Victorian Gas Planning Report Update

March 2020

Gas Transmission Network Planning for Victoria

Important notice

PURPOSE

AEMO publishes this Victorian Gas Planning Report Update in accordance with rule 323 of the National Gas Rules. This publication is based on information available to AEMO at 31 January 2020, although AEMO has endeavoured to incorporate more recent information where practicable.

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ACKNOWLEDGEMENT

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VERSION CONTROL

Version	Release date	Changes
1	March 2020	Initial release

Executive summary

The *2020 Victorian Gas Planning Report Update* (VGPR Update) provides information about changes in the supply-demand balance over the next five years (2020-24, called the outlook period) and the Victorian Declared Transmission System (DTS), since AEMO published the 2019 VGPR in March 2019[1].

The 2020 VGPR Update complements AEMO's 2020 *Gas Statement of Opportunities* (GSOO)[2], which assesses wider gas supply adequacy in eastern and south-eastern Australia to 2039.

The 2020 VGPR Update highlights that:

- Committed annual gas supply forecasts provided to AEMO by Victorian gas producers have increased by approximately 10% for 2020-23 compared to the 2019 VGPR, due to some anticipated projects progressing into committed projects. Despite the near-term increase in forecasts, committed supply is forecast to reduce by 37% from 2022 to 2024 due to field decline. Without additional gas supply, removal of pipeline constraints, or a liquefied natural gas (LNG) import terminal, gas supply restrictions and curtailment may be necessary from 2024.
- While the peak day supply forecasts provided to AEMO by gas producers have increased slightly for 2022 and 2023 since the publication of the 2019 VGPR, there is a significant reduction in 2024 due to a key Gippsland gas field and several smaller gas fields being forecast to cease production sometime between mid-2023 and mid-2024.
- The forecast Victorian supply shortfall for a 1-in-2 year peak system demand day during winter 2024 is 27 terajoules (TJ), while the forecast shortfall on a 1-in-20 year peak day is 153 TJ. System demand does not include gas for gas-powered generation (GPG) of electricity, which peaked at 242 TJ a day (TJ/d) during winter 2019.
- There are several anticipated projects (projects considered reasonably likely to proceed during the outlook period) which could improve the annual supply balance. The majority of these projects are located in the Otway Basin, which would be constrained by the capacity of the South West Pipeline (SWP), hence forecast peak day supply issues would not be resolved without an expansion of the SWP.
- Resolving forecast peak day shortfalls will require the progression of potential projects (currently not considered likely to proceed during the outlook period), the expansion of pipelines for importing additional gas supply, or an LNG import terminal.
- The Victorian gas supply adequacy forecasts are becoming increasingly uncertain:
  - It is difficult to determine precisely when gas fields will cease producing, which creates some risks to supply for 2023 and 2024. If the fields cease production earlier than forecast, then there are risks to the security of supply during 2023.
  - There has been a substantial drop in international LNG spot prices. While eastern Australia exports few spot cargoes, there may be impacts due to oil-linked LNG contracts and further reductions in international LNG demand with the spread of the coronavirus (COVID-19).

[1] The 2019 VGPR forecast supply and demand, and pipeline capacity adequacy, for the outlook period 2019-23.

[2] At https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

- In the short term, low international LNG prices are likely to increase supply from Queensland into the domestic market, potentially reducing Victorian production down to minimum contracted levels and extending the life of fields.
- In the long term, lower international prices may suppress exploration and development expenditure, reducing the longer-term supply outlook.

– This supply uncertainty is exacerbated by demand uncertainty. Fluctuating gas prices, uncertainties around renewable energy output, coal generation outages or closures, and the timing of proposed investments in new generation and electricity transmission could all materially impact GPG consumption.

– The Victorian Government has lifted the ban on onshore conventional gas exploration and development from July 2021, although the timing of any new supply and the quantities of gas that may become available are still unclear.

Actual demand and consumption trend

Annual Victorian gas consumption[3] continues to be relatively constant at approximately 200 petajoules (PJ) per year since 2014, as shown in Table 1. GPG consumption increased significantly in 2019 to support electricity demand during a high number of unplanned coal-fired generation outages. GPG consumption has increased since the March 2017 closure of the Hazelwood Power Station, with demand peaking during periods of high demand and reduced variable renewable generation in the National Electricity Market (NEM).

