Victorian Gas Planning Report

March 2019

Gas Transmission Network Planning for Victoria

Important notice

PURPOSE

AEMO publishes this Victorian Gas Planning Report in accordance with rule 323 of the National Gas Rules. This publication is based on information available to AEMO at 31 January 2019, although AEMO has endeavoured to incorporate more recent information where practicable.

DISCLAIMER

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ACKNOWLEDGEMENT

AEMO acknowledges the support, co-operation and contribution of all participants in providing data and information used in this publication.

VERSION CONTROL

Version	Release date	Changes
1.0	28/3/2019	New document

Executive summary

The 2019 *Victorian Gas Planning Report* (VGPR) provides information about the supply demand balance over the next five years (2019-23, called the outlook period) in Victoria, and the Victorian Declared Transmission System (DTS).

The 2019 VGPR complements AEMO's *Gas Statement of Opportunities* (GSOO), which assesses the wider gas supply adequacy in eastern and south-eastern Australia.

Key findings

- Gas supply forecasts provided to AEMO by gas producers show an overall increase since the publication of the 2018 VGPR Update, due to some projects receiving approval after reaching final investment decision (only committed projects are included in the supply demand balance).
- While Victoria is forecast to have sufficient gas production to supply all forecast Victorian demand throughout the five-year outlook period to 2023, production decline continues and will reduce the available gas to supply to New South Wales and South Australia.
  - Gippsland producers have advised that annual production will reduce by 22% from 2019 to 2023, compared to the 38% reduction forecast in the 2018 VGPR Update.
  - Port Campbell producers have advised that annual production will reduce by 74% from 2019 to 2023, which is consistent with the 68% reduction forecast in the 2018 VGPR Update.
  - Victoria has supplied, on average, 150 petajoules per year (PJ/y) to Tasmania, New South Wales, and South Australia from production surplus to Victorian gas consumption over the last five years. The annual production surplus is forecast to decline to 23 PJ in 2023.
- Winter peak day supply adequacy is forecast to continue to tighten during the outlook period. Without additional gas supply capacity, gas supply restrictions and curtailment of gas-powered generation (GPG) for electricity may be necessary on a peak winter day from 2023.
  - Producers have advised that total Victorian winter production will reduce from 1,275 terajoules per day (TJ/d) in 2019 to 847 TJ/d in 2023, which is a 34% decrease. Prospective production projects, currently uncommitted, could increase production up to 1,030 TJ/d in 2023.
  - The Iona underground gas storage (UGS) facility will be essential for supporting Victorian peak day demand including GPG, which can exceed 1,200 TJ/d. There will be an increased risk of storage depletion due to a cold winter, gas production restrictions, or high levels of GPG demand.
  - Supply shortfalls for South Australia and New South Wales GPG could occur if above-average GPG demand in these states coincides with a Victorian peak winter day from 2023.
- Additional sources of gas supply are currently being investigated to address supply adequacy, including increased gas exploration and production that may increase committed Victorian production from 246 PJ in 2023 to 326 PJ. Other additional sources of supply include gas transported via pipelines from Queensland, or the importation of liquefied natural gas (LNG).
- The Western Outer Ring Main (WORM) gas pipeline has become a committed project. Commissioning is targeted for June 2021. This will reduce the refilling risk for the Iona UGS facility and help support peak day GPG demand.

Actual demand and consumption trend

Annual Victorian DTS gas consumption[1] has been relatively consistent at approximately 200 PJ/y for the last decade, as shown in Table 1. This stable annual consumption is due to declining industrial gas usage being offset by increasing winter residential consumption, although this varies due to weather conditions[2].

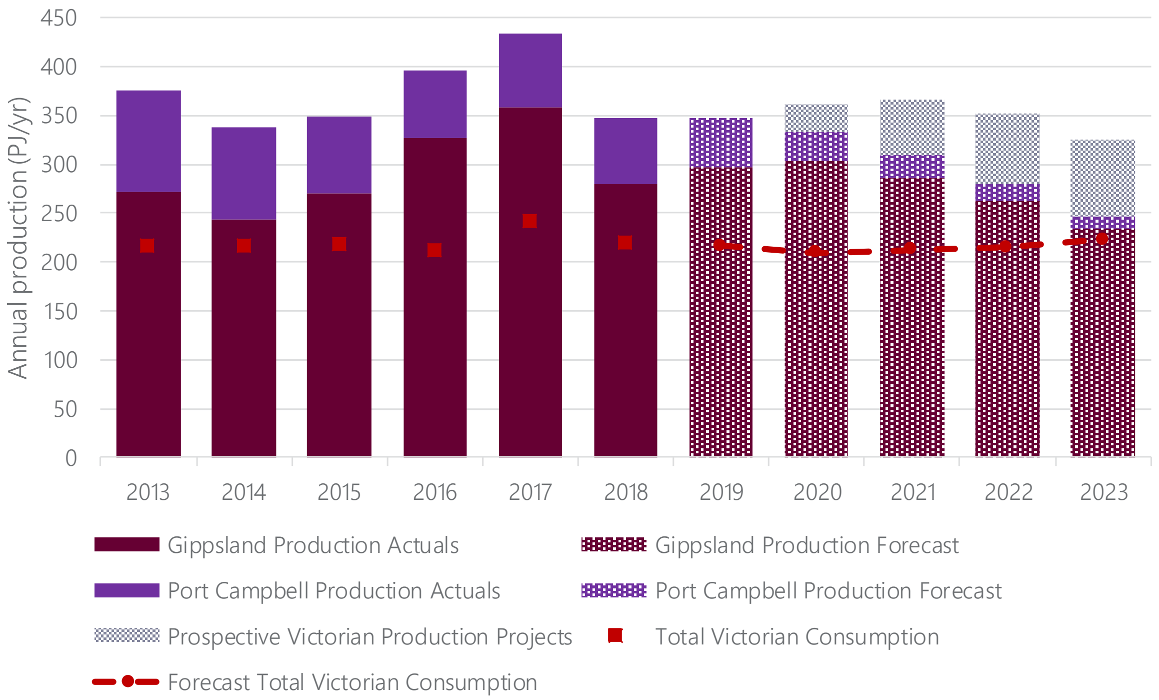
Prior to 2017, annual gas consumption for GPG had been low, at 3-4 PJ/y, since the end of drought conditions in 2009[3]. Increased GPG gas consumption during 2017 and 2018 was due to the closure of the Hazelwood Power Station in March 2017. GPG consumption in 2018 was lower than the peak 2017 year, due to an increase in black coal-fired (in New South Wales), hydro, and renewable generation.

Table 1 Annual gas consumption and peak gas total demand, 2013-18

	2013	2014	2015	2016	2017	2018
DTS system consumption (PJ)	197	191	205	200	203	194
DTS GPG consumption (PJ)	3	4	3	3	15	10
Victorian non-DTS consumption (PJ)	17	22	10	8	23	16
Total Victorian consumption (PJ)	217	217	218	211	241	220
Annual cumulative EDD[A]	1,242	1,163	1,472	1,331	1,447	1,372
Actual DTS peak total demand (TJ/d)	1,165	1,214	1,179	1,187	1,279	1,132

A. EDD (effective degree days) is a measure of coldness. The higher the forecast EDD, the more gas is expected to be used for heating.

Figure 1 Annual production (petajoules per year) by location



The 2018 Victorian DTS peak demand day occurred on Thursday 28 June 2018. The total demand[4] of 1,132 terajoules (TJ) was comprised of 1,078 TJ of system demand and 54 TJ of GPG.

[1] Demand refers to capacity or gas flow on an hourly or daily basis. Consumption refers to gas usage over a monthly or annual period.

[2] Annual variations in system consumption – residential, commercial, and industrial gas usage – are mainly due to temperature. As the 2017 VGPR noted, lower consumption in 2014 was due to a mild Victorian winter, while increased consumption in 2015 corresponded with the coldest winter in 26 years.

[3] Drought conditions in 2007-08 resulted in high levels of GPG, as reduced water was available for hydro generation and cooling for coal-fired generation.

[4] Total demand is equal to the sum of system demand and GPG but excludes exports.

Gas consumption and peak day demand in 2018 was relatively low, due to it being the third-warmest year in Victoria on record[5].

Forecast annual production

Forecast annual Victorian production is shown in Figure 1, with additional information in Table 2. The large 86 PJ reduction in annual production between 2017 and 2018 was less than the 107 PJ reduction forecast by producers in the 2017 VGPR and 2018 VGPR Update, mainly due to higher Port Campbell production.

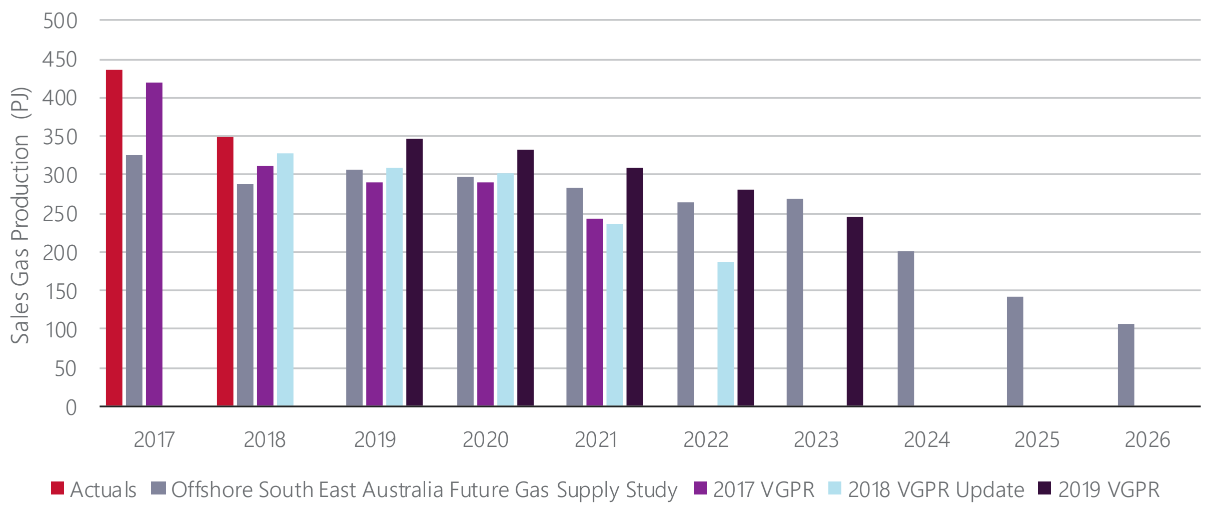
Table 2 Forecast annual consumption and production supply, 2019-23, with 2018 actuals

	2018 (actual)	2019	2020	2021	2022	2023
DTS system consumption (PJ)	194	200	200	201	202	203
DTS GPG consumption (PJ)	10	7	4	5	6	9
Victorian non-DTS consumption (PJ)	16	9	5	6	6	11
Total Victorian consumption (PJ)	220	217	209	212	215	223
Total available production supply (PJ)	348	347	333	310	280	246
Surplus / shortfall quantity (PJ)	128	130	124	97	65	23

Note: totals may not add up due to rounding.

The forecast production decline has lessened since the forecasts published in the 2017 VGPR and 2018 VGPR Update, due to some projects receiving approval with a final investment decision (only committed projects are included in the forecast production). The most significant of these is the West Barracouta Project[6], discussed in the 2018 VGPR Update, which is expected to produce gas from 2021. The Sole Project, to be processed via the Orbost Gas Plant, was included in the 2018 VGPR Update. Figure 2 shows a comparison of previous supply forecasts and the 2019 VGPR supply forecast. Additional proposed, but uncommitted production projects[7] could increase 2023 production from 246 PJ up to 326 PJ.

Figure 2 Victorian production forecasts by year (PJ/y)



[5] See http://www.bom.gov.au/climate/current/annual/vic/archive/2018.summary.shtml.

[6] BHP news release, 13 December 2018, at https://www.bhp.com/media-and-insights/news-releases/2018/12/bhp-approves-west-barracouta-project.

[7] "Production projects" do not include LNG import facilities or storage.

The *Offshore South East Australia Future Gas Supply Study*[8] estimated the remaining 2P[9] reserves available in offshore Victoria at the start of 2019 to be 3,233 PJ, while the Core Energy Group Data[10] estimated the remaining 2P reserves to be 2,803 PJ. If current supply projections are accurate, available Victorian offshore 2P reserves will decline to between 1,718 PJ and 1,288 PJ by the end of 2023, a 47-54% reduction.

The Dory prospect on the outer eastern edge of the Gippsland Basin represented a large potential prospect that might have deferred the transition into smaller, deeper fields which contain a higher level of gas impurities requiring additional processing. The media and Esso have reported[11,12] that the drilling program (that included the Baldfish and Hairtail wells at a cost of $120m) failed to yield commercial quantities of hydrocarbons. Future gas supply is expected to be from a combination of smaller, higher cost fields and the importation of LNG into Victoria, which is consistent with other analysis[13,14]. Longer term production decline is discussed further in the 2019 GSOO.

The Longford Gas Conditioning Plant is required to process gas from higher impurity fields. As the low impurity fields deplete, Longford production is expected to be limited by the Gas Conditioning Plant's capacity and eventually the total production is expected to approach this capacity limit. The Longford Gas Conditioning Plant has a reported capacity of 427 TJ/d, which equates to approximately 150 PJ/y[15].

Annual supply adequacy

Gippsland producers (operators of the Longford and Lang Lang gas plants, and the Sole Project processed via the Orbost Gas Plant) have advised that annual production will reduce by 22% during the five-year outlook period, from 298 PJ in 2019 to 234 PJ in 2023.

Port Campbell producers (operators of the Otway and Minerva gas plants, and the Casino development, processed via the Iona UGS facility), have advised that annual production will reduce by 74% from 49 PJ in 2019 to 12 PJ in 2023. Therefore, as shown in Figure 2 above, total Victorian production is expected to reduce from 347 PJ in 2019 to 246 PJ in 2023 (unless additional production projects are developed).

While this means Victoria is forecast to have enough production to supply all forecast Victorian demand on an annual basis, winter monthly gas consumption in Victoria is up to three times (typically 25-30 PJ/month) the summer monthly gas consumption (of approximately 10 PJ/month). This is expected to result in a tight winter gas supply demand balance in Victoria and an increased reliance on the Iona UGS facility to meet Victorian demand during winter by the end of the outlook period.

This is also expected to reduce gas supplies for export to New South Wales and South Australia, which will become more reliant on Queensland gas supplies from 2021 to 2023. The impacts of reduced Victorian supplies for these states, including supporting GPG demand and pipeline transportation capacity limitations, are explored further in the 2019 GSOO.

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[8] Australian Government, Department of Industry, Innovation and Science, November 2017, at https://www.industry.gov.au/data-and-publications/offshore-south-east-australia-future-gas-supply-study.

[9] 2P (proved and probable) is considered the best estimate of commercially recoverable reserves.

[10] Consultant report commissioned by AEMO and published with the GSOO, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[11] The Australian, "Exxon's $120m Bass Strait bet fails to deliver gas", 15 November 2018, (paywall) at www.theaustralian.com.au/business/mining-energy/exxons-120m-bass-strait-bet-fails-to-deliver-gas.

[12] The Australian Financial Review, "Esso-BHP to boost east coast gas with $550m Bass Strait project", 13 December 2018, (paywall) at www.afr.com/business/energy/gas/essobhp-to-boost-east-coast-gas-with-550m-bass-strait-project-20181213-h192ej.

[13] Australian Government, Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, November 2017.

[14] The Age, "Gas import terminals 'inevitable' but won't lower prices, say analysts", 5 October 2018, at www.theage.com.au/business/the-economy/gas-import-terminals-inevitable-but-won-t-lower-prices-say-analysts-20181005-p507yo.html.

[15] BHP media release, "Longford Gas Conditioning Plant Project Approval", 13 December 2012, at https://www.bhp.com/media-and-insights/news-releases/2012/12/longford-gas-conditioning-plant-project-approval.

Forecast peak day supply

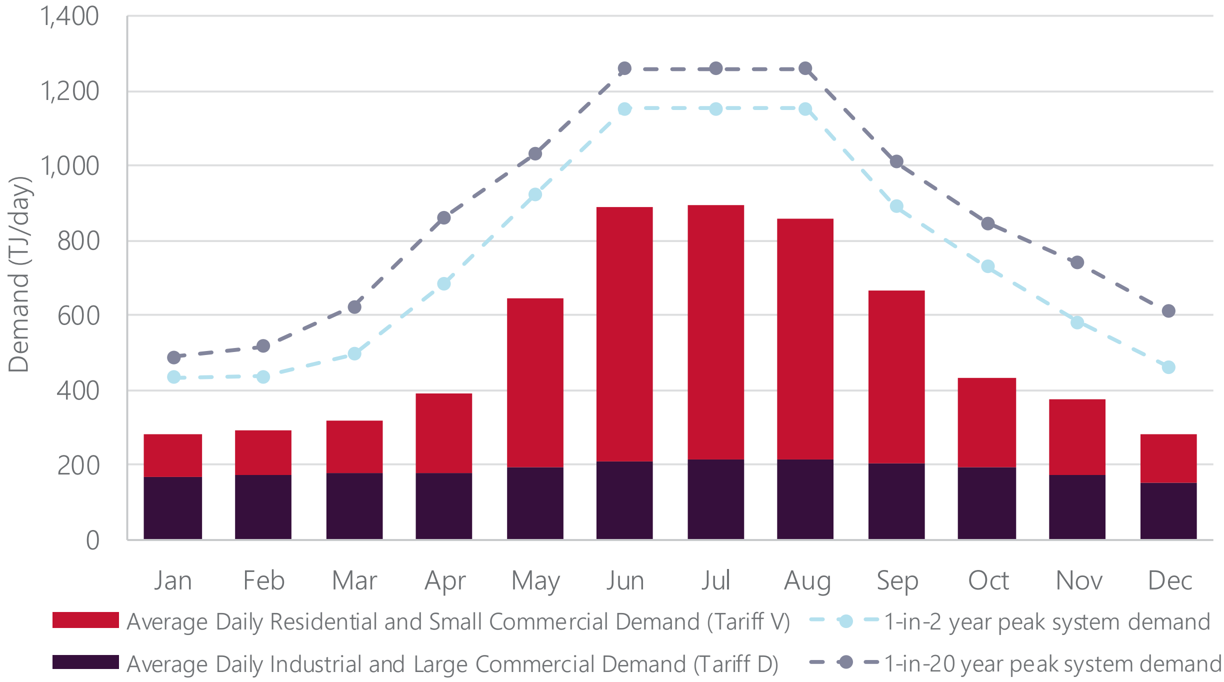
While annual production for 2018 was slightly higher than previous forecasts, mainly due to higher Port Campbell production, the actual peak day supply capacity was approximately 40 TJ/d lower than forecast for 2018.

Gippsland producers have advised that their maximum daily production capacity will reduce by 25% from 1,078 TJ/d in 2019 to 805 TJ/d in 2023. Port Campbell producers have advised that daily production capacity will reduce by 79% from 197 TJ/d in 2019 to 42 TJ/d in 2023.

Therefore, total daily Victorian production capacity will reduce from 1,275 TJ/d in 2019 to 847 TJ/d in 2023. This is less than average daily winter demand, which is approximately 900 TJ/d, as shown in Figure 3. During a cold winter, average daily demand can exceed 950 TJ/d[16].

As a result, reliance on the Iona UGS facility and the Dandenong LNG storage will increase to supply forecast peak winter demand.

Figure 3 Average daily demand by month with 1-in-2 and 1-in-20 peak day demand forecasts (TJ/d)



Peak day supply adequacy

AEMO forecasts that DTS peak system demand will increase slightly over the outlook period, as shown in Table 3. New housing and population growth (which increases winter demand) are forecast to more than offset the reductions from declining industrial load, inner city residential developments using electric instead of gas appliances, and improvements in energy efficiency.

As Victorian gas supply capacity has improved since the publication of the 2018 VGPR Update, there is expected to be sufficient supply capacity to meet a 1-in-2-year and a 1-in-20-year peak system demand day (which does not include GPG). Supply is still forecast to tighten during the outlook period.

Without additional gas supply capacity, restrictions and curtailment of GPG may be necessary in 2023 on a 1-in-20-year peak system demand day despite the additional pipeline capacity provided by the WORM.

Peak day supply will not be sufficient if the Iona UGS reservoir inventory has been depleted.

[16] Winter 2015 was the coldest in 26 years (since 1989). Average daily demand in July 2015 was 976.6 TJ/d, the highest on record.

Table 3 **Forecast peak day supply adequacy, 2018-22 (TJ/d)**

	2019	2020	2021	2022	2023
Total supply (including Victorian LNG)	1,843	1,694	1,625	1,548	1,414
DTS available supply including constraints	1,528	1,483	1,431	1,388	1,269
1-in-2-year peak DTS system demand	1,147	1,146	1,152	1,161	1,164
Surplus / Shortfall quantity on 1-in-2-year peak day	381	337	280	228	106
1-in-20-year peak DTS system demand	1,246	1,245	1,250	1,260	1,264
Surplus / shortfall quantity on 1-in-20-year peak day	282	238	182	128	5

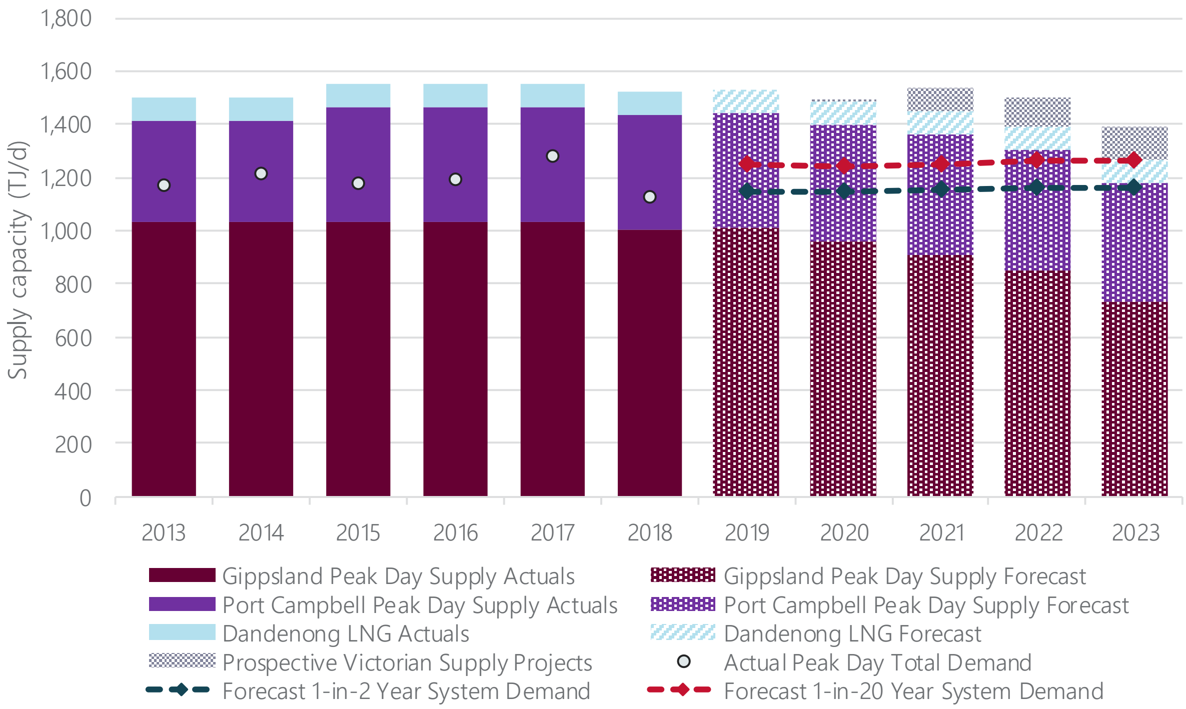
Note: totals may not add up due to rounding.

Due to the location of gas supplies, transmission constraints, and Victorian non-DTS gas consumption, not all the peak day supply capacity is available to supply the DTS. Port Campbell maximum daily production capacity, when combined with the Iona UGS facility capacity, continues to have a capacity exceeding the South West Pipeline (SWP) capacity, although the facilities at Port Campbell also supply the Mortlake Power Station.

The Port Campbell supply capacity via the SWP is forecast to increase from 434 TJ/d in 2019 to 449 TJ/d in 2021 when the WORM is expected to be available.

Figure 4 highlights a shortfall or surplus as the difference between the forecast peak demand day dotted line and the supply capacity stacked bar. 'Prospective Victorian supply projects' includes projects or developments which have not reached financial investment decision (FID) but are anticipated to proceed during the outlook period.

Figure 4 **Peak day supply capacity by location (TJ/d)**



Additional supplies within the outlook period

AEMO has received project information on a number of uncommitted offshore gas supply projects across the Gippsland and Otway basins.

As discussed above, these projects could increase the annual production quantities from 246 PJ to 326 PJ in 2023 (noting that the VGPR only considers committed gas supply projects in the adequacy assessment). Further information on these projects is included in Chapter 4.

Prospective and potential projects[17] to increase supply and reduce the risk of a peak demand day shortfall include:

- **Additional gas production**.
  - The Kipper Unit Joint Venture has a proposed project to drill additional wells into the Kipper gas field. These wells were part of the original Kipper plan and are referred to as Stage 1B. The current schedule is for the Kipper Stage 1B wells to be drilled in 2020[18].
  - Following Esso's November 2018 announcement that the Dory drilling program failed to yield commercial quantities of hydrocarbon, the Gippsland Basin Joint Venture (GBJV) is assessing other potential opportunities to develop resources for supply into the market[19].
  - Beach Energy has announced that it intends to develop the Blackwatch gas field in Port Campbell, along with undertaking exploration drilling targeting the Enterprise and Artisan prospects. In the event of a successful discovery, this gas is expected to be processed through the Otway Gas Plant. Beach have also proposed further development of the Thylacine and Geographe fields[20].
  - Cooper Energy is proposing a redevelopment of the Henry-2 well in 2020 targeting an additional 20 TJ/d of production[21], and also conducting studies on two exploration prospects, Annie and Elanora, in the Otway Basin[22].
- **Additional gas storage capacity**.
  - Lochard Energy intends to increase the Iona UGS reservoir withdrawal capacity to increase the facility supply capacity to 520 TJ/d by 2021. This increased supply capacity is expected to continue to be limited by the transportation capacity of the SWP towards Melbourne, even after the construction of the WORM, which will increase SWP capacity. The construction of the WORM is expected to assist with reservoir refilling as Port Campbell production declines.
  - Lochard Energy has agreed to purchase a number of depleted gas fields near the Iona UGS facility, with the intention of converting some of these fields to gas storage reservoirs[23]. Additional storage reservoirs are not expected to be available prior to 2023. Lochard Energy has received Australian Competition and Consumer Commission (ACCC) approval[24] to complete this acquisition.
  - GB Energy acquired the Golden Beach field in May 2018. A project team is currently conducting engineering studies and seeking approvals for the field to be brought online in 2021[25]. Initially, the gas field is expected to produce over two to three years, before being used as a storage reservoir.

[17] 'Prospective supply' includes projects or developments which have not reached FID but are anticipated to proceed during the outlook period. 'Potential projects' are uncommitted gas supply projects that have not reached FID, which are considered less likely but could potentially proceed during the outlook period.

[18] Exxon Mobil, "Esso offshore projects" factsheet, August 2018, at https://cdn.exxonmobil.com/~/media/australia/files/publications/fact-sheets/publication_em-offshore-activities-fact-sheet-august-2018.pdf.

[19] The Australian Financial Review, "Esso-BHP to boost east coast gas with $550m Bass Strait project", 13 December 2018, (paywall) at https://www.afr.com/business/energy/gas/essobhp-to-boost-east-coast-gas-with-550m-bass-strait-project-20181213-h192ej.

[20] Beach Energy, Investor Presentation, October 2018, at https://www.beachenergy.com.au/wp-content/uploads/2018/10/BeachEnergyInvestor presentation.pdf.

[21] Cooper Energy, "FY18 Results & FY19 Outlook", 13 August 2019, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Fy18-Aug-12-investor-pack.pdf.

[22] Cooper Energy, Presentation to Goldman Sachs Emerging Energy Companies Conference, 28 November 2018, at http://member.afraccess.com/media?id=CMN://2A1120361&filename=20181128/COE_02053102.pdf.

[23] The Australian Financial Review, "Origin Energy, QIC's Lochard sign storage assets deal", 4 February 2019, (paywall) at https://www.afr.com/street-talk/origin-energy-qicbacked-lochard-sign-heytesbury-deal-20190201-h1aqkg.

[24] ACCC media release, 21 Mar 2019, at https://www.accc.gov.au/media-release/lochard%E2%80%99s-acquisition-of-heytesbury-gas-reservoirs-not-opposed.

[25] GB Energy, "Golden Beach Pipeline", at https://gbenergy.com.au/wp-content/uploads/2019/01/190114-Golden-Beach-Pipeline-Consultation-Plan_Rev2-003.pdf.

- **LNG import terminals**.
  - Five LNG import terminal projects have been proposed for south-east Australia, two of which are located within Victoria:
    - AGL has proposed the development of a floating LNG import terminal at Crib Point, near Hastings. AGL has advised that, if approved, this facility is not expected to be available before winter 2022[26].
    - Esso is also actively considering a potential LNG import project to bring additional supply to the east coast gas market from 2022[27].
- **Supply from Queensland or Northern Territory**.
  - Winter 2018 saw Queensland gas flowing south to supply the winter load in New South Wales and South Australia. Victoria also received gas from Queensland via Culcairn in New South Wales, but this was less than the flow back to New South Wales via the Eastern Gas Pipeline (EGP).
  - Commercial operation of the Northern Gas Pipeline (NGP) began on 3 January 2019 to supply up to 90 TJ/d into the East Coast Grid at Mount Isa. This reduces demand off the South West Queensland Pipeline (SWQP), making this capacity available for supply into New South Wales, South Australia, and Victoria.
  - As Victorian production declines, the existing pipeline capacity outside of Victoria will constrain the southbound flow of Queensland gas without a major pipeline infrastructure upgrade.
  - The high winter and low summer gas consumption in Victoria means that a new pipeline may only be required to supply Victoria for 3-4 months of the year based on forecast production. This may make the economics of a new pipeline challenging if utilisation cannot be increased.
- **Hydrogen**.
  - Hydrogen can be safely added to natural gas supplies at 10% by volume without changes to distribution pipelines and appliances. Hydrogen could be produced via electrolysis using electricity generated by wind and solar generators[28].
  - The Council of Australian Governments (COAG) Energy Council has requested Australia's Chief Scientist, Dr Alan Finkel, to develop a strategy to allow up to 10% hydrogen in the domestic gas networks[29].
  - While hydrogen is not expected to have a material impact on natural gas demand during the outlook period, AEMO will continue to monitor the development of this strategy.

[26] AGL web page, "AGL Gas Import Jetty Project", at https://www.agl.com.au/about-agl/how-we-source-energy/gas-import-project. Viewed 5 February 2019.

[27] Reuters, "Exxon Mobile considers importing LNG to Australia", 18 June 2018, at https://www.reuters.com/article/us-exxon-mobil-australia-lng/exxonmobil-considers-importing-lng-to-australia-idUSKBN1JE02R.

[28] Hydrogen for Australia's Future – A briefing paper for the COAG Energy Council, August 2018.

[29] Proposal for a national hydrogen strategy – presented to COAG Energy Council, December 2018.

Contents

Tables

Figures

1. Introduction

The *Victorian Gas Planning Report* (VGPR) assesses the adequacy of the Victorian declared transmission system (DTS) to supply peak day gas demand and annual consumption over a five-year outlook period. The most recent VGPR was published in March 2017. Due to material changes to the DTS and new gas production forecast information, a VGPR Update was published in March 2018[30].

All times in this report are Australian Eastern Standard Time (AEST).

1.1 What's new in the 2019 VGPR?

The 2019 VGPR features changes in the classification of gas production and supply forecasts provided by gas producers. The document now includes aggregated information on uncommitted gas supply projects, as provided by gas producers, that are likely to proceed during the outlook period (which this report refers to as "prospective supply").

This change in the application of the gas production and supply capacity forecasts will enable stakeholders to reconcile the forecasts in this document with the 2019 *Gas Statement of Opportunities* (GSOO).

1.1.1 Gas supply classification definitions

The classifications of gas supply in the 2019 VGPR are:

- **'Available supply'** – this comprises developed gas reserves and committed new gas supply projects. It includes developments or projects which have successfully passed a financial investment decision (FID) and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational. Available supply is made up of two components:
  - **'Contracted supply'**[31] – this is firm gas supply currently contracted by market participants.
  - **'Uncontracted supply'**[32] – this is gas that is currently available to be contracted or sold into the spot market by gas producers.
- **'Prospective supply'**[33] – this considers gas supply from undeveloped reserves or contingent resources, that producers forecast to be available as part of their best production estimates provided to AEMO. It includes projects or developments which have not reached FID but are anticipated to proceed during the outlook period (for example, there is a development plan that utilises existing infrastructure). This supply is discussed in Chapter 3.
- **'Potential projects'** – these are uncommitted gas supply projects that have not reached FID, which could potentially proceed during the outlook period. These projects have not been included in the prospective supply forecast and are discussed in Chapter 4. They are considered less likely than the prospective supply projects to be developed during the outlook period, due to:

[30] Recent VGPR publications are available at http://aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

[31] In previous VGPRs, this was classified as 'available supply'.

[32] In previous VGPRs, this was classified as 'prospective supply'. Because gas producers have started selling their uncontracted gas into spot markets, such as the Victorian Declared Wholesale Gas Market and Short Term Trading Markets, AEMO has moved this gas to the available supply classification.

[33] This is a new classification to allow participants to reconcile VGPR and GSOO forecasts.

  - The discovered gas fields being classified as contingent resources (not proven reserves) where commercial recovery is dependent on the development of new technology or where evaluation of the gas resource is still at an early stage, or
  - Insufficient gathering pipeline or appropriate gas processing capacity being available, or
  - The project requiring new infrastructure that currently does not have approved planning permits or environmental approvals.
- **'Exploration projects'** – these projects are associated with undiscovered gas resources, also known as "plays", that are usually mapped using seismic data. These 'prospective resources' have not been physically proven with exploration wells, so commercial quantities of hydrocarbons may not actually be present. Neighbouring wells and seismic data are used to estimate the 'gas in place', with the reported prospective resource volumes usually representing the estimated recoverable volume of hydrocarbons. These projects are not included in any of the supply forecasts, and are also discussed in Chapter 4.

1.2 The Victorian Declared Transmission System

The DTS supplies natural gas to the majority of Victorian households and businesses, as well as to New South Wales communities along the Murray River between Moama and Albury. It transports gas from the Longford production facility in the east, to and from Culcairn in the north (connecting to the New South Wales gas transmission system), and Port Campbell in the west (connecting to the Otway and Minerva gas production facilities, the Iona Underground Gas Storage [UGS] facility, and to South Australia via the SEA Gas Pipeline).

The DTS is divided into six system withdrawal zones (SWZs), defined in Appendix A5: Ballarat; Geelong; Gippsland; Melbourne; Northern; and Western (the Western Transmission System or WTS).

Figure 5 is a high-level map of the Victorian gas transmission network, including the DTS (in blue) and other gas transmission pipelines.

1.3 Gas planning in Victoria

1.3.1 Roles and responsibilities

AEMO operates the Victorian DTS and provides information about gas supply and demand, system constraints, capability, and development proposals, to assist in the efficient planning and development of gas markets and facilities.

The DTS service provider, APA Group, owns and maintains the DTS assets. As the asset owner, APA must submit an Access Arrangement proposal to the Australian Energy Regulator (AER) every five years, which contains their proposed capital and operating expenditures. The AER assesses the proposal and then provides APA with an appropriate cost recovery structure to fund the continued service of the network and any approved projects.

Figure 5 The Victorian Declared Transmission System

The timing of any capital investment in the DTS is ultimately decided by APA Group. Under the National Gas Law (NGL) and the NGR, the framework allows the APA Group to adjust actual capital expenditure from that assessed by AER during the Access Arrangement period as conforming, and to propose a more efficient capital expenditure for approval at the end of the Access Arrangement period.

Third-party asset owners maintain and augment connected infrastructure, including production and storage facilities, and interconnected pipelines.

1.3.2 Planning basis and definitions

AEMO prepares and publishes a planning review (in the form of the VGPR) once every two years by 31 March, in accordance with NGR rule 323.

Where AEMO becomes aware of any information that materially alters the most recently published planning review, rule 323(5) requires AEMO to update that planning review as soon as practicable.

In accordance with rule 324, participants are required to provide AEMO with forecast information. Under rule 324(6), AEMO must keep this forecast information confidential except to the extent of the information that AEMO is required to provide in the VGPR.

In producing the VGPR, AEMO assesses DTS supply and system adequacy to meet a forecast 1-in-2-year and 1-in-20-year peak system demand day over the outlook period:

- A 1-in-2 forecast is defined as a peak day system demand forecast with a 50% probability of exceedance (POE). It means the forecast is expected, on average, to be exceeded once in two years, and is considered the most probable forecast.

- A 1-in-20 forecast is defined as a peak day system demand forecast for severe weather conditions, with a 5% POE. It means the forecast is expected, on average, to be exceeded once in 20 years, and is used for DTS capacity planning.

System demand does not include supply for the gas-powered generation of electricity (GPG)[34]. Under rule 323(3), AEMO is also required to assess the impact of GPG demand on 1-in-2-year peak system demand days.

AEMO uses "demand" to describe hourly and daily usage of gas; "consumption" is used for monthly and annual usage of gas.

The Gas Industry Act and the Gas Safety Act also impose obligations on network operators and owners relating to the reliability of gas supply. The reliability of gas supply refers to the continuity of supply to customers. Energy Safe Victoria (ESV) regards an unplanned loss of supply (or interruption) to a customer in any circumstance as a potentially dangerous and undesirable event.

AEMO uses these legislative requirements, along with the planning standard, to assess the adequacy of the DTS to support peak demand days. This assessment is used to recommend what augmentations or additional gas supplies are required to reduce the risk of an unplanned loss of supply and subsequent risks to public safety.

1.4 Review of 2018

Gas consumption during 2018 was relatively low, due to it being the third-warmest year in Victoria on record[35]. The annual cumulative EDD[36] was 1,372, which is 5% lower than the 1,447 in 2017.

The 2018 Victorian DTS peak demand day occurred on Thursday 28 June. Total demand was 1,132 terajoules (TJ), which comprised 1,078 TJ of system demand and 54 TJ of GPG demand.

The key observations for the peak demand period[37] of 2018 are:

- Average system demand was 791 TJ/d, lower than the 822 TJ/d average observed in 2017.
- Longford Gas Plant production, as shown in Figure 6, was on average approximately 200 TJ/d lower compared to 2017.
- The reduced Longford production resulted in an increased utilisation of Iona UGS during the peak demand period. Total Iona UGS net injections into the South West Pipeline (SWP) were 12.6 petajoules (PJ) in 2018, compared to 5.0 PJ in 2017.
- Net injections from New South Wales via Culcairn into the Victorian Northern Interconnect (VNI) were 3.9 PJ, although 41.8 PJ was transported to New South Wales via the Eastern Gas Pipeline (EGP). During the previous three peak demand periods, there was an overall net export of gas to New South Wales via the VNI and higher flows north along the EGP.
- Net supply from Queensland to the southern states (predominantly New South Wales and South Australia) via the South West Queensland Pipeline (SWQP) was 16.7 PJ during the peak demand period, compared to 5.2 PJ in 2017 as shown in Figure 7.
- DTS connected GPG reduced from 15 PJ in 2017 to 10 PJ in 2018. Non-DTS connected GPG also decreased from 22 PJ in 2017 to 14 PJ in 2018.

[34] Total demand is the sum of system demand and GPG demand.

[35] See http://www.bom.gov.au/climate/current/annual/vic/archive/2018.summary.shtml.

