	2012	2013	2014	2015	2016
Gippsland	Longford available	789.6	854.3	854.3	855.8	841.5	834.6
	Longford prospective	189.5	120.5	126.0	148.0	142.0	166.0
	VicHub available	35.0	85.0	69.0	69.0	69.0	20.0
	VicHub prospective	0.0	0.0	0.0	0.0	0.0	0.0
	BassGas available	65.0	65.0	65.0	65.0	65.0	65.0
	BassGas prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Gippsland available	889.6	1004.3	988.3	989.8	975.5	919.6
	Gippsland available plus prospective	**1079.1**	**1124.8**	**1114.3**	**1137.8**	**1117.5**	**1085.6**
Geelong	Iona available	500.0	492.0	480.0	560.0	550.0	550.0
	Iona prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Otway available	312.7	188.2	182.7	199.7	195.2	192.7
	Otway prospective	0.0	0.0	0.0	0.0	0.0	0.0
	SEA Gas available	102.0	86.8	78.8	97.8	89.3	82.3
	SEA Gas prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Geelong available plus prospective [a]	**914.7**	**767.0**	**741.5**	**857.5**	**834.5**	**825.0**
Northern	Culcairn available	50.0	60.0	60.0	60.0	60.0	50.0
	Culcairn prospective	1.5	1.5	5.0	5.0	5.0	5.0
	Northern available plus prospective	**51.5**	**61.5**	**65.0**	**65.0**	**65.0**	**55.0**
Melbourne	LNG available	87.0	87.0	87.0	87.0	87.0	87.0
Total available		1941.3	1918.3	1876.8	1994.3	1957.0	1881.6
Total prospective		191.0	122.0	131.0	153.0	147.0	171.0
Total available plus prospective		**2132.3**	**2040.3**	**2007.8**	**2147.3**	**2104.0**	**2052.6**

a. Participants indicate that the total for Iona and SEA Gas is available to both South Australia and Victoria. The quantity available to Victoria will depend on the market

A1.6 Comparing peak day injection capability with peak day pipeline capacity

This section describes peak day capacity for the following pipelines:

- LMP
- SWP
- New South Wales – Victoria Interconnect pipeline, and
- Western Transmission System

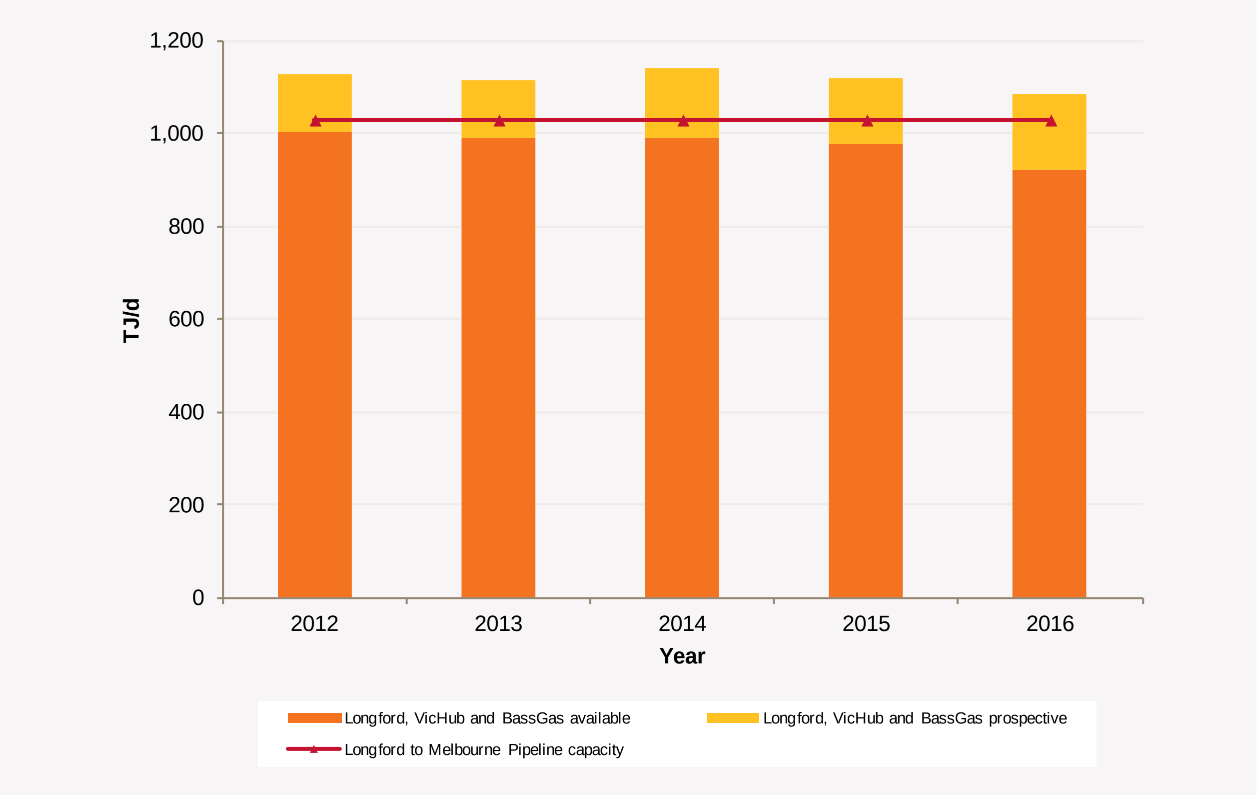
and compares these with forecast injection capability.