The 2019 DTS peak demand day occurred on Friday 9 August 2019. The total demand[4] on this day of 1,308 TJ comprised 1,199 TJ of system demand and 109 TJ of GPG demand. This was the highest demand day on record for the Victorian DTS.

Table 1 Annual gas consumption and peak gas total demand, 2014-19

	2014	2015	2016	2017	2018	2019
DTS system consumption (PJ)	191	205	200	203	194	197
DTS GPG consumption (PJ)	4	3	3	15	10	20
Victorian non-DTS consumption (PJ)[A]	22	10	8	23	16	16
Total Victorian consumption (PJ)	217	218	211	241	220	233
Annual cumulative EDD[B]	1,163	1,472	1,331	1,447	1,372	1,432
Actual DTS peak total demand (TJ/d)	1,214	1,179	1,187	1,279	1,132	1,308

A. Non-DTS consumption is predominantly gas use at the Mortlake and Bairnsdale power stations.
B. EDD (effective degree days) is a measure of coldness. The higher the EDD, the more gas is typically used for heating.

Forecast annual production

Figure 1 shows forecast and actual annual production, with additional information provided in Table 2. Actual production was slightly lower in 2019 than in 2018 and was close to the 2019 VGPR forecast.

Forecast production has increased from the 2019 VGPR due to most of the anticipated supply projects reaching Financial Investment Decision (FID) stage (this is a trigger for inclusion in the committed production forecast). This is consistent with the findings in the Australian Competition and Consumer Commission (ACCC) *Gas Inquiry January 2020 interim report*[5].

A steep decline in production is projected towards the end of the outlook period, with total committed Victorian production reducing from 318 PJ in 2022 to 201 PJ in 2024. This is due to a key Gippsland gas field

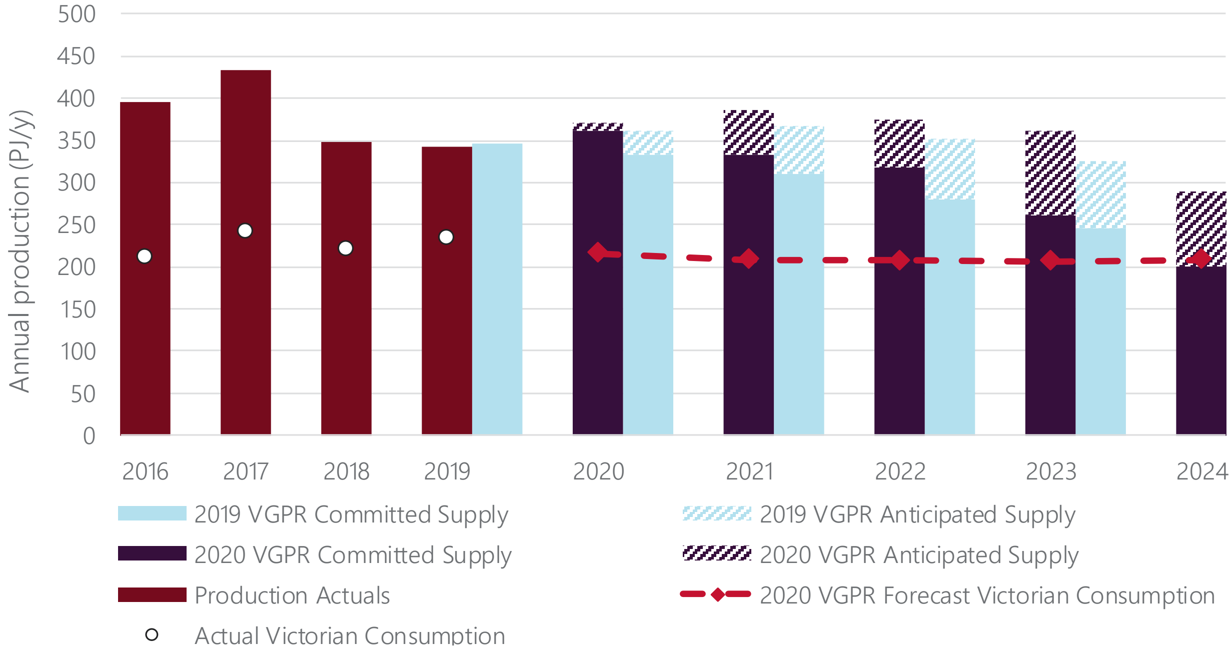
[3] Demand refers to capacity or gas flow on an hourly or daily basis. Consumption refers to gas usage over a monthly or annual period.