[36] EDD, or Effective Degree Days, is a measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for space heating purposes.

[37] Peak demand period in this report is defined as 1 May to 30 September.

Figure 6 Daily Longford production flows (TJ/d)

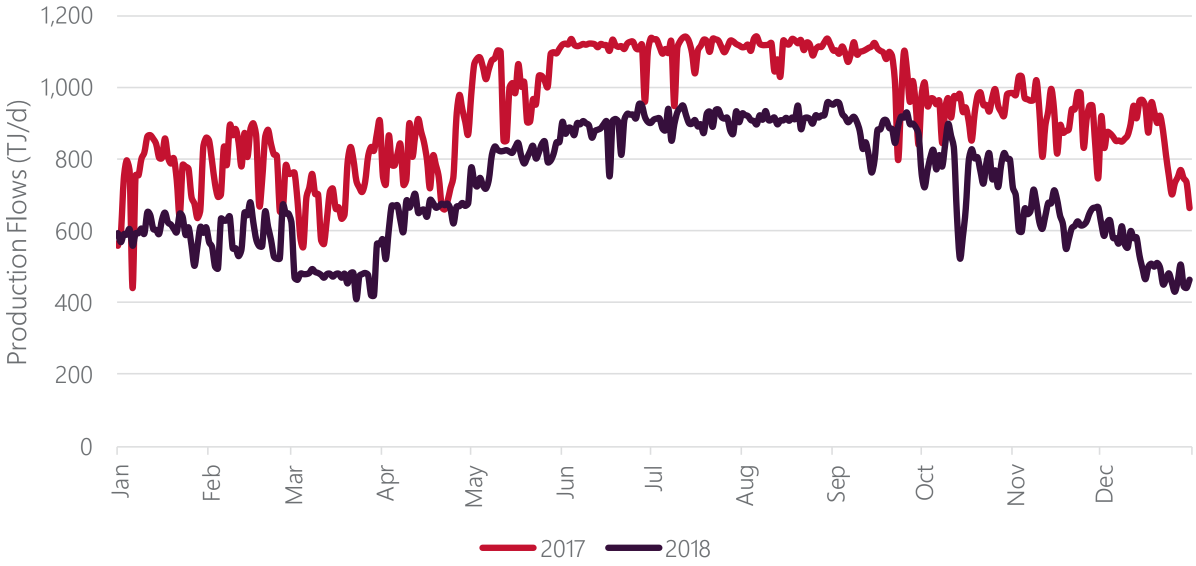
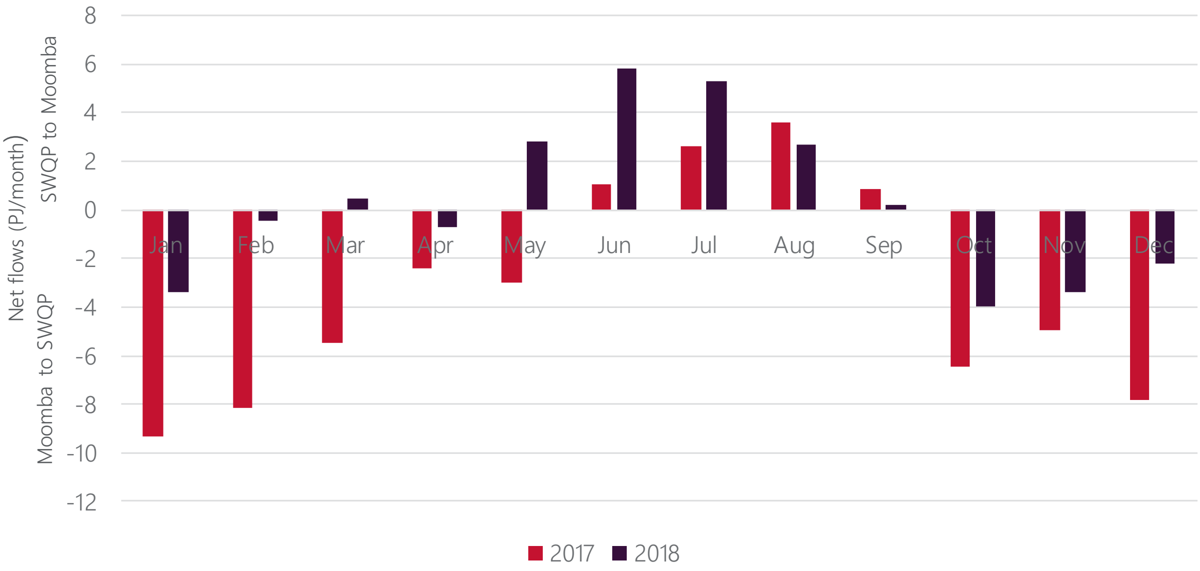


Figure 7 Net flow from Queensland to the southern states by month (PJ/month)



2. Gas usage forecast

Key findings

- Average annual system consumption[38] is forecast to increase slightly during the outlook period, from 200 PJ in 2019 to 203 PJ in 2023. This is in contrast to the 2017 VGPR and 2018 VGPR Update, where a slight decrease in annual system consumption was forecast.
- The forecast peak system demand for 2019 is:
  - 1,147 TJ/d for a 1-in-2-year peak system demand day.
  - 1,246 TJ/d for a 1-in-20-year peak system demand day.
- Over the 2019-23 outlook period, the 1-in-2-year and 1-in-20-year peak system demand days are forecast to increase by 1.4% and 1.5% respectively.
- Annual DTS-connected GPG consumption decreased by 32% in 2018 to 10 PJ/y. From 2019, annual DTS-connected GPG consumption is forecast to decrease further, due to new renewable generation coming online. An increase in GPG consumption is forecast towards the end of the outlook period, due to the announced closure of the coal-fired Liddell Power Station in New South Wales.

Background

The gas usage forecasts in the 2019 VGPR were produced using the GSOO demand forecasting methodology[39]. The VGPR forecasts are a subset of the gas usage forecasts in the 2019 GSOO for eastern and south-eastern Australia, also published in March 2019.

There are some material differences between the 2018 and 2019 VGPR forecasts, with the forecasting methodology updated to use a probabilistic rather than a deterministic forecast[40], and 2018 actual gas usage being incorporated into the forecasting models.

The gas usage forecasts for the DTS and Victoria over the outlook period include:

- Annual consumption.
- 1-in-2-year peak system demand day forecast.
- 1-in-20-year peak system demand day forecast.

2.1 Historical gas usage

System demand is the daily gas use by residential, commercial, and industrial gas customers. It also includes compressor and heater fuel gas use and an allowance for unaccounted for gas (UAFG), but excludes GPG demand. Total demand is the sum of system demand and GPG demand.

[38] Annual system consumption can vary by up to plus or minus 5% due to climatic conditions, i.e. whether it is a mild or cold winter.

[39] AEMO, *Demand Forecasting Methodology Information Paper*, 2018, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[40] Ibid.

System demand is split into:

- Tariff V demand, consisting of residential and small commercial customers normally consuming less than 10 TJ per year (TJ/y) of gas.
- Tariff D demand, consisting of large commercial and industrial customers normally consuming more than 10 TJ/y of gas.

Compressor and heater fuel gas use are proportionally allocated by energy volume to both Tariff V and Tariff D demand.

System demand is primarily driven by Tariff V gas usage for space heating, which depends on a number of variables including:

- Daily temperature profile – including the overnight minimum and daily maximum temperature.
- Previous day's temperature profile.
- The average wind speed – higher wind velocities increase the heat loss from the average dwelling.
- The number of sunshine hours due to the radiant heat impact, and its influence on behaviour (residential customers are more likely to turn off heating and go outside if it is sunny).
- Seasonal differences in heating sensitivity (residential customers are less likely to use heating, or as much heating under the same temperature conditions, outside of winter compared to during winter).
- Changes in the usage pattern of industrial customers affecting the base load.

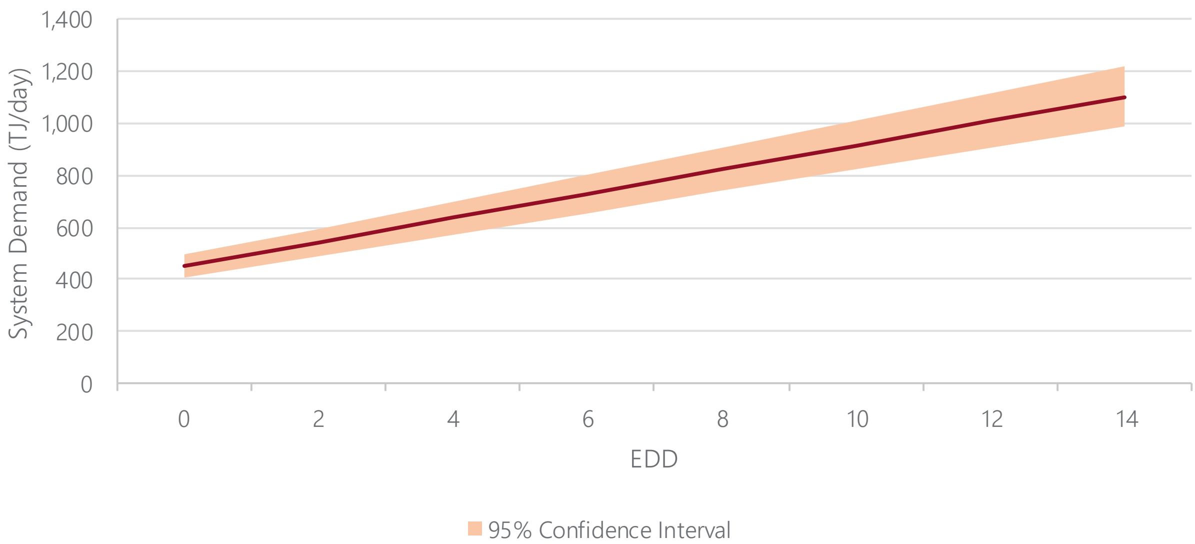
AEMO uses a measure called the Effective Degree Day (EDD) to forecast system demand. The temperature profile, average wind speed, and sunshine hours are used to calculate the EDD for each gas day.

This section discusses historical demand behaviour and trends observed, and the relationship between system demand and EDD over time. The analysis only uses data for Monday to Thursday (which are classified as Type 1 days provided they are not public holidays), because demand behaviour differs on Fridays, weekends and public holidays.

2.1.1 Relationship between system demand and EDD

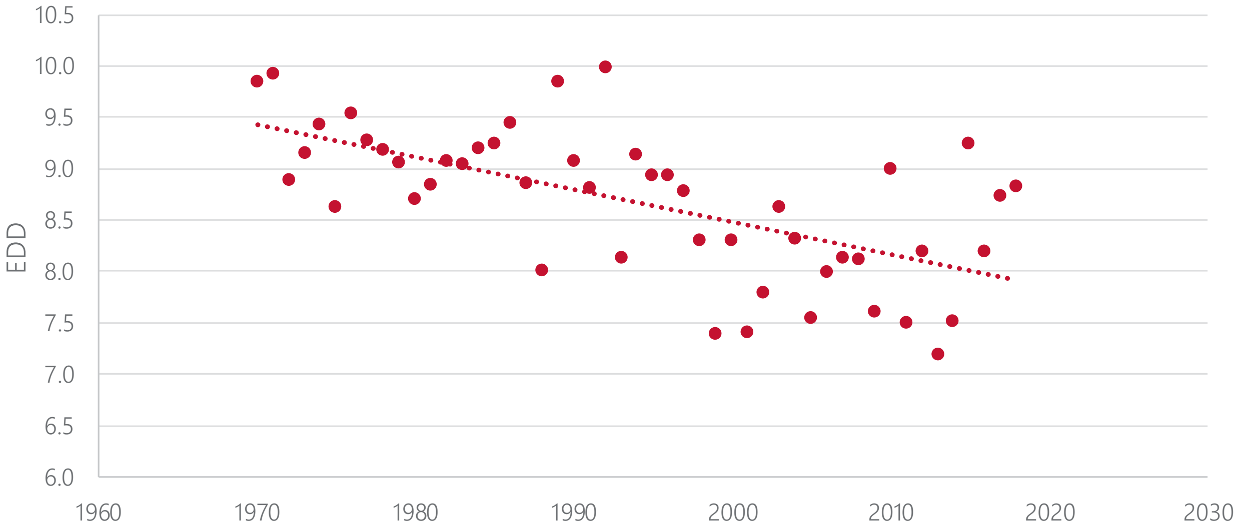
Although there are a number of factors that impact system demand, the main driver is EDD. Figure 8 illustrates that, on average, system demand increased by 47 TJ per EDD. This roughly means that for the same wind and sunshine hours, system demand increases by approximately 47 TJ/d when the average temperature is 1°C colder.

Figure 8 EDD vs. system demand for Type 1 days during winter 2018



The average daily EDD during winter has decreased over time, as shown in Figure 9, predominately due to climate change[41]. This average year-on-year decrease in EDD is small at 0.04, so the decreasing EDD only contributes to an average reduction in daily system demand of approximately 3 TJ/d per year. This reduction is being offset by increasing customer numbers.

Figure 9 Average daily EDD (June to September) 1970-2018



2.1.2 Consumption trends

Tariff V consumption has been increasing over time, as shown in Figure 10. This is attributed primarily to significant population growth in Victoria, from 4 million in 1984 to 6.5 million people in 2018[42].

In contrast, Tariff D consumption has plateaued and has been in decline. Tariff D consumption increased from 1984 to 1990, before decreasing as a result of the early 1990s recession. From 2002, Tariff D consumption has been decreasing, due to manufacturing moving offshore to seek lower labour costs[43].

This decline accelerated due to increasing gas prices[44] (from 2006 to 2017 average gas prices for large industrial customers on the east coast have increased from approx. $5/GJ to $10/GJ[45]) and the economic slowdown caused by the Global Financial Crisis (GFC).

[41] NEIR, "Review of EDD weather standards for Victorian gas forecasting", April 2016, at http://nieir.com.au/wp-content/uploads/2016/07/NIEIR-EDD-Review-April-2016.pdf.

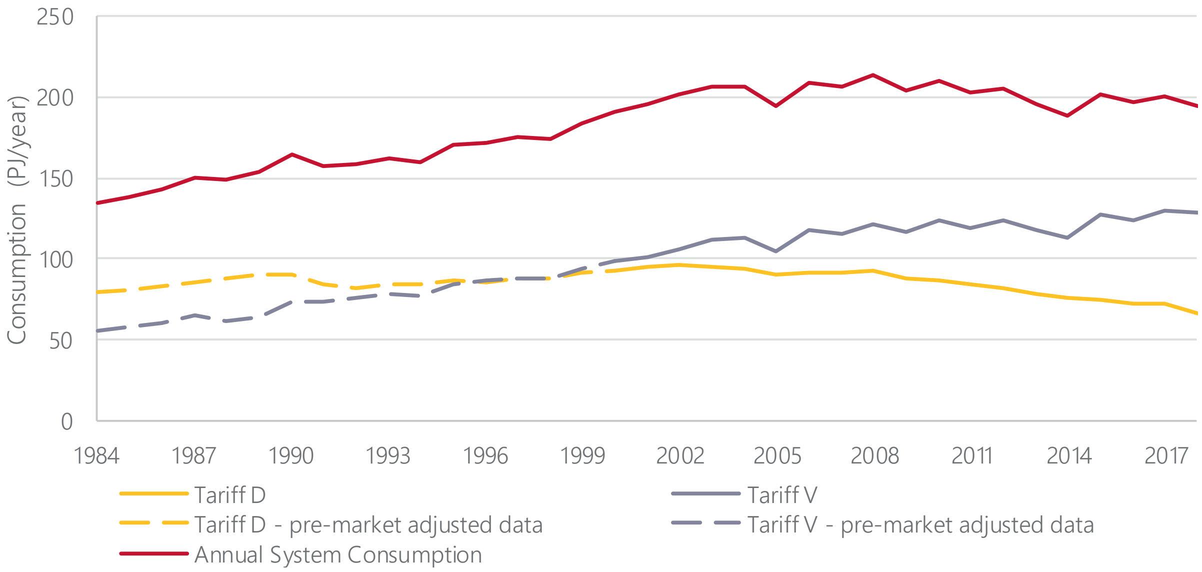
[42] Australian Bureau of Statistics, "Population by sex, states and territories, 30 June, 1901 onwards", at http://www.abs.gov.au/AUSSTATS/ABS@Archive.nsf/log?openagent&3105065001_table2.xls&3105.0.65.001&Data%20Cubes&7BB5E247A5A2F416CA25717600229537&0&2006&23.05.2006&Latest.

[43] Reserve Bank of Australia, "Conditions in the Manufacturing Sector" June 2016, at https://www.rba.gov.au/publications/bulletin/2016/jun/pdf/bu-0616-4.pdf.

[44] Department of Industry, Innovation and Science, "Energy costs and export competitiveness: evidence from Australian industries" June 2018, at https://www.industry.gov.au/sites/g/files/net3906/f/June%202018/document/pdf/energy_costs_and_export_competitiveness_-_evidence_from_australian_industries.pdf.

[45] Oakley Greenwood, "Gas price trends review 2017" p.7 March 2018, at https://www.energy.gov.au/sites/default/files/gas_price_trends_review_2017.pdf.

Figure 10 Tariff D, Tariff V and annual system consumption (PJ/y) 1984-2018



Note. Prior to 2000, the Tariff types were residential, commercial, and industrial. This data has been adjusted to align with the current Tariff V and Tariff D definitions.

2.2 Forecast consumption

This section presents the DTS total annual consumption forecasts, which includes:

- System consumption (Tariff V, Tariff D, compressor fuel gas, and UAFG).
- DTS-connected GPG consumption.

It also presents total Victorian consumption, which includes:

- Total DTS consumption.
- Non-DTS Tariff V and Tariff D consumption at Bairnsdale, Lang Lang, and demand off the South Gippsland pipeline.
- GPG consumption at Bairnsdale and Mortlake.

2.2.1 Annual consumption

Annual DTS total gas consumption is forecast to increase from 207 PJ/y in 2019 to 212 PJ/y in 2023, as shown in Table 4 and Figure 11.

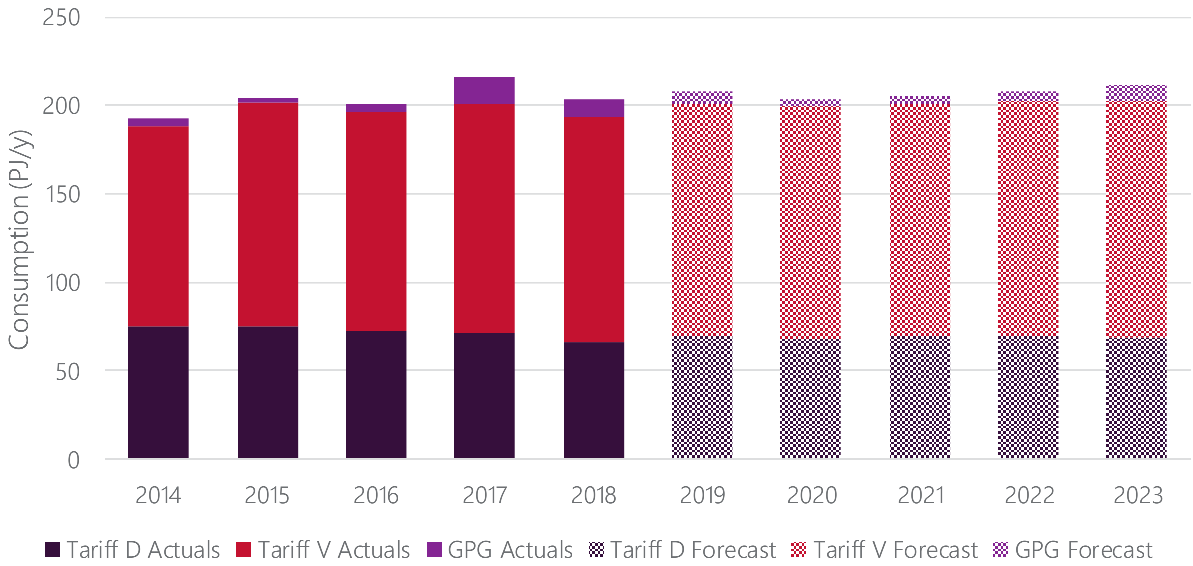
This is attributed primarily to a forecast increase in both Tariff V and GPG annual consumption. This is higher than the 2018 VGPR Update, which projected total consumption reducing to 206 PJ in 2022.

Table 4 Total annual gas consumption forecast (PJ/y)

	2019	2020	2021	2022	2023	Change over outlook
Tariff V	131	132	132	133	134	2.0%
Tariff D	69.4	68.2	69.4	69.7	69.0	-0.5%
System consumption	200	200	201	202	203	1.1%
DTS GPG consumption	7.2	4.1	4.7	5.8	9.0	25%
Total DTS consumption	207	204	206	208	212	1.9%
Non-DTS system consumption	1.28	1.27	1.30	1.33	1.34	4.7%
Non-DTS GPG consumption	8.2	4.2	4.6	5.1	10.0	22%
Total Victorian consumption	217	209	212	215	223	2.7%

Note: totals and change over outlook percentage may not add up due to rounding.

Figure 11 Historical and forecast total annual gas consumption, 2014-23



2.2.2 Tariff V consumption

Tariff V annual consumption, which comprises residential and small commercial customers, is projected to increase by 2% over the outlook period.

The increase is driven by population growth, which is forecast to increase the number of Tariff V connections, as shown in Figure 12. The impact of population growth is offset by the decreasing consumption per household due to improved energy efficiency and electric appliance use in high density developments. This is consistent with the forecasts submitted by distributors AusNet Services and Australian Gas Networks in their AER Access Arrangements[46,47].

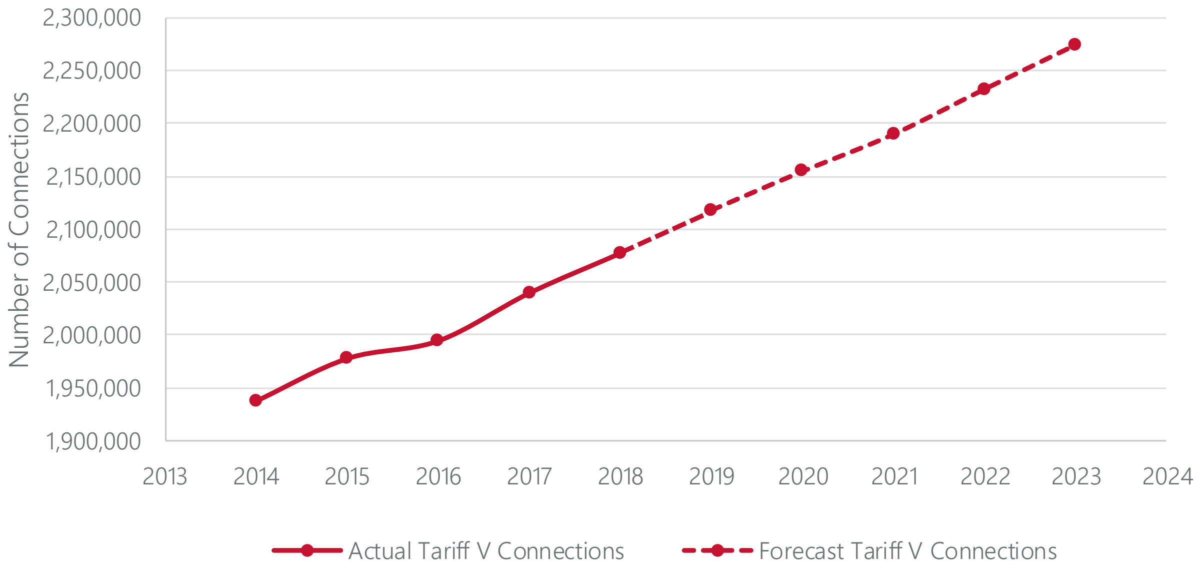
This increase contrasts with the 2018 VGPR Update, which forecast a 0.7% decline. AEMO's modelling has been updated to differentiate between electric appliance installation in high density developments and continuing gas appliance installation in suburban developments. This trend is supported by carbon

[46] Ausnet Services, "Gas Access Arrangement Review 2018-2022: Access Arrangement Information", at https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Access%20Arrangement%20Information%202018-2022%20-%2020161221%20-%20Public.

[47] Australian Gas Networks, "Victoria and Albury Final Plan December 2016", at https://www.aer.gov.au/system/files/AGN%20-%20Final%20Plan%20-%20Access%20Arrangement%20Information%20for%20our%20Victorian%20and%20Albury%20natural%20gas%20distribution%20networks%202018-2022%20-%2020161222%20-%20Public.pdf.

abatement schemes, such as the Victorian Energy Efficiency Target (VEET)[48] promoting the reduction of greenhouse gas emissions. The VEET encourages gas use for hot water and space heating, because currently in Victoria the use of electric appliances generates more greenhouse gas emissions than natural gas appliances[49].

Figure 12 Historical and forecast DTS connections, 2014-23



As Table 5 shows, the behaviour varies in different SWZs:

- In the Melbourne zone, Tariff V consumption is forecast to marginally decrease as the projected number of new connections is offset by reduced consumption per household, reflecting the greater proportion of high-density developments that use electrical appliances.
- In the Ballarat, Geelong, Gippsland, Western, and Northern zones, Tariff V consumption is forecast to increase due to the number of new connections in the low-density population growth corridors on the fringe of Melbourne that are expected to continue to install gas appliances.

Table 5 Annual Tariff V consumption (PJ/y) by SWZ

	2019	2020	2021	2022	2023	Change over outlook
Ballarat	8.7	8.8	9.0	9.2	9.5	9.5%
Geelong	11.0	11.1	11.3	11.5	11.8	7.2%
Melbourne	93.7	93.5	92.9	93.1	93.2	-0.6%
Gippsland	5.6	5.8	5.9	6.2	6.4	13.6%
Western	1.3	1.3	1.3	1.3	1.3	2.1%
Northern	10.9	11.0	11.2	11.4	11.6	6.7%
DTS Tariff V system consumption	131.1	131.6	131.6	132.8	133.7	2.0%
Non-DTS Tariff V system consumption	0.55	0.58	0.60	0.62	0.64	16.4%
Total Victorian Tariff V	131.7	132.1	132.2	133.4	134.3	2.1%

Note: totals and change over outlook percentage may not add up due to rounding.

[48] Essential Services Commission, "Victorian Energy Efficiency Target Scheme Performance Report 2015" p. 22, at https://www.esc.vic.gov.au/sites/default/files/documents/DMS%20413%20-%20Victorian%20Energy%20Efficiency%20Target%20Performance%20Report%202015%20-%20August%202106%20-%2020160824.pdf.

[49] Ibid.

2.2.3 Tariff D consumption

Tariff D annual consumption is forecast to have a 0.5% reduction during the outlook period. The 2018 VGPR Update predicted a decline in annual Tariff D consumption of 2.2% over a five-year period, with the change primarily driven by a relatively flat gas price forecast, as seen in the 2019 GSOO and advice received from large Tariff D customers.

The ACCC observed that domestic prices remain at levels that threaten the long-term viability of many Tariff D users[50]. If gas prices increase higher than forecast, annual Tariff D consumption is likely to be lower than that provided in Table 6.

Table 6 Annual Tariff D consumption (PJ/y) by SWZ

	2019	2020	2021	2022	2023	Change over outlook
Ballarat	1.7	1.6	1.7	1.7	1.7	0.1%
Geelong	10.9	10.7	10.9	10.9	10.9	0.1%
Melbourne	35.6	35.1	35.7	35.8	35.3	-0.8%
Gippsland	9.2	8.7	8.9	8.9	8.9	-3.0%
Western	2.9	2.9	2.9	2.9	2.9	0.1%
Northern	9.3	9.2	9.4	9.4	9.4	1.7%
DTS Tariff D system consumption	69.4	68.2	69.4	69.7	69.0	-0.5%
Non-DTS Tariff D system consumption	0.73	0.69	0.70	0.71	0.70	-4.1%
Total Victorian Tariff D	70.1	68.9	70.1	70.4	69.7	-0.6%

Note: totals and change over outlook percentage may not add up due to rounding.

2.2.4 Annual GPG consumption

Victorian gas usage for power generation is driven by events and conditions in the National Electricity Market (NEM). Higher GPG consumption occurred between 2007 and 2011 due to drought conditions in eastern Australia, which reduced the availability of water for hydroelectric generation and cooling for coal-fired generators.

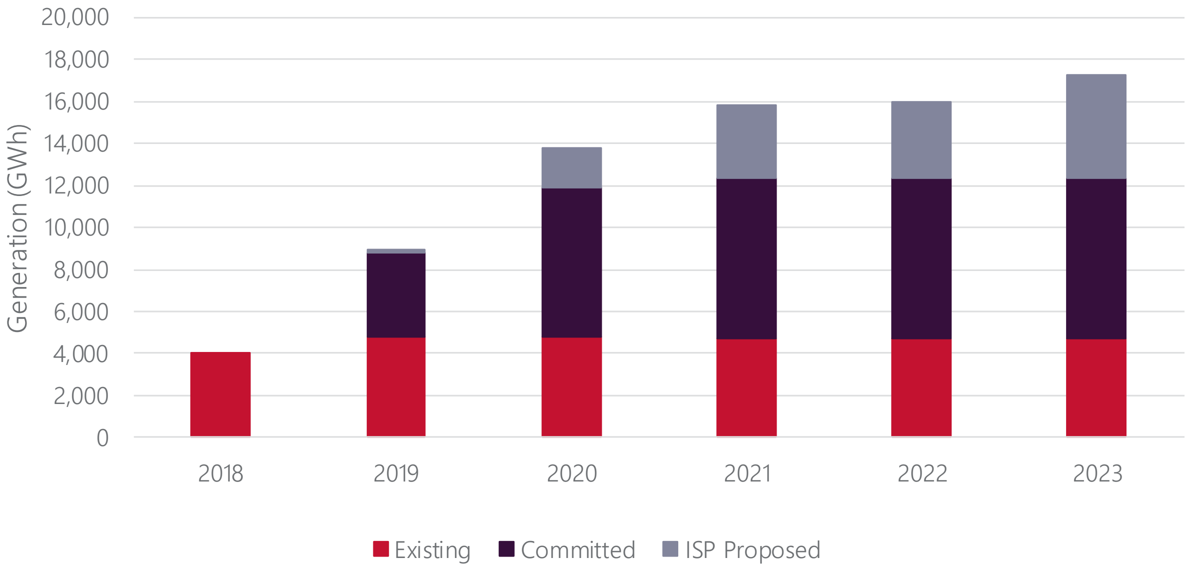
In 2017, GPG consumption increased to 15 PJ/y, 500% above the 2016 quantity, due to the March 2017 closure of the coal-fired Hazelwood Power Station. In 2018, the GPG consumption decreased by 32% to 10 PJ/y, due to increased New South Wales black coal generation output, the commissioning of additional renewable generation, and increased hydro generation.

Figure 11 provides a comparison between historic and forecast GPG consumption.

As presented in Table 4, GPG consumption is forecast to reduce a further 28% to 7 PJ/y, then to 4 PJ/y in 2020. This is due to the increase in the amount of renewable generation that is forecast to be commissioned during the outlook period, as shown in Figure 13. This increase is consistent with the requirement to meet the Victorian Renewable Energy Target (VRET) and the Federal Large-scale Renewable Energy Target (LRET).

[50] ACCC, "Gas Inquiry 2017-2020 Prelim Report" p. 67, 20 December 2018, at https://www.accc.gov.au/system/files/Gas-Inquiry-December-Interim-Report-2018.pdf.

Figure 13 Existing, committed, and proposed renewable generation in Victoria, 2018-23



The increase in forecast GPG consumption from 2021 to 2023 is primarily driven by the announced closure of the Liddell coal-fired power station in New South Wales in 2022[51].

The forecasting methodology assumes generation and transmission assets are developed in line with the Neutral scenario in AEMO's 2018 Integrated System Plan (ISP), which is a least-cost-based engineering optimisation plan for the NEM transmission system[52].

The 2018 ISP forecast a large amount of additional renewable generation being built in Victoria, in addition to that already committed[53], as shown in Figure 13. If investments in renewable generation do not meet those projected by the ISP, GPG consumption is forecast to be higher than the forecasts provided in Table 4.

Further, if coal outages during the summer peak electricity demand period are higher than forecast, summer GPG consumption is also likely to be higher than forecast.

2.2.5 Total monthly consumption

Monthly system consumption forecasts for January to December 2019 are shown in Table 7. These are similar to the forecasts provided in the 2017 VGPR:

- Maximum monthly system consumption is forecast to be 27.3 PJ per month (PJ/month) during July, with slightly lower amounts during June and August.
- System consumption during summer is forecast to be less than 10 PJ per month, with increased consumption during the shoulder seasons leading into and following winter.

[51] AGL, "Frequently asked questions about Liddell Power Station", 18 July 2018, at https://thehub.agl.com.au/articles/2018/07/the-facts-on-liddell-power-station-2.

[52] AEMO, *Integrated System Plan*, July 2018, at https://www.aemo.com.au/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf.

[53] AEMO, ISP – 2018 Generation and Transmission Outlooks, 17 December 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Generation-and-Transmission-Outlooks.zip.

Figure 14 Average daily demand compared to peak day system demand forecasts

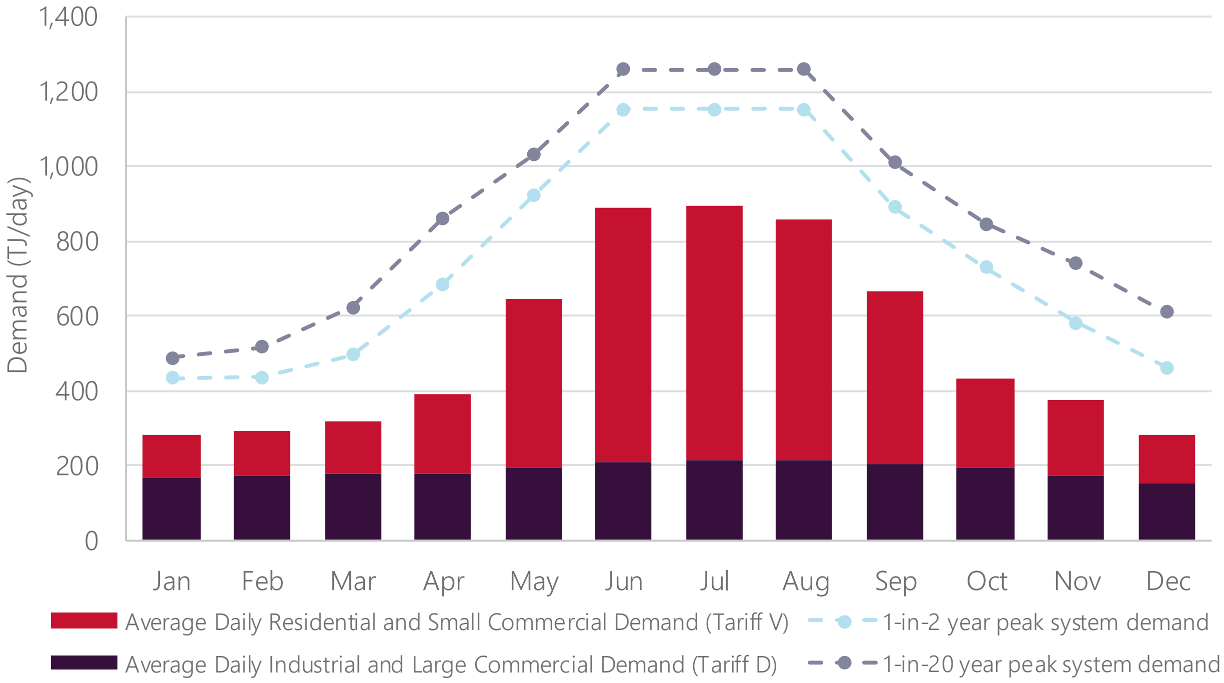


Figure 14 illustrates the monthly gas consumption increases during winter, with the average daily July demand of 939 TJ being three times the average daily January demand of 308 TJ.

DTS-connected GPG monthly consumption is forecast to increase in April and May 2019 (0.9 PJ/month and 1.3 PJ/month respectively) due to increased NEM demand and lower generation output from rooftop solar photovoltaic (PV).

Table 7 Forecast monthly gas consumption for 2019 (PJ/month)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System consumption	*8.24*	*8.52*	10.5	13.3	20.4	26.3	27.3	25.0	19.0	14.6	11.6	9.49
GPG consumption	*2.6*	*0.9*	0.4	0.9	1.3	0.9	0.6	0.4	0.5	0.3	0.3	0.2
Total consumption	*10.8*	*9.4*	10.9	14.2	21.7	27.2	27.9	25.4	19.5	14.9	11.9	9.69

Note. Operational actuals for January and February prior to final settlements.

These forecasts are reported by SWZ in Appendix A2, Table 27.

2.3 Peak day demand forecast

This section reports annual DTS peak day system demand forecasts over the five-year outlook period from 2019, and monthly peak day gas demand forecasts for January 2019 to December 2019. These forecasts are reported by SWZ in Appendix A2.

The 1-in-2-year and 1-in-20-year non-DTS Victorian peak day system demand forecasts are also included in Appendix A2 (Table 25 and Table 26).

2.3.1 Annual peak day system demand

Peak day system demand is primarily driven by Tariff V gas usage for space heating, which significantly increases with decreasing temperatures, as shown in Figure 8.

The 1-in-2-year and 1-in-20-year peak day system demand forecasts, summarised in Table 8 and Table 9, show a projected increase in Tariff V peak day demand, while Tariff D peak day demand is forecast to remain relatively flat during the outlook period.

Table 8 Annual 1-in-2-year peak day demand forecast (TJ/d)

	2019	2020	2021	2022	2023	Change over outlook
Tariff V	909	912	912	922	927	1.9%
Tariff D	238	234	239	238	237	-0.4%
System demand	1,147	1,146	1,152	1,161	1,164	1.5%

Note: totals and change over outlook percentage may not add up due to rounding.

Table 9 Annual 1-in-20-year peak day demand forecast (TJ/d)

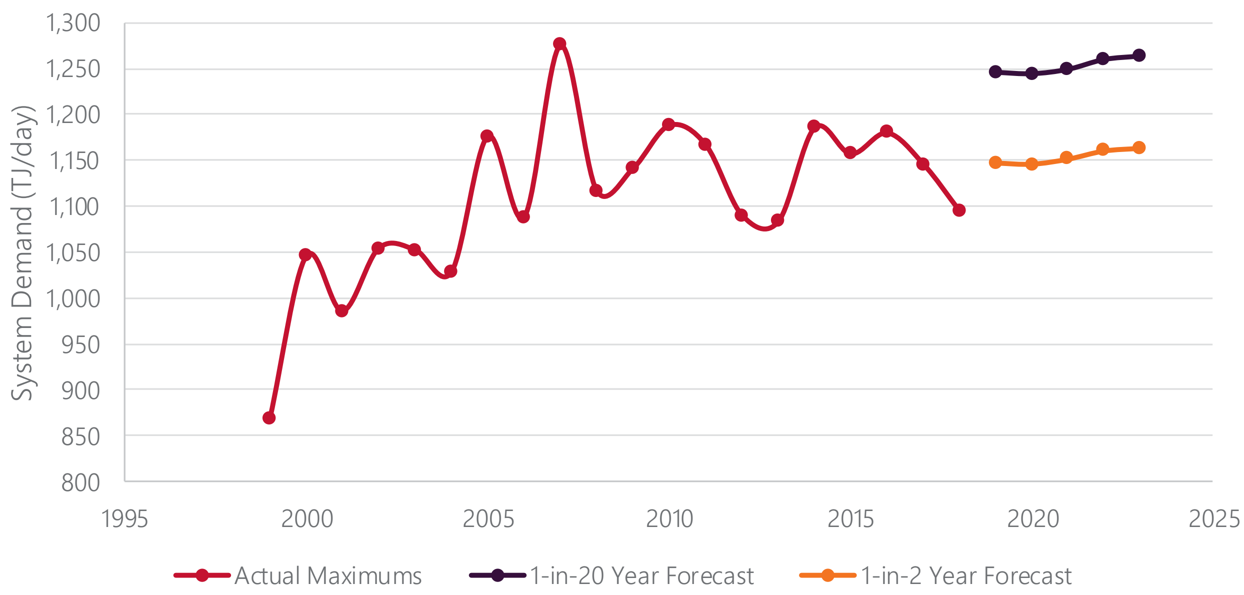
	2019	2020	2021	2022	2023	Change over outlook
Tariff V	999	1,001	1,000	1,010	1,019	2%
Tariff D	247	244	249	250	246	-0.7%
System demand	1,246	1,245	1,250	1,260	1,264	1.4%

Note: totals and change over outlook percentage may not add up due to rounding.