A1.6.1 Gippsland SWZ peak day available supply compared with LMP capacity

Figure A1-9 compares forecast available supply from the Gippsland SWZ injection points (Longford, VicHub and BassGas) with the capacity of the LMP. Over the outlook period, the capacity of the LMP (1,030 TJ/d) exceeds forecast available supply but is lower than available plus prospective supply.

Over the past two years, the maximum daily injections into the LMP have been less than 900 TJ/d (see Chapter 4, Section 4.2.1), partly because of the average weather conditions over the last two years and also because of injection behaviour in the Geelong SWZ.

Figure A1-9 — Gippsland SWZ peak day available supply compared with LMP capacity



A1.6.2 Geelong SWZ peak day available supply compared with SWP capacity

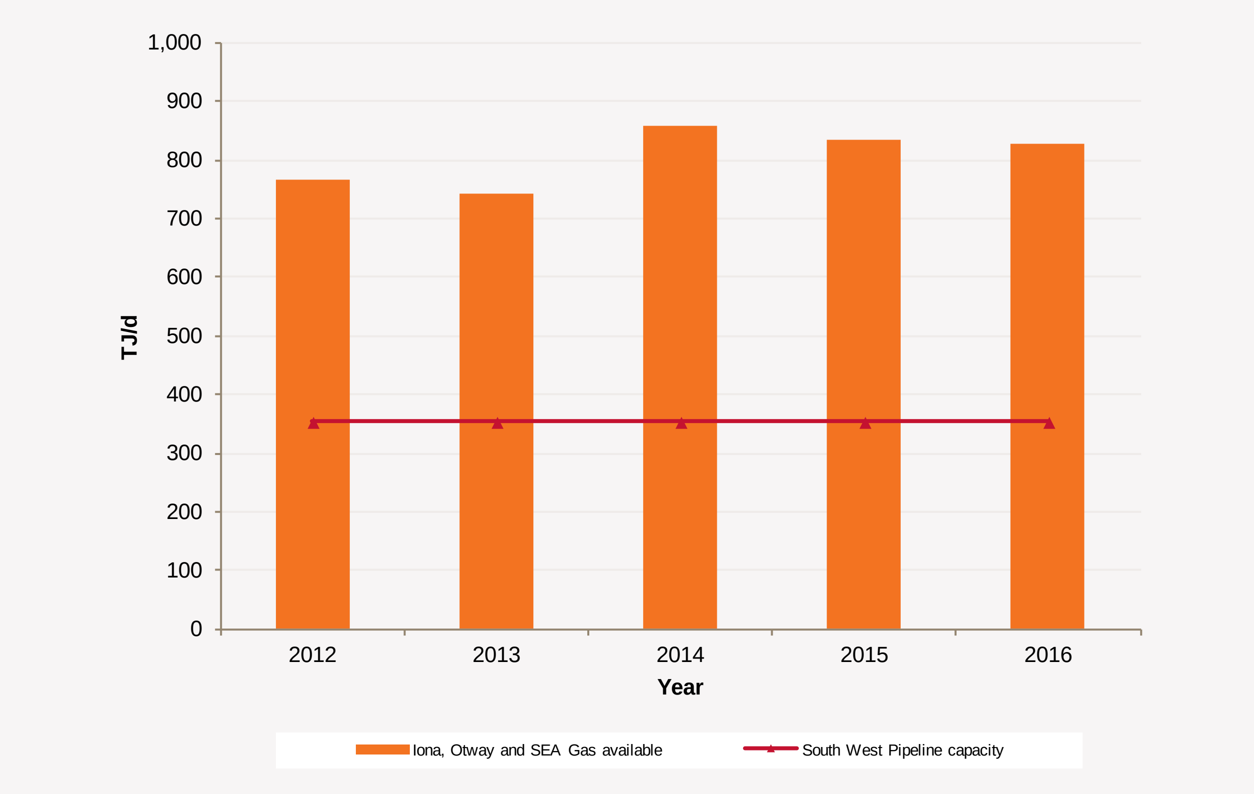
Figure A1-10 compares the forecast available supply at the Geelong SWZ injection points (Iona, Otway, and SEA Gas) with available SWP capacity. The figure indicates that pipeline capacity is the overriding constraint for Geelong SWZ suppliers.