[4] Total demand is equal to the sum of system demand (which is residential, commercial, and industrial gas use) plus GPG, but excludes exports.

[5] At https://www.accc.gov.au/system/files/Gas%20inquiry%20January%202020%20interim%20report.pdf.

and several smaller Gippsland fields being forecast to cease production sometime between mid-2023 and mid-2024. All Otway Basin gas fields are also forecast to cease production during the outlook period unless anticipated gas field development and plant modification projects proceed. If all the anticipated Otway Basin projects proceed, gas production in the Port Campbell region would remain at 2019 levels through to 2024.

Figure 1 Annual Victorian production (PJ per year) and 2019 VGPR vs. 2020 VGPR Update forecasts



Gas reserves and their production profiles are always subject to some uncertainty, with field owners bringing differing assumptions and perspectives to their estimates. This in turn creates uncertainty and risk in forecasting supply adequacy. Gas fields' remaining life could extend well past their forecast depletion date, as the Minerva gas field did[6], or could deplete earlier than forecast, as one of the large original Gippsland Basin fields processed by the Longford Gas Plant did[7].

Table 2 Forecast Victorian annual consumption and production supply, 2020-24, with 2019 actuals (PJ)

	2019 (actual)	2020	2021	2022	2023	2024
DTS system consumption	197	197	196	196	195	195
DTS GPG consumption	20	8	5	5	6	8
Victorian non-DTS consumption	16	11	7	7	6	5
Total Victorian consumption	233	216	209	208	207	208
Total available Victorian production	**343**	**361**	**333**	**318**	**260**	**201**
Surplus / shortfall quantity	**111**	**145**	**124**	**111**	**54**	**-7**
Anticipated supply projects		10	54	56	101	88

Note: totals may not add up due to rounding.

The coronavirus (COVID-19) is causing disruptions to the global LNG market[8]. Depending on the extent and duration of the virus-induced downturn, this may reduce global LNG demand and impact LNG exports from

[6] BHP, "BHP Operational Review for the quarter ended 30 September 2019", 17 October 2019, at https://www.bhp.com/-/media/documents/media/reports-and-presentations/2019/191017_bhpoperationalreviewforthequarterended30september2019.pdf?la=en.

[7] ACCC, 2017-2020 Gas Inquiry: Interim report, p. 30, at https://www.accc.gov.au/publications.

[8] Reuters, "Global LNG-Asian LNG prices fall to $2.70/mmBtu amid coronavirus outbreak", 14 February 2020, at https://www.reuters.com/article/global-lng/global-lng-asian-lng-prices-fall-to-2-70-mmbtu-amid-coronavirus-outbreak-idUSL4N2AE2BM.

Queensland, as well as reduce domestic demand. The Queensland producers may then choose to sell additional gas into the domestic market while global LNG demand is reduced, which would reduce the amount of Victorian gas supplied to New South Wales and South Australia, potentially reducing Victorian production down to minimum contracted levels. These potential impacts were not modelled in the 2020 GSOO or this 2020 VGPR Update.

Forecast annual supply adequacy

AEMO highlighted declining Victorian production in the 2018 VGPR Update, which forecast shortfalls in 2022 without commitment to additional gas supply projects. The 2019 VGPR forecast improved annual supply with several projects reaching FID, but a tight peak day supply-demand balance was forecast in 2023.

A shortfall in meeting annual Victorian gas consumption is now forecast from 2024 without additional gas supply. If the Victorian gas fields deplete earlier than forecast, there is a risk of an annual supply shortfall in 2023, with shortfalls most likely to occur on winter peak days.