These forecasts are lower for 2019 than in the 2018 VGPR Update, where the 1-in-2-year and 1-in-20-year peak system demand day forecasts were 1,182 TJ/d and 1,292 TJ/d respectively. AEMO has updated its VGPR forecasting methodology to be consistent with the current GSOO methodology, utilising a probabilistic, rather than deterministic forecasting approach.

As shown in Figure 15, this forecast aligns with previous historical peak system demand days experienced. This forecast incorporates the impact of the warming trend in shown in Figure 9 and decreasing system consumption in Figure 10, while the increasing number of connections, as shown in Figure 12, will result in an overall upwards trend.

Figure 15 Historical peak day maximums and forecast peak day demands, 1999-23

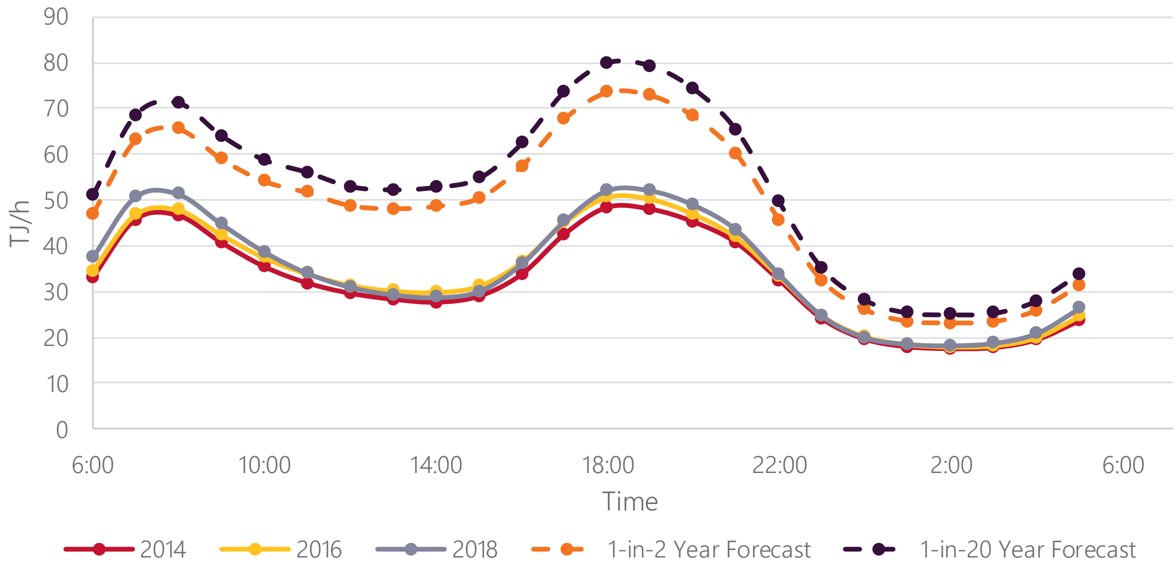


2.4 Peak hourly demand forecast

Figure 16 shows the average hourly winter demand has increased during the morning and evening peak demand periods. This is a result of an increasing number of Tariff V connections and decreasing Tariff D baseload demand (as shown in Figure 10).

The hourly winter demand on 1-in-2-year and 1-in-20-year peak system demand days is also included in Figure 16, illustrating the substantial increase in demand that occurs on peak days.

Figure 16 Average hourly winter and forecast peak day system demand profile



The peak hourly system demand forecast for each SWZ has been produced by applying the modelled winter peak demand profile at each Custody Transfer Meter (CTM) to the peak day system demand forecast, then aggregating for all CTMs in each SWZ. Peak hourly system demand forecasts for annual forecasts over the outlook period and monthly forecasts for January 2019 to December 2019 are presented in Appendix A2 (Table 30).

2.5 Monthly peak day forecast

Table 10 shows forecast peak day system demand for each month during 2019. The peak day system demand is forecast to occur during the three coldest winter months; June, July, and August. Monthly peak day system demand is influenced by weather conditions and seasonal industrial demand changes.

Monthly forecast peak day system demand by SWZ for 2019 is shown in Appendix A2 (Table 29).

Table 10 Forecast monthly peak day system demand (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2-year	432	437	496	686	934	1,147	1,147	1,147	910	730	581	461
1-in-20-year	488	517	621	861	1,110	1,246	1,246	1,246	1,103	845	739	609

3. Supply adequacy

Key findings

- Gas production forecasts provided to AEMO by gas producers are higher than those provided for the 2018 VGPR Update. Most of the increase is from the Gippsland Basin, due to some projects receiving approval after reaching FID.
- As a result of the higher production forecast in this VGPR, there is projected to be sufficient Victorian production to:
  - Supply annual Victorian gas consumption throughout the outlook period.
  - Meet forecast 1-in-2-year and 1-in-20-year peak system demand days, assuming that the Western Outer Ring Main[54] (WORM) is commissioned by 2022.
- Gas production however is still forecast to decline to 2023, where the forecast supply and demand are finely balanced.
  - In 2023, negligible Victorian supplies could be available to neighbouring jurisdictions on a peak demand day without additional supply capacity being made available.
  - Gas supply restrictions and curtailment of GPG may be necessary on a 1-in-20-year peak system demand day if additional supplies are not brought to market.
- Other sources of gas supply are forecast to be required to ensure continued supply to neighbouring jurisdictions, and supply to GPG on peak demand days. Prospective and potential additional supply includes new Victorian production, additional storage capacity and liquefied natural gas (LNG) imports. See Chapter 4 for additional information on prospective and potential future supply sources.

3.1 DTS supply sources

AEMO assesses supply adequacy based upon its demand forecast, provided in Chapter 2, and the forecast available supply, using data provided to AEMO by producers and facility operators (see below).

Gas supply classifications in the 2019 VGPR and 2019 GSOO have been changed, as defined in Chapter 1. These changes have been made to:

- Reflect current market conditions where uncontracted supply is being sold directly into the market by the gas producers.
- Improve the alignment in supply forecasts between the VGPR and GSOO, and allow for reconciliation between the two documents.
- Assess whether the uncommitted gas supply projects could prevent possible shortfalls.

VGPR and GSOO: Differences in assessing supply adequacy

While the 2019 GSOO is using the same Victorian gas production forecasts as the 2019 VGPR, there are differences in how each document assesses supply adequacy, so forecast outcomes differ slightly.

[54] For background information on the WORM see Section 6.3.

The GSOO takes a holistic approach and includes economic modelling to determine how gas is supplied to the entire east coast of Australia, whereas the VGPR assumes that Victorian demand is met by indigenous supply from Gippsland and Port Campbell prior to exports being supported.

Given the 20-year outlook that the GSOO must provide, it will continue to assess supply adequacy with the inclusion of projects that may only be in the their early, or conceptual, stages of development. In addition to this, a new case to assess supply adequacy has been introduced in the 2019 GSOO that will only look at existing and committed gas developments for the next 20 years. This will provide an outlook that is similar to the supply forecast produced in the Offshore South Eastern Australia Future Gas Supply Study[55] (as shown in Figure 18), except for the whole of the east coast.

For more information on the supply adequacy of the eastern and south-eastern Australian gas markets, refer to the 2019 GSOO.

3.1.1 Production facilities

DTS production capacity by supply source is reported by SWZ in Table 11, along with facility ownership details[56].

Table 11 DTS production facilities by SWZ

SWZ	Supply source	Project	Project Ownership
Gippsland	Longford Gas Plant	Gippsland Basin Joint Venture	• Esso Australia Resources, 50% • BHP Billiton Petroleum, 50%
		Kipper Unit Joint Venture	• Esso Australia Resources, 32.5% • BHP Billiton Petroleum, 32.5% • Mitsui E&P Australia, 35%
	Lang Lang Gas Plant	BassGas Project	• Beach Energy Limited, 53.75% • Mitsui E&P Australia, 35% • Prize Petroleum International, 11.25%
	Orbost Gas Plant	Sole Gas Project	• Cooper Energy, 100%
Port Campbell (Geelong)	Otway Gas Plant	Otway Gas Project	• Beach Energy Limited, 60% • O.G Energy, 40%
		Halladale/Speculant Project	• Beach Energy Limited, 60% • O.G Energy, 40%
	Minerva Gas Plant	Minerva Joint Venture	• BHP Billiton Petroleum, 90% • Cooper Energy, 10%
	Iona Gas Plant	Iona UGS	• QIC, 100%
		Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui E&P Australia, 50%

[55] See https://www.industry.gov.au/sites/default/files/2018-12/offshore-south-east-australia-future-gas-supply-study-terms-of-reference.pdf.

[56] The ownership details refer to the project. In some cases, the supply source and the projects can have different ownership. For sources of ownership information, see:

- https://www.exxonmobil.com.au/en-au/energy/oil/oil-operations/longford-plants.
- https://www.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/kipper-tuna-turrum.
- https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1057114/BPT_Acquisition_of_further_Otway_and_Bass_interests.pdf.
- https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2017.02.27-ASX-Sole-Gas-Project.pdf.
- https://www.asx.com.au/asxpdf/20181005/pdf/43yzwr51vzcfd2.pdf.
- https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2018.05.01-MGP-announcement.pdf.
- https://www.qic.com.au/knowledge-centre/gi-media-release-20151008.
- https://www.mitsui.com/au/en/group/1216674_9223.html, https://www.mitsui.com/jp/en/release/2018/1226191_11215.html.
- https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/CH-GSA-ASX--announcement.pdf.

3.1.2 Storage facilities

There are two storage facilities in the DTS:

- Iona UGS, located in Port Campbell (Geelong zone).
- Dandenong Liquefied Natural Gas (LNG) storage facility, located in the Melbourne zone.

Iona UGS

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports GPG demand in South Australia via the SEA Gas Pipeline and can supply the Mortlake Power Station.

The current total Iona UGS storage reservoir capacity is 26 PJ. The injection capacity into the storage reservoirs is 155 TJ/d[57].

Following the drilling of an additional Iona storage well in 2018, additional committed plant expansions will be completed to increase the Iona UGS supply capacity from 440 TJ/d to 480 TJ/d from 1 May 2019, with a further expansion to 520 TJ/d in 2021. Additional information is provided in Chapter 4.

Dandenong LNG storage

The Dandenong LNG storage facility has a capacity of 12,400 tonnes (680 TJ), with approximately 10,565 tonnes (580 TJ) of this capacity available to market participants.

For forecasting and planning purposes, it is assumed that:

- The LNG storage capacity is full or nearly full at the start of each winter.
- Vaporisation capacity of up to 100 tonnes per hour (t/h), equivalent to 5.5 terajoules per hour (TJ/h), is available over 16 hours for peak shaving purposes. This capacity equates to the vaporisation of 87 TJ/d, reflecting the firm daily capacity of the facility.
- The facility is able to vaporise 180 t/h (9.9 TJ/h), its maximum (non-firm rate) capacity, during abnormal and emergency system conditions.

Dandenong LNG is usually scheduled for either:

- Intraday peak shaving purposes when additional supply is required to maintain critical system pressures. It is usually scheduled from 2.00 pm or 6.00 pm but can be scheduled at any time if AEMO intervenes in the Victorian gas market.
- Market response by market participants to balance their supply and demand during peak days. This can occur during any schedule, including at 6.00 am.

3.1.3 Interconnected pipelines

There are four pipelines with connections to the DTS:

- Eastern Gas Pipeline (EGP), via the VicHub connection point into the Longford to Melbourne Pipeline (LMP).
- Tasmanian Gas Pipeline (TGP), via the TasHub connection point into the LMP.
- Young to Culcairn Pipeline, off the Moomba to Sydney Pipeline (also known as the Culcairn Interconnection).
- South East Australia Gas (SEA Gas) Pipeline, which supplies gas into the SWP via the SEA Gas, Otway and Mortlake connection points.

[57] See https://www.aemo.com.au/Gas/Gas-Bulletin-Board.

3.2 Annual supply demand balance

This section lists the annual gas supply and its adequacy during the outlook period. The forecast does not take into account DTS storage facilities, as these facilities provide seasonal balancing for the peak demand periods and are not expected to provide annual supplies.

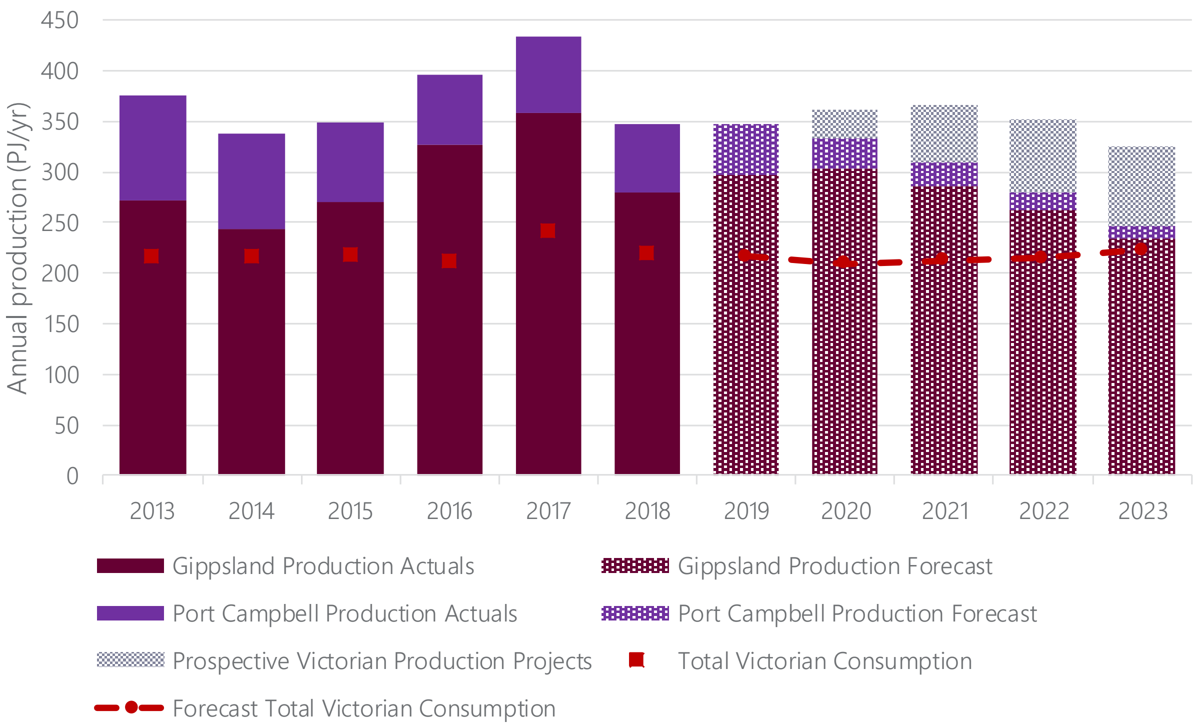
3.2.1 Annual production forecasts

Gas production forecasts provided by gas producers shows that Victorian gas production is forecast to decline by 29% during the five-year outlook period, from 347 PJ in 2019 to 246 PJ in 2023.

The Victorian annual production forecast is shown in Figure 17:

- Gippsland production is forecast to reduce by 22% from 298 PJ in 2019 to 234 PJ in 2023.
- Port Campbell production is forecast to reduce by 74% from 49 PJ in 2019 to 13 PJ in 2023.
- Prospective Victorian production projects encompasses the uncommitted supply that is considered likely to be brought online from 2020 onwards. If all prospective projects become committed within this timeframe and produce as advised, 2023 forecast production would increase from 246 PJ to 326 PJ.

Figure 17 Annual production by location



3.2.2 Production decline

The gas production forecasts provided to AEMO by gas producers are higher overall than those provided for the 2018 VGPR Update, with most of the increase coming from the Gippsland Basin.

Since the 2018 VGPR Update, a number of projects have been approved by reaching FID (AEMO only considers committed projects in the adequacy assessment). The most significant project is the West Barracouta Project, which was discussed in the 2018 VGPR Update as a potential source of supply. In mid-December 2018, the West Barracouta project passed FID, with increased gas production expected from

2021[58]. It is estimated that the field contains approximately 137 PJ of "wet" gas[59,60]. This project is forecast to operate until the late 2020s[61].

Exploration is also occurring with Beach Energy and Cooper Energy announcing offshore drilling programs in the Port Campbell area. These projects cannot be included in the supply adequacy assessment as a gas resource has not been "discovered". Supply from these resources will be included when they are in the planning and development phases.

Although gas production forecasts have increased compared to the 2018 VGPR Update, production is still forecast to decline during the outlook period. A comparison of the gas supply forecasts submitted to AEMO by producers for the 2018 VGPR Update and 2019 VGPR is shown in Table 12. This only compares "available" gas supply, which is existing developments and approved projects.

Table 12 2018 VGPR Update and 2019 VGPR supply forecast comparison

		2019	2020	2021	2022	2023
Gippsland	2018 VGPR	269	275	214	171	
	2019 VGPR	298	304	286	262	234
	Change (%)	11%	11%	34%	53%	
Port Campbell	2018 VGPR	39	28	23	16	
	2019 VGPR	49	29	23	17	13
	Change (%)	26%	4%	0%	6%	
Total	2018 VGPR	309	303	237	187	
	2019 VGPR	347	333	310	280	246
	Change (%)	12%	10%	31%	50%	

Figure 18 shows a comparison of the production forecasts in previous VGPRs with those provided in the Offshore South East Australia Future Gas Supply Study ('Commonwealth Study'). The Commonwealth Study was commissioned by the Commonwealth Government and published in November 2017 with data provided by the National Offshore Petroleum Titles Administrator (NOPTA), with assistance from Geoscience Australia.

Actual 2018 Victorian production was approximately 6% higher than the forecast published in the 2018 VGPR Update and approximately 21% higher than forecast in the Commonwealth Study. The actual production decrease from 2017 to 2018 was 86 PJ, less than the 107 PJ forecast provided by producers for the 2017 VGPR and 2018 VGPR Update.

With updated information from gas producers since the 2018 VGPR Update, the production forecasts are now higher than the numbers presented in the Commonwealth Study, as well as the 2017 VGPR and 2018 VGPR Update. However, all forecasts continue to project production declines throughout the outlook period.

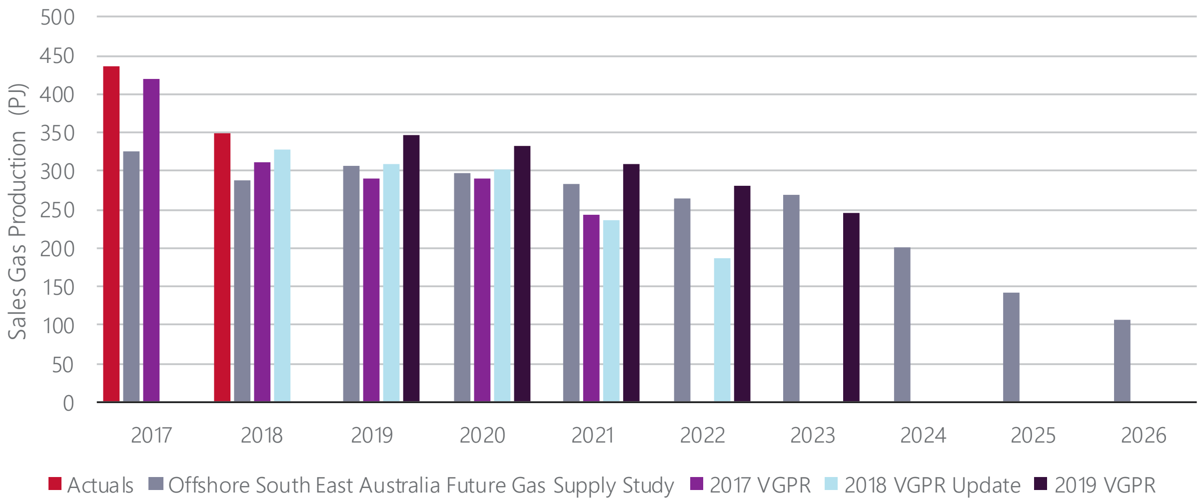
[58] ExxonMobil, media release, "ExxonMobil makes final investment decision to develop West Barracouta gas project", 13 December 2018, at https://www.exxonmobil.com.au/en-au/company/news-and-updates/news-releases-and-alerts/exxonmobil-makes-final-investment-decision-to-develop-west-barracouta-gas-project?parentId=1cebbb9b-beed-4e5f-9cdd-de9af04ce13a.

[59] This is natural gas that contains less methane (typically less than 85% methane) and more ethane, LPG and condensate, therefore the production of natural gas would be lower than indicated.

[60] The Australian Financial Review, "Esso-BHP to boost east coast gas with $550m Bass Strait project", 13 December 2018, (paywall) at www.afr.com/business/energy/gas/essobhp-to-boost-east-coast-gas-with-550m-bass-strait-project-20181213-h192ej.

[61] Sydney Morning Herald, "New gas slated for Queensland and Victoria could lift looming shortage", 14 December 2018, at https://www.smh.com.au/business/the-economy/new-gas-slated-for-queensland-and-victoria-could-lift-looming-shortage-20181213-p50m0z.html.

Figure 18 Victorian offshore production forecasts by year (PJ)



Reserves

Proved and probable (2P) reserves are the most commonly reported indicator of recoverable gas quantities:

- The Commonwealth Study estimated the 2P reserves available in offshore Victoria at the start of 2019 to be 3,233 PJ.
- The ACCC Gas Inquiry 2017-2020 Interim report[62] published in December 2018 estimated the remaining 2P reserves to be 3,286 PJ[63].
- The Core Energy Group Data[64] estimated the remaining 2P reserves to be 2,803 PJ.

Contingent resources (2C) are potentially recoverable but face technological or financial hurdles that prevent commercial development. These may be upgraded and classified as 2P reserves sometime in the future when these hurdles are overcome (for example, higher prices).

The ACCC Gas Inquiry 2017-2020 Interim report estimated the 2C resources in offshore Victoria as at 30 June 2018 to be 2,108 PJ.

Prospective resources – with sub-classes such as prospect, lead, and play – are quantities of hydrocarbons that are estimated, on a given date, to be potentially recoverable from undiscovered accumulations (that is, this gas may or may not be present and if present, may not be economic to produce). Possible options to increase future supply are discussed in Chapter 4.

3.2.3 Annual supply adequacy

Table 13 shows the annual supply adequacy forecast over the five-year outlook period. This assessment of projected production and demand provides an indication of when new projects may need to be brought online to ensure continuity of supply.

The production forecasts show that:

- At the start of the outlook period, there is approximately 130 PJ/y of gas available to supply New South Wales, South Australia and Tasmania. By 2023, this is forecast to reduce to 23 PJ/y of gas available to support neighbouring jurisdictions.

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[62] Australian Competition and Consumer Commission, *Gas Inquiry 2017-2020: Interim Report*, December 2018, at https://www.accc.gov.au/system/files/Gas-Inquiry-December-Interim-Report-2018.pdf.

[63] AEMO has calculated 2P reserves at the start of 2019 by using the numbers published in the ACCC report and deducting the actual production numbers.

[64] Core Energy Group Data is located on the AEMO GSOO web page, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

- There is 80 PJ of prospective (uncommitted but likely to proceed) gas production forecast to be available in 2023 that could be used to supply neighbouring jurisdictions, should these projects be approved.

Victoria has supplied, on average, 150 PJ/y to South Australia, New South Wales and Tasmania from production surplus to Victorian consumption. As noted above, this annual production surplus is forecast to decline to 130 PJ/y in 2019 through to 23 PJ in 2023. If additional production does not eventuate in Victoria, then 130 PJ/y must come from other sources. The maximum physical capacity of gas flow from Queensland to the southern states through existing pipeline infrastructure is 145 PJ/y.

To ensure continued gas supply to neighbouring jurisdictions, prospective supply projects will need to become committed projects or increased volumes of gas from Queensland will be required. The impacts of reduced Victorian supplies for other states are explored further in the 2019 GSOO.

Table 13 Total gas production by SWZ (PJ/y), 2019-2023

	Supply source	2019	2020	2021	2022	2023
Gippsland[A]	Contracted	287	252	101	101	27
	Uncontracted	11	52	185	161	207
	Total available	**298**	**304**	**286**	**262**	**234**
	Prospective	0	8	29	48	60
	Total available plus prospective	**298**	**312**	**315**	**311**	**294**
Port Campbell (Geelong)[B]	Contracted	49	19	15	10	7
	Uncontracted	0	10	8	7	6
	Total available	**49**	**29**	**23**	**17**	**13**
	Prospective	0	21	28	24	19
	Total available plus prospective	**49**	**50**	**51**	**42**	**32**
Total available		347	333	310	280	246
Total DTS consumption[C]		207	204	206	208	212
Total Victorian non-DTS consumption		9	5	6	6	11
Total Victorian consumption		217	209	212	215	223
Surplus / shortfall quantity		130	124	98	65	23
Total prospective		0	29	57	73	80

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Project, Sole Gas project, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes the Otway and Minerva gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.
C. Total consumption includes system demand and GPG demand.

3.3 Peak day supply demand balance

In their submissions for this year's VGPR, gas producers have indicated an improvement in the outlook for peak day supply. As a result, there are unlikely to be shortfalls in 2021 and 2022 (as was forecast in the 2018 VGPR Update), however 2023 is finely balanced without additional supply capacity. Peak day production capacities are still forecast to decline, which places a greater reliance on storage to meet peak day demand.

Gas supplies available for export to New South Wales, Tasmania, and South Australia on a peak demand day will also reduce. The 2019 GSOO assesses supply adequacy for these regions.

3.3.1 Forecast peak day supply

Table 14 shows the total available peak day gas supply capacity by supply source.

Table 14 Peak day maximum daily quantity (MDQ) capacity by supply source (TJ/d), 2019-23

SWZ	Supply source	2019	2020	2021	2022	2023
Gippsland[A]	Contracted	972	841	275	275	85
	Uncontracted	106	192	706	648	720
	Total available	**1,078**	**1,033**	**981**	**924**	**805**
	Prospective	0	9	89	112	122
	Total available plus prospective	**1,078**	**1,042**	**1,071**	**1,036**	**927**
Port Campbell (Geelong)[B]	Contracted	642	420	462	446	436
	Uncontracted	35	155	134	131	125
	Total available	**677**	**575**	**596**	**577**	**562**
	Prospective	0	72	92	77	111
	Total available plus prospective	**677**	**647**	**689**	**654**	**672**
Melbourne	LNG	87	87	87	87	87
Total available		1,843	1,694	1,665	1,588	1,454
Total available supply to the DTS including pipeline constraints		**1,528**	**1,483**	**1,446**	**1,388**	**1,269**
1-in-20-year peak system demand		1,246	1,245	1,250	1,260	1,264
DTS surplus/shortfall quantity on 1-in-20 peak day		**282**	**238**	**197**	**128**	**5**
Total prospective		0	81	182	189	233

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Project, Sole Gas project, and Lang Lang production facilities. The combined Longford number is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes Iona UGS, Otway, and Minerva. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

3.3.2 Peak day supply adequacy

Based on advice from gas producers and storage providers, the available peak day supply capacity is projected to decrease by 21% over the outlook period. This will remain sufficient to meet a 1-in-20-year peak system demand day, although without additional capacity supply, there is very little capacity available to support GPG. Most GPG units connected to the DTS can use diesel as an alternative fuel.

Combined system demand and high levels of winter GPG demand on a 1-in-2-year peak system demand day, as was experienced on 3 August 2017[65], is similar to the demand on a 1-in-20-year peak system demand day. GPG supportability is assessed in Section 6.2.

The supply adequacy assessment uses a mass balance analysis combined with hydraulic pipeline modelling which included:

- Committed gas supply information available to AEMO.
- Plant peak day supply capacity, from the total supply (shown in Table 14).
- DTS pipeline capacities including approved expansions (discussed in Chapters 5 and 6).

This peak day supply analysis assumed that the full capacity of the Iona UGS and Dandenong LNG storage facilities are available, and not restricted due to low storage inventories.

The assessment only considers firm sources of gas supply. Imports from Culcairn via the VNI have not been included in the peak day supply capacity. Culcairn supply also depends on operational and market conditions in the New South Wales transmission system, including demand in southern New South Wales and the operation of Uranquinty Power Station. Any gas from Culcairn into Victoria would reduce supply from Longford into Victoria due to increased EGP flows to support New South Wales' gas demand.

[65] The total demand on Thursday 3 August 2017 of 1,275 TJ was comprised of 1,148 TJ for system demand and 127 TJ for GPG.

Linepack in interconnected pipelines, including SEA Gas, EGP, and TGP, may be available on a peak day. This is not included in the available peak day supply, because it relies on sufficient pipeline linepack being maintained at all times. Sufficient linepack may not be available if there were consecutive peak days.

The peak day supply adequacy assumes that the WORM will be commissioned by 2022. As a result, the Port Campbell supply capacity (inclusive of Western Transmission System) is forecast to increase from 434 TJ/d in 2019 to 449 TJ/d by winter 2022.

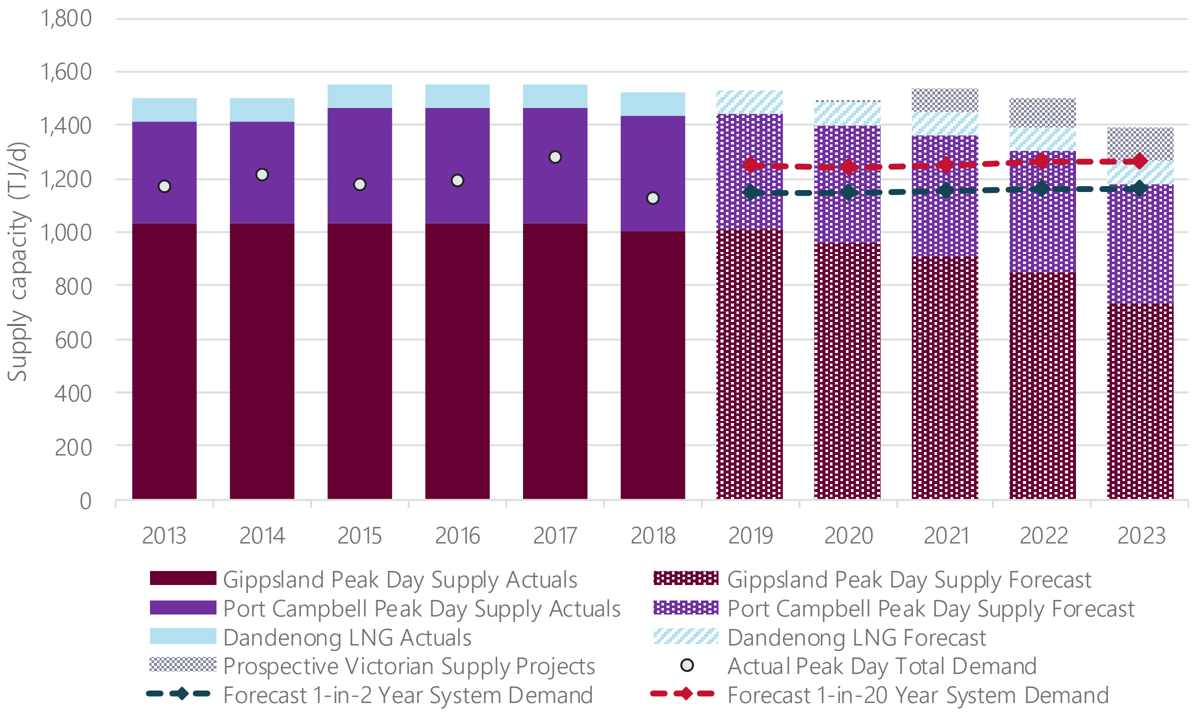
With the commissioning of the WORM, there are no projected shortfalls, but (per Table 16 below) the supply demand balance in 2023 is still forecast to be finely balanced and, without additional supplies being brought to market, could result in:

- Gas supply restriction and curtailment of GPG being necessary on a 1-in-20 peak system demand day.
- Negligible Victorian supplies being available to neighbouring jurisdictions on a 1-in-20 peak system demand day.

Due to the location of gas supplies, transmission constraints, and Victorian non-DTS gas consumption, not all the peak day supply capacity is available to the DTS. Port Campbell maximum daily production capacity, when combined with the Iona UGS facility, still has capacity exceeding the SWP capacity. As a result, on peak system demand days, there is still supply available from Port Campbell to South Australia and the Mortlake Power Station.

Figure 19 demonstrates a shortfall or surplus as the difference between the forecast peak demand day dotted line and the supply capacity stacked bar, taking into account pipeline constraints.

Figure 19 Peak day supply capacity by location (TJ/d)



It shows that Victorian maximum daily supply capacity is forecast to reduce by 21%, from 1,843 TJ in 2019 to 1,454 TJ in 2023:

- Gippsland maximum daily supply capacity is forecast to reduce by 25% from 1,078 TJ in 2019 to 805 TJ in 2023.

- Port Campbell maximum daily supply capacity, which includes Iona UGS, is forecast to reduce by 17% from 677 TJ in 2019 to 562 TJ in 2023. This remains higher than the SWP capacity, which is forecast to increase from 434 TJ/d in 2019 to 449 TJ/d in 2023.

2019 peak day outlook

There is forecast to be sufficient supply to the DTS on a 1-in-20-year peak system demand day during winter 2019. Table 15 shows that 596 TJ/d of spare capacity is projected to be available to supply DTS-connected GPG demand and to flow to neighbouring jurisdictions.

Table 15 DTS capacities and expected supply on a 1-in-20 peak demand day, 2019 (TJ/d)

		Total plant capacity	Pipeline capacity	DTS potential supply	Expected supply	Remaining supply capacity
Gippsland		1,078	1,030	1,030	850	228
Port Campbell	To Melbourne	677	414	434	396	281
	To WTS		20			
Melbourne	LNG storage	87		87	0	87
Total supply		**1,842**	**1,464**	**1,551**	**1,246**	
1-in-20-year system demand		1,246	1,246	1,246	1,246	
DTS surplus/shortfall quantity (TJ/d)		**596**	**218**	**305**		**596**

2023 peak day outlook

Table 16 shows that, while no supply shortfall is forecast in 2023, the forecast decline in production means that on a 1 in 20 system demand day there is projected to be only 190 TJ/d of spare capacity available to support other states and the Mortlake Power Station. Only 12 TJ of firm-rate Dandenong LNG is available to supply DTS GPG demand.

In this forecast, the majority of Gippsland daily production, from the Longford, Lang Lang and Orbost gas plants, is scheduled to supply the DTS. Approximately 65 TJ/d of Gippsland gas is required to support demand in eastern Victoria, southern New South Wales, and Tasmania as this is the only source of supply, so this portion of Gippsland gas cannot be used to support the DTS without curtailing customers in these locations.

This forecast has also assumed that the WORM (as approved by the AER) is constructed and commissioned by 2022, which enables the increased supply from the Port Campbell region.

Table 16 DTS capacities and expected supply on a 1-in-20 peak demand day, 2023 (TJ/d)

		Total plant capacity	Pipeline capacity	DTS potential supply	Expected supply	Remaining supply capacity
Gippsland		805	1,030	805	740	65
Port Campbell	To Melbourne	562	429	449	449	113
	To WTS		20			
Melbourne	LNG storage	87		87	75	12
Total supply		**1,454**	**1,479**	**1,341**	**1,264**	
1-in-20-year system demand		1,264	1,264	1,264	1,264	
DTS surplus/shortfall quantity (TJ/d)		**190**	**215**	**77**		**190**

If neighbouring jurisdictions were to experience gas demand above their state average coincident with a 1-in-20-year peak system demand day occurring in Victoria, those jurisdictions' gas requirements could not be met by Victorian supply.

4. Potential future gas supply sources

Key findings

- In the Gippsland Basin:
  - The Kipper Unit Joint Venture (KUJV) is planning further development of the Kipper field, known as the Kipper Stage 1B project, to increase production rates from the existing 2P reserves, and;
  - The large Dory prospect did not find commercial quantities of hydrocarbons during exploration drilling in 2018.
- In the Otway Basin:
  - Additional production wells are planned to be drilled in the Thylacine and Geographe fields, and;
  - Exploration wells are planned for four small prospects.
- There are two LNG import terminals proposed for Victoria, and a proposed LNG import terminal at Port Kembla in New South Wales that could provide additional supply to Victoria via the EGP.
- There is a series of committed and proposed expansions of the Iona UGS facility that would provide additional peak day supply capacity.
- Gas imports from Queensland to Victoria and the other southern states will be constrained by the capacity of pipelines outside of Victoria, including the Moomba to Sydney Pipeline (MSP). If Gippsland production continues to reduce as forecast, resulting in minimal gas flows to New South Wales via the EGP, there is unlikely to be sufficient spare MSP capacity available to enable Queensland gas to flow into Victoria via the Young to Culcairn Lateral (Culcairn Interconnection) during winter.

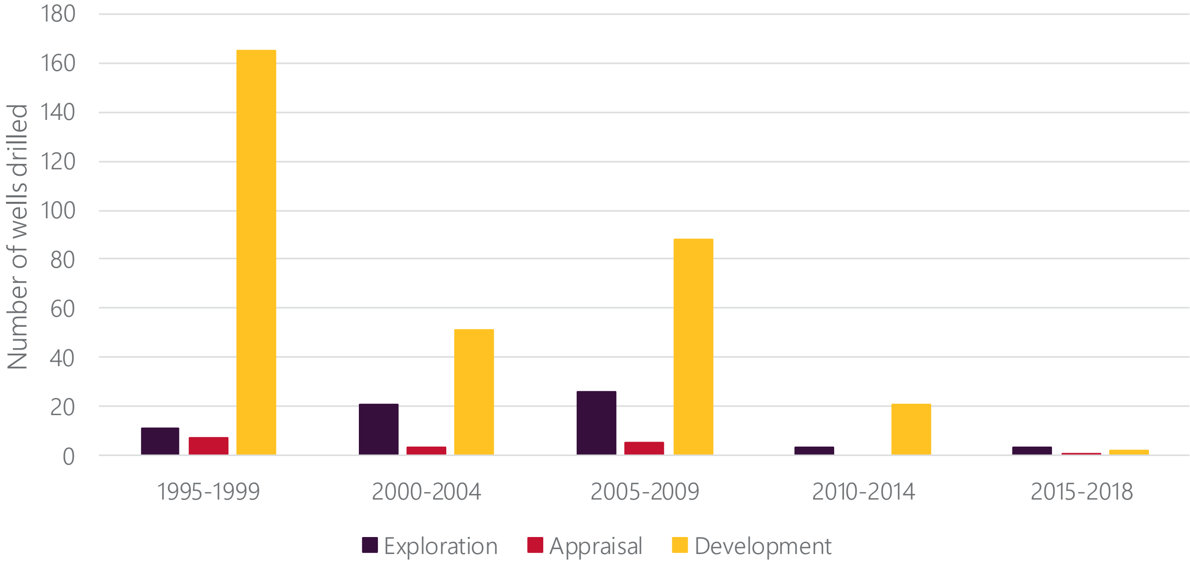
4.1 Overview

There are several brownfield and greenfield projects in the offshore Gippsland and Otway basins currently being considered for exploration and development by producers over the outlook period.