The SWP can transport up to 353 TJ/d under favourable linepack conditions when the pressure at Iona is up to 9,500 kPa. AEMO operations usually maintain pipeline operational flexibility in normal winter conditions by setting beginning-of-day SWP operating pressures. This could constrain SWP capacity to 295 TJ/d when Gippsland SWZ injections are very high. Usually SWP capacity will be between 300 TJ/d and 350 TJ/d.

The actual SWP capacity has been approached on a few occasions over the last two years (see Chapter 4, Section 4.2.1).

Modelling was done to determine the increase in SWP capacity that would result from the installation of a “mid-line” compressor station. The studies show that the capacity increase varies depending on the location and size of the compressor station. For example, the installation of a 5,000 kW compressor might increase the capacity of the SWP by approximately 20%.

Figure A1-10 — Geelong SWZ peak day available supply compared with SWP capacity[30]



30 Participants have not reported any prospective supply.

A1.6.3 Northern SWZ peak day available supply compared with Interconnect capacity

The New South Wales – Victoria Interconnect pipeline, which is metered at Culcairn in the Northern SWZ, has the capacity to import 92 TJ/d into the Victorian gas market when both the Young and Springhurst compressors are operating and Uranquinty Power Station is not operating. This capacity exceeds the injection volumes that were forecast by participants (see Section A1.5.1).

A1.6.4 Western Transmission System pipeline capacity

The Western Transmission System supplies gas to the western SWZ (see Figure A1-1) and connects to the rest of the DTS in the Port Campbell area. It has a pipeline capacity of 28 TJ/d. The capacity to inject gas into the Western Transmission System from injection points in the Port Campbell area is forecast to exceed this pipeline capacity.

A1.7 Comparing peak day demand with supply capability

This section compares the forecast winter peak day system demand, presented in Section A1.4, with the forecast supply capability, including pipeline capacity, presented in Section A1.5 and Section A1.6.

A1.7.1 Peak day DTS system demand compared with supply capability

As shown in Figure A1-11 and Table A1-15, the forecast 1-in-20 peak day DTS system demand can be met over the period 2012 to 2015 by the combination of Gippsland available supplies and SWP maximum capacity.

For 2016, meeting peak day system demand requires an additional 9 TJ/d of peak capacity beyond the sum of Gippsland available plus SWP maximum capacity. This is a shortfall of less than one percent. This might be supplied from LNG available, Gippsland prospective, SWP capacity expansion, or import from Culcairn.

Compared with last year's forecasts[31], system demand is now forecast to be more easily met because of reduced system demand (e.g. 2015 forecast demand is 95 TJ/d lower than last year's forecast).

A1.7.2 Peak day Western Transmission System demand compared with supply

The supply capability of the Western Transmission System (see Section A1.6.4) is forecast to exceed the forecast 1-in-20 peak day demand (see Section A1.4.4) throughout the five-year outlook period.

[31] AEMO. "2010 Victorian Annual Planning Report Update". Published 30 November 2010. Figure 3-1. Available http://www.aemo.com.au/planning/0400-0026.pdf.

Figure A1-11 — Winter peak day system demand compared with supply capability

Table A1-15 — Winter peak day system demand compared with supply capability (TJ/d)

Demand / Supply	2012	2013	2014	2015	2016
Winter 1-in-20 peak day demand[a]	1,280	1,273	1,269	1,274	1,282
Winter 1-in-2 peak day demand[a]	1,162	1,155	1,151	1,155	1,163
Gippsland available[b]	1,004.3	988.3	989.8	975.5	919.6
SWP capacity[c]	353.0	353.0	353.0	353.0	353.0
Total Gippsland available plus SWP capacity	**1,357.3**	**1,341.3**	**1,342.8**	**1,328.5**	**1,272.6**
Culcairn available[b]	60.0	60.0	60.0	60.0	50.0
LNG that can be delivered[d]	60.0	60.0	60.0	60.0	60.0
Gippsland prospective[b]	120.5	126.0	148.0	142.0	166.0
Culcairn prospective[b]	1.5	5.0	5.0	5.0	5.0
Iona, Otway, and SEA Gas available[b] minus SWP capacity	414.0	389.0	505.0	482.0	472.0

a. See Section A1.4.4 .

b. See Section A1.5.4.

c. See Section A1.6.2.

d. See Section A1.5.1.