Anticipated (that is, not committed) Victorian production projects could increase 2024 production from 201 PJ to 289 PJ. Some anticipated projects noted in previous VGPRs have transitioned into committed projects, however this typically only occurs within the first two years of the outlook period. This can be seen in Figure 1, where the 2019 VGPR committed plus anticipated supply forecast for 2020 equals the new 2020 VGPR committed supply forecast. This means supply adequacy for 2023-24 may be uncertain for another couple of years.

While Victoria is forecast to have enough production to supply all forecast Victorian demand on an annual basis from 2020 to 2023, the supply-demand balance is tightening. Winter monthly gas consumption in Victoria is up to three times (typically 25-30 PJ/month) summer monthly gas consumption (of approximately 10 PJ/month). This is expected to result in:

- A tight winter gas supply-demand balance in Victoria.
- Increased reliance on the Iona Underground Storage (UGS) facility in 2023.
- Reduced gas available for export to New South Wales and South Australia on peak days, making these regions more reliant on Queensland gas supplies towards the end of the outlook period. Without supply from Victoria, supply to these states would be limited by the capacity of the South West Queensland Pipeline, and the Moomba to Sydney and the Moomba to Adelaide pipelines. The impacts of reduced Victorian supplies for these states, including supporting GPG demand and pipeline transportation capacity limitations, are explored in the 2020 GSOO.

Forecast GPG consumption

DTS-connected GPG consumption is forecast to decline from 20 PJ in 2019 to 8 PJ in 2020, and to stay relatively flat around this level to 2024 (see Table 2), due to the increased amount of renewable generation that is forecast to be commissioned during the outlook period to meet the Victorian Renewable Energy Target (VRET).

There is, however, forecasting uncertainty for GPG. Factors that could increase GPG consumption include:

- Coal-fired generators operating with lower than forecast reliability (more outages).
- Coal-fired generators closing earlier than forecast.
- Weather patterns that result in lower than forecast solar or wind generation.
- Delays in the connection or commissioning of new renewable generation.
- Delays in electricity transmission investments noted in AEMO's *Draft 2020 Integrated System Plan* (ISP)[9].
- Lower than forecast gas prices.

[9] See p. 11-14, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/draft-2020-integrated-system-plan.pdf?la=en.

If GPG consumption is higher than forecast, this would increase the risk of a supply shortfall towards the end of the outlook period.

Forecast peak day supply

Gas producers have advised that the total daily Victorian production capacity will reduce from 1,214 TJ/d in 2020 to 631 TJ/d in 2024, driven mainly by a decrease in Gippsland peak day supply capacity. The production decline is accentuated in the peak day supply forecast, because an increasing number of the remaining fields are only able to produce gas at a constant rate[10].