The Victorian gas price increased between 2014 and 2016, coinciding with the start-up of the Gladstone LNG export plants in Queensland[66]. Victorian offshore exploration and development, shown in Figure 20, remained relatively low from 2015 to 2018. The sustained increased gas prices since 2016 have provided the market signal for further investment, with increased exploration and development planned over the outlook period. Details of these projects are provided in this chapter.

[66] Oakley Greenwood, "Gas Price Trends Review 2017", March 2018, at https://www.energy.gov.au/sites/default/files/gas_price_trends_review_2017.pdf.

Figure 20 Offshore wells drilled in offshore south east Australia 1995-2018



National Offshore Petroleum Titles Administrator (NOPTA), Well Database, at https://nopims.dmp.wa.gov.au/Nopims/Search/Wells.

Government organisations are also facilitating additional exploration. NOPTA is conducting a review of southeast Australian offshore petroleum titles to determine if there are any commercial offshore resources that could be brought into production[67].

In December 2018, the Federal Resources Minister announced the Extended Gas Supply Strategy Implementation Plan[68] to address gas supply issues. The plan focuses on reviewing the gas regulatory framework to improve information exchange for gas resources and reserves, as well as improve cooperation with the public and stakeholders around gas projects. As part of this project, the Council of Australian Governments (COAG) Energy Council is also reviewing the current Retention Lease[69] regimes with the intent of increasing exploration activity and the commercial development of discovered gas resources.

The Victorian Government's Victorian Gas Program, which commenced in 2017, will continue to run through to 2020. The program is evaluating the feasibility of onshore conventional resource production and storage development[70]. It should be noted that if the development of conventional resources is permitted after 2020, any prospects identified by this program are likely to take two to five years before the gas resources can be developed and supplying Victoria.

The following sections provide an overview of the possible future gas supply sources, covering prospective supply, potential projects, and exploration projects. The basis for including projects in these categories is discussed in Chapter 1. Where information has not been provided to AEMO or has not been permitted to be disclosed by AEMO by the relevant operator, information about these projects has been drawn from publicly available sources.

4.2 Prospective supply

Prospective supply projects include undeveloped reserves or contingent resources, which are anticipated to be developed during the outlook period.

[67] National Offshore Petroleum Titles Administrator (NOPTA), "South East Australia Commerciality Review" 28 September 2018, at http://www.nopta.gov.au/media/news/2018/20180928-seacom.html.

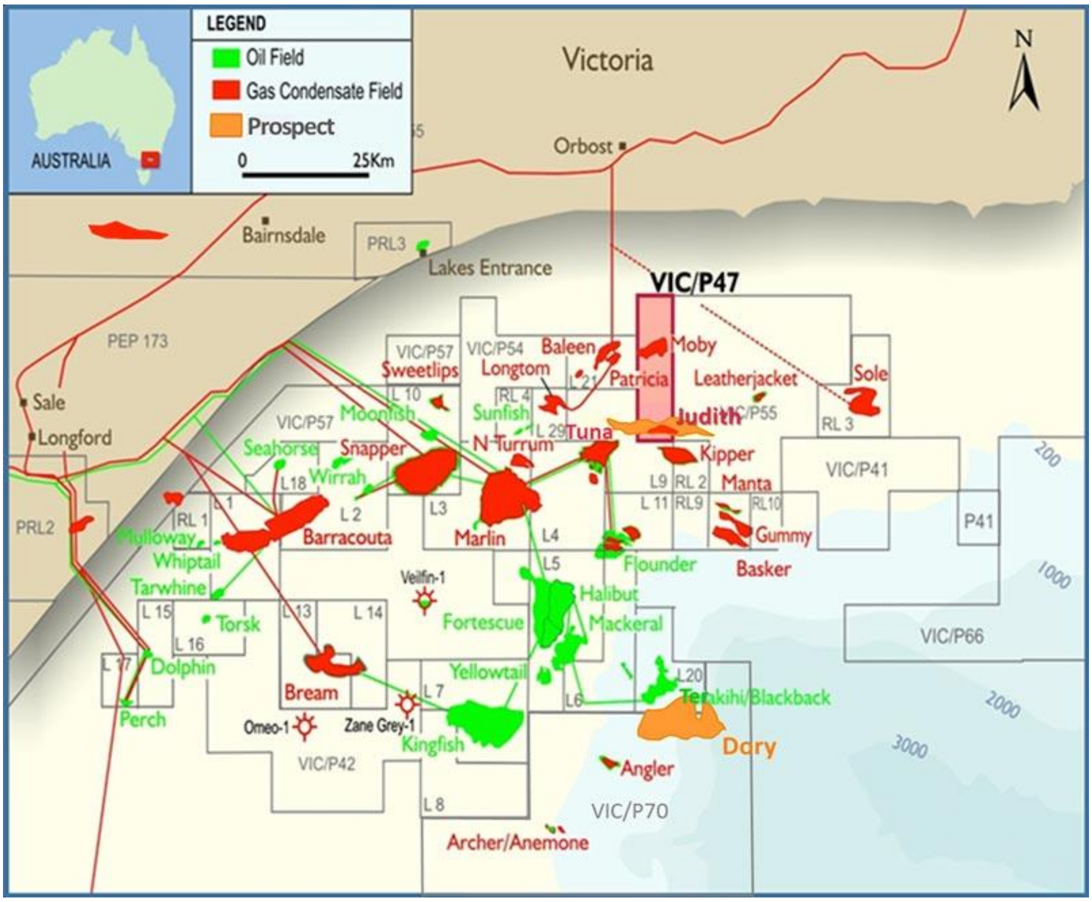
[68] COAG Energy Council, "Extended Gas Supply Strategy Implementation Plan" 19 December 2018, at http://coagenergycouncil.gov.au/publications/extended-gas-supply-strategy-implementation-plan.

[69] Retention leases provide security of tenure over a discovered resource that is not currently commercial due to technological or market barriers, but may become so within 15 years.

[70] See http://earthresources.vic.gov.au/earth-resources/victorian-gas-program.

Gippsland Basin

Figure 21 Gippsland Basin titles map



Emperor Energy Limited, "Offshore Gippsland Basin – Exploration Permit – VIC/P47", at https://archive-petroleumacreage.industry.slicedtech.com.au/sites/archive.petroleumacreage/files/files/2011/release-areas/Gippsland/documents/gippsland-ql-lrg.jpg.

Kipper Stage 1B

Title holder Kipper Unit Joint Venture

Operator Esso Australia Resources Pty Ltd

Permit/Lease VIC/L09 & VIC/L25 (Production Licenses)

Discovered 1986

Estimated reserves 654 PJ[71] (Represents total Kipper reserves, including produced Kipper Stage 1A reserves)

Planned production date 2021[72]

Gas was initially brought online from the Kipper and Turrum fields in 2017. The Kipper Stage 1B project is part of the continued development of the Kipper field. The additional subsea wells will be tied into the existing Kipper infrastructure. Gas from this field contains high levels of carbon dioxide, so it needs to be processed through the Longford Gas Conditioning Plant (GCP). The additional Kipper Stage 1B wells are planned to be drilled in 2020, which will increase production rates from the existing 2P reserves from 2021.

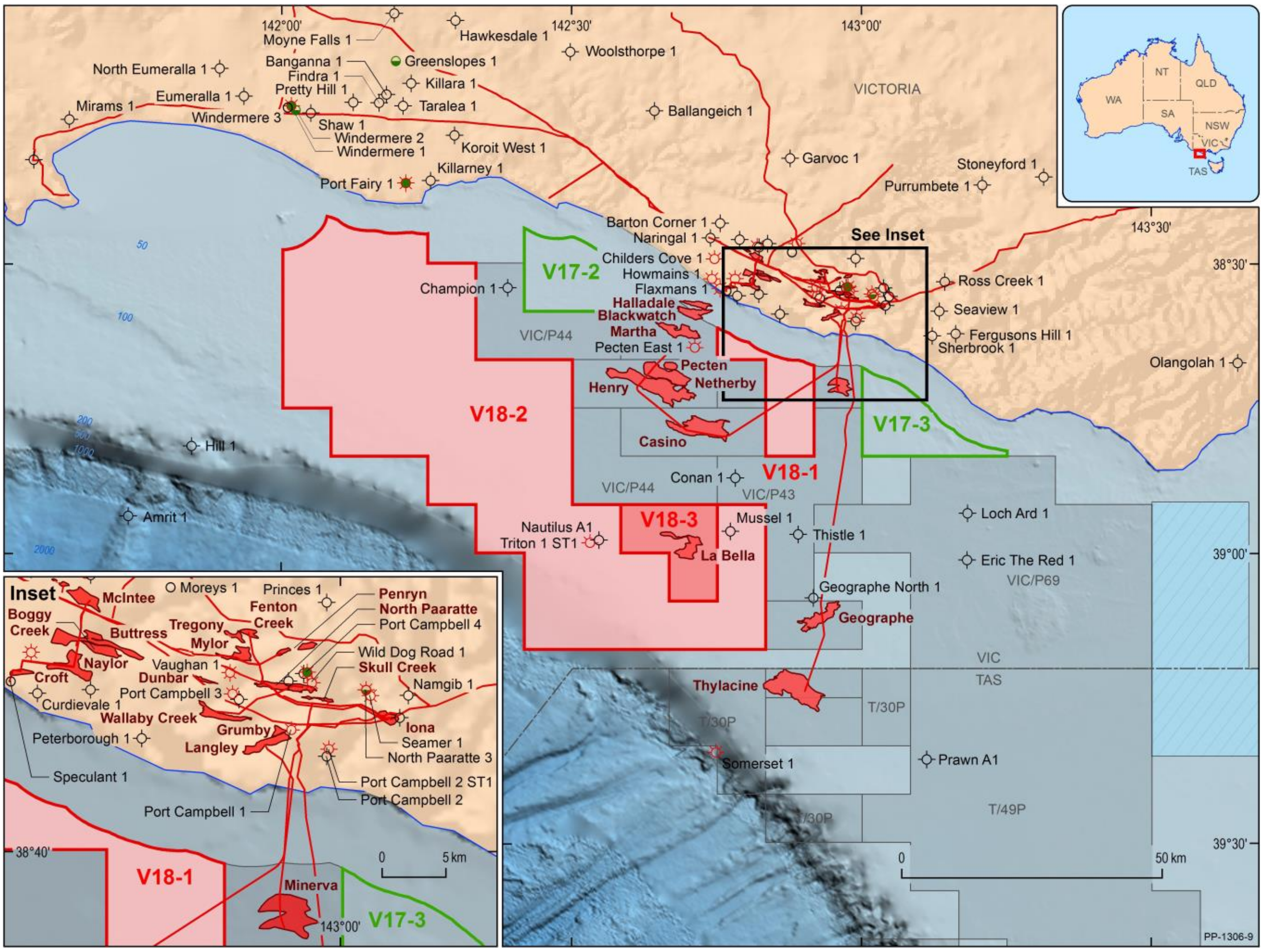
Information about this project was provided to AEMO.

[71] Exxon Mobil, "Kipper Tuna Turrum Project", at https://cdn.exxonmobil.com/~/media/australia/files/operations/ktt-fact-sheet--may-2017.pdf.

[72] ExxonMobil, "Offshore projects", at https://www.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/offshore-projects.

Otway Basin

Figure 22 Otway Basin titles map



Geoscience Australia, Inner Otway Basin Release Area Map, at https://petroleum-acreage.gov.au/2018/geology/otway-basin/inner-otway-basin/inner-otway-basin-release-area-map

Thylacine and Geographe

Title holder Beach Energy, O.G Energy

Operator Beach Energy

Permit/Lease T/30P, T/L2, T/L3 (Thylacine), VIC/L23 (Geographe)

Discovered 1999

Estimated reserves 224 PJ[73]

Estimated production date 2020

Further development wells are planned to be drilled in the Thylacine and Geographe gas fields to extend their production life. Development wells (3 and 4A) are planned to be drilled in the Geographe field, with works expected to commence during 2019, and production being targeted for 2020[74]. A further four development

[73] Otway undeveloped 2P gas is 249 PJ with 90% related to Otway Project. Beach Energy, "Reserves and contingent resources as at 30 June 2018" 2 July 2018, at https://www.asx.com.au/asxpdf/20180702/pdf/43w6c231f8xryg.pdf.

[74] Beach Energy, "2018 Asia Roadshow Presentation" 8 October 2018, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1109059/BPT_BPT_2018_Asia_Roadshow_Presentation.pdf.

wells in the Thylacine gas field are planned to be completed by 2022, with production planned to commence in 2023[75].

Information about this project was provided to AEMO.

Henry

Title holder Casino Henry Joint Venture Project

Operator Cooper Energy

Permit/Lease VIC/L30

Discovered 2001

Estimated reserve 48 PJ (2P)[76]

Planned production date FY 2020[77]

Cooper Energy has stated that it is in the process of completing engineering and subsurface studies for the redevelopment of the Henry-2 production well. FID is expected to be made in 2019, subject to JV approval and rig availability. The gas from the Casino Henry fields is expected to be processed through either the Iona UGS facility, or the Minerva Gas Plant. Cooper Energy has signed an agreement to acquire Minerva Gas Plant from BHP after cessation of gas processing for the Minerva field and subject to the completion of regulatory approvals.

Information about this project was provided to AEMO.

Blackwatch

Title holders VIC/L1(v) (Victorian Production License – Beach Energy); VIC/RL11 (Retention Lease – Cooper Energy and Mitsui E&P)[78]

Operator Beach Energy and Cooper Energy

Permit title holders VIC/L1(v) (Victorian Production Licence – Beach Energy); VIC/RL11 (Retention Lease – Cooper Energy and Mitsui E&P)[79]

Discovered 2016

Estimated reserves 25 PJ (2P), 12 PJ (1P)[80]

Planned production date 2020[81]

This field straddles a permit boundary with Beach Energy on one side and Cooper Energy and Mitsui on the other, as shown in Figure 22. Beach Energy are intending to be the operator of the Blackwatch field and have advised that it plans to drill a Blackwatch development well during 2019[82]. This would tie into the existing infrastructure used to produce the Halladale and Speculant fields[83]. FID for the development of the

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75 Tender Information for drilling works, ICN Gateway, "Beach Energy – Otway Offshore Project", at https://gateway.icn.org.au/project/4222/beach-energy-otway-offshore-project.

76 Cooper Energy, "FY18 Results & FY19 Outlook" 13 August 2018, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Fy18-Aug-12-investor-pack.pdf.

77 Cooper Energy, "FY18 Results & FY19 Outlook" 13 August 2018, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Fy18-Aug-12-investor-pack.pdf.

78 National Offshore Petroleum Title Administrator, "Titleholders" 23 July 2018, at https://www.nopta.gov.au/_documents/neats/Titleholders_July2018.xlsx.

79 National Offshore Petroleum Title Administrator, "Titleholders" 23 July 2018, at https://www.nopta.gov.au/_documents/neats/Titleholders_July2018.xlsx.

80 Beach Energy, "Reserves and contingent resources as at 30 June 2018" 2 July 2018, at https://www.asx.com.au/asxpdf/20180702/pdf/43w6c231f8xryg.pdf.

81 Beach Energy, "Quarterly Report for the period ended 31 December 2018" 31 January 2018, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1129917/BPT_Quarterly_report_for_the_period_ended_31_December_2018.pdf.

82 Beach Energy, "Quarterly Report for the period ended 31 December 2018" 31 January 2018, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1129917/BPT_Quarterly_report_for_the_period_ended_31_December_2018.pdf.

83 Beach Energy, "2018 Asia Roadshow Presentation" 8 October 2018, at https://www.beachenergy.com.au/wp-content/uploads/2018/10/BPT_BPT_2018_Asia_Roadshow_Presentation.pdf.

Blackwatch field is subject to commercial and regulatory approvals. This is currently being discussed between Beach Energy and the adjacent tenure holders.

Information about this project was provided to AEMO.

4.3 Potential projects

Potential projects are uncommitted gas supply projects that are considered less likely than the prospective supply projects to be developed during the outlook period.

Gippsland Basin

Manta

Title holder Cooper Energy

Operator Cooper Energy

Permit/Lease VIC/RL13 (Retention Lease)

Discovered 1984 (Manta), 1983 (Basker), 1990 (Gummy)

Estimated resource Manta - 106 PJ (2C)

The Manta-1 exploration well discovered 106 PJ of contingent resources (2C). Subject to rig availability, Cooper Energy plans to drill the Manta-3 appraisal well in 2020 to refine the Manta resource estimate[84].

The Orbost Gas Plant is expected to be at capacity processing gas from the Sole field (25 PJ/y[85]). Manta is expected to be developed if there is an Orbost Gas Plant capacity upgrade or following the depletion of the Sole gas field[86].

Information about this project was provided to AEMO.

Golden Beach

Title holder GB Energy

Operator GB Energy

Permit/Lease VIC/RL1(V) (Retention Lease)

Discovered 1967

Estimated resource 50 PJ[87]

Estimated production date 2021[88]

GB Energy acquired the Golden Beach field in May 2018. A project team is currently conducting engineering studies and seeking approvals for the field to be brought online in 2021[89]. Initially, the gas field is expected to produce at 60-80 TJ/d, with production reducing to 40-50 TJ/d over two to three years, before being used as a storage reservoir. The storage development is discussed further in Section 4.5.

Geophysical and geotechnical surveys are planned to be undertaken in March-April 2019, which will verify the reservoir and withdrawal capacities. GB Energy have advised that they intend to construct a new pipeline in

[84] Cooper Energy, "Investor Update" October 2018, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Oct--investor-pack-update-.pdf.

[85] Cooper Energy, "Investor Pack Update" 15 May 2018, at https://www.cooperenergy.com.au/Upload/2018.05.15-may-investor-pack-update-.pdf.

[86] Cooper Energy, "Investor Update" October 2018, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Oct--investor-pack-update-.pdf.

[87] Gippsland Times, "Origin signs off on an agreement to buy Golden Beach gas" 28 February 2018, at http://www.gippslandtimes.com.au/story/5929449/origin-signs-off-on-an-agreement-to-buy-golden-beach-gas/.

[88] Gippsland Times, "Offshore Gas Project" November 2018, at http://www.gippslandtimes.com.au/story/5759602/offshore-gas-project/.

[89] Ibid.

late 2019 or early 2020 and process the gas in a newly constructed gas processing plant. Gas is expected to be available at the Longford close proximity point (CPP)[90].

AEMO did not request information about this field, as GB Energy is not a registered participant.

South East Remora

Title holder Gippsland Basin Joint Venture (GBJV)

Operator Esso Australia Resources Pty Ltd

Permit/Lease VIC/RL4 (Retention Lease)

Discovered 2010

Estimated resource 280 PJ[91]

Estimated production date 2024+

NOPTA has approved the renewal of the retention lease[92] for this permit. As the field has a high level of carbon dioxide and mercury, it requires processing through the Longford GCP. GBJV has stated that the Longford GCP does not currently have spare capacity to process this gas, and it is proposing to delay development of this field for at least a further five years[93].

Some information was provided in the long-term forecast, but this was not included in prospective supply as it is outside the outlook period.

East Pilchard

Title holder Gippsland Basin Joint Venture

Operator Esso Australia Resources Pty Ltd

Permit/Lease VIC/L9

Discovered 2001

Estimated resource Unknown

Estimated production date Unknown

The initial exploration well, East Pilchard-1, was drilled in 2001 but was plugged and suspended for future gas supply[94]. Esso has stated that it is assessing the Pilchard gas field and it may be drilled and developed in a future campaign[95]. The exploration well indicated high carbon dioxide levels of between 11% and 22%, so the gas is expected to need to be processed through the Longford GCP[96].

Some information was provided in the long-term forecast, but this was not included in prospective supply as it is outside the outlook period.

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[90] GB Energy, "Golden Beach Pipeline", at https://gbenergy.com.au/wp-content/uploads/2019/01/190114-Golden-Beach-Pipeline-Consultation-Plan_Rev2-003.pdf.

[91] The Australian, "Oil giants ExxonMobil and BHP bid for delay on new Bass Strait gas", 30 May 2017, (paywall) at https://www.theaustralian.com.au/business/mining-energy/oil-giants-exxonmobil-and-bhp-bid-for-delay-on-new-bass-strait-gas/newsstory/a2fcf1fdce5e889b38344be5678b0d9c.

[92] NOPTA, "VIC/RL4 – Renewal" 26 September 2018, at https://neats.nopta.gov.au/ApprovalTracking/ApplicationDetails/5dc0431c-526e-46d7-8430-d8f2165ad6eb?applicationType=Renewal.

[93] Exxon Mobil Corporation, "2017 Financial Statements and Supplemental Information" 28 February 2018, at https://cdn.exxonmobil.com/~/media/global/files/investor-reports/2018/2017-form-10k.pdf.

[94] National Offshore Petroleum Titles Administrator, "Wells", at https://nopims.dmp.wa.gov.au/Nopims/Search/Wells.

[95] ExxonMobil, "Esso offshore projects", at https://cdn.exxonmobil.com/~/media/australia/files/publications/fact-sheets/publication_em-offshore-activities-fact-sheet-august-2018.pdf.

[96] Esso Australia Pty Ltd, "Well Completion Report East Pilcahrd-1 Volume 2 Interpretive Data" November 2001, at http://er-info.dpi.vic.gov.au/documentation/scratch/hyp_of/OPENFILE_MANUALLY_CONTROLLED/OPENFILE/final_data_packages/WCR_2009/Offshore_Gippsland_WCR_2_of_5_Blackback1_Gurnard1_V3.0b_Feb_09/EastPilchard_1/PE908923/PE908923__((_EAST_PILCHARD-1_WCR_Vol.2__interpretive__))_.pdf.

Judith

Title holder Emperor Energy

Operator Emperor Energy Limited

Permit/Lease VIC/P47 (Exploration Permit)

Discovered 1989

Estimated resource Judith North ~133 PJ[97] (2C)[98]; Greater Judith structure ~925 PJ[99]

Emperor Energy has been granted a renewal of its exploration permit until February 2023. An independent resource statement, verified by reservoir modelling with 3D seismic survey data, identified a 2C resource of 133 PJ. Drilling of an exploration well is planned in early 2021 to prove this gas resource in the Judith North structure[100]. A P50 resource of 925 PJ in the Greater Judith structure has also been identified, but the amount of drilling required to access this resource has not been assessed[101].

AEMO did not request information about this field, as Emperor Energy is not a registered participant.

Moby

Title holder Emperor Energy

Operator Emperor Energy Limited

Permit/Lease VIC/P47 (Exploration Permit)

Discovered 2004

Estimated resource 60 PJ (2C)[102]

The field is in the same permit as the Judith field, which is held by Emperor Energy. Mapping by a previous operator has indicated that the Moby gas reserve is uneconomic at present[103]. Exploration activities for this permit are focused on the Judith field and the Greater Judith structure. No further exploration of the Moby field has been proposed.

AEMO did not request information about this field, as Emperor Energy is not a registered participant.

Longtom

Title holder SGH Energy VICP54

Operator SGH Energy VICP54

Permit/Lease VIC/L29 (Production License)

Discovered 1995

Estimated reserve 80 PJ[104]

Planned production date Unknown

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[97] 122 billion cubic feet (bcf). This report uses a conversion factor of 1.055 PJ/bcf, unless otherwise stated.

[98] Emperor Energy, “Gas Production Dynamic Modelling – Judith Gas Field” 21 November 2018, at https://emperorenergy.com.au/wp-content/uploads/2018/11/21-Nov-18-Gas-Production-Dynamic-Modelling-Judith-Gas-Field-.pdf.

[99] 825 bcf.

[100] NOPTA, “Work Program” 23 July 2018, at www.nopta.gov.au_documents/neats/WorkProgram_July2018.xlsx.

[101] Emperor Energy, “Gas Production Dynamic Modelling – Judith Gas Field” 21 November 2018, at https://emperorenergy.com.au/wp-content/uploads/2018/11/21-Nov-18-Gas-Production-Dynamic-Modelling-Judith-Gas-Field-.pdf.

[102] Enegex website http://www.enegex.com/projects/vicp47-gippsland-basin/

[103] Oil Basins Limited, “ASX Market Announcements” 10 August 2017, at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=2ahUKEwip9uKL8IzhAhVNeysKHVMLBIIQFjAAegQICRAC&url=https%3A%2F%2Fhotcopper.com.au%2Fdocumentdownload%3Fid%3DuOMxKKzFkiWRTLKhOROKAxjvSTYO5Aq1zBGZr%252FV1ke92GA%253D%253D&usg=AOvVaw1sxbYyl0sjlvhYUSMrj-RF.

[104] Australian Financial Review, “SGH Energy mulls $150m boost to east coast gas push”, 18 December 2017, (paywall) at http://www.afr.com/business/energy/gas/sgh-energy-mulls-150m-boost-to-east-coast-gas-push-20171218-h06k6v.

The Longtom gas field was in production from 2009 until 2015, when operations were indefinitely suspended due to a major electrical fault. This issue was rectified in January 2017 after new underwater cables were laid. While both wells (Longtom-3 and Longtom-4) are ready to resume production, agreement needs to be reached with the owners of the Patricia-Baleen pipeline (Cooper Energy) and the Orbost Gas Plant (APA Group) before gas production can resume[105].

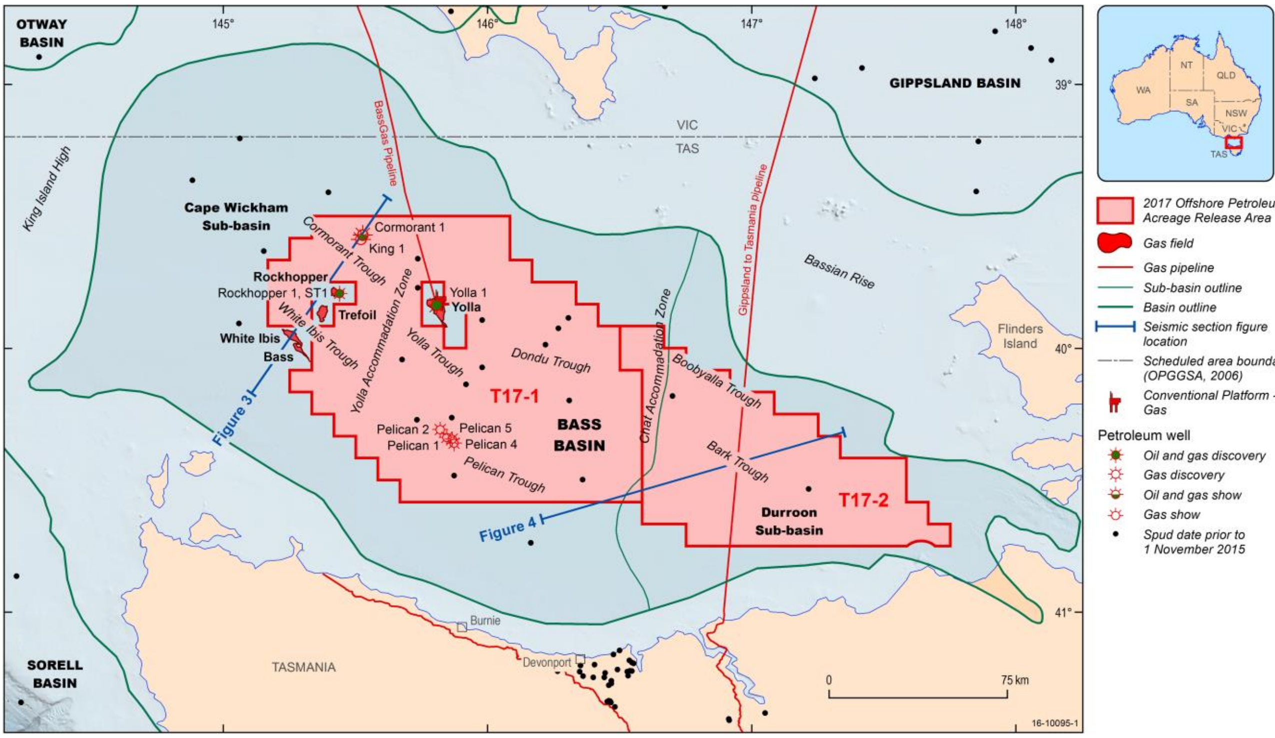
No public information has been made available on production resuming since the publication of the 2018 VGPR Update. SGH Energy estimates that 20 PJ of gas could be made available from the field. The operator has flagged that drilling Longtom-5 well and working over Longtom-4 could increase the recoverable gas quantity by another 60 PJ[106].

As noted above, the Orbost Gas Plant is expected to be at capacity processing gas from the Sole field and potentially the Manta gas field. Production from the Longtom gas field could occur if the capacity of the Orbost Gas Plant was increased or following the depletion of the Sole and Manta gas fields.

AEMO did not request information about this field, as SGH Energy is not a registered participant.

Bass Basin

Figure 23 Bass basin titles map



Geoscience Australia, "Bass Basin Regional Geology", at https://2017-petroleumacreage.industry.slicedtech.com.au/2017/geology/bass-basin/bass-basin-regional-geology.

Trefoil

Title holder BassGas Project

Operator Beach Energy

Permit/Lease T/RL2

[105] Financial Review, "SGH Energy CEO Margaret Hall sees Longtom gas as part of solution for east cost" 12 March 2017, at https://www.afr.com/business/energy/gas/sgh-energy-ceo-margaret-hall-sees-longtom-gas-as-part-of-solution-for-east-coast-20170310-guvogs.

[106] Australian Financial Review, "SGH Energy mulls $150m boost to east coast gas push", 18 December 2017, at http://www.afr.com/business/energy/gas/sgh-energy-mulls-150m-boost-to-east-coast-gas-push-20171218-h06k6v.

Discovered 2004

Estimated resource 54 PJ (2C)[107]

Planned production date 2020-2021

The operator is planning to evaluate the Trefoil field in FY19 and, subject to FID, field development could occur in 2020-21. Gas from Trefoil would likely backfill production from the Yolla field as it depletes[108].

No information has been received by AEMO concerning this field.

Otway Basin

Martha

Title holder Casino Henry Joint Venture Project

Operator Cooper Energy

Permit/Lease VIC/R11 (Retention Lease)

Discovered 2004

Estimated reserve 9.6 PJ[109] (2C)

Planned production date Unknown

The Martha gas field was initially discovered by Santos in 2004 but was abandoned due to its small size and high cost to develop[110]. Cooper Energy is now the operator but currently does not have any development plans for the field.

No information has been received by AEMO concerning this field.

La Bella

Title holder Beach Energy

Operator Beach Energy

Permit/Lease V18-3

Discovered 1993

Estimated reserve 114 PJ (2C)[111]

Planned production date Unknown

Beach Energy recently acquired the exploration permit containing the La Bella gas resource. It was previously discovered by BHP in 1993 but was not developed due to the field's small size and high carbon dioxide levels[112].

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107 Beach Energy, "Reserves and contingent resources as at 30 June 2018" 2 July 2018, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1106381/BPT_2018_Investor_Briefing_presentation.pdf.

108 Beach Energy, "Beach targets $2b free cash flow and 40 Mmboe over five years" 19 February 2018, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1106381/BPT_2018_Investor_Briefing_presentation.pdf.

109 AWE, "AWE Target's Statement – Mitsui Offer" p. 63, 21 February 2018, at https://www.asx.com.au/asxpdf/20180221/pdf/43rsjw7rj17pj6.pdf.

110 Australian Government, "Offshore South East Australia Future Gas Supply Study" p. 32, November 2017, at https://www.industry.gov.au/sites/default/files/2018-12/offshore-south-east-australia-future-gas-supply-study.pdf.

111 WHL Energy, "WHL Energy progressing La Bella development window of opportunity" 26 June 2013, at https://www.asx.com.au/asxpdf/20130626/pdf/42gpjcbn9b7yxh.pdf.

112 BHP, "Well Completion Report Interpretive Data", at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=5&cad=rja&uact=8&ved=2ahUKEwi6zrH7orXgAhXWSH0KHcJwCaoQFjAEegQIBhAC&url=http%3A%2F%2Fer-info.dpi.vic.gov.au%2Fdocumentation%2Fscratch%2Fhyp_of%2FSCANS_REEDITED_IMAGES%2Fraw%2Fwells%2Fotw_off%2Ffinal%2Faz%2Flabl1%2Fpe900368__((_LA_BELLA-1_WCR_Vol.2__interpretive__))_.pdf&usg=AOvVaw0vFUDhxHw-zQwM2gj3vvfL.

Beach Energy has stated that it is considering drilling a development well as part of its upcoming drilling campaign in 2020[113]. The field lies within tie-back distance to existing infrastructure at the Thylacine and Geographe fields for processed through the Otway Gas Plant, which has carbon dioxide removal equipment.

No information has been received by AEMO concerning this field.

4.4 Exploration projects

Exploration projects are associated with undiscovered gas resources that are usually mapped using seismic data. These are "prospective resources" that have not been proven with exploration wells, so commercial quantities of hydrocarbons may not actually be present.

Gippsland Basin

Greater Dory

Title holder Esso Deepwater Gippsland Pty Ltd

Operator Esso Deepwater Gippsland Pty Ltd

Permit/Lease VIC/P70 (Exploration Permit)

Discovered 2008

Prospective resource Unknown

In the 2018 VGPR Update, the Dory gas field was identified as a potential low impurity, large accumulation with reserves of up to 2,300 PJ[114]. In 2018, Esso Deepwater drilled two exploration wells, Hairtail and Baldfish, in the Dory gas field[115] that did not encounter commercial quantities of hydrocarbons[116].

While the Dory gas field did not prove any gas reserves, the VIC/P70 permit area is large and has a number of further leads. Esso have submitted plans with NOPTA to drill an exploration well in 2020 to 2022[117].

No further information has been received by AEMO concerning this field.

Manta Deep

Title holder Cooper Energy

Operator Cooper Energy

Permit/Lease VIC/RL13 (Retention Lease)

Discovered 1984 (Manta), 1983 (Basker), 1990 (Gummy)

Prospective resource Manta Deep – 526 PJ[118]

Manta Deep is a gas resource located below the Manta gas reserve discussed in Section 4.2. Cooper has assessed Manta Deep as an unrisked, best-estimate prospective resource of 526 PJ[119]. Subject to rig

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[113] Upstream, "Beach successful in La Bella bid" 13 February 2019, at https://www.upstreamonline.com/live/1701104/beach-successful-in-la-bella-bid.

[114] The Australian, "Exxon's Bass Strait prospect could ese east coast gas shortage", 8 August 2017, (paywall) at https://www.theaustralian.com.au/business/miningenergy/exxons-bass-strait-prospect-could-ease-east-coast-gas-shortage/news-story/840e24a74776de594a617b098d326246.

[115] National Offshore Petroleum Titles Administrator, "Wells", accessed at https://nopims.dmp.wa.gov.au/Nopims/Search/Wells.

[116] The Australian Financial Review, "Esso-BHP to boost east coast gas with $550m Bass Strait project", 13 December 2018, (paywall) at www.afr.com/business/energy/gas/essobhp-to-boost-east-coast-gas-with-550m-bass-strait-project-20181213-h192ej.

[117] National Offshore Petroleum Titles Administrator, "Work Program" 23 July 2018, at https://www.nopta.gov.au/_documents/neats/WorkProgram_July2018.xlsx.

[118] Cooper Energy "Address to the 2018 Annual General Meeting of Cooper Energy Ltd by the Managing Director, David Maxwell" 8 November 2018, at http://www.openbriefing.com/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20181108%2F02045583.pdf.

[119] Cooper Energy "Address to the 2018 Annual General Meeting of Cooper Energy Ltd by the Managing Director, David Maxwell" 8 November 2018, at http://www.openbriefing.com/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20181108%2F02045583.pdf.

availability, Cooper Energy plans to drill the Manta-3 appraisal well in 2020 to both confirm the Manta 2C resource and explore for additional resources located in Manta Deep prospect.

The Orbost Gas Plant is at capacity processing gas from Sole (25 PJ/y[120]). Manta is expected to be developed upon further upgrade of the Orbost gas plant capacity or following depletion of the Sole gas fields[121].

Information about this project was provided to AEMO.

Chimaera East

Title holder Cooper Energy

Operator Cooper Energy

Permit/Lease VIC/RL13, VIC/RL14, VIC/RL15 (Retention Leases)

Discovered 1984

Prospective resource 230 PJ[122]

Planned production date Unknown

New interpretation of 3D seismic data has identified a best estimate prospective resource of 230 PJ in the Chimaera East gas field. The play is near the previously drilled Chimaera-1 exploration well that discovered gas in this field and identified the prospective Manta gas field. The operators have not stated when they plan to drill an exploration well, although likely to be following the development of Manta.

No information has been received by AEMO concerning this field.

Greater Judith

Title holder Emperor Energy

Operator Emperor Energy Limited

Permit/Lease VIC/P47 (Exploration Permit)

Discovered 1989

Estimated resource Greater Judith structure ~ 925 PJ[123]

A P50 resource of 925 PJ in the Greater Judith structure has been identified in addition to the Judith resource discussed in Section 4.3, but the amount of drilling required to access this resource has not been assessed[124].

AEMO did not request information about this field, as Emperor Energy is not a registered participant.

Pointer

Title holder Carnarvon Hibiscus, 3D Oil Limited

Operator Carnarvon Hibiscus

Permit/Lease VIC/P57 (Retention Lease)

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[120] Cooper Energy, "Investor Pack Update" 15 May 2018, at https://www.cooperenergy.com.au/Upload/2018.05.15-may-investor-pack-update-.pdf.

[121] Cooper Energy, "Investor Update" October 2018, at https://www.cooperenergy.com.au/Upload/Documents/PresentationsItem/Oct--investor-pack-update-.pdf.

[122] Cooper Energy, "Prospective Resource Upgrade at Manta field and Chimaera East prospect" 4 May 2016, at http://member.afraccess.com/media?id=CMN://6A762676&filename=20160504/COE_01737677.pdf.

[123] 825 bcf.

[124] Emperor Energy, "Gas Production Dynamic Modelling – Judith Gas Field" 21 November 2018, at https://emperorenergy.com.au/wp-content/uploads/2018/11/21-Nov-18-Gas-Production-Dynamic-Modelling-Judith-Gas-Field-.pdf.

Prospective resource 248[125] PJ[126]

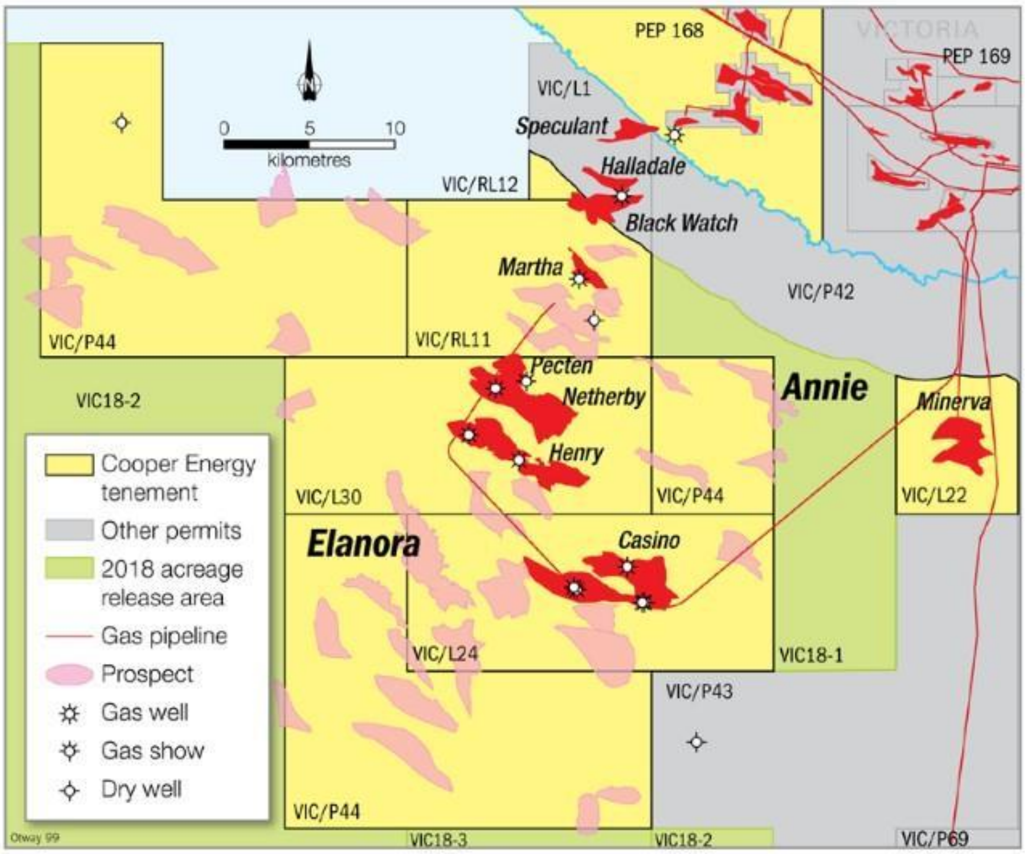
Planned production date Unknown

The title holders have been granted a five-year renewal on their retention lease. A re-evaluation of the field identified Pointer, a best estimate prospective resource of 248 PJ. The planned work program involves further seismic re-processing of the field and drilling of an exploration well in 2022 or 2023[127].

AEMO did not request information about this field, as Carnarvon Hibiscus is not a registered participant.

Otway Basin

Figure 24 Annie and Elanora gas fields in the Otway Basin



Cooper Energy, "Prospective Resource Assessment for Otway Basin Annie and Elanora Prospects" 8 November 2018, at http://member.afraccess.com/media?id=CMN://2A1116321&filename=20181108/COE_02045553.pdf.

Annie

Title holders Cooper Energy, Mitsui E&P

Operator Cooper Energy

Permit/Lease VIC/P44

Discovered N/A (Prospective Resource)

[125] 235 billion cubic feet (bcf).

[126] Australian Financial Review, "SGH Energy mulls $150m boost to east coast gas push", 18 December 2017, (paywall) at http://www.afr.com/business/energy/gas/sgh-energy-mulls-150m-boost-to-east-coast-gas-push-20171218-h06k6v.

[127] Ibid.

Prospective resource 76 PJ[128]

Annie has been identified as a play from 3D seismic data. Further exploration and appraisal is required to determine the existence of commercial quantities of hydrocarbons. Exploration drilling is planned to commence during 2019, to prove the resource[129]. The well is targeting the Waarre A and Waarre C formations, which are the production reservoirs for the Casino and Minerva gas fields. The field is near the existing Casino, Henry, and Netherby offshore production infrastructure and would require a 7 km pipeline tie-in.

No information has been received by AEMO concerning this field.

Elanora

Title holders Cooper Energy, Mitsui, E&P Australia

Operator Cooper Energy

Permit/Lease VIC/24, VIC/L30, VIC/P44

Discovered N/A (Prospective Resource)

Prospective resource 108 PJ[130]

Elanora has also been identified as a play from 3D seismic data. The well is targeting the Waarre A formation, which is the production reservoir for the Casino, Henry and Netherby gas fields. Exploration drilling is planned to commence during 2019, to prove this resource[131]. The field is near the existing Casino offshore production infrastructure and would require a 6 km pipeline tie-in.

No information has been received by AEMO concerning this field.

Enterprise

Title holder Beach Energy, O.G Energy

Operator Beach Energy

Permit/Lease VIC/P42 (V) (Retention)

Discovered N/A (Prospective Resource)

Estimated resource Unknown

Estimated production date FY 2021[132]

Seismic surveys completed identify a play, showing direct indications of hydrocarbons in this petroleum zone[133]. An exploration well is planned to be drilled in 2020 using extended reach drilling[134]. If exploration is successful in proving the resource, production through the Otway Gas Plant could commence in 2020-21.

Information about this project was provided to AEMO.

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[128] Energy-Pedia News, "Australia: Cooper Energy completes Prospective Resource Assessment for Otway Basin Annie and Elanora Prospects", 8 November 2018, at https://www.energy-pedia.com/news/australia/cooper-energy-completes-prospective-resource-assessment-for-otway-basin-annie-and--elanora-prospects-175101.

[129] NOPSEMA, "Otway Basin Exploration Drilling" 10 December 2018, at https://www.nopsema.gov.au/environmental-management/activity-status-and-summaries/details/456.

[130] Energy-Pedia News, "Australia: Cooper Energy completes Prospective Resource Assessment for Otway Basin Annie and Elanora Prospects" 8 November 2018, at https://www.energy-pedia.com/news/australia/cooper-energy-completes-prospective-resource-assessment-for-otway-basin-annie-and--elanora-prospects-175101.

[131] NOPSEMA, "Otway Basin Exploration Drilling" 10 December 2018, at https://www.nopsema.gov.au/environmental-management/activity-status-and-summaries/details/456.

[132] Beach Energy, "Asia Roadshow Presentation" October 2018, at https://www.beachenergy.com.au/wp-content/uploads/2018/10/BPT_BPT_2018_Asia_Roadshow_Presentation.pdf.

[133] Beach Energy, "FY18 Half Year Results Presentation" July 2018, at https://www.beachenergy.com.au/wp-content/uploads/2018/10/BPT_FY18_Half_Year_Results_Presentation.pdf.

[134] Beach Energy, "Enterprise Project" December 2018, at https://www.beachenergy.com.au/wp-content/uploads/2019/01/Beach-Energy-ENTERPRISE-Project-Info-Sheet_Dec-2018.pdf.

Artisan

Title holder Beach Energy

Operator Beach Energy, O.G Energy

Permit/Lease VIC/P43

Discovered N/A (Prospective Resource)

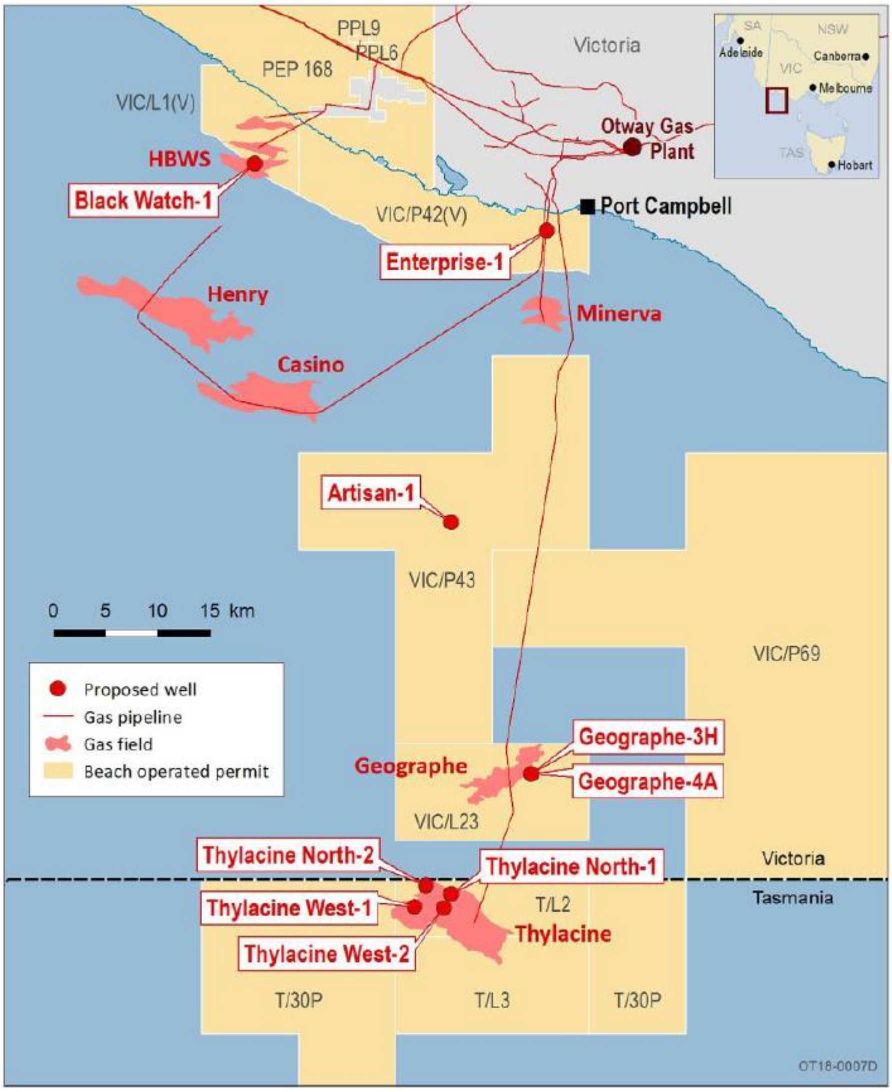
Estimated resource Unknown

Estimated production date 2022

Exploration drilling in the Artisan gas field is planned for 2020. If successful results follow, production is planned for 2022[135]. The Artisan gas field would tie into existing infrastructure from the adjacent Thylacine and Geographe fields.

Information about this project was provided to AEMO.

Figure 25 Beach Energy gas field development and exploration in the Otway Basin



Beach Energy, "Investor Briefing", 27 September 2018, https://www.beachenergy.com.au/wp-content/uploads/2018/10/BPT_2018_Investor_Briefing_presentation.pdf

[135] Beach Energy, Investor Presentation, October 2018, at https://www.beachenergy.com.au/wp-content/uploads/2018/10/BeachEnergyInvestorpresentation.pdf.

4.5 Gas storage

Gas storage is an increasingly important service, which enables retailers and large gas users to manage the seasonal variations in demand. Increasing storage volumes and deliverability would help address the tight peak winter day supply demand balance.

Three options to increase Victorian gas storage capacity are being considered within the outlook period.

Iona Underground Gas Storage expansion

Following the drilling of an additional Iona storage well in 2018, additional committed plant expansions will be made to increase the Iona UGS supply capacity from 440 TJ/d to 480 TJ/d from 1 May 2019. A staged expansion to 520 TJ/d in 2021 is also committed and a further expansion up to 570 TJ/d is being considered, as shown in Table 17.

Table 17 Iona UGS planned expansions[A]

Year	Iona UGS supply capacity (TJ/d)
2019	480
2020	480
2021	520
2022	520
2023	570

A. The expansion numbers do not take into account the potential acquisition of the depleted Heytesbury gas fields.

Increased Iona UGS supply will help offset the forecast supply capacity reduction in Port Campbell production, but will remain limited by the SWP transportation capacity towards Melbourne, however Iona UGS is also used to supply gas to the Mortlake Power Station and to South Australia via the SEA Gas Pipeline.

SWP capacity will continue to limit Iona UGS supply into the DTS even after the construction of the WORM. The WORM will enable further SWP capacity increases to be developed as it provides another supply point into Melbourne.

Lochard Energy has proposed acquiring the Heytesbury Assets from Origin Energy[136]. The Heytesbury Assets consist of several depleted onshore gas fields near Port Campbell in Victoria, in close proximity to the Iona UGS facility. Lochard Energy has confirmed with AEMO that subject to further assessments, the Heytesbury reservoirs may complement existing planned Iona expansions by further increasing the storage volume and supply capacity. The ACCC has stated that they will not oppose the acquisition[137].

Golden Beach underground gas storage facility in the Gippsland Basin

The Golden Beach gas reservoir discussed in Section 4.3, has also been proposed for development into an underground gas storage facility[138]. Origin has entered into a foundation storage contract with GB Energy for the storage facility. The facility would supply peak period demand by injection gas into the DTS at the Longford CPP.

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[136] Financial Review, "Origin Energy, QIC's Lochard sign storage assets deal" 4 February 2019, at https://www.afr.com/street-talk/origin-energy-qicbacked-lochard-sign-heytesbury-deal-20190201-h1aqkg.

[137] ACCC media release, 21 Mar 2019, at https://www.accc.gov.au/media-release/lochard%E2%80%99s-acquisition-of-heytesbury-gas-reservoirs-not-opposed.

[138] Origin, "Origin secures more gas for domestic users" 26 February 2019, at https://www.originenergy.com.au/about/investors-media/media-centre/origin_secures_more_gas_for_domestic_users.html.

New underground gas storage facility in the Otway Basin

The 2018 VGPR Update noted that an investigation into additional gas storage sites in the Otway Basin was being undertaken as part of the Victorian Gas Program[139]. The program report is due to be released in 2019. It is not known whether it will consider the additional transmission system capacity that would be required to facilitate the increase from a new storage facility (as the SWP currently limits Iona UGS supply into the DTS).

4.6 Imports into the DTS

Based on Victorian production forecasts provided in Chapter 3, peak day supply is projected to be insufficient to meet peak day demand beyond 2023 unless gas supplies increase.

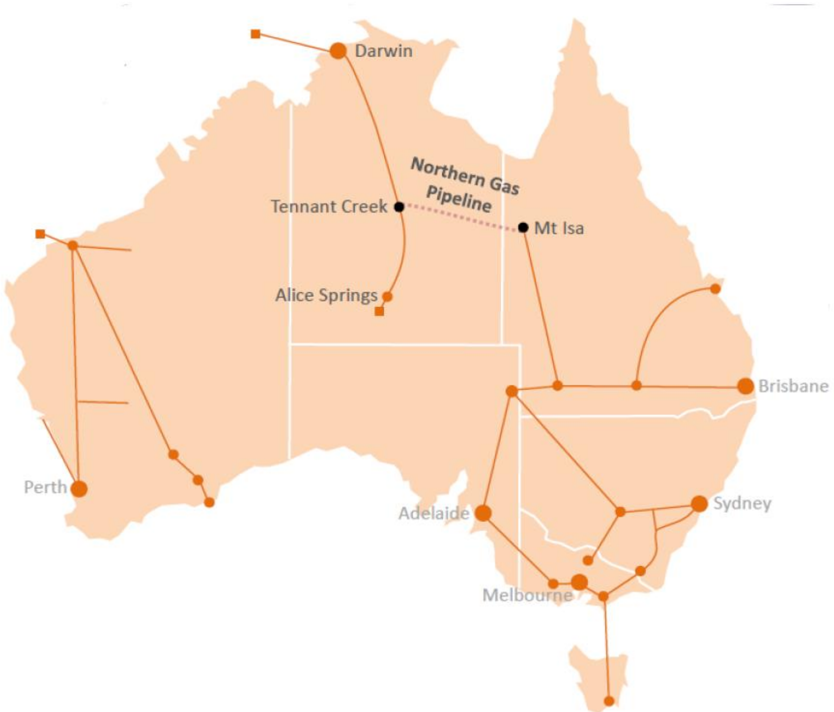
Queensland has more gas reserves than the other regions in eastern Australia, with over 80% of the 2P reserves and 65% of the 2C resources[140]. If there is insufficient new southern production, the southern states will become more reliant on imports from either Queensland or will require an LNG import terminal.

Gas supply capacity from Queensland to the southern states is forecast to be limited by pipeline capacity. Projects to augment existing pipelines, or construct new pipelines, that would provide increased pipeline capacity for shipping additional gas south from Queensland, have been proposed.

Northern Gas Pipeline

Commercial operation of the Northern Gas Pipeline (NGP) began on 3 January 2019. Figure 26 shows the NGP route which can supply up to 90 TJ/d[141] to a number of gas consumers in the Mount Isa region and the east coast gas market.

Figure 26 Northern Gas Pipeline connection to the east coast



Jemena, "Northern Gas Pipeline Business Briefings and Open Office", 23 March 2018, at https://jemena.com.au/documents/pipeline/negi/presentations/jemena-ngp-business-briefings-and-open-office-moun.

[139] Information about the Victorian Gas Program is at http://earthresources.vic.gov.au/earth-resources/victorian-gas-program.

[140] ACCC, "2017-2020 Gas Inquiry: Interim report" p. 11, at https://www.accc.gov.au/publications.

[141] ABC News, "Construction of the Northern Gas Pipeline beings in Tennant Creek", July 2017, at https://www.abc.net.au/news/rural/2017-07-12/construction-on-northern-gas-pipeline-begins-in-tennant-creek/8700332.

Mount Isa was traditionally fed from the Carpentaria pipeline, which sourced gas form the SWQP. The NGP offsets flow from the SWQP that used to supply Mount Isa, which leaves more SWQP southbound capacity available to flow towards New South Wales and Victoria via the MSP.

On peak demand days, the MSP south flow is constrained, so this project will not assist in meeting peak day supply shortfalls in Victoria.

Moomba to Sydney (MSP) Expansion

APA discussed options to expand the southbound MSP capacity with AEMO in March 2018. APA has stated that capacity could be increased following the installation of additional compression stations.

If Victorian production, particularly from Gippsland, declines to the point that all Gippsland production is supplying Victoria and Tasmania, with little flow up the EGP, the MSP capacity would need to be increased so that it could supply all New South Wales demand, plus supply additional gas to Victoria.

Culcairn Interconnection expansion (New South Wales)

The only pipeline that can currently supply gas into Victoria is the Young to Culcairn lateral (known as the Culcairn Interconnection) off the MSP. Gas imports into Victoria through Culcairn are limited to 150 TJ/d[142] due to capacity constraints on the New South Wales transmission pipeline system. Supply into the Culcairn Interconnection requires compression from the MSP at Young. The compressors at Culcairn are not able to compress south into Victoria.

The capacity of the VNI to receive imports into the DTS at Culcairn is 223 TJ/d.

APA have proposed projects to increase the Culcairn supply capacity into Victoria, but as noted above, the capacity of the MSP to supply all New South Wales demand also needs to be considered if Victorian gas supplies are not increased.

Narrabri Gas Project

The Santos Narrabri Gas Project is in the Gunnedah Basin in New South Wales. The proposed 200 TJ/d gas plant would be located south-west of Narrabri. The Narrabri Gas Project is currently being assessed by the New South Wales Department of Planning ahead of a decision by the Independent Planning Commission[143,144].

In 2017, APA Group entered into a memorandum of understanding with Santos to investigate developing the Western Slopes Pipeline, which would connect the Narrabri Gas Project to the MSP[145], as shown in Figure 27. This could increase the capacity of the MSP to supply additional gas to support New South Wales demand, and potentially supply Victoria on peak days.

The Hunter Gas Pipeline Project has proposed constructing this pipeline with Jemena to transport gas from Narrabri to Newcastle, as shown in Figure 27. It has government approval but has not progressed[146].

The project was initially proposed to run from the Wallumbilla gas hub in Queensland to Newcastle and was known as the Queensland Hunter Gas Pipeline (QHGP). A large diameter QHGP may have been able to connect to the EGP to supply Victoria, although constructing additional piping around Sydney would be required.

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[142] APA, "Moomba Sydney Pipeline" April 2018, at https://www.apa.com.au/globalassets/documents/info/schematic/msp-schematic.pdf.

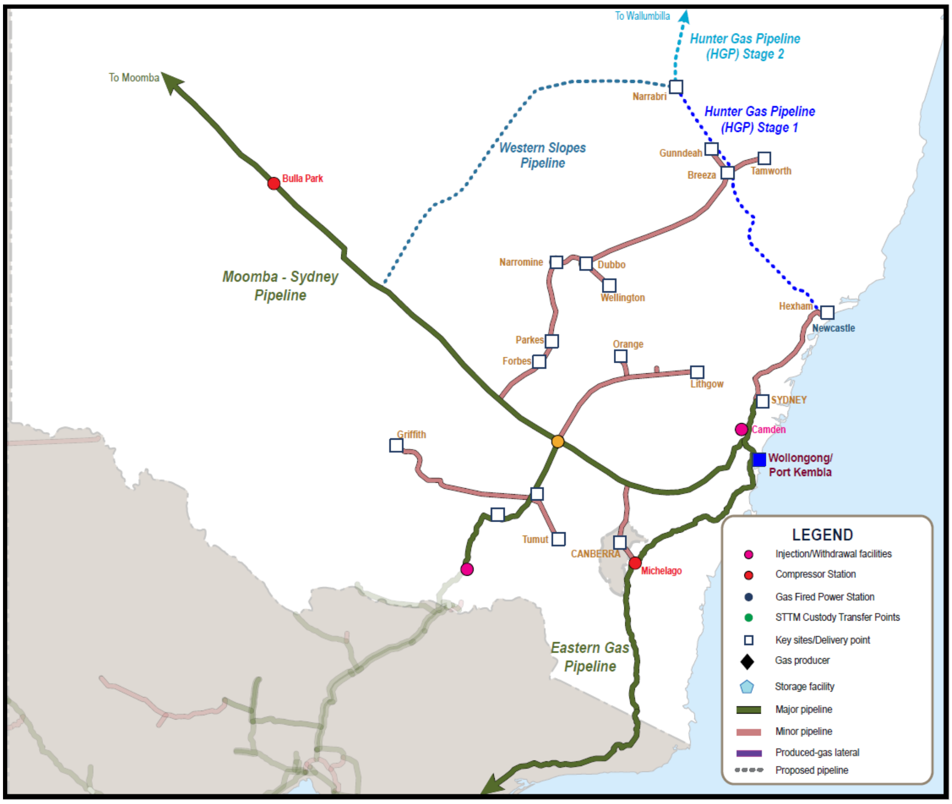
[143] Santos, "Local Narrabri gas to underpin new manufacturing jobs in northwest NSW" 27 February 2019, at https://www.santos.com/media-centre/announcements/local-narrabri-gas-to-underpin-new-manufacturing-jobs-in-northwest-nsw/.

[144] Santos, "Narrabri Gas Project", at https://narrabrigasproject.com.au/about/narrabri-gas-project/.

[145] Santos, "Environmental Impact Statement Introduction" 31 January 2017, at https://majorprojects.accelo.com/public/ab28b35d20333c02a9eebd9fdff42a13/Chapter%2001%20Introduction.pdf.

[146] Hunter Gas Pipeline, "Hunter Gas Pipeline Project", at http://www.huntergaspipeline.com.au/hunter-gas-pipeline.

Figure 27 Proposed New South Wales gas infrastructure



4.7 LNG import terminals

There are currently five proposed LNG import terminals in Australia:

- Two in New South Wales[147,148].
- One in South Australia[149].
- Two in Victoria.

Only the two Victorian and one of the New South Wales import terminals could provide additional peak day supply capacity to Victoria. In Victoria, AGL has proposed an import terminal at Crib Point and ExxonMobil is also proposing a facility without providing a location.

The proposed facility at Port Kembla in New South Wales would connect into the EGP, potentially providing additional supply to Victoria through reverse flow along this pipeline.

The proposed import facilities intend to utilise Floating Storage Regasification Unit (FSRU) technology, as described in the 2018 VGPR Update. Most LNG tanker volumes range between 140,000 and 170,000 m^3 (approximately 3,250 to 4,000 TJ)[150]. Supply capacity typically ranges between 500 and 800 TJ/d, which would enable supply of up to 130-160 PJ/y.

The actual total volume supplied would depend on commercial requirements of the facility owner as well as market dynamics. The operational benefits and constraints of a FSRU are outlined in Table 18.

[147] AIE, "Port Kembla Gas Terminal", at https://ausindenergy.com/file/2018/06/Project-Overview.pdf.

[148] The Sydney Morning Herald, "Newcastle port could be home to $500 million gas import terminal" 5 December 2018, at https://www.smh.com.au/business/companies/newcastle-port-could-be-home-to-500-million-gas-import-terminal-20181205-p50kc9.html.

[149] LNG World News, "Venice Energy lines up Port Adelaide LNG import project" 23 July 2018, at https://www.lngworldnews.com/venice-energy-lines-up-port-adelaide-lng-import-project/.

[150] The Oxford Institute for Energy Studies, "The outlook for Floating Storage and Regasification Units (FSRUs)" July 2017, at https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/07/The-Outlook-for-Floating-Storage-and-Regasification-Units-FSRUs-NG-123.pdf.

Table 18 Benefits and disadvantages of LNG import terminals

Benefits	Disadvantages
• An LNG import terminal would provide an additional high capacity supply source, improving DTS supply reliability. • An LNG import terminal provides an additional storage facility for the DTS, where gas can be immediately discharged into the DTS for peak shaving and emergency purposes. • Additional LNG imports could be sourced in the event of an extended gas production facility outage or sustained high GPG demand during winter due to a prolonged coal fired generator outage. • The impact of long-term maintenance can be mitigated by replacing the FSRU with an alternate vessel if required[151]. • An LNG import terminal could be developed in relatively short time frame to mitigate supply shortfalls with a construction period of 18 months (supply of long lead time items may need to be managed).	• Maintaining LNG supply to the FSRU requires careful procurement planning to ensure that supply is maintained without interrupting the supply of gas for the DTS. Procurement needs to take into account the travel time from the LNG production facility, and the impact of production disruptions. • The FSRU needs to be nearly empty prior to being re-filled from an LNG import ship. If an LNG ship arrives early and cannot unload in a timely manner, the FSRU operator may incur demurrage costs. If the ship arrives late, it could result in re-gasification rates being restricted. A DTS supply shortfall could occur if there are insufficient alternative gas supply sources. • While a single import terminal would be sufficient to increase peak day and winter peak period gas supply, a second import terminal or LNG storage tanks would have to be utilised to ensure security of supply, as is the case in other countries, e.g. Boston, USA. • The vaporised gas requires conditioning prior to being injected into the DTS to increase the amount of inerts and odorant to meet the gas quality standard[152].

AGL LNG Import Terminal

The AGL LNG Import Terminal is proposed to be built at Crib Point, near Hastings in Victoria[153]. This is subject to the project reaching FID, which is expected in FY 2020[154]. An Environmental Effects Statement (EES) is currently being completed to enable regulatory approval of the project. If the environmental and regulatory approvals are received in a timely manner, construction could occur in 2021[155].

The FSRU is proposed to be permanently moored at the Crib Point Jetty[156], with a 56 km high-pressure pipeline connecting the FSRU to the DTS. The tie in point would be just east of Pakenham on the Longford to Melbourne Pipeline as shown in Figure 28[157]. AGL has entered into a development agreement and an associated 20-year Gas Transportation Agreement with APA Group for the development of this pipeline[158].

AGL has entered into memorandums of understanding with a number of potential gas customers and has been in negotiations with LNG suppliers located in the Asia Pacific region for approximately 40 PJ per year[159]. In December 2018 AGL executed a contract with Höegh for the supply of a FSRU unit[160].

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151 AGL, "AGL Gas Import Jetty Project" 10 September 2018, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/how-we-source-energy/crib-point/document-updates-120918/epbc-referral---agl-gas-import-jetty-project.pdf?la=en&hash=278FFD93A1AFDE43B2707460A59B9937.

152 Carbon dioxide (CO_2), nitrogen (N2), Helium (He), Argon (Ar) and Oxygen (O2).

153 AGL, "AGL Gas Import Jetty Project Map A: Location Overview" 22 November 2017, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/how-we-source-energy/crib-point/document-updates-120918/map-a---location-overview.pdf?la=en&hash=3F9F19FA51F5AB343174EAD63D9AFFB2.

154 AGL, "Half-year results webcast" 7 February 2019, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/investors/webcasts-and-presentations/2019/arkadin-script-of-live-webcast-qa.pdf.

155 AGL, "AGL Gas Import Jetty Project Map A: Location Overview" 22 November 2017, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/how-we-source-energy/crib-point/document-updates-120918/map-a---location-overview.pdf?la=en&hash=3F9F19FA51F5AB343174EAD63D9AFFB2.

156 The Sydney Morning Herald, "APA to build pipelines for AGL's Victorian gas import terminal" 12 June 2018, at https://www.smh.com.au/business/the-economy/apa-to-build-pipelines-for-agl-s-victorian-gas-import-terminal-20180612-p4zkwp.html.

157 APA, "Crib Point Pakenham pipeline January 2019", https://www.apa.com.au/about-apa/our-projects/crib-point-to-pakenham-pipeline/.

158 APA, "APA to develop Crib Point Pakenham pipeline for AGL's LNG import facility" 12 June 2018, at https://www.apa.com.au/news/asx-releases/2018/apa-to-develop-crib-point-packenham-pipeline-for-agls-lng-import-facility/.

159 Australian Financial Review, "AGL Energy invites LNG bids for $250m Vic import terminal" 19 November 2017, at http://www.afr.com/business/energy/gas/agl-energy-invites-lng-bids-for-250m-vic-import-terminal-20171118-gzo380.

160 AGL, "Half-year results webcast" 7 February 2019, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/investors/webcasts-and-presentations/2019/arkadin-script-of-live-webcast-qa.pdf.

AGL has indicated that the annual supply from the FSRU will be at least 40 PJ/y and up to 100 PJ/y[161]. Depending on demand, 12 to 40[162] LNG shipments would supply the FSRU annually.

The preliminary design for the re-gasification system includes a firm capacity of approximately 550 TJ/d and an 'as available capacity' of 830 TJ/d[163]. The lower firm vaporisation rate takes into account operational considerations affecting supply reliability, including unit redundancy and maintenance requirements.

Information about this project was provided to AEMO. As the project has not received regulatory and environmental approvals, it is classified as a potential project and is not included in the prospective supply forecast. AEMO will continue to engage with AGL on this project.

Figure 28 Proposed pipeline route

APA, "Crib Point Pakenham Pipeline", at https://www.apa.com.au/about-apa/our-projects/crib-point-to-pakenham-pipeline/

Esso LNG Import Terminal

Esso has stated that it is "actively considering a potential LNG import project to bring additional supply to the east coast gas market"[164] which could be operational by 2022[165,166]. Esso has not provided information on the location for its proposed LNG import terminal.

AEMO has identified the Esso operated Long Island Point gas fractionation and crude oil storage facility near Hastings as a potential LNG import location. This location already includes wharf facilities for liquefied petroleum gas (LPG) tanker ships[167].

No information has been received by AEMO concerning this project. The project has been classified as a potential project and has not been included in the prospective supply forecast.

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161 AGL, "Half-year results webcast" 7 February 2019, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/investors/webcasts-and-presentations/2019/arkadin-script-of-live-webcast-qa.pdf.

162 AGL, "AGL Gas Import Jetty Project", at https://www.agl.com.au/about-agl/how-we-source-energy/gas-import-project.

163 See https://www.apa.com.au/globalassets/documents/our-current-projects/crib-point-to-pakenham/technical-reports/10_cpt-agl-cia-report-60582811-rev4.pdf.

164 OffshoreEnergyToday.com, "ExxonMobil spins drill bit off Australia in search of new gas source" 28 August 2018, at https://www.offshoreenergytoday.com/exxonmobil-spins-drill-bit-off-australia-in-search-of-new-gas-source/.

165 Reuters, "ExxonMobil considers importing LNG to Australia" 18 June 2018, at https://www.reuters.com/article/us-exxon-mobil-australia-lng/exxonmobil-considers-importing-lng-to-australia-idUSKBN1JE02R.

166 Oil Price, "ExxonMobil Looks to Build LNG Import Terminal Off Australia's East Coast" 19 June 2018, at https://oilprice.com/Latest-Energy-News/World-News/ExxonMobil-Looks-To-Build-LNG-Import-Terminal-Off-Australias-East-Coast.html.

167 Long Island Point overview, at https://www.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/long-island-point.

Port Kembla Import Terminal

Australian Industrial Energy (AIE) is proposing to construct a $200-300 million[168] LNG import terminal at Port Kembla, as shown in Figure 27. An environmental impact statement (EIS) was submitted with the New South Wales government in November 2018. Subject to regulatory approvals, construction is planned to commence during 2019 and take 12 to 14 months, with production commencing in 2020[169].

AIE entered an agreement with Höegh LNG in August 2018 for the supply of a 170,000 m^3 FSRU[170] and signed 12 memorandums of understanding with industrial users for the supply of gas[171].

The LNG import terminal would connect into the EGP, as shown in Figure 27, supplying 100 PJ/y of gas[172] and providing 4 PJ storage capacity to enable flexibility gas supply during peak demand periods[173]. AIE has indicated that they are also investigating supplying gas to a new GPG unit, which would reduce the available gas supply[174].

The facility would supply a significant portion of Sydney's demand, which would leave more Longford gas available to supply Victoria.

Additional gas from the FSRU could also be injected into the DTS through VicHub. Physical modifications would need to be made to facilitate increased EGP injections into the DTS beyond the current 120 TJ/d capacity of VicHub[175]. Upgrades to the EGP compressor stations would also be required to enable southbound compression on the EGP towards Victoria.

4.8 Hydrogen

Hydrogen can be safely added to natural gas at 10% by volume without changes to distribution pipelines and appliances. Hydrogen could be produced via electrolysis of water, using electricity generated by wind and solar generators.

Currently, there are hydrogen pilot projects planned in South Australia and New South Wales. While there are currently no domestic supply projects planned for Victoria, on 18 December 2018 the Victorian Government announced a $2 million Victorian Hydrogen Investment Program (VHIP)[176] to gauge market interest and assess the status of industry-led projects. The VHIP is also expected to fund investment in hydrogen research and pilot projects[177].

While hydrogen is not expected to have a material impact on natural gas demand during the five-year outlook period, AEMO is involved with several industry working groups and will continue to monitor its development.

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[168] AIE, "Australian Industrial Energy Consortium select Port Kembla, NSW for landmark LNG import terminal and enter FEED" 4 June 2018, at https://www.nswports.com.au/assets/Uploads/AIE-Port-Agreement-Announcement-4-June2018-Final.pdf.

[169] ABC News, "NSW's first LNG import terminal planned for Port Kembla, expected to drive down gas prices" 5 June 2018, at https://www.abc.net.au/news/2018-06-04/nswss-first-lng-terminal-to-drive-down-power-prices/9832486.

[170] Australian Industrial Energy, "FSRU Inspection", at https://ausindenergy.com/2018/09/12/fsru-inspection/.

[171] The Sydney Morning Herald, "Forrest to build NSW's first LNG import terminal at Port Kembla" 4 June 2018, at https://www.smh.com.au/business/the-economy/forrest-to-build-nsw-s-first-lng-import-terminal-at-port-kembla-20180604-p4zja7.html.

[172] ABC News, "NSW's first LNG import terminal planned for Port Kembla, expected to drive down gas prices" 5 June 2018, at https://www.abc.net.au/news/2018-06-04/nswss-first-lng-terminal-to-drive-down-power-prices/9832486.

[173] AIE, "Report for Australian Industrial Energy – Port Kembla Gas Terminal" 5 November 2018, at https://majorprojects.accelo.com/public/210738cfc6d9f31a9e23ea7489bdb162/00%20Port%20Kembla%20Gas%20Terminal%20EIS.pdf.

[174] AIE, "Australian Industrial Energy Consortium selects Port Kembla, NSW for landmark LNG import terminal and enters FEED", 4 June 2018, at https://ausindenergy.com/file/2018/06/AIE-Port-Agreement-Announcement-4-June-2018-1.pdf.

[175] Gas Bulletin Board, https://www.aemo.com.au/Gas/Gas-Bulletin-Board.

[176] Victorian Department of Environment, Land, Water and Planning, "Victorian Hydrogen Investment Program", https://www.energy.vic.gov.au/renewable-energy/victorian-hydrogen-investment-program.

[177] The Victorian Premier, "New Program To Drive Investment In Hydrogen Energy, at https://www.premier.vic.gov.au/new-program-to-drive-investment-in-hydrogen-energy/.

5. DTS pipeline capacities

Key findings

- There has been no significant change to pipeline capacities for this outlook period. The pipeline capacities are summarised in Table 19.
- These pipeline capacities will be used for the application of constraints in the Declared Wholesale Gas Market (DWGM), and to assess any proposed DTS service provider and facility operator maintenance plans.

Table 19 Summary of DTS pipeline capacities

Pipeline		Maximum capacity (TJ/d)	Comment
Longford to Melbourne	Injections only at the Longford CPP	990	No change from previous years, includes injections from the Longford Gas Plant, VicHub and TasHub injection points.
	Injections at the Longford CPP and Pakenham CPP	1,030	No change from previous years, includes supply from the Lang Lang Gas Plant through the BassGas injection point at Pakenham.
South West Pipeline	To Melbourne	415	Excludes WTS demand of 19 TJ/d taking total Iona CPP injections to 434 TJ/d. Capacity will increase with the commissioning of the WORM, discussed further in Chapter 6.
	To Port Campbell	145	Minor reduction of 2 TJ/d from 2018 VGPR Update due to increased WTS demand.
Victorian Northern Interconnect	To Melbourne	226	Limited to 150 TJ/d due to constraints in the New South Wales transmission network.
	To New South Wales via Culcairn	223	202 TJ/d on a 1-in-20-year peak system demand day.

5.1 Longford to Melbourne Pipeline capacity

The LMP runs from the Longford Gas Plant to Dandenong City Gate (DCG), which is the main supply point into the Melbourne inner ring-main. The pipeline is supplied by the Longford CPP[178] and the BassGas injection point.

The transportation capacity of the pipeline is dependent on the location of the supply and delivery pressures, shown in Figure 29:

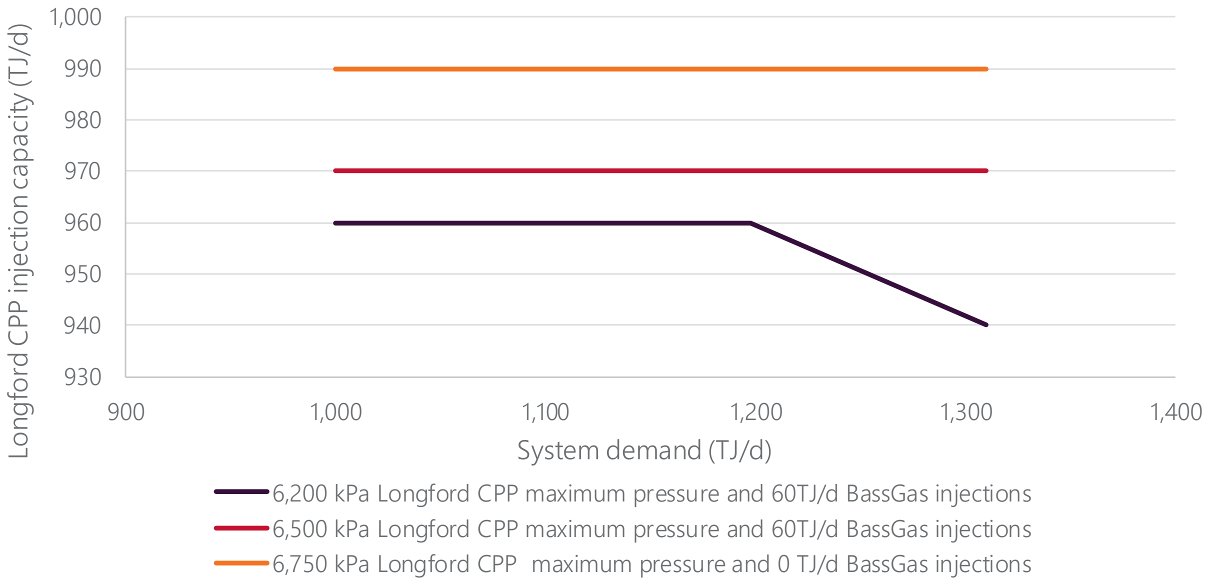
- Maximum pipeline capacity of 1,030 TJ/d consists of:
  - 970 TJ/d injections at Longford CPP.
  - 60 TJ/d injections at BassGas, connected at Pakenham.

[178] Longford CPP includes the Longford, VicHub and TasHub injection points.

- Maximum Longford CPP injection capacity is 990 TJ/d:
  - This is limited by the maximum injection pressure of 6,750 kilopascals (kPa).
  - 0 TJ/d BassGas injections.

Figure 29 shows the impact of reduced Longford CPP injection pressure on LMP capacity on days when system demand is above 1,000 TJ. This was discussed further in the 2017 VGPR[179].

Figure 29 Longford CPP injection capacity with varying conditions



5.2 South West Pipeline capacity

The SWP is a bi-directional pipeline that runs between Port Campbell and Lara, where it connects to the Brooklyn to Lara Pipeline (BLP) that runs from Lara to the Brooklyn city gate (CG). The South West Pipeline (SWP) can also supply the Brooklyn to Corio Pipeline (BCP) through the Lara CG.