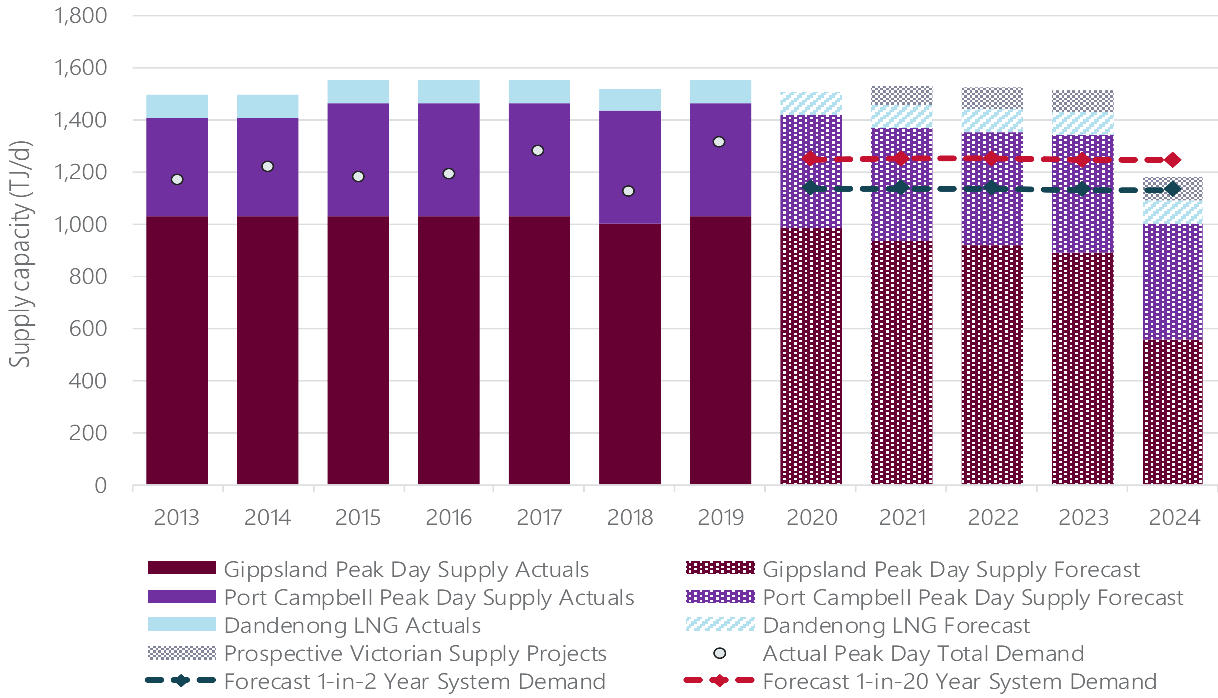
Peak day supply adequacy

Forecast peak day supply has increased compared to the 2019 VGPR, while forecast 1-in-2 and 1-in-20 year peak day demand forecasts have reduced slightly. The significant change is that forecast data for 2024 (not included in the 2019 VGPR outlook period), which is shown in Figure 2, highlights that without additional gas supply, gas supply restrictions and curtailment are likely in 2024.

The large reduction in 2024 is due to several fields being forecast to cease production across 2023 and 2024. This includes advice from Esso Australia Resources that another of the key Gippsland Basin fields (processed by the Longford Gas Plant) is forecast to cease production during this period. If offshore fields deplete earlier than forecast, there is a risk of insufficient peak day supply and the curtailment of GPG during winter 2023.

In winter 2023 and 2024, there will be an increased reliance on gas storage to meet winter demand. This increases the risk of the storage inventory being depleted if it is not carefully managed, or if there is an unexpected gas supply reduction or if GPG consumption is higher than forecast.

Figure 2 Actual and forecast peak day supply capacity (including pipeline constraints) by location, and peak day demand, 2013-24 (TJ/d)



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

The Western Outer Ring Main (WORM) is a planned augmentation of the DTS that will increase the Iona UGS refilling capacity and increase the capacity of the SWP to support peak day demand.

In December 2019, the Victorian Government determined that an Environmental Effects Statement (EES) will be required for the WORM project[11]. AEMO has assumed a delay from asset owner APA Group's target mid-2021 completion date[12], and that the WORM will not be available until mid-2022. Delays beyond this date will increase the risk of depleting Iona storage levels and reduce the available peak day supply capacity, further tightening the supply-demand balance.

Table 3 summarises forecast DTS supply adequacy under 1-in-2 and 1-in-20 peak day system demand forecasts[13]. This does not include DTS GPG demand, which peaked at 242 TJ/d during winter 2019.

Table 3 Forecast DTS peak day supply adequacy excluding GPG, 2020-24 (TJ/d)

	2020	2021	2022	2023	2024
Total supply capacity (including Victorian LNG)	1,781	1,746	1,703	1,576	1,238
DTS available supply including pipeline constraints	1,508	1,457	1,442	1,431	1,093
1-in-2 peak DTS system demand	1,136	1,136	1,135	1,131	1,131
Surplus/shortfall quantity on 1-in-2 peak day	**372**	**321**	**306**	**327**	**-27**
1-in-20 peak DTS system demand	1,249	1,252	1,252	1,245	1,246
Surplus/shortfall quantity on 1-in-20 peak day	**259**	**205**	**190**	**185**	**-153**
Anticipated supply projects including constraints		73	82	82	87

Note: totals may not add up due to rounding. DTS peak day demand in this table is slightly lower than the 2020 GSOO Victorian peak day demand forecast, due to non-DTS Victorian gas demand.

Additional supply options within the outlook period

The production forecasts in this report only include projects that are currently producing or those that have committed timeframes for development. New supplies from currently uncommitted projects can still be brought into production during this five-year period and change the supply adequacy outlook.