The SWP is typically used to:

- Transport gas from the Port Campbell production and Iona UGS facilities (Iona CPP[180]) towards Melbourne during periods of high gas demand.
- Support Iona UGS reservoir refilling, and supply to the Mortlake Power Station and to South Australia via the SEA Gas Pipeline[181], during periods of lower gas demand in the summer and shoulder seasons.

5.2.1 South West Pipeline to Melbourne

SWP to Melbourne pipeline transportation capacity[182] increases as system demand supplied from the pipeline increases and is therefore maximised on peak system demand days. Winchelsea compressor station (CS) can be operated to increase SWP transportation capacity to Melbourne when system demand is above 800 TJ/d. Figure 30 shows the SWP capacity for Iona CPP injections to the SWP and WTS.

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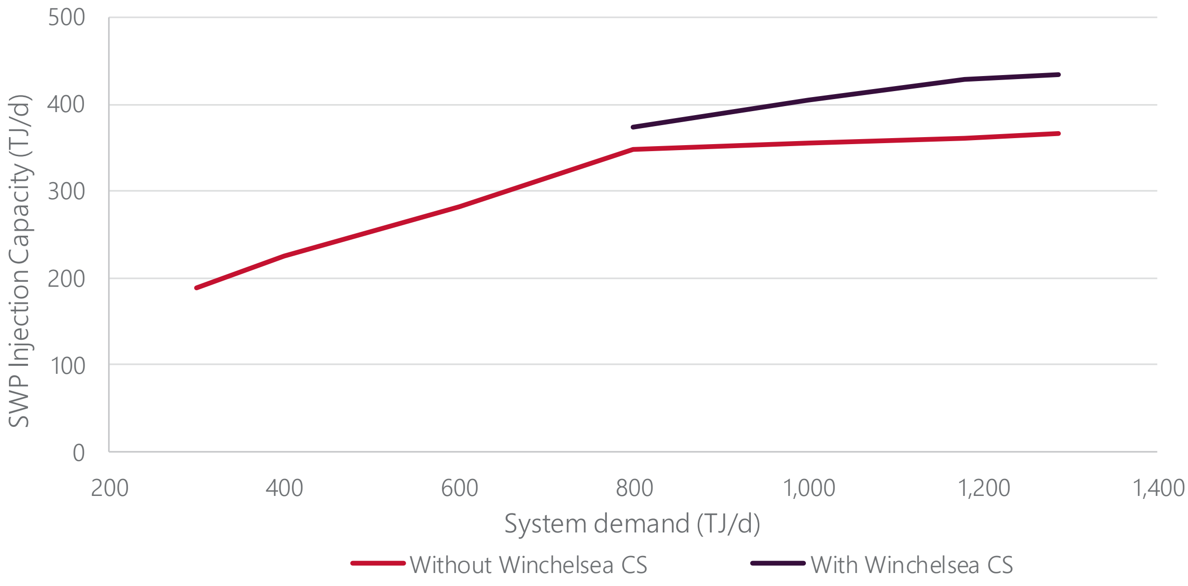
[179] Available at http://aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2017/2017-VICTORIAN-GAS-PLANNING-REPORT.pdf.

[180] Iona CPP includes the following injection and withdrawal points: Iona, SEA Gas, Mortlake, and Otway.

[181] Compression facilities at Port Campbell are required to withdraw gas from the SWP into Iona UGS and to supply SEA Gas and Mortlake.

[182] SWP transportation capacity to Melbourne is the total Iona CPP injections minus WTS demand.

Figure 30 SWP injection capacity to Melbourne



The SWP injection capacity with the Winchelsea CS remains at 415 TJ/d on a 1-in-20-year peak system demand day (1,246 TJ/d) for winter 2019. This is expected to increase with the commissioning of the WORM.

The injection capacity has reduced by up to 10 TJ/d on lower system demand days as part of APA Group's safety management program. This will reduce the maximum operating pressure (MOP) of the BCP from 7,390 kPa to 5,150 kPa, which will limit Lara CG and BLP CG outlet pressures. This was identified as the most cost-effective way of removing the BCP rupture hazard through the 2018-22 APA Access Arrangement.

The Laverton North Power Station is the only GPG unit that could increase SWP capacity, but only if it generates for 24 hours per day (generally it shuts down overnight between 11.00 pm and 5.00 am). As a result, this has not been included in the capacity modelling for the SWP, which is consistent with the AEMO's Gas Planning Approach (Appendix A5). If generation were to occur overnight, then AEMO may schedule the market at an increased SWP capacity to maximise transportation.

5.2.2 South West Pipeline to Port Campbell

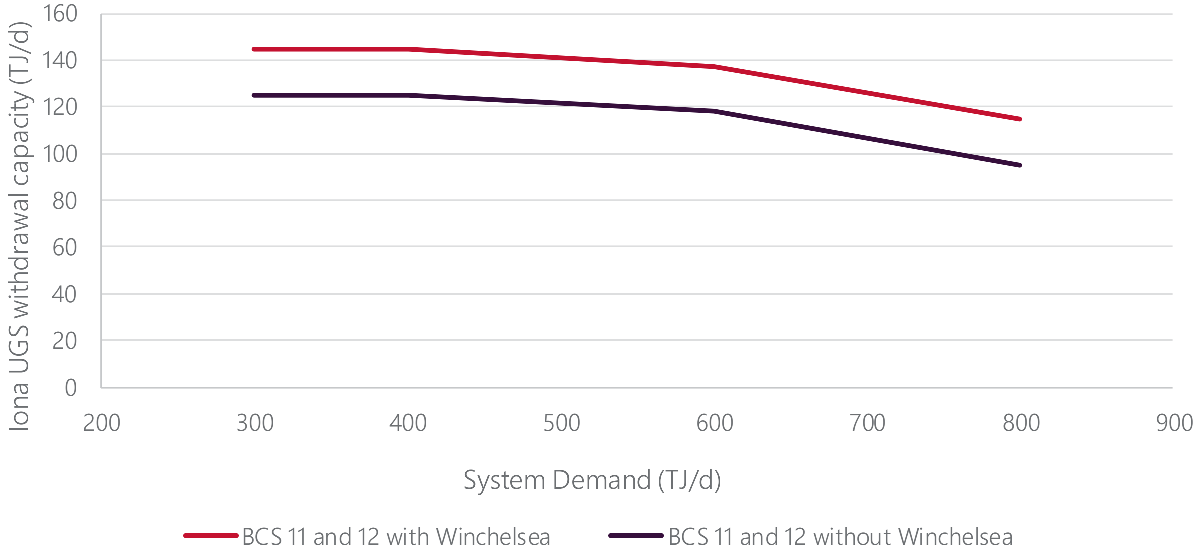
Figure 31 shows the Melbourne to Port Campbell pipeline transportation capacity to support SWP withdrawals to the Iona UGS facility. SWP withdrawal capacity is at its maximum on low system demand days when Winchelsea CS is available and Brooklyn CS Units 11 and 12 are compressing into the BLP.

Under these conditions, the maximum SWP withdrawal capacity is 145 TJ/d when system demand is less than 400 TJ/d. This decrease of 2 TJ/d from the 2018 VGPR Update is due to an increase in WTS demand.

To support SWP withdrawals during the shoulder season and mild winter days, Brooklyn CS Unit 8 or 9 is required to support Geelong morning and evening peak demand.

With the recent Winchelsea CS augmentation to enable bi-directional compression along the SWP, SWP withdrawals are reduced by approximately 20 TJ/d when the Winchelsea CS is not available.

Figure 31 SWP withdrawal capacity with Brooklyn CS Units 11 and 12 with and without Winchelsea compression



Due to the location of the Laverton North and Newport power stations, and their high offtake rate, SWP transportation capacity towards Port Campbell is impacted by the operation of these generators. The completion of the Brooklyn CS and Winchelsea CS augmentations has reduced the impact of these power stations on SWP withdrawal capacity.

The impact of Laverton North Power Station operation on the SWP withdrawal capacity will vary depending on its offtake rate and operating hours. The greatest impact is when the generator is operating at full rate, which reduces the SWP hourly withdrawal rate by approximately a half.

The impact of Newport Power Station operation on SWP withdrawal capacity was revised for the 2018 VGPR Update. The SWP withdrawal capacity reduces by 1 TJ/d for every 13 TJ/d of Newport Power Station demand. This was previously a 1 TJ/d reduction for every 10 TJ/d of Newport Power Station demand.

5.3 Victorian Northern Interconnect capacity

Table 20 provides a summary of the VNI pipelines.

Table 20 Victorian Northern Interconnect (VNI) pipelines

Pipeline	Maximum Allowable Operating Pressure	Notes
T74 (300 mm)	• Wollert to Euroa Pressure Reduction Station (PRS); 7,400 kPa • Euroa PRS to Wodonga; 8,800 kPa	• Original pipeline supporting Northern DTS demand, including Bendigo via Wandong, and the Echuca and Koonoomoo laterals.
T119 (400 mm)	• Wollert to Barnawartha; 10,200 kPa, (Pipeline is upgradable to 15,300 kPa)	• New pipeline completed in 2017 predominately for supporting exports to and imports from NSW. • Can also supply Northern DTS demand via the T74 pipeline by flowing gas through the Wollert PRS, Euroa PRS and the Barnawartha PRS.
T99 (450 mm)	• Barnawartha to Culcairn; 10,200 kPa	• Supports exports to and imports from NSW.

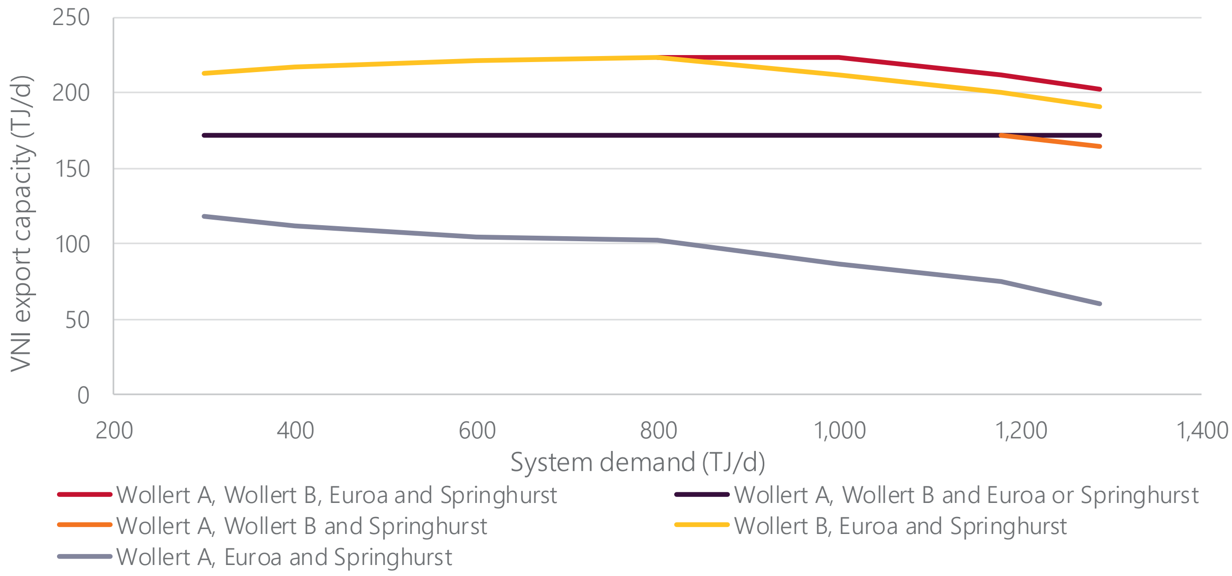
5.3.1 Victorian Northern Interconnect export capacity

The VNI export capacity is dependent on the availability of the Wollert, Euroa, and Springhurst compressors, and the capacity varies with different compressor configurations. The operating conditions for VNI exports remain unchanged from the 2017 VGPR.

With consideration of these export modes, the capacity is the higher of either:

- The DTS maximum export capacity (red or yellow curves shown in Figure 32) when the DTS supply pressure to Culcairn is greater than 8,600 kPa, or
- Up to 172 TJ/d (black line in Figure 32) when the DTS supply pressure is lower than 8,600 kPa and all three Culcairn compressors are operating. This requires a minimum supply pressure of 7,000 kPa.

Figure 32 Victorian Northern Interconnect export capacity



On peak system demand days, the T74 pipeline cannot support the Northern zone demand with Wollert A compression[183] alone, and additional gas must be supplied to it from the T119 pipeline via Wollert B compression or Culcairn injections. Supply from the T119 is through the Wollert, Euroa, or Barnawartha pressure reduction stations (PRS).

The system conditions required to support a 202 TJ/d export capacity on a 1-in-20-year peak system demand day remain as set out in the 2017 VGPR. At least 1,446 TJ/d[184] of gas supply into the DTS would be required to support this export quantity.

5.3.2 Victorian Northern Interconnect import capacity

Figure 33 shows the VNI import capacity with varying compressor configurations.

The maximum VNI import capacity of 226 TJ/d is achieved on a 1-in-20-year peak system demand day with both the Euroa and Springhurst compressors operating. The import capacity is reduced if either compressor is offline, but more so when the Springhurst CS is offline, due to the increased distance from Culcairn to the Euroa CS.

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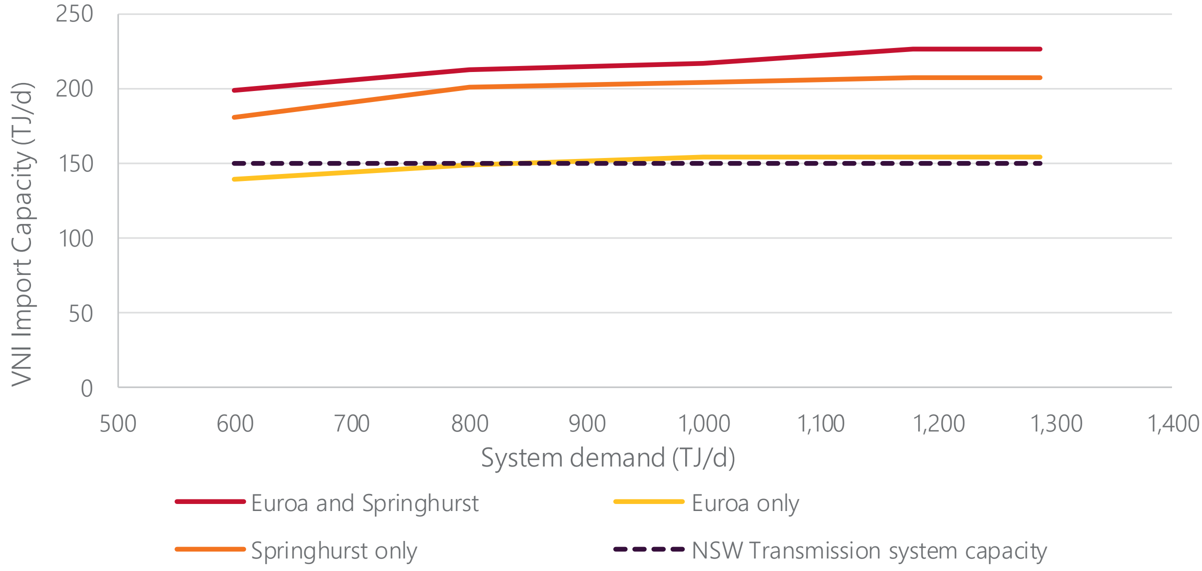
[183] As stipulated in the Service Envelope Agreement, between APA and AEMO, a maximum of two Wollert A compressor units can be operated on a continuous basis. The third available compressor unit is to be treated as a standby unit.

[184] System demand on a 1-in-20-year peak system demand day for 2019 is forecast to be 1,246 TJ and assumes no gas is exported through Culcairn. This increases the supply requirement to 1,446 TJ to facilitate 200 TJ of Culcairn exports.

Figure 33 Victorian Northern Interconnect import capacity



The operator for the New South Wales transmission system north of Culcairn has advised AEMO that up to 150 TJ/d of imports into the DTS can be supported[185]. For most compressor configurations, the import capacity of the VNI is higher than the Culcairn supply capacity. These VNI import capacities are unchanged from the 2017 VGPR.

5.4 Future pipeline connections

As discussed in Chapter 4, a proposed LNG import terminal connection at Pakenham and the connection of the WORM at Wollert (discussed in Chapter 6), are likely to impact the operating dynamics and capacity of the DTS. For example, the LMP has historically been a uni-directional pipeline flowing from Longford towards Melbourne, which may change following the connection of the proposed LNG import terminal at Pakenham. Higher pressures at Pakenham may also impact BassGas injections into the DTS.

As additional information is made available, AEMO will assess the impact of these new connections on system operations and pipeline capacities.

[185] The import capacity is reduced if Uranquinty Power station is operating, or if there is high system demand off the Young to Culcairn lateral.

6. Declared Transmission System adequacy

Key findings

- The DTS capacity is expected to be sufficient to support forecast peak system demand days during the outlook period (supply adequacy is discussed in Chapter 3). The DTS peak day system capacity is 1,382 TJ/d without Dandenong LNG, and 1,505 TJ/d with firm rate LNG injections.
- Forecast GPG demand can be supported over the outlook period. Peak shaving Dandenong LNG injections may be required on 1-in-20 peak system demand days to support critical system pressures.
- The WORM gas pipeline is now a committed project and is expected to be commissioned during 2021. This will increase the SWP transportation capacity, reduce the refilling risk for Iona UGS, improve system security through increased system linepack, and support peak day GPG demand.
- While AEMO and APA are still collaborating on the design of the WORM, initial modelling indicates that it will have the following impacts on SWP transportation capacity:
  - On a 1-in-20 peak system demand day, SWP injection capacity increases from 434 TJ/d to 449 TJ/d. Another compressor on the BLP (between Lara and Plumpton), or pipeline looping upstream and downstream of the Winchelsea CS is required to increase this further.
  - On a 300 TJ/d system demand day, SWP withdrawal capacity increases from 145 TJ/d to 256 TJ/d with one Wollert B compressor flowing into the WORM. With two Wollert B compressors flowing into the WORM this is expected to increase to approximately 300 TJ/d.
- The Notice of a Threat to System Security issued following the publication of the 2017 VGPR for peak day supply to Warragul will be resolved following the commissioning of the Warragul looping project, which APA has planned for June 2019. If a peak demand day occurs prior to commissioning, curtailment of a large commercial customer may still be required.

6.1 Peak day system capacity

Peak day system capacity[186], shown in Figure 34, quantifies the main sources of DTS supply – the LMP[187], Iona CPP, and Dandenong LNG injections – required to meet total DTS demand (including GPG).

The area under the curve represents the feasible operating envelope of the DTS, assuming sufficient gas supply is available.

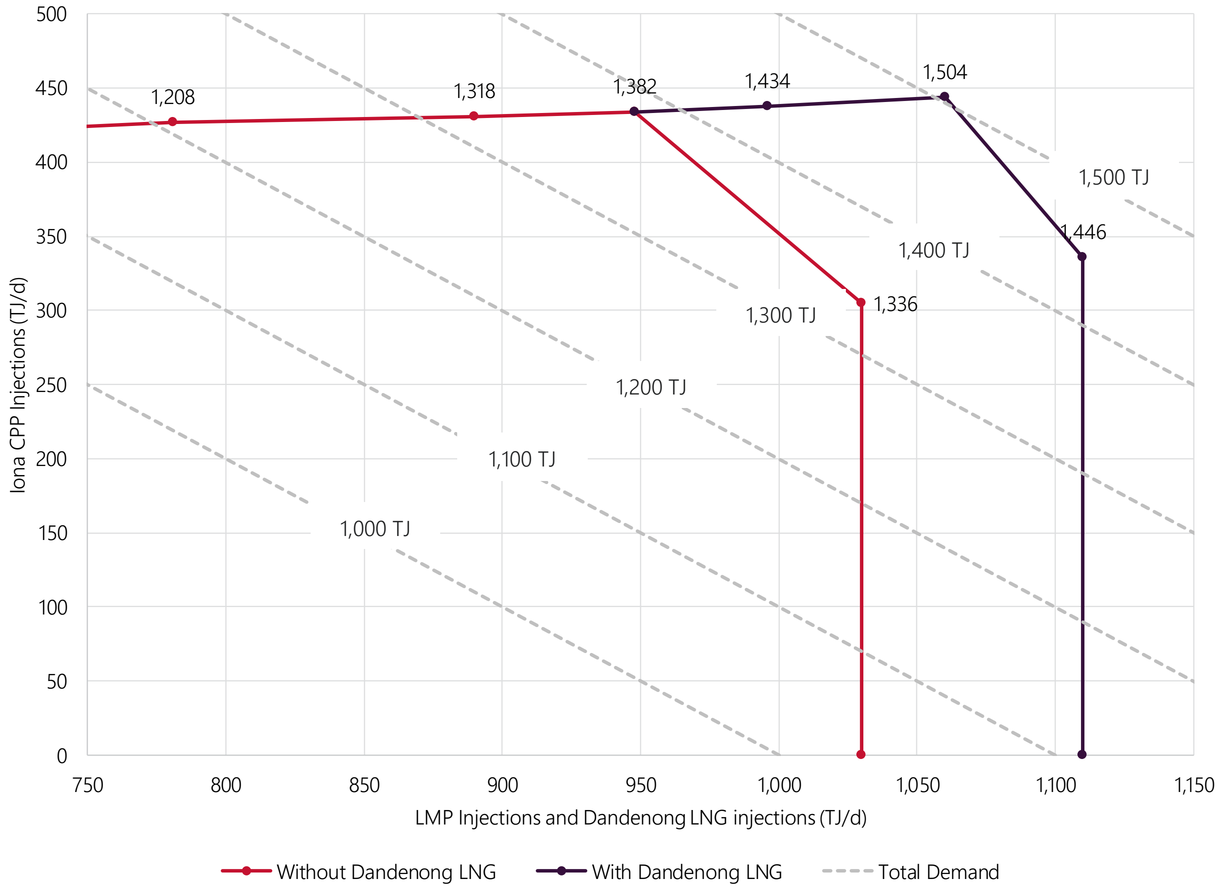
[186] Peak day system capacity includes system demand, 25 TJ/d GPG demand, and system compressor fuel gas.

[187] LMP injection facilities include Longford CPP and BassGas.

Note that:

- The LMP and SWP cannot operate at their respective maximum capacity at the same time. There is a restriction of supply into the Melbourne demand zone which is defined as the system 'back-off effect', limiting the available supply into the DTS.
  - Addition of the WORM may increase system capacity, by increasing usable system linepack; however further investigation is required (as discussed in Section 6.3).
- The maximum DTS capacity of 1,504 TJ is achieved with Dandenong LNG injecting at its maximum firm rate[188] of 87 TJ/d.
- Culcairn injections and/or withdrawals are not currently included in the system capacity modelling. Culcairn injections are considered to be equivalent to LMP injections, where an increase in Culcairn injections and a corresponding reduction in LMP supply results in the same system capacity.

Figure 34 Declared Transmission System peak day capacity



6.2 Supporting gas-powered generation

DTS-connected GPG units have historically operated as peaking stations during times of high electricity demand, or during coal fired generator outages. AEMO has observed an increase in DTS-connected GPG demand since the March 2017 closure of the Hazelwood Power Station, as shown in Figure 35.

The DTS has limited capacity to support unforecast GPG demand during winter, because:

- The DTS has low usable linepack in comparison to the demand on the network.

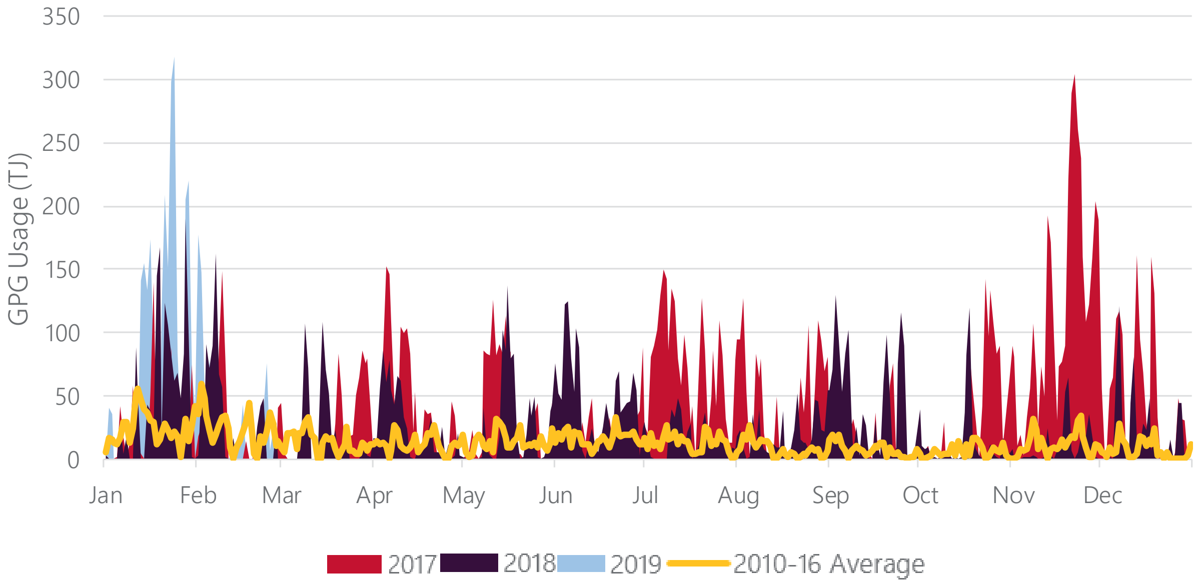
[188] Dandenong LNG maximum firm rate is 87 TJ/d at 5.5 TJ/hr for 16 hours.

- GPG demand that starts during the gas day reduces the time and gas supply options available to increase DTS injections so the end of day linepack target can still be reached.
- Instantaneous GPG hourly demand can be high and can reduce linepack levels quickly, particularly during the morning and evening peak demand periods.

To better manage the uncertainties of GPG demand, the AEMO gas control room:

- Monitors forecast GPG in both the DWGM demand forecasts and NEM pre-dispatch.
- Seeks confirmation from market participants which supply gas for GPG units in the DTS.
- Communicates regularly with AEMO's NEM control room and its support teams regarding forecast electricity demand, NEM reserve levels, and generator outages.

Figure 35 Daily DTS-connected GPG demand for 2017, 2018, and 2019 (YTD) vs 2010-16 average



AEMO has modelled three scenarios to assess the adequacy of the DTS to support forecast demand for DTS-connected GPG, discussed in Chapter 2:

- Scenario 1: Peak GPG demand in summer (400 TJ system demand) – see Section 6.2.1.
- Scenario 2: Peak GPG demand in winter (1,180 TJ system demand) – see Section 6.2.2.
- Scenario 3: Event-driven severe GPG demand in winter (1,180 TJ system demand) – see Section 6.2.3.

The following assumptions apply to the modelled scenarios:

- GPG demand is forecast at the start of gas day in the 6.00am DWGM market schedule.
- No intra-day changes to GPG demand or demand profile[189].

If GPG demand is unforecast at the start of the gas day, the likelihood of requiring peak shaving Dandenong LNG and/or curtailment of GPG demand to prevent critical pressure breaches increases proportionally to the amount of unforecast GPG demand.

[189] Inter-day changes are manageable if scheduled accordingly at each scheduling horizon.

6.2.1 Peak GPG demand in summer

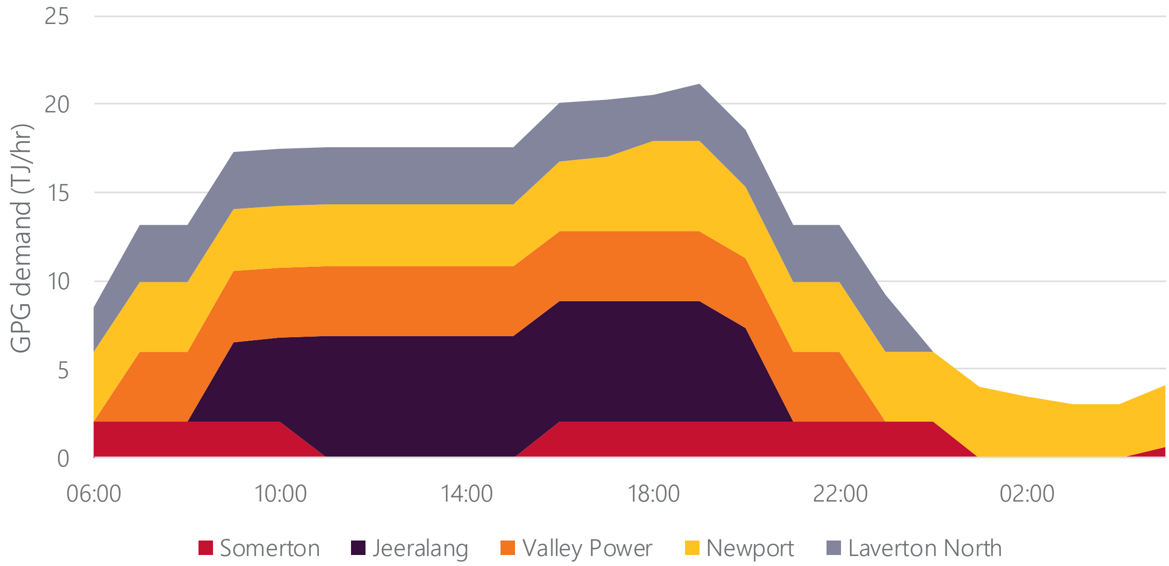
This scenario modelled a peak summer GPG demand of 317 TJ occurring on a 400 TJ system demand day. Such an event may occur if there is a heat event in Victoria that results in high electricity demand, coinciding with NEM transmission line reclassifications or low NEM generation reserves.

The modelled demand profile, shown in Figure 36, resembles the demand profile of the heat event on 24 and 25 January 2019[190], which impacted Victoria and South Australia.

The modelling for this scenario determined that:

- The system can support the modelled GPG demand profile, by maximising the LMP capacity with Longford CPP and BassGas injections.
- SWP withdrawals of up to 95 TJ/d can be supported. The reduction in the SWP withdrawal capacity occurs due to Laverton North and Newport gas demand, as described in Section 5.2.2.
- Culcairn withdrawals of up to 120 TJ/d can be achieved without the use of Dandenong LNG. Quantities above this level are possible if Dandenong LNG is used to support Wollert inlet pressures during the afternoon to evening GPG demand peak.

Figure 36 Modelled peak GPG demand profile during summer



6.2.2 Peak GPG demand in winter

This scenario modelled a peak winter GPG demand of 178 TJ/d on a 1-in-2-year peak system demand day of 1,180 TJ. Two different generator demand profiles were used to represent two system demand days with the same level of GPG demand. The GPG gas demand profile, shown in Figure 37, was developed based on economic modelling and historical winter demand.

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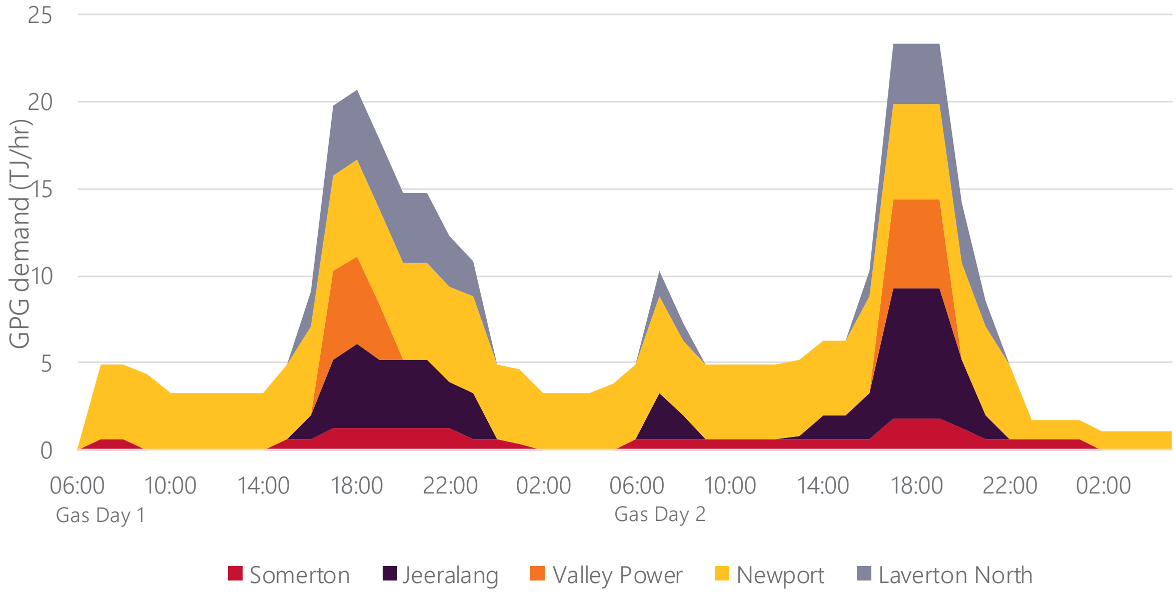
[190] DTS-connected GPG consumption was approximately 320 TJ on 25 January 2019.

Figure 37 Modelled peak GPG demand profile during winter



The modelling for this scenario predicted that the system can support the modelled GPG demand profile without Dandenong LNG injections on a 1-in-2-year peak system demand day, by maximising supply from the Longford CPP and Iona CPP.

Culcairn withdrawals were not included in the model, however, some withdrawals could be supported without Dandenong LNG, as the modelled Dandenong City Gate inlet pressure remained above the minimum requirement.

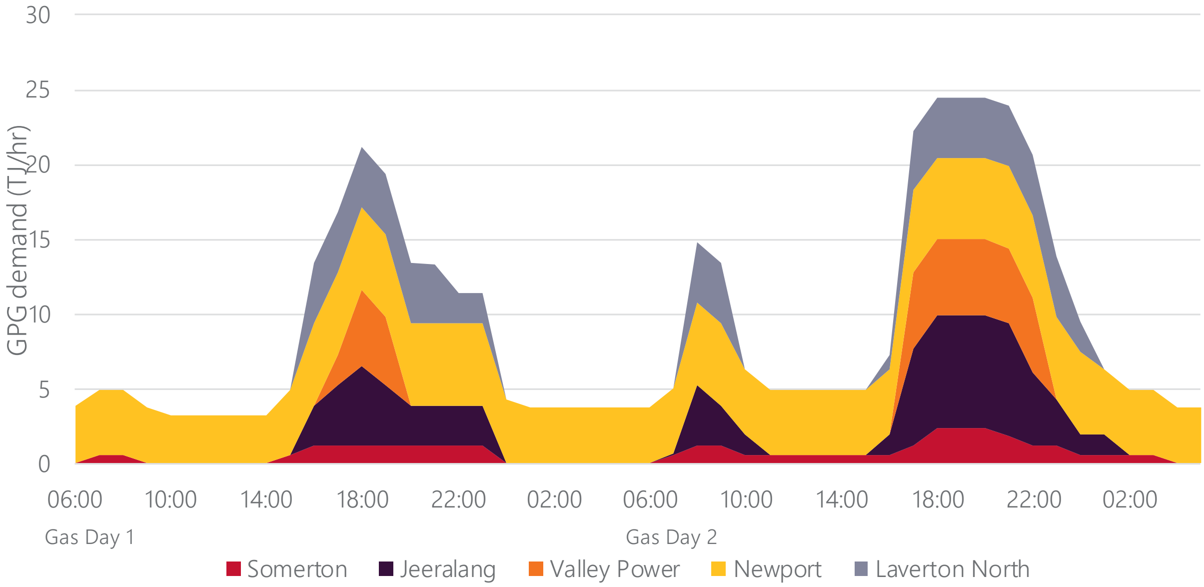
The most recent similar day to these conditions was 3 August 2017, which was comprised of 1,152 TJ system demand and 127 TJ of GPG demand, both of which were higher than forecast at the beginning of the gas day.

6.2.3 Event-driven severe GPG demand in winter

This scenario modelled a severe event occurring on a 1-in-2-year peak system demand day of 1,180 TJ. The event creates a peak GPG demand day of 182 TJ/d followed by an exceptionally high GPG demand day of 265 TJ/d. The demand profile was developed based on economic modelling where a weather event involving heavy rainfall results in mine flooding, impacting multiple coal generators. The profile is shown in Figure 38.

The key difference between the "Peak GPG demand" and the "event-driven severe GPG demand" scenarios in winter is that there is significantly less usable linepack during the event-driven scenario.

Figure 38 Event driven severe GPG profile during winter



Modelling for this case study determined that:

- While the system can support GPG demand of 265 TJ/d, the Dandenong City Gate inlet reaches its minimum operational pressure, even with the GPG demand being forecast, due to the higher hourly demand values.
- If GPG or system demand increases, or if any of the demand is unforecast, peak shaving Dandenong LNG injections would be required to support critical system pressures.

Culcairn withdrawals were not included in this model and could not be supported without firm rate Dandenong LNG injections.

6.3 System augmentations

6.3.1 Western Outer Ring Main

The WORM is an augmentation of the DTS that will connect the SWP/BLP to the VNI and LMP, and create a Wollert hub. The project was proposed to the AER as part of the most recent APA Access Arrangement submission.

In November 2017, the AER published its final decision on the APA Victorian Transmission System Access Arrangement that applies from 1 January 2018 to 31 December 2022[191]. It approved tariffing for the construction of the new pipeline to increase SWP transportation capacity and improve security of supply across the Victorian DTS.

APA's WORM proposal in the approved 2018-22 Access Arrangement[191] included:

- A 49.3 km[192], 500 mm pipeline from Wollert to Plumpton, as shown in Figure 39.
- The installation of additional compression at Wollert station B, that would compress gas from the Pakenham–Wollert pipeline into the WORM.

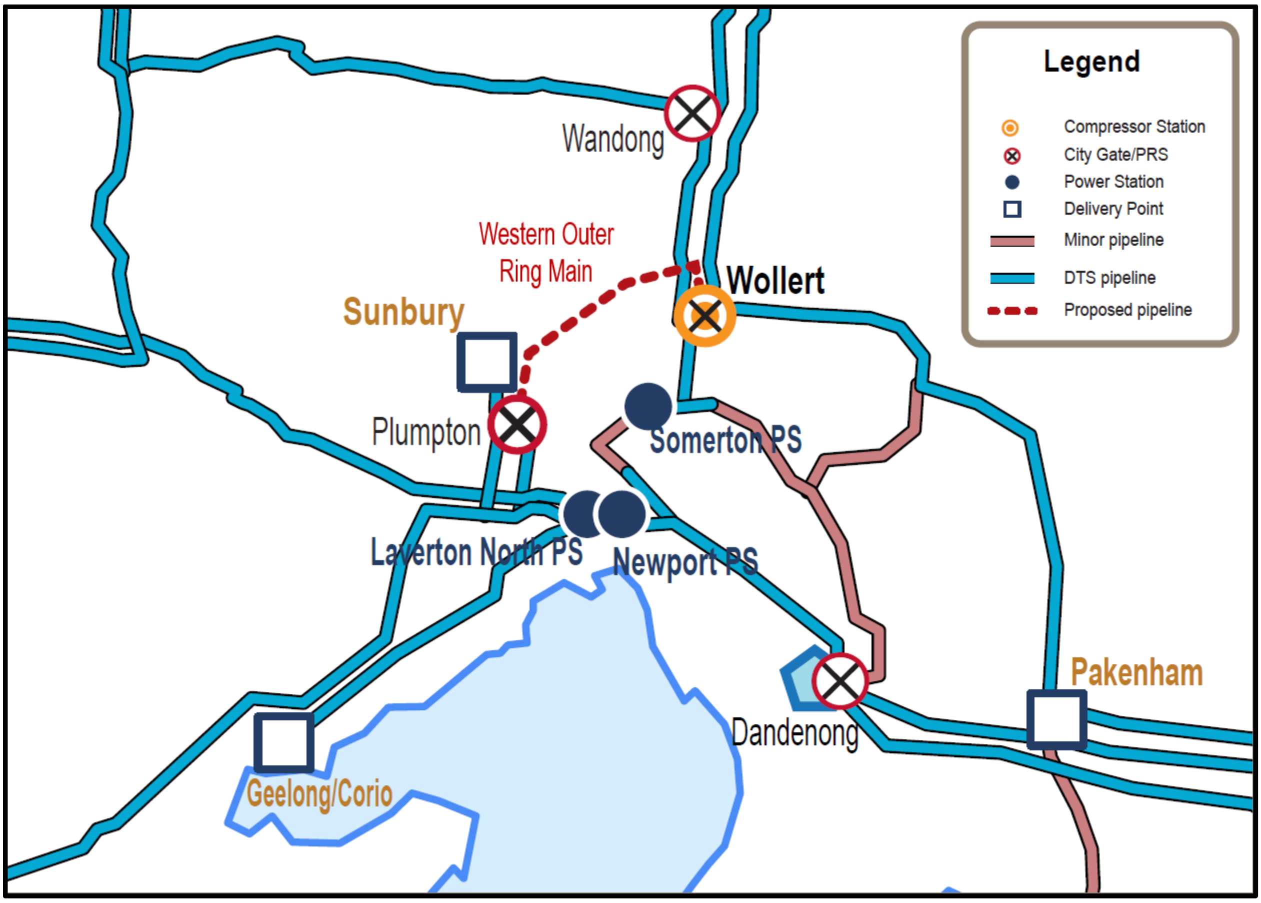
[191] AER. APA Victorian Transmission System - Access Arrangement 2018-22, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2018-22.

[192] Due to delays in acquiring the easement, the originally proposed route is no longer available.

- A new PRS at Wollert, that would enable flow from the WORM into the Pakenham–Wollert pipeline.

The pipeline is targeted to be commissioned during 2021[193], however the delivery date is dependent on easement acquisitions.

Figure 39 Proposed WORM pipeline



The AER approved the construction of the WORM to:

- Improve capacity and security across the Victorian DTS.
- Improve DTS linepack management, with the ability to shift linepack between all three major pipelines as required.
- Reduce reliance on the Brooklyn CS for SWP withdrawals to refill Iona UGS.
- Provide capacity for future growth in Melbourne's west and north, to facilitate new offtakes into distribution systems, or new GPG sites along the WORM.

AEMO and APA are collaborating on the design to achieve these benefits. Design options include, but are not limited to, WORM tie-in options at Wollert, compressor configurations, operational flexibility, linepack management options, and the ability to maintain system security during abnormal events.

Once complete, the WORM will link together all three major DTS pipelines at Wollert, creating new pipeline capacity interdependencies. The VNI and SWP export capacities will both be dependent on compression at Wollert, which may limit both pipelines maximum capacities. LMP, VNI and SWP injections will also interact, as each of the pipelines demonstrates a back-off effect in relation to the others. AEMO will further assess this effect once the WORM design has been finalised.

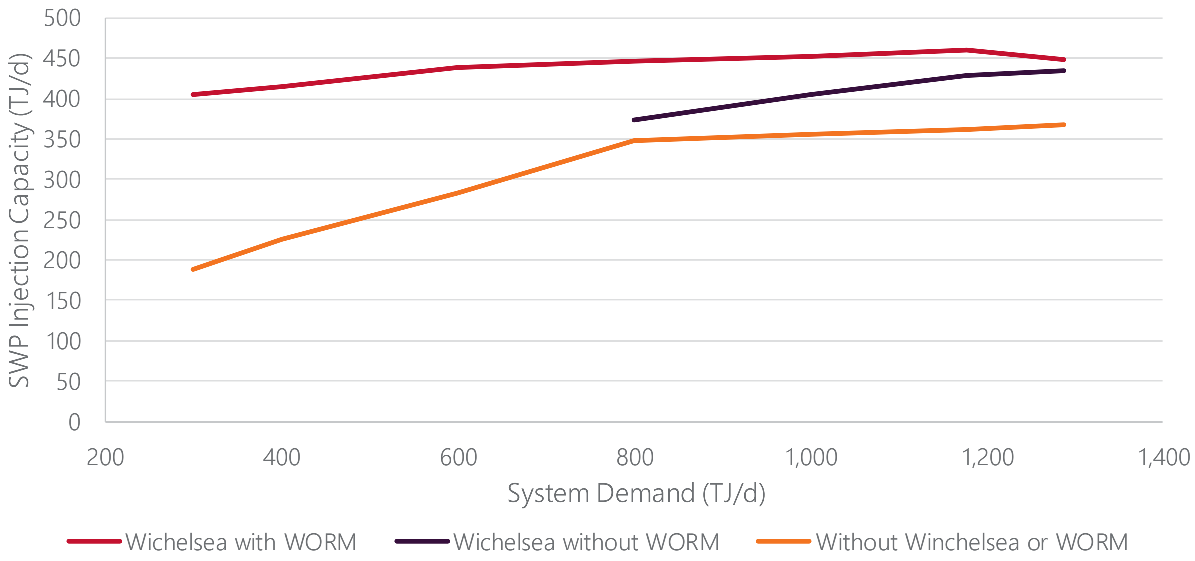
[193] See https://www.apa.com.au/globalassets/asx-releases/2019/2019-02-20-interim-results-presentation-1h-fy19-5.pdf.

SWP injection capacity

Figure 40 shows the indicative SWP injection capacity (inclusive of WTS) with the WORM. The modelling assumed:

- Only two Centaur compressors available at Wollert CS.
- A 64 km, 500 mm pipeline from Wollert to Plumpton PRS (modelled prior to APA securing a shorter route).
- A new PRS at Wollert, from the WORM into the Pakenham–Wollert pipeline.
- A withdrawal rate of 120 TJ/d at Culcairn.
- Brooklyn–Corio Pipeline is limited to 5,150 kPa (reduced MOP).

Figure 40 Modelled SWP injection capacity, and the expected impact of the WORM



The modelled reduction in SWP transportation capacity on high demand days occurs due to the pressure in the Wollert end of the WORM being lower than the Pakenham–Wollert pipeline. This is the result of the WORM pressure being depleted by high demand on a 1-in-20-year peak system demand day. The impact of the proposed LNG import terminal(s) and additional compression will require further analysis.

After completion of the WORM:

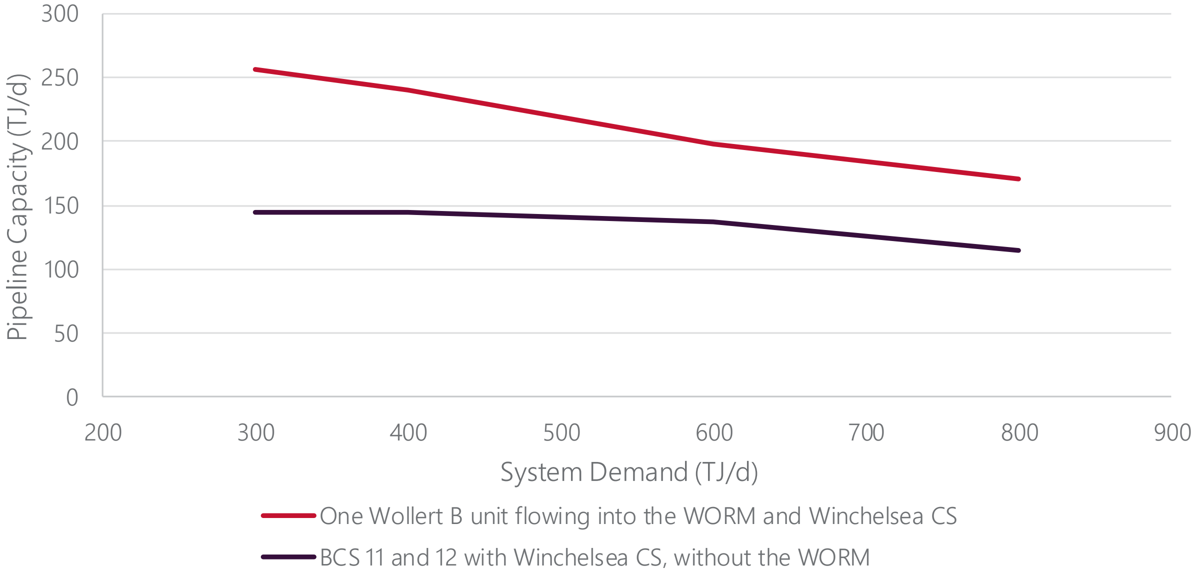
- SWP transportation capacity will no longer be constrained by the capacity of the Brooklyn CG, which will facilitate future SWP expansions.
- On lower demand days, Iona CPP injections will be able to support the majority of the DTS demand.

SWP withdrawal capacity

Figure 41 shows the indicative SWP withdrawal capacity with the WORM. The modelling assumed the same physical assets listed in the injection case and the following system conditions:

- A withdrawal rate of 100 TJ/d at Culcairn.
- Brooklyn–Corio Pipeline is not utilised for export capacity, only for supplying the Geelong region (due to the reduced MOP).
- The WORM and VNI are assigned one Wollert B compressor each.

Figure 41 SWP withdrawal capacity, and the projected impact of the WORM



The withdrawal capacity in Figure 41 was limited by the pressure reduction along the WORM, between Wollert and Winchelsea. A third unit at the Wollert CS is expected to provide up to 50 TJ/d of additional withdrawal capacity at the Iona CPP and provide redundancy for Culcairn and SWP withdrawals during maintenance periods. Modelling will be completed when the design of the WORM is finalised.

6.3.2 Warragul looping project

In the 2017 VGPR, AEMO identified a threat to system security for the supply to the Warragul Custody Transfer Meter (CTM). The Warragul CTM is supplied from the Lurgi Pipeline, via a 4.7 km 100 mm diameter pipeline lateral.

Forecasts projected that:

- Growth in large commercial and residential demand supplied by the Warragul CTM would exceed the infrastructure capacity.
- Investment would be required by winter 2019 to reduce the risk of gas supply shortfalls to end users on a peak demand day.

APA proposed duplicating the existing Warragul supply line with the construction of a 4.8 km, 150 mm diameter pipeline. The AER approved this pipeline in APA's 2018-22 Access Arrangement[194]. The proposed pipeline will predominantly follow the existing pipeline route and is targeted to be commissioned by June 2019[195].

There is still a risk of curtailment to end users if a peak demand day occurs prior to the commissioning of the pipeline. AEMO will continue to work with the distributor and retailer for a large commercial site in Warragul to monitor and respond if necessary to peak demands.

AEMO will withdraw the Notice of a Threat to System Security issued in 2017 once the pipeline is commissioned. The new pipeline will enable the minimum contractual Warragul pressure to return to 1,400 kPa.

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[194] AER. APA Victorian Transmission System - Access Arrangement 2018-22, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2018-22.

[195] APA, Warragul looping project factsheet, March 2018, at https://www.apa.com.au/globalassets/documents/our-current-projects/warragul-looping-project/warrugul-looping_infosheet_016.pdf.

6.3.3 SWP to Waurn Ponds Pipeline

The SWP to Waurn Ponds Pipeline project (previously referred to as the SWP to Anglesea Pipeline) will provide a second source of supply to the Geelong region, which will support increasing peak hourly demand in the Surf Coast Shire and Bellarine Peninsula.

The project includes a new 20.2 km, 10,200 kPa, 250 mm diameter pipeline lateral that connects to the SWP west of Geelong and runs to Waurn Ponds. The project will include a city gate with custody metering and pressure regulation at Waurn Ponds for connection to the AusNet Services gas distribution system.

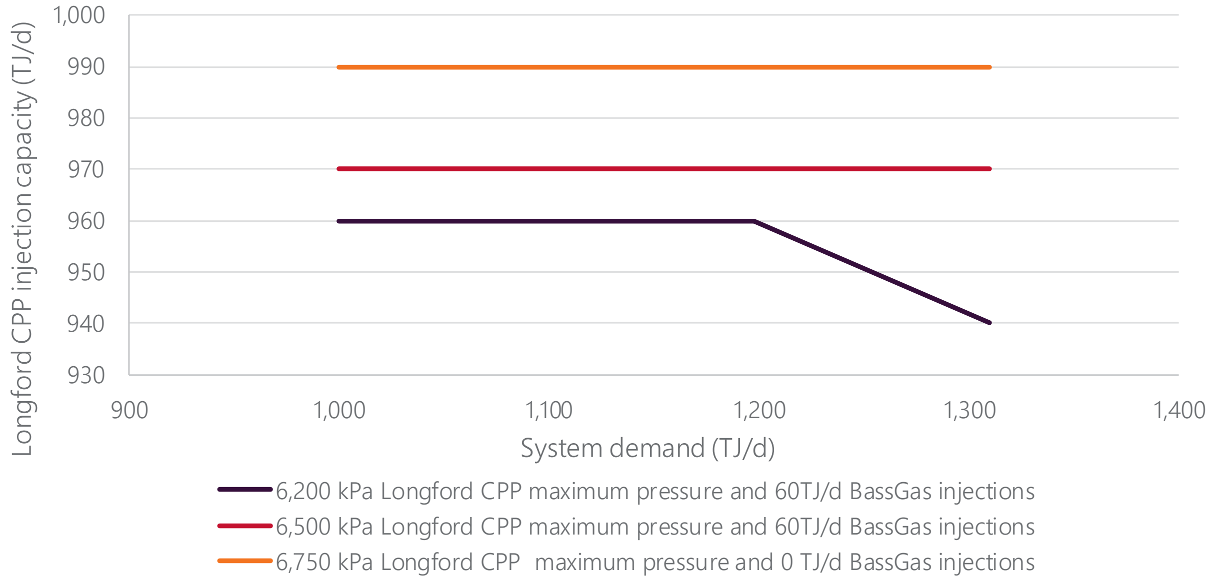
This connection has the potential to impact the SWP injection and withdrawal capacity, depending on its configuration. AEMO has had initial discussions with APA and AusNet Services about the design and operation of this pipeline, with the aim of increasing the SWP injection capacity during winter and having minimal impact on the withdrawal capacity during summer.

The pipeline has been approved by the AER in the APA's 2018-22 Access Arrangement[196]. Information provided by APA indicates the pipeline is likely to be commissioned during 2022.

[196] AER. APA Victorian Transmission System - Access Arrangement 2018-22, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2018-22.

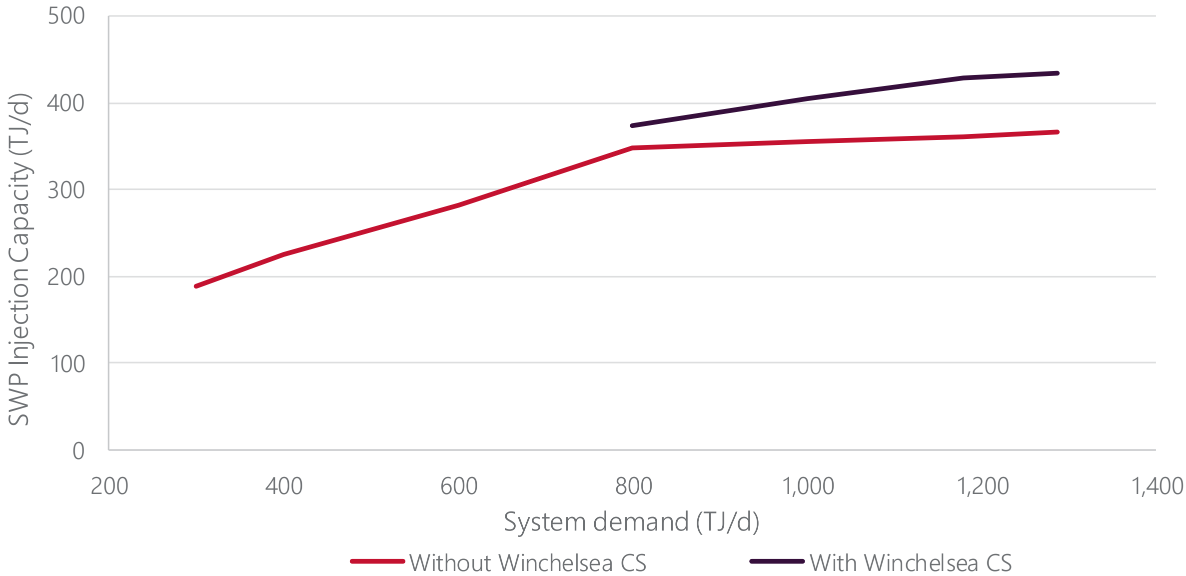
A1. DTS pipeline capacity charts

A1.1 Longford to Melbourne Pipeline

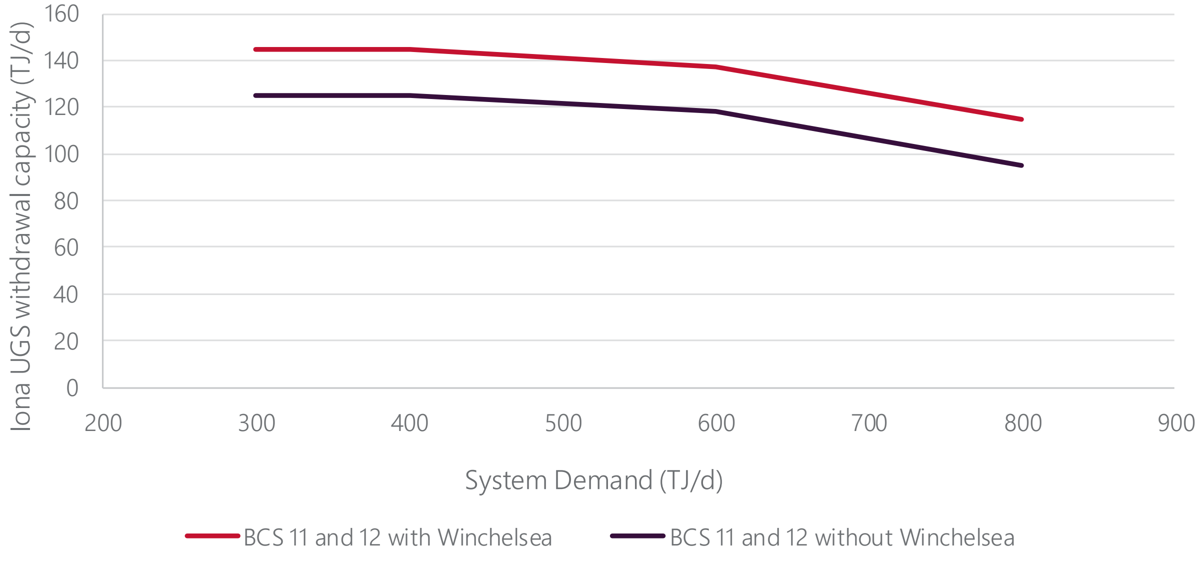


A1.2 South West Pipeline

A1.2.1 To Melbourne

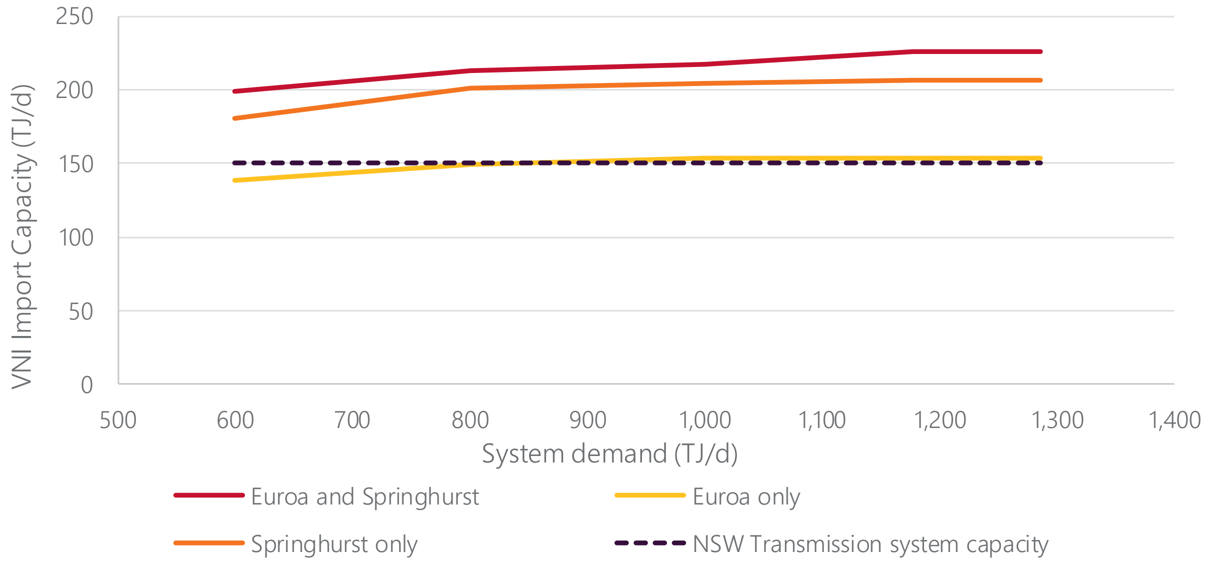


A1.2.2 To Port Campbell

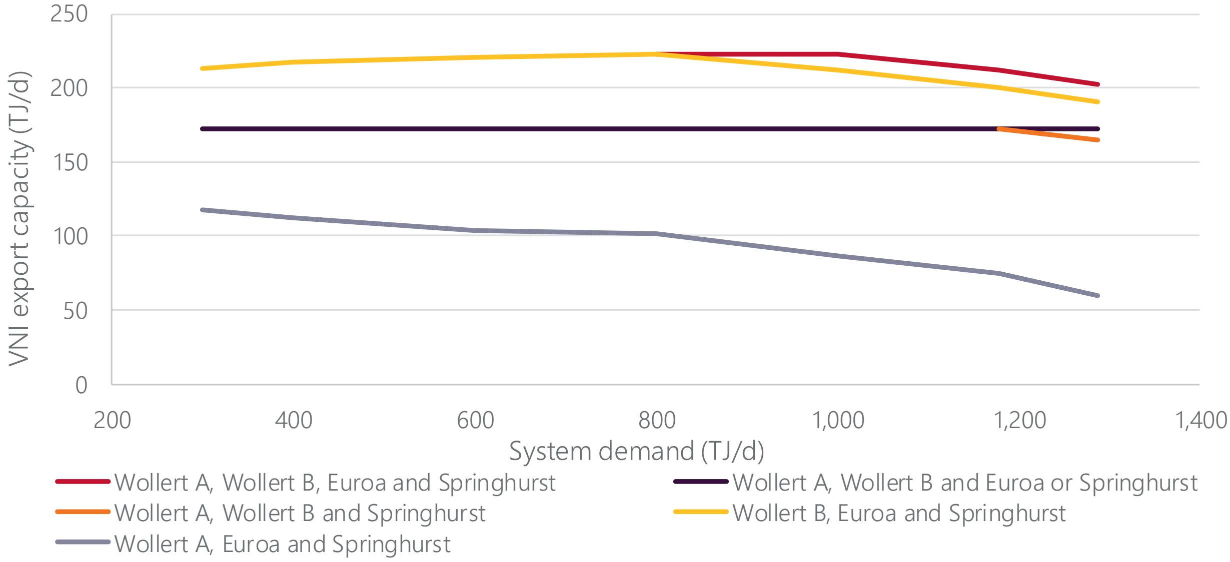


A1.3 Victorian Northern Interconnect

A1.3.1 To Melbourne



A1.3.2 To New South Wales



A2. Gas demand forecast data by system withdrawal zone

A2.1 Annual consumption and demand

Totals and change over outlook percentages may not add up due to rounding.

Table 21 Annual system consumption (PJ/y) by SWZ (Tariff V and D split)

SWZ		2019	2020	2021	2022	2023	Change over outlook
Ballarat	Tariff V	8.7	8.8	9.0	9.2	9.5	9.5%
	Tariff D	1.7	1.6	1.7	1.7	1.7	0.1%
	SWZ demand	**10.3**	**10.5**	**10.7**	**10.9**	**11.1**	**8.0%**
Geelong	Tariff V	11.0	11.1	11.3	11.5	11.8	7.2%
	Tariff D	10.9	10.7	10.9	10.9	10.9	0.1%
	SWZ demand	**21.8**	**21.9**	**22.2**	**22.4**	**22.6**	**3.7%**
Gippsland	Tariff V	5.6	5.8	5.9	6.2	6.4	13.6%
	Tariff D	9.2	8.7	8.9	8.9	8.9	-3.0%
	SWZ demand	**14.8**	**14.5**	**14.8**	**15.1**	**15.2**	**3.3%**
Melbourne	Tariff V	93.7	93.5	92.9	93.1	93.2	-0.6%
	Tariff D	35.6	35.1	35.7	35.8	35.3	-0.8%
	SWZ demand	**129.2**	**128.6**	**128.6**	**129.0**	**128.4**	**-0.6%**
Northern	Tariff V	10.9	11.0	11.2	11.4	11.6	6.7%
	Tariff D	9.3	9.2	9.4	9.4	9.4	1.7%
	SWZ demand	**20.1**	**20.2**	**20.5**	**20.8**	**21.0**	**4.4%**
Western	Tariff V	1.3	1.3	1.3	1.3	1.3	2.1%
	Tariff D	2.9	2.9	2.9	2.9	2.9	0.1%
	SWZ demand	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**0.7%**

Table 22 Annual 1-in-2-year peak daily demand (TJ/d) by SWZ

SWZ		2019	2020	2021	2022	2023	Change over outlook
Ballarat	Tariff V	57.8	59.1	60.2	62.0	63.5	9.9%
	Tariff D	5.7	5.6	5.8	5.7	5.7	0.2%
	SWZ demand	**63.5**	**64.7**	**66.0**	**67.7**	**69.3**	**9.0%**
Geelong	Tariff V	75.9	77.3	78.3	80.2	81.7	7.6%
	Tariff D	40.1	39.5	40.3	40.2	40.2	0.2%
	SWZ demand	**116.1**	**116.7**	**118.7**	**120.4**	**121.9**	**5.0%**
Gippsland	Tariff V	39.6	40.9	42.0	43.7	45.1	14.0%
	Tariff D	27.4	26.1	26.7	26.6	26.6	-2.9%
	SWZ demand	**67.0**	**67.0**	**68.7**	**70.3**	**71.7**	**7.1%**
Melbourne	Tariff V	655.5	653.6	649.6	652.4	651.1	-0.7%
	Tariff D	125.2	123.4	126.2	125.8	124.3	-0.7%
	SWZ demand	**780.8**	**777.0**	**775.8**	**778.2**	**775.5**	**-0.7%**
Northern	Tariff V	71.8	72.9	73.8	75.5	76.7	6.9%
	Tariff D	30.1	29.8	30.7	30.6	30.7	1.8%
	SWZ demand	**101.9**	**102.7**	**104.4**	**106.1**	**107.4**	**5.4%**
Western	Tariff V	8.4	8.5	8.5	8.6	8.6	2.1%
	Tariff D	9.4	9.3	9.5	9.4	9.4	0.2%
	SWZ demand	**17.9**	**17.7**	**18.0**	**18.0**	**18.1**	**1.1%**

Table 23 Annual 1-in-20-year peak daily demand (TJ/d) by SWZ

SWZ		2019	2020	2021	2022	2023	Change over outlook
Ballarat	Tariff V	63.5	64.8	66.0	67.9	69.8	9.9%
	Tariff D	6.0	5.9	6.0	6.0	6.0	-0.1%
	SWZ demand	**69.5**	**70.7**	**72.0**	**73.9**	**75.8**	**9.0%**
Geelong	Tariff V	83.4	84.7	85.9	87.9	89.8	7.6%
	Tariff D	41.7	41.2	42.1	42.2	41.7	-0.1%
	SWZ demand	**125.1**	**126.0**	**127.9**	**130.1**	**131.4**	**5.0%**
Gippsland	Tariff V	43.5	44.8	46.1	47.8	49.6	14.0%
	Tariff D	28.5	27.3	27.8	27.9	27.5	-3.2%
	SWZ demand	**72.0**	**72.1**	**73.9**	**75.7**	**77.2**	**7.2%**
Melbourne	Tariff V	720.2	717.0	712.1	714.5	715.6	-0.6%
	Tariff D	130.2	128.9	131.6	132.1	128.9	-1.0%
	SWZ demand	**850.4**	**845.9**	**843.7**	**846.6**	**844.5**	**-0.7%**
Northern	Tariff V	78.9	80.0	80.9	82.7	84.3	6.9%
	Tariff D	31.3	31.1	32.0	32.2	31.8	1.6%
	SWZ demand	**110.2**	**111.1**	**112.9**	**114.8**	**116.1**	**5.4%**
Western	Tariff V	9.3	9.3	9.3	9.4	9.5	2.1%
	Tariff D	9.8	9.7	9.9	9.9	9.8	-0.1%
	SWZ demand	**19.1**	**19.0**	**19.2**	**19.3**	**19.3**	**1.0%**

Table 24 Annual peak hourly demand (TJ/h) by SWZ

	SWZ	2019	2020	2021	2022	2023
Max. hourly demand on 1-in-2-year peak demand day	Ballarat	4.4	4.5	4.6	4.7	4.8
	Geelong	6.2	6.3	6.4	6.5	6.6
	Gippsland	4.0	4.0	4.1	4.2	4.3
	Melbourne	47.3	47.1	47.0	47.1	47.0
	Northern	6.0	6.0	6.1	6.2	6.3
	Western	1.1	1.1	1.1	1.1	1.1
	System demand	**69.0**	**68.9**	**69.3**	**69.8**	**70.0**
Max. hourly demand on 1-in-20-year peak demand day	Ballarat	4.8	4.9	5.0	5.1	5.3
	Geelong	6.7	6.8	6.9	7.0	7.1
	Gippsland	4.3	4.3	4.4	4.5	4.6
	Melbourne	51.5	51.3	51.1	51.3	51.2
	Northern	6.5	6.5	6.6	6.7	6.8
	Western	1.2	1.1	1.2	1.2	1.2
	System demand	**75.0**	**74.9**	**75.2**	**75.8**	**76.1**

Table 25 Annual 1-in-2 Non-DTS and Victoria peak day demand forecast (TJ/d)

	2019	2020	2021	2022	2023	Change over outlook
Tariff V (non-DTS)	2.8	3.0	3.2	3.4	3.6	29%
Tariff D (non-DTS)	2.9	2.9	2.8	2.8	2.8	-3%
System demand non-DTS	5.7	5.8	6.0	6.2	6.4	13%
System demand DTS	1,147	1,146	1,152	1,161	1,164	1.5%
System demand VIC	1,153	1,152	1,158	1,167	1,170	1.5%

Table 26 Annual 1-in-20 Non-DTS peak day demand forecast (TJ/d)

	2019	2020	2021	2022	2023	Change over outlook
Tariff V (non-DTS)	2.9	3.1	3.3	3.5	3.7	29%
Tariff D (non-DTS)	3.0	2.9	2.9	2.9	2.9	-3%
System demand non-DTS	5.8	6.0	6.2	6.4	6.6	13%
System demand DTS	1,246	1,245	1,250	1,260	1,264	1.4%
System demand VIC	1,252	1,251	1,256	1,267	1,271	1.5%

A2.2 Monthly consumption and demand for 2019

Table 27 Monthly gas consumption (PJ/month) for 2019 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SWZ consumption	Ballarat	0.32	0.32	0.39	0.57	0.96	1.35	1.40	1.23	0.91	0.63	0.45	0.33
	Geelong	1.15	1.17	1.24	1.52	1.94	2.48	2.63	2.31	1.85	1.52	1.35	1.19
	Gippsland	0.89	0.82	0.91	1.04	1.32	1.54	1.45	1.55	1.36	1.18	1.01	0.91
	Melbourne	5.52	5.55	6.58	8.53	13.7	17.9	18.7	17.0	12.6	9.35	7.28	5.76
	Northern	0.98	0.99	1.17	1.40	2.11	2.58	2.64	2.48	1.92	1.51	1.21	1.00
	Western	0.25	0.25	0.26	0.27	0.38	0.44	0.47	0.47	0.43	0.39	0.33	0.30
	System consumption	**9.11**	**9.10**	**10.5**	**13.3**	**20.4**	**26.3**	**27.3**	**25.0**	**19.0**	**14.6**	**11.6**	**9.49**

Table 28 Monthly GPG consumption (TJ/month) in 2019 by SWZ

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	135	15	6	38	66	15	63	12	7	6	0	2
Gippsland	249	34	38	98	136	56	98	23	21	13	1	5
Melbourne	583	469	364	732	1,118	791	453	352	477	256	300	151
Northern	-	-	-	-	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-	-	-	-	-
Total DTS consumption	**967**	**518**	**408**	**869**	**1320**	**862**	**613**	**387**	**504**	**275**	**301**	**158**

Table 29 Monthly peak daily demand (TJ/d) in 2019 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day demand	Ballarat	18	18	25	35	51	65	65	65	65	38	30	20
	Geelong	56	55	59	70	88	110	110	110	110	75	64	58
	Gippsland	35	35	38	46	55	67	67	67	67	47	43	38
	Melbourne	268	270	311	454	621	781	781	781	781	489	384	287
	Northern	44	48	53	68	89	107	107	107	107	65	47	44
	Western	11	11	10	13	16	17	17	17	17	15	13	13
	System demand	**432**	**437**	**496**	**686**	**921**	**1,094**	**1,113**	**1,067**	**891**	**730**	**581**	**461**
1-in-20 peak day demand	Ballarat	21	23	33	46	58	71	71	71	71	45	40	30
	Geelong	62	61	70	85	98	120	120	120	120	86	78	70
	Gippsland	38	37	43	54	60	73	73	73	73	53	51	43
	Melbourne	306	331	401	579	699	853	853	853	853	571	498	399
	Northern	48	53	63	82	99	117	117	117	117	74	57	53
	Western	12	12	12	15	17	18	18	18	18	17	15	14
	System demand	**488**	**517**	**621**	**861**	**1,031**	**1,194**	**1,217**	**1,206**	**1,011**	**845**	**739**	**609**

Table 30 Monthly peak hourly demand (TJ/h) in 2019 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max. hourly demand on 1-in-2 peak demand day	Ballarat	1.27	1.28	1.73	2.44	3.55	4.52	4.52	4.52	4.52	2.64	2.09	1.42
	Geelong	3.55	3.51	3.78	4.48	5.64	7.08	7.08	7.08	7.08	4.81	4.11	3.72
	Gippsland	2.08	2.06	2.24	2.74	3.28	4.02	4.02	4.02	4.02	2.78	2.56	2.28
	Melbourne	17.88	17.98	20.72	30.23	41.40	52.28	52.28	52.28	52.28	32.59	25.59	19.14
	Northern	2.52	2.76	3.05	3.93	5.17	6.25	6.25	6.25	6.25	3.78	2.71	2.57
	Western	0.62	0.63	0.57	0.71	0.86	0.94	0.94	0.94	0.94	0.85	0.73	0.71
Max. hourly demand on 1-in-20 peak demand day	Ballarat	1.47	1.63	2.32	3.18	4.03	4.95	4.95	4.95	4.95	3.11	2.79	2.10
	Geelong	3.94	3.88	4.47	5.43	6.24	7.70	7.70	7.70	7.70	4.81	4.96	4.46
	Gippsland	2.29	2.19	2.54	3.22	3.58	4.36	4.36	4.36	4.36	2.78	3.04	2.56
	Melbourne	20.37	22.05	26.72	38.55	46.60	57.12	57.12	57.12	57.12	32.59	33.20	26.55
	Northern	2.81	3.08	3.62	4.77	5.71	6.81	6.81	6.81	6.81	3.78	3.30	3.08
	Western	0.68	0.67	0.65	0.83	0.94	1.02	1.02	1.02	1.02	0.85	0.85	0.78

A3. System operating parameters

A3.1 Critical system pressures

AEMO operates the system to maintain connection pressure obligations across the DTS, where gas flows are maintained within the limits specified in the relevant connection deed and agreement schedules.

As gas demand increases, however, there is a risk that critical minimum pressure may be breached, potentially requiring customer curtailment to return the system to a secure state.

The system is in a secure state when the following conditions apply:

- The system is operating within the requirements of the gas quality procedures, and breaches of the gas quality procedures do not require intervention by AEMO.
- There is no threat to public safety.
- There is no threat to the supply of gas to customers, and system pressures and flows are within, and are forecast to remain within, the agreed operating limits (see Table 31).

Table 31 lists key critical locations and associated pressure obligations (maximum allowable operating pressure (MAOP) and minimum operating pressure (MinOP)). This table is required to be published under Rule 323(3)(g), and can also be found in AEMO's Wholesale Market Critical Location Pressures[197].

Table 31 Critical location pressure in the Declared Transmission System

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of data and comments
Longford to Melbourne	6,890	Longford	4,500	Connection Agreement. Operational maximum pressure of 6,750 kPa applies due to operating limits at the plant.
		Sale	4,800	AEMO-Distributor Connection Deed
		Gooding CS Inlet	4,200	APA design parameter
		Loy Yang B GPG	4,000	
		VicHub	4,200	Connection Agreement
		TasHub	4,200	Connection Agreement
		BassGas	3,500	Connection Agreement
		Dandenong CG Inlet	3,200	APA Design Parameter
		Wollert CG Inlet	3,000	APA Design Parameter
Lurgi	2,760	Morwell Porters Rd	2,650	
		Warragul	1,400	AEMO-Distributor Connection Deed
		Pakenham South	1,400	AEMO-Distributor Connection Deed
		Jeeralang GPG	2,500	

[197] Available at http://aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-Critical-Location-Pressures-NGR-10.pdf.

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of data and comments
Metropolitan Ring Main	2,760	Dandenong Terminal Station	2,650	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Dandenong North	2,500	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Brooklyn (Melbourne side)	1,700 1,800	AEMO-Distributor Connection Deed Brooklyn compressor suction min pressure requirement
		Keon Park	2,200	AEMO-Distributor Connection Deed
		Newport GPG	1,800	
		Somerton GPG	2,000	
Wollert to Euroa	8,800	Wandong PRS inlet	3,700	APA design parameter
		Euroa CS inlet	3,200	APA design parameter
Euroa to Wodonga	7,400	Wodonga	2,400	AEMO-Distributor Connection Deed
		Shepparton	2,400	AEMO-Distributor Connection Deed
		Echuca	1,200	AEMO-Distributor Connection Deed
		Rutherglen	2,400	AEMO-Distributor Connection Deed
		Koonoomoo	1,200	AEMO-Distributor Connection Deed
Victorian Northern Interconnect	10,200	Euroa CS Inlet	3,200	APA design parameter
		Springhurst CS Inlet	3,000	APA design parameter
		Culcairn	2,700	Connection Agreement
Brooklyn Corio Pipeline	7,390 5,150 MOP	Corio (Avalon, Lara and Werribee)	2,300 w 1,900 s	7,390 kPa Pipeline licence pressure 2,300 kPa during high flow (winter), 1,900 kPa during low flow (summer), Distributor Connection Deed
		Coogee Methanol	1,800	
		Laverton North GPG	1,700	
Brooklyn Lara Pipeline	10,200	Qenos	3,800	3,800 kPa approved AEMO-Distributor Connection Deed (Wyndham Vale & Qenos) Usually controlled >4,500 kPa by BLP CG
Brooklyn Ballan Pipeline	7,400	Sunbury	2,000	AEMO-Distributor Connection Deed
		Ballarat	2,100	AEMO-Distributor Connection Deed
		Plumpton PRS	4,500	APA design minimum pressure
South West Pipeline	10,200	Iona	3,800	Connection Agreement Operational maximum pressure of 9,500 kPa applies due to operating limits at the plant
		SEAGas	3,800	Connection Agreement
		Winchelsea Inlet	4,500	APA Design Parameter
		Colac	3,800	APA Group-Distributor Connection Deed
Western Transmission System	7,400	Iluka	2,500	APA Group-Distributor Connection Deed
		Portland	2,800	AEMO-Distributor Connection Deed
Wandong to Bendigo	7,390	Bendigo	3,000	AEMO-Distributor Connection Deed
		Maryborough	3,000	AEMO-Distributor Connection Deed
		Carisbrook	3,000	AEMO-Distributor Connection Deed

A3.2 Gas storage operating parameters

A3.2.1 Dandenong LNG facility

The LNG storage provider requires one hour pre-notification (by AEMO) ahead of commencing injections into the DTS. This is to enable preparation and plant cool down due to the low temperatures of the LNG process. Injections of LNG in the first and last hour need to be equal or less than 5.5 TJ/h, to assist with the cool-down and warm-up of the re-liquidation process. The LNG is generally scheduled at the firm rate of 5.5 TJ/h for 16 hours, which equates to the firm contracted rate of 87 TJ/d.