AEMO has been advised by producers that a number of projects are currently being investigated that could improve the forecast annual supply; however none of these projects could resolve the peak day supply issues, due to either the relatively flat production profiles available from these projects, or SWP capacity constraints.

Resolving the forecast peak day shortfall will require one of the following options:

- An LNG import terminal:
  - AGL has proposed the development of a floating LNG import terminal at Crib Point, near Hastings. AGL continues to progress the EES process, with an outcome expected in mid-2020.
  - AIE's proposed floating LNG import terminal at Port Kembla in Wollongong in New South Wales could provide peak day supply capacity into Victoria, if subsequent projects facilitated southbound flows on the Eastern Gas Pipeline and expanded the VicHub connection into the DTS.

[11] Victoria Land, Water and Planning, "Reasons for decision under Environment Effects Act 1978", 22 December, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/446979/Reasons-for-Decision.pdf.

[12] APA, "Western Outer Ring Main Pipeline", December 2019, at https://www.apa.com.au/globalassets/documents/our-current-projects/worm/worm_a3_update-01.pdf.

[13] A 1 in-2 forecast means the forecast is expected to be exceeded, on average, one year in every two, and represents demand in average weather conditions. A 1-in-20 forecast means the forecast is expected to be exceeded, on average, one year in every 20 years, and represents extreme weather conditions.

- Esso is no longer progressing plans for an import terminal at Longford[14], however, other new parties have contacted AEMO and expressed interest in the feasibility of an import terminal.

- One of the following pipeline expansions for importing additional gas supply:
  - Increase in the SWP capacity (beyond the capacity increase provided by the WORM) to utilise the anticipated and potential projects proposed in the Port Campbell region.
  - Increase in the pipeline capacity between Wallumbilla and Culcairn (via Moomba), or the construction of a new pipeline to increase the supply capacity from Queensland.
- A combination of projects, which would need to include some additional pipeline capacity along with additional gas storage capacity such as the Golden Beach gas storage project[15].

The Victorian Gas Program has assessed the potential for onshore conventional gas in Victoria and determined that the moratorium on conventional exploration and development should cease on 1 July 2021. The report concluded that the prospective resource estimate for onshore Victoria ranges from 128 PJ to 830 PJ, with the most likely estimate (P50) of 547 PJ. Prospective resources[16] are quantities of gas that are estimated to be potentially recoverable from undiscovered accumulations identified on the basis of indirect evidence, but exploration wells have not yet been drilled.

The Victorian Gas Program Progress Report No. 4[17] noted that: *"The additional 128-830 petajoules of gas that could be produced in the state would contribute to gas supply but would not meet Victoria's forecasted shortfalls. The additional gas would improve energy security by increasing the diversity of gas supply. It would also benefit industrial users, particularly in regional areas, by providing new options for local gas supplies"*.

AEMO will continue to monitor developments and work with industry on any future sources of gas supply.

[14] The Sydney Morning Herald, "ExxonMobil shelves Victorian gas import terminal plan", 2 December 2019, at https://www.smh.com.au/business/companies/exxonmobil-shelves-victorian-gas-import-terminal-plan-20191201-p53fri.html.

[15] Golden Beach Gas Production and Storage Infrastructure Project, at https://gbenergy.com.au/s/Golden-Beach-Gas-Production-and-Infrastructure-Project.pdf.

[16] Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) standards at https://www.spe.org/industry/docs/PRMS-Guide-for-Non-Technical-Users-2007.pdf.

[17] Victorian Government, Victorian Gas Program, at https://earthresources.vic.gov.au/__data/assets/pdf_file/0005/524489/VGP_PR04-120320-Low-Res.pdf.

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Tables

Figures

1. Introduction

The *Victorian Gas Planning Report Update* (VGPR Update) 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 2019[18].

Where AEMO becomes aware of any information that materially alters the most recently published VGPR, the National Gas Rules (NGR) require AEMO to update the report as soon as practicable. The material changes that prompted this VGPR Update are:

- Updated gas production forecasts indicate that without additional supply, winter peak day shortfalls are expected from 2024.
- Updates