Table 32 LNG operating parameters

Year	Min. hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure range (kPa)[198]
2019-23	2.2	10.0	5.5	5.5	2,750-2,760

A3.2.2 Iona underground storage

Iona UGS requires two hours' notification to switch between withdrawals to storage and injection into the DTS. The storage operating parameters shown in Table 33, including injection and withdrawal rate and pressures, have been historically and are foreseeably sustainable. These may, however, be impacted by a combination of maintenance, peak demand conditions, and a low total storage inventory.

Table 33 Iona UGS operating parameters

Year	Min. hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure Range (kPa)
2019	1.00	20.00	5.00	10.00	4,500-9,600
2020	1.00	20.80	5.21	10.42	4,500-9,600
2021	1.00	22.70	5.68	11.35	4,500-9,600
2022	1.00	22.70	5.68	11.35	4,500-9,600
2023	1.00	23.80	5.94	11.88	4,500-9,600

A3.2.3 Compressor utilisation in 2018

Table 34 lists the hours of usage for each DTS compressor station by month for 2018, and Figure 42 compares the total operating hours by compressor stations from 2016 to 2018.

Key points are:

- The most utilised compressors in the DTS in 2018 were the Brooklyn compressors, which have been heavily used to support Iona UGS refill over the lower demand period and are also used to support Ballarat and Geelong demand during winter.
- Compared to 2016 and 2017, however, the total usage of the Brooklyn compressors has reduced. This is because the reconfiguration of Brooklyn CS in March 2018 allowed gas to be compressed directly into the BLP, removing compression to Geelong outside of winter.

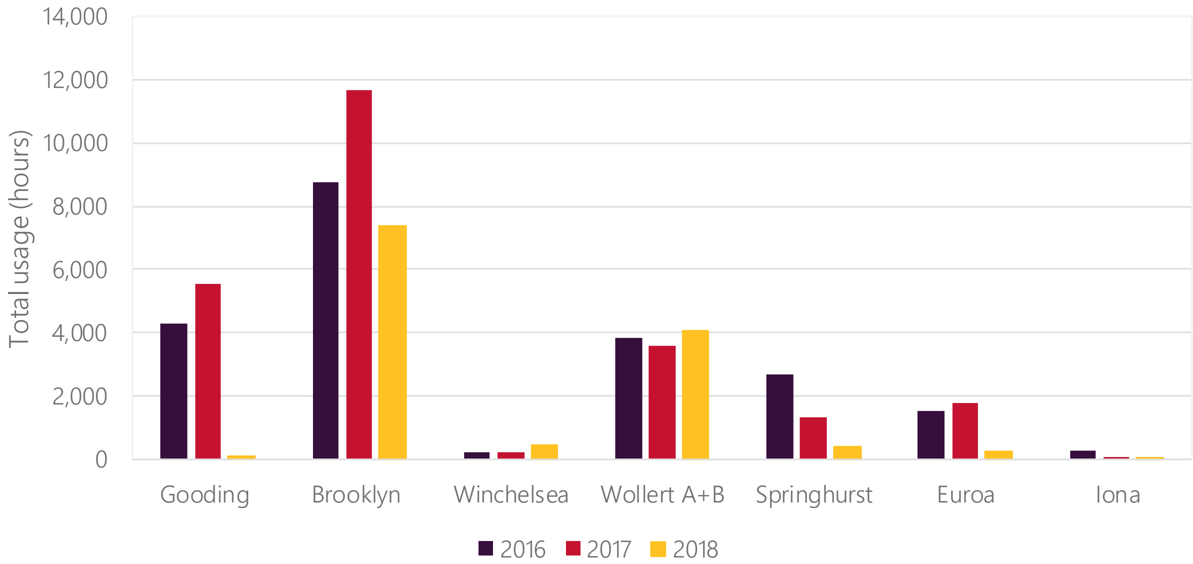
[198] The minimum and maximum pressure is based on injection in the 2,800 kPa system.

- The total usage of the Gooding compressors has also reduced significantly compared to previous years, because typically these compressors are run when total Longford injection exceeds approximately 700 TJ/d.

Table 34 Total operating hours by compressor station in 2018

Compressor station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn	715	1,178	433	856	553	91	243	177	579	873	692	971
Winchelsea	0	1	0	1	20	153	73	94	41	38	0	3
Iona	0	2	0	0	2	0	1	1	4	3	0	3
Gooding	0	3	0	2	39	8	24	1	4	2	3	0
Wollert (A+B)	578	321	175	438	520	88	85	253	447	485	481	193
Euroa	73	6	1	10	20	36	11	10	16	45	12	0
Springhurst	44	0	0	6	12	18	8	57	28	165	40	0

Figure 42 Total operating hours by compressor station (2016-18)



A4. DTS service provider assets, maintenance and system augmentations

A4.1 Critical DTS assets

Critical assets in the DTS are considered the assets required to maintain system security on peak demand days. Table 35 outlines these assets by SWZ and operational purpose.

Table 35 Critical DTS assets

SWZ	Asset	Description	Purpose/role
Melbourne	Brooklyn Compressor Station	• Two Saturn compressors: Unit 8 rated at 850 kW and Unit 9 rated at 950 kW. • Two Centaur compressors: Unit 11 rated at 2,850 kW and Unit 12 rated at 3,500 kW. • Unit 10 (Centaur compressor) is only available to AEMO to operate under certain conditions as stated in the Service Envelope Agreement.	• Provides compression to the Brooklyn–Corio pipeline, SWP and the Brooklyn–Ballan pipeline. • The Centaur machines are used to supply Laverton GPG and Iona UGS withdrawals. • The Saturn machines are used only to supply system demand.
	Wollert Compressor Station	• Station B: Two Centaur compressors; Unit 4 and Unit 5 rated at 4,550 kW. • Station A: Three Saturn compressors; Unit 1 and Unit 2 rated at 950 kW and Unit 3 rated at 850 kW.	• Provides compression to the Wollert to Wodonga pipeline and assists supply to NSW via the NSW–Vic Interconnect at Culcairn. Exports to NSW are generally not possible without Wollert Centaur compression.
	Dandenong LNG Facility	• The LNG facility has a maximum capacity of 180 t/h, requiring the availability of three vaporisers, three pumps and one boil off compressor. The LNG contracted rate is 100 t/h for 16 hrs, which provides up to 87 TJ/d.	• The LNG facility is used mainly to supplement supply on days of high peak gas demand. LNG can be used also by participants throughout the year to balance their portfolio (market scheduled LNG).
	Brooklyn–Lara Pipeline CG (BLP CG)	• Five regulator runs • Two water bath heaters • Station inlet and outlet isolation valves	• One of the three main supply sources to the Melbourne Metropolitan Region along with Wollert CG and Dandenong CG. • It supplies gas from Port Campbell gas fields. The station regulates high pressure gas supply from the Brooklyn–Lara Pipeline to supply either the Brooklyn–Corio Pipeline (BCP) or the Brooklyn–Corio Pipeline CG.

SWZ	Asset	Description	Purpose/role
	Brooklyn–Corio Pipeline CG (BCP CG)	• Five regulator runs • Two water bath heaters • Two station inlet isolation valves	• Brooklyn–Corio Pipeline CG primarily regulates gas supply from the BCP to supply the South Melbourne system. The BCP CG also incorporates a bypass run to facilitate reverse flow from the South Melbourne system to supply to the BCP when compression is not needed.
	Dandenong CG	• Eight Regulator runs; which are categorised into Station A (3 regulator runs) and Station B (5 regulator runs) • Station inlet and outlet isolation valves	• Is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Wollert CG. • The station provides pressure regulation of gas being supplied into Dandenong to Princess Hwy and Dandenong to West Melbourne pipelines.
	Wollert CG	• Four Regulator runs • One water bath heater • Station inlet and outlet isolation valves	• Is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Dandenong CG. • It provides pressure regulation of gas being supplied into the Keon Park to Wollert transmission pipeline. The facility provides two sources of gas supply, one from Longford gas facility via Pakenham to Wollert pipeline and the other from Moomba gas facility via the Wollert to Wodonga pipeline.
Geelong (Port Campbell)	Winchelsea Compressor Station	• One Taurus Compressor rated at 5,740 kW.	• Provides compression to increase SWP network transportation capacity to Brooklyn. • Provides additional SWP capacity to support Iona UGS refilling.
Gippsland	Gooding Compressor Station	• Four Centaur Compressors each rated at 2,850 kW. – Up to three compressor units can be operated simultaneously, with one redundant unit.	• Provides compression within LMP when total Longford injections exceed approx. 700 TJ/d. • Compression is utilised to increase transportation capacity of LMP, maintain DCG inlet pressure above its min operating pressure during peak period and to move gas away from Longford injection point to prevent backing off the Longford plant before the peak demand when linepack is low.
Northern	Euroa Compressor Station	• One Centaur Compressor rated at 4,550 kW.	• Provides compression to the Euroa to Wodonga pipeline mainly for increasing export capacity to NSW when higher pressure is required at Culcairn. The compressor may be also used to increase import capacity into Victoria from NSW.
	Springhurst Compressor Station	• One Centaur Compressor rated at 4,550 kW.	• Provides compression for imports or exports via NSW–VIC interconnect at Culcairn.
Western	Iona Compressor Station	• Two reciprocating compressors rated at 300 kW each.	• Provides compression to Western Transmission Network from the SWP.

A4.2 DTS service provider proposed maintenance schedule

AEMO facilitates the South East Australian Gas Wholesale Maintenance Workshop in February, August, and November each year. Workshops are held with the DTS service provider and the facility operators of gas production facilities, storage providers and interconnected pipelines across the South East of Australia, to identify any potential supply adequacy issues, and threats to system security.

The gas transmission network is physically integrated and a holistic approach to maintenance coordination across South East of Australia needs to be conducted to ensure gas supply capacity is adequate. The workshop provides an opportunity to minimise or avoid overlapping planned maintenance activities that either restrict the supply or transportation of gas to or within South East Australia.

AEMO, under Rule 326, coordinates maintenance planning of the DTS with the DTS service provider on a weekly basis. The DTS service provider's maintenance schedule for 2019 and the capacity impact is shown in Table 36. The maintenance is scheduled to minimise impacts to DTS capacity. The import and export transmission capacities shown in the table are based on a monthly 1-in-2-year peak system demand day.

Changes to the maintenance schedule are published to the Natural Gas Services Bulletin Board in the Capacity Outlook Report (INT 922) for short-term maintenance, and Medium Term Capacity Outlook Report (INT 928) for medium to long-term maintenance.

Table 36 Maintenance for 2019

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
Melbourne	Brooklyn Compressor Station	Unit 11	4 Mar - 15 Mar 2019	-	65	Up to 5 days unit outage, with 8-hour recall.
		Unit 12	18 Mar - 29 Mar 2019	-	65	Up to 5 days unit outage, with 8-hour recall.
		Full Station	1 Apr - 5 Apr 2019	-	0	Total facility outage for 1 day within the maintenance period. Recall time of 4 hours. The full station outage period has been scheduled during expected periods of net injections at Iona UGS.
			30 Sep - 11 Oct 2019	-	0	
	Wollert Compressor Station	Station A	9 Apr - 15 Apr 2019	-	217	Total station outage for 1 day during maintenance period, with recall 4 hours
			26 Aug - 30 Aug 2019	-	168	Total station outage for 1 day during maintenance period, with recall 4 hours
		Unit 4	7 Oct - 18 Oct 2019	-	180	Up to 5 days unit outage, with 8-hour recall.
		Unit 5	21 Oct - 1 Nov 2019	-	180	Up to 5 days unit outage, with 8-hour recall.
		Station B	25 Mar - 5 Apr 2019	-	0	No export capacity is available for 1 day during these maintenance periods
			4 Nov - 15 Nov 2019	-	0	
	Dandenong LNG Facility		13 May - 1 June 2019	0	-	Total LNG facility outage for 10 days within maintenance period. The site may be recalled within 2 hrs if there is a threat to system security. Maintenance will be postponed, if LNG is scheduled in market on the day.
			25 Nov - 20 Dec 2019	0	-	
Geelong	Winchelsea Compressor Station		15 Apr - 26 Apr 2019	240	127	Total station outage for 1 day during maintenance period, with recall 4 hours
			7 Oct - 15 Oct 2019	250	125	Up to 5 days unit outage, with 8-hour recall.

SWZ	Asset unavailable	Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
		19 Oct - 25 Oct 2019	250	125	Total station outage for 1 day during maintenance period, with recall 4 hours
Gippsland	Gooding Compressor Station	11 Mar - 15 Mar 2019	700	-	Total station outage for 1 day during maintenance period, with recall 4 hours
		9 Sep - 20 Sep 2019	700	-	Total station outage for 1 day during maintenance period, with recall 4 hours
Northern	Euroa Compressor Station	18 Feb - 1 Mar 2019	120	172	Total station outage for 1 day during maintenance period, with recall 4 hours
		12 Aug - 23 Aug 2019	131	168	Up to 5 days unit outage, with 8-hour recall.
		26 Aug - 6 Sep 2019	131	172	Total station outage for 1 day during maintenance period, with recall 4 hours
	Springhurst Compressor Station	13 May - 24 May 2019	138	172	Total station outage for 1 day during maintenance period, with recall 4 hours
		4 Nov - 15 Nov 2019	132	172	Up to 5 days unit outage, with 8-hour recall.
		18 Nov - 29 Nov 2019	132	172	Total station outage for 1 day during maintenance period, with recall 4 hours

Note: Dash line ("-") indicates no impact to import or export capacity

A4.3 Other proposed maintenance

The DTS service provider will be performing a series of pipeline inspections (pigging) works during 2019:

- T33 (South Melbourne to Brooklyn) pipeline pigging in April 2019.
- T57 (Ballan to Ballarat 300mm) pipeline pigging in May 2019.
- T62 (Derrimut to Sunbury) pipeline pigging in May 2019.

Pipeline inspections are carried out on in-service pipelines, but do not affect pipeline capacity. The timing of these works will depend on resource availability, suitable flows, and pressure conditions.

A5. Victorian gas planning approach

A5.1 DTS system withdrawal zones

The DTS is divided into six zones, shown in Figure 43:

- Northern.
- Geelong.
- Melbourne.
- Western (Western Transmission System).
- Ballarat.
- Gippsland.

The SWZs are used to report demand forecast, and to assess adequacy by zone.

A5.2 Victorian gas planning criteria

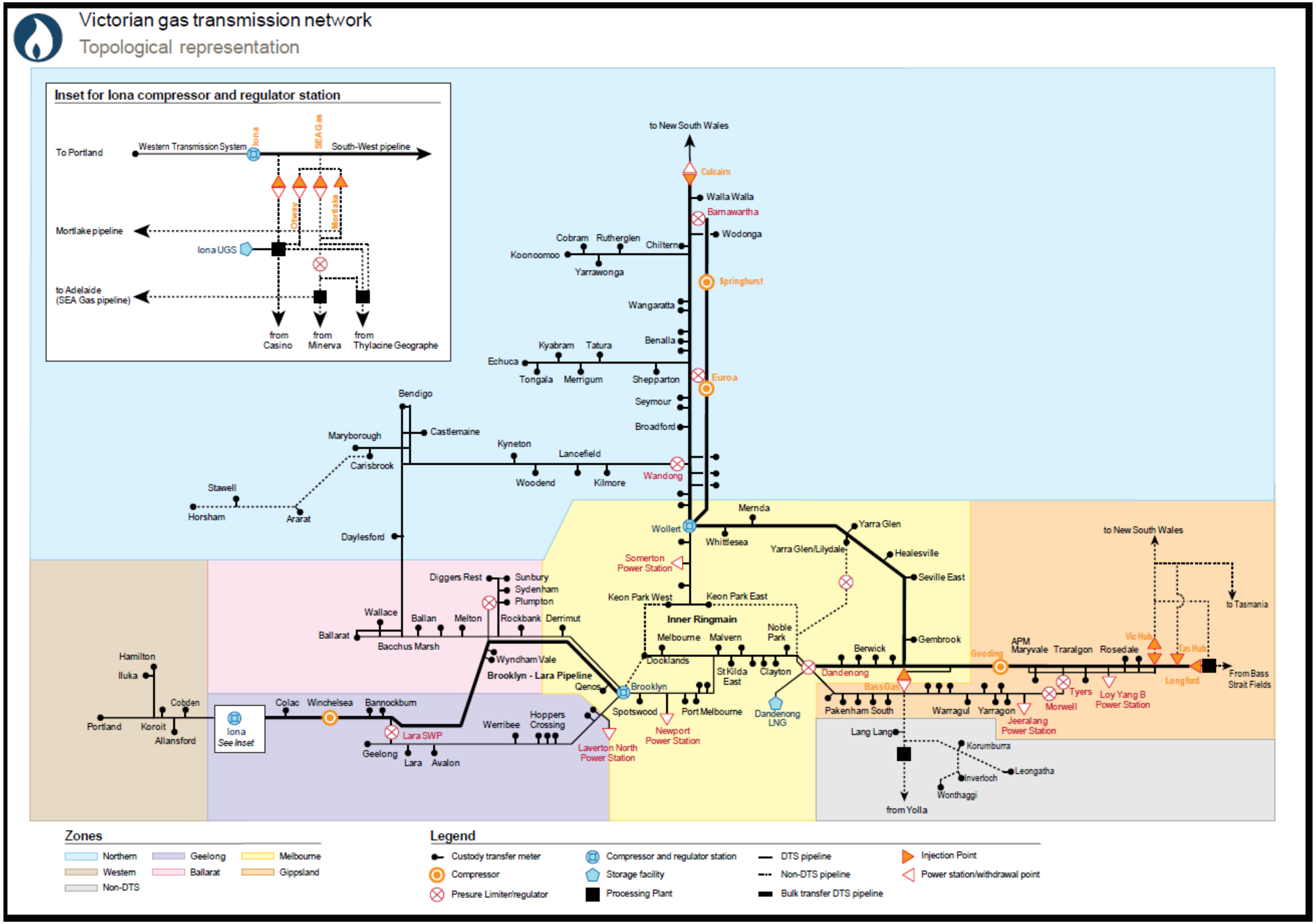
Under Rule 323(1), AEMO must publish a planning review, *"by no later than 31 March 2015 and by 31 March in every second year thereafter"*.

AEMO's planning objective is to identify the most economically efficient expansion of the DTS as demand grows, while maintaining a safe and secure system (taking into account relevant uncertainties), and the timely provision of this information to the market.

AEMO assesses and reports on the adequacy of the gas supply and transmission capacity to meet forecast demand by carrying out detailed computer simulations of the DTS.

When a DTS augmentation requirement is identified, AEMO publishes the information in the VGPR or a detailed planning report specific to that augmentation.

Figure 43 System Withdrawal Zones in the DTS



A5.3 Victorian gas planning methodology

AEMO's planning methodology involves a series of assessments of gas supply and demand, system capacity, and system adequacy, to ensure a safe and reliable supply over the outlook period.

Figure 44 shows an overview of the gas planning methodology, and Table 37 provides more detail for the numbered steps.

Figure 44 Gas planning methodology overview

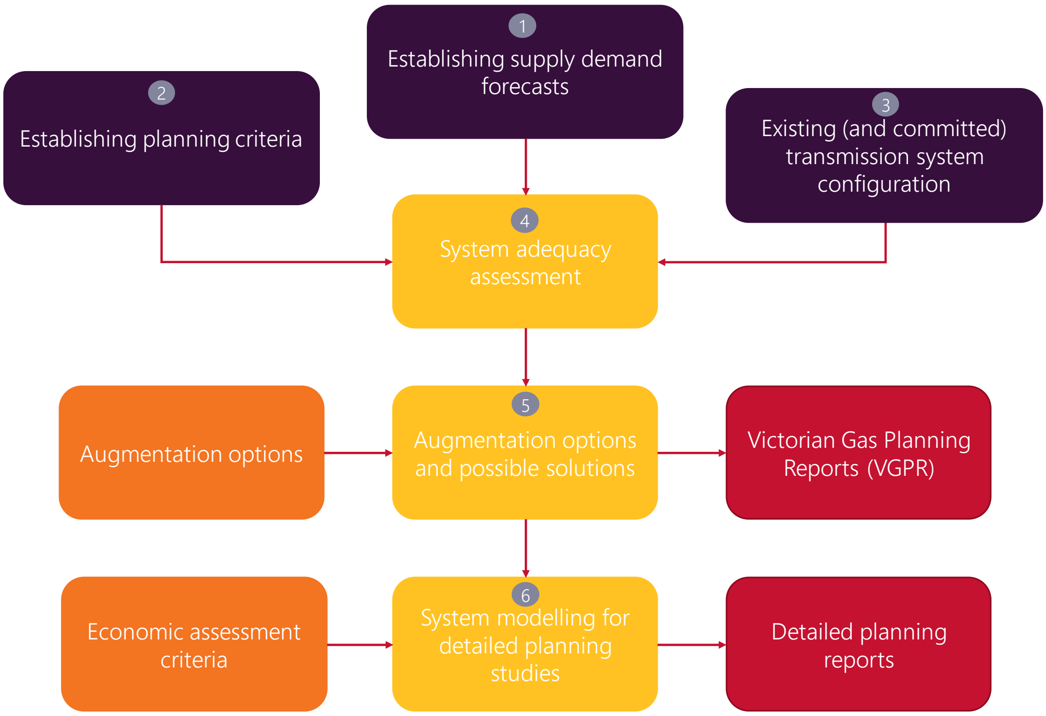


Table 37 Gas planning methodology summary

Process step	Detail
1. Establishing supply demand forecast	Planning assumptions consist of forecasts of gas supply, demand and other operational assumptions such as load profiles. These assumptions are validated based on historical data available in the database before commencing modelling work. As part of the VGPR process, five-year forecasts of peak day demand are prepared for each market sector, and for all system withdrawal zones (SWZ), based on a range of anticipated injection and withdrawal scenarios.
2. Establishing planning criteria	The planning criteria address the operating characteristics that must be satisfied over the planning period if the system is to be capable of safe and reliable operation. These include the critical minimum pressures at key locations from the Wholesale Market System Security Procedures (Victoria)[A], and a range of other operating criteria that need to be satisfied, such as linepack targets.
3. Existing and committed transmission system configuration	In conjunction with the DTS service provider, AEMO creates and maintain the DTS models representing the current system configuration. AEMO determines system capacity using a calibrated gas transmission system model (specifically, the Gregg Engineering WinFlow (steady state) and WinTran (transient) software modules). AEMO's gas transmission system model is calibrated annually using actual winter metered gas injections and withdrawals on selected high and moderate demand days. Annual model calibration refines the model to ensure that it accurately simulates the observed pressures and flows throughout the DTS. The methodology and a set of assumptions and pipelines parameters are set out in the Guidelines for the Determination of the Victorian Gas Declared Transmission System Capacity document, jointly owned by AEMO and the DTS service provider.

Process step	Detail
4. System adequacy assessment	AEMO assess the system performance with the Gregg Engineering software and notifies the market about potential system constraints via the VGPR. The gas flows and pressures in the DTS are modelled under a range of demand and supply scenarios over a five-year outlook. A system constraint is identified when the secure system parameters are breached (representing a potential threat to system security).
5. Augmentation options and possible solutions	AEMO evaluates potential solutions, which involves considering a number of possible options available to restore the system to a secure state: • Augmentations or upgrades to the gas transmission system. • Additional or new supply capacity and storage. The adequacy assessment studies consider a range of solutions, to the extent this is feasible, given the availability of data and commercial confidentiality. However, given the outlook period and the use of less detailed analysis, the constraints and constraint solutions must be treated as indicative only.
6. System modelling for detailed planning studies	AEMO performs detailed planning studies under the following circumstances: • On request from APA Group to help its access arrangement review. • When AEMO has identified a need for efficient augmentation investment, and the gas industry has not taken sufficient initiative. • By request from regulators or government agencies to independently review requirements for augmentations. The aim is to identify the economically efficient solution and facilitate the required investment(s). The planning reports for the detailed planning studies are published as required.

A. Available at http://aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-System-Security-Procedures-NGR-11.pdf

A5.4 Planning assumptions

AEMO applied a series of network assumptions and conditions in modelling:

- Table 38 to Table 41 list the standard modelling assumptions used by AEMO.
- AEMO used assumptions for capacity modelling for SWP (Table 42) and Northern zone export (Table 43).
- An additional modelling assumption reflected known injection point capabilities at each injection point.
- To better reflect real-world conditions, the adequacy of the system to meet peak demand was modelled using typical beginning-of-day (BoD) linepack[199] (lower than the linepack target) and surprise cold weather[200].

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 BoD operating conditions are also critical. Modelled system capacity is based on pressures less than MAOP which optimise operational capabilities.

A5.4.1 Supply assumptions

Table 38 and 0 list assumptions relating to the supply of gas to the DTS.

[199] The BoD target is 850 TJ, being the total DTS linepack which includes both passive and active linepack.

[200] If BoD injections are lower than required for the actual demand (due to actual demand exceeding forecast demand), linepack is depleted more quickly than expected, until injections are rescheduled upwards.

Table 38 Gas DTS supply modelling assumptions

Supply assumptions and conditions	Notes
Longford injections at flat hourly profile	Normal operating condition.
VicHub injections at flat hourly profile	Normal operating condition.
Iona and SEA Gas injection at flat hourly profile	Normal operating condition.
NSW injection at Culcairn at flat hourly profile	Normal operating condition.
LNG contracted vaporisation rate at 100 t/h for 16 hours	For peak shaving purposes to support critical system pressures, LNG is effective only up to 10.00 pm. Modelling assumed 11 hours LNG, equivalent to 60 TJ.

Table 39 Gas DTS modelling heating values

Location	Heating value (Megajoules/m^3)
Longford	38.67
BassGas	38.63
Iona (winter)	37.95
Iona (summer)	37.60
LNG	39.11

A5.4.2 Demand assumptions

Table 40 lists assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table 40 Gas DTS demand modelling assumptions for 1-in-20-year peak system demand day

Demand assumptions	Notes
Load profiles calculated by AEMO	Calculated from historical flow data for each custody transfer meter.
Load distribution as per AEMO forecasts	Based on historical custody transfer meter data and expected system configuration changes.
Supply to Horsham pipeline at Carisbrook	Carisbrook to Horsham pipeline modelled with demand at Ararat, Stawell, Horsham (connected in 1998). The minimum pressure requirement at Horsham is 1,200 kPa (AusNet design requirement).
Transmission UAFG determined at Longford	Calculated from calibrated model data.
BOC liquefaction operating, let-down gas operating	Full supply to this customer is normally required.
Existing GPG demand (open-cycle gas turbine [OCGT])	A 25 TJ/d GPG demand profile[A].

A. The GPG demand profile is from 12.00 pm until 9.00 pm.

Analysis for the five-year VGPR outlook is based on a 1-in-20-year peak system demand day forecast, which is the agreed standard with APA Group.

Tariff D and Tariff V[201] load changes are based on demand forecasts, existing GPG demand is based on GPG capacity for 1,300 TJ/d with historical load profiles, and future GPG demand is based on known GPG development proposals (which are checked for consistency with the NTNDP and with APA Group, for any committed connections to the DTS).

Export load is treated differently, due to the need for consistency with any proposals that have been considered by APA Group, which are accounted for by the modelling.

[201] Tariff D customers use more than 10 TJ/y or 10 GJ/h and are typically industrial and large commercial customers. Tariff V customers are small commercial and residential customers.

A5.4.3 Impact of operational factors modelling assumptions

Table 41 lists the assumptions relating to operation of the DTS and assist with the management of linepack and constraints specified in various agreements.

Table 41 Impact of operational factor modelling assumptions

Location	Operational assumptions	Notes
Longford	Maximum pressure is 6,750 kPa.	To conform to normal operating practice. Assumed to peak momentarily at 6,750 kPa before reducing again.
	Minimum pressure is 4,500 kPa.	
Iona	Maximum pressure is 9,500 kPa.	As per pipeline licences, operating agreements and practice.
	Minimum pressure is 4,500 kPa.	
Culcairn	Minimum pressure is 8,600 kPa for exports, 6,500 kPa for imports.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
Brooklyn–Lara Pipeline	Minimum pressure is 4,500 kPa.	Pipeline design requirement for BLP.
Brooklyn City Gate	Minimum pressure is 3,200 kPa.	Normal operating condition.
Wollert City Gate	Minimum pressure is 3,000 kPa.	Normal operating condition.
Dandenong City Gate	Minimum pressure is 3,200 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
	Maximum allowable operation pressure (MAOP) and delivery pressures in connection and service envelope agreements not infringed.	Service Envelope Agreement and Connection Deed requirements (for example, a minimum 3,100 kPa at the DCG).
Other factors	BoD and end-of-day (EoD) linepack are equal.	For capacity modelling, mining of linepack not allowed.
	BoD linepack 20 TJ below target[A].	Used for lateral constraint modelling.
	DTS service provider's pipeline, regulator and compressor assets and operating conditions as specified in the Service Envelope Agreement.	Agreement between APA Group and AEMO.
	BoD and EoD pressures similar at key network locations.	Required for system security.
	Regulators, compressors, and valves are set to reflect operational guidelines.	Required for operational and system security reasons.
	Gas delivery temperature above 2°C.	Gas Quality Regulations requirement.

A. The normal BoD linepack target is 850 TJ, which includes both passive and active linepack. In this case, the BoD linepack is 830 TJ.

A5.4.4 Capacity modelling assumptions

Modelling assumptions are listed in Table 42 for SWP capacity, and Table 43 for Northern capacity. Under different operating conditions on the day, the capacity result will differ.

Table 42 SWP capacity modelling assumptions

SWP capacity assumptions		Notes
Injections		For SWP to Melbourne: • Maximum injection from Iona and the rest will be supplied from Longford and/or BassGas for all cases. For SWP to Port Campbell: • Maximum injection from Longford and/or BassGas for all cases.
GPG demand		No GPG demand for all cases at Laverton North and Newport.
Culcairn export demand		Export demand of up to 150 TJ/d was used for all types of system demand as that is the minimum export that must be met on any system demand day up to 1-in-20-year peak system demand day.
Compressors		For SWP to Melbourne: • For the case with Winchelsea compressor in place, the target compressor outlet was set to 10,200 kPa; compressor would control on maximum power during model runs. For SWP to Port Campbell: • Capacity for varying compressor configurations at Brooklyn was determined to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	**Iona**	Maximum pressure is 9,500 kPa. Pressure not allowed to increase over the modelling period. Minimum pressure is 4,500 kPa.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.
	Wandong CG[A]	Minimum pressure is 3,500 kPa.

A. Wandong CG pressure varied on different system demand days to maximise capacity, considering minimum pressure at Bendigo CG.

Table 43 Northern capacity modelling assumptions and conditions

Northern capacity assumptions		Notes
Injections		Maximum injection from Longford does not exceed 970 TJ/d. The rest will be supplied from Iona and/or BassGas for all cases.
GPG demand		GPG demand for all cases varied as agreed between AEMO and APA Group.
LNG		LNG was required to maintain system security for the 1-in-20 peak system demand day case.
Compressors		Capacity for varying compressor configurations was determined, to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Northern zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	**Culcairn**	Modelled minimum pressure is 8,600 kPa for Northern export capacity modelling cases. Modelled minimum pressure is 4,500 kPa for Northern import capacity modelling cases.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.
	Wandong CG[A]	Minimum pressure is 3,500 kPa.

A. Wandong CG pressure varied on different system demand days to maximise capacity, considering minimum pressure at Bendigo CG.

Due to DTS characteristics and the nature of operational practice, AEMO must consider a number of operational factors that impact system capacity determinations:

- **Beginning-of-day-linepack**.
  - Linepack is the pressurised gas stored in transmission pipelines throughout the DTS. It varies considerably throughout the day, as it is drawn down from the start of the gas day to balance a fairly constant hourly injection rate with the morning and evening demand peaks. Linepack reaches a

minimum by around 10.00 pm. Overnight, injections exceed demand and linepack is replenished until the start of the morning peak at around 6.00 am, when linepack is at its highest level.

- **Demand forecast error**.
  - Daily demand forecast errors occur due to changes in the weather, large loads varying from the initial forecast (such as GPG), and weather forecast errors.
  - When actual demand is higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system ability to meet demand. When actual demand is lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the injection points, generally only after the 10.00 pm scheduling horizon, to avoid breaching upper operating limits.
- **Delivery pressure**.
  - Supply pressure drives gas through a pipeline. The higher the supply pressure, the higher the average level of linepack and effective system capacity.
- **Injection profiles**.
  - For operational reasons, gas production plants generally operate at a constant injection rate.
  - Varying the injection rate to reflect demand throughout the day can increase the ability to supply demand. In particular, an injection profile with a higher injection rate during the first half of the day can increase gas transport capability.
  - Gas sources that can be injected for short periods at times of high demand, such as LNG, can 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 distributions across the DTS. If a specific load is located close to an injection point, the gas transport capability is higher than if the load is located further away.

A5.4.5 Seasonal variations in DTS capacity

The DTS characteristics change in summer and shoulder seasons due to the following factors:

- Residential demand is reduced due to lower space heating needs.
- GPG load increases due to increasing electricity demand for air conditioning and relatively low gas price.
- Compressors station have lower maximum compressor power available due to the downgraded performance of the gas turbines (and engines) in summer ambient temperature conditions.

When modelling summer or shoulder, some key system parameters need to be set differently from the winter assumptions. AEMO and APA Group have discussed and agreed on seasonal conditions and parameters such as load distribution and load profiles for these periods.

Measures, abbreviations and glossary

Units of measure

Abbreviation	Unit of measure
Bcf	Billion cubic feet
EDD	Effective degree days
kPa	Kilopascals
mmboe	Million barrels of oil equivalent
MJ/m^3	Megajoules per cubic metre
PJ	Petajoules
PJ/y	Petajoules per year
t/h	Tonnes per hour
TJ	Terajoules
TJ/d	Terajoules per day
TJ/h	Terajoules per hour
TJ/y	Terajoules per year

Abbreviations

Abbreviation	Expanded name
2C	Contingent Resources
2P	Proved and Probable
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AIE	Australian Industrial Energy
BCP	Brooklyn to Corio Pipeline
BLP	Brooklyn to Lara Pipeline
CG	City Gate

Abbreviation	Expanded name
COAG	Council of Australian Governments
CPP	Close Proximity Point
CS	Compressor Station
CTM	Custody Transfer Meter
DCG	Dandenong City Gate
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
ESV	Energy Safe Victoria
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
GBJV	Gippsland Basin Joint Venture
GCP	Gas Conditioning Plant
GFC	Global Financial Crisis
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
ISP	Integrated System Plan
KTT	Kipper Tuna Turrum
KUJV	Kipper Unit Joint Venture
LMP	Longford to Melbourne Pipeline
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MDQ	Maximum Daily Quantity
MOP	Maximum Operating Pressure
MSP	Moomba to Sydney Pipeline
NGL	National Gas Law
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority

Abbreviation	Expanded name
NOPTA	National Offshore Petroleum Titles Administrator
OCGT	Open cycle gas turbine
POE	Probability of Exceedance
PRS	Pressure Reduction Station
PV	Photovoltaic
QHGP	Queensland Hunter Gas Pipeline
SEA Gas	South East Australian Gas
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zones
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for Gas
UGS	Underground Storage
VEET	Victorian Energy Efficiency Target
VGPR	Victorian Gas Planning Report
VNI	Victorian Northern Interconnect
VRET	Victorian Renewable Energy Target
WORM	Western Outer Ring Main
WTS	Western Transmission System

Glossary

Term	Definition
1-in-2 peak day	The 1-in-2 peak day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (DTS) and injected at Pakenham.
BOC Gases Australia Limited	The BOC plant, situated next to APA Group in Dandenong, liquefies natural gas for storage in APA Group's liquefied natural gas (LNG) tank.
connection point	A gas delivery point, transfer point, or receipt point.
Culcairn	The gas transmission network interconnection point between Victoria and New South Wales.

Term	Definition
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 and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the DWGM) or may be registered as market participants in their own right.
Dandenong Terminal Station	The Dandenong Terminal Station is located adjacent to the LNG storage facility. The Dandenong Terminal Station receives gas from the Dandenong City Gate, the Lurgi line (Morwell-Dandenong TP), and the BOC liquefaction plant. The terminal station facilitates the metering and regulating of gas before it flows into the Distribution networks or back into the Declared Transmission System.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the *National Gas (Victoria) Act*, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Transmission System constraint	A constraint on the gas Declared Transmission System.
Declared Wholesale Gas Market (DWGM or market)	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.
distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
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. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
gas supply	The total volume of gas a facility is able to supply on an annual basis
gas supply capacity	The maximum volume of gas a facility is able to supply in a single day
injection	The physical injection of gas into the transmission system.
lateral	A pipeline branch.
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 liquefied natural gas (LNG) storage facility is located at Dandenong.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand.

Term	Definition
maximum hourly quantity	Maximum hourly quantity (MHQ) of gas supply or demand.
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 a maximum hourly quantity (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, and quality parameters) for the purpose of billing or monitoring quality of supply.
metropolitan ring main	The 450 mm, distributor-owned pipeline from Dandenong to Keon Park to West Melbourne.
natural gas	A naturally occurring hydrocarbon comprising methane (CH4) (between 95% and 99%) and ethane (C2H6).
participant	A person registered with AEMO in accordance with the Victorian gas industry Market and System Operation Rules (MSOR).
peak day profile	The hourly profile of injection or demand occurring on a peak day.
peak demand period	Peak demand period in this report is defined as 1 May to 30 September.
peak flow rate	The highest hourly flow rate of gas or maximum hourly quantity (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 that in AEMO's reasonable opinion is likely to occur in respect of that system point under normal conditions for the following 12-month period.
peak loads	A short duration peak in gas demand.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
petajoule (PJ)	An International System of Units (SI) unit, 1 PJ equals 1,015 Joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including 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.
retailer	A seller of bundled energy service products to a customer.
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the Market and System Operation Rules (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.
shoulder season	The period between low (summer) and high (winter) gas demand, it includes the calendar months of March, April, May, September, October, and November.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
Statement of Opportunities	The Statement of Opportunities published annually by AEMO.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).

Term	Definition
summer	In terms of the gas industry, December to February of a given fiscal year.
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; 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. • Compressor station power and efficiency.
system coincident peak day	The day of highest system demand (gas). See also system demand.
system constraint	See Declared Transmission System 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 gas powered generation (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 withdrawal point	A gas Declared Transmission System (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 Declared Transmission System (gas DTS) that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 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 V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial gas consumers.
Tasmanian Gas Pipeline	The pipeline from VicHub (Longford) to Tasmania.
terajoule	Terajoule (TJ). An International System of Units (SI) unit, 1 TJ equals 1,012 Joules.
unaccounted for gas (UAFG)	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising gas losses, metering errors, timing, heating value error, allocation error, and other factors.
Underground Gas Storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date. The only UGS currently in the DTS, is the Iona UGS located in the Port Campbell region.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas Declared Transmission System (DTS) at Longford, facilitating gas trading at the Longford hub.
Western Transmission System (WTS)	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 Declared Transmission System (DTS).
winter	In this report is defined as 1 June to 31 August of a given calendar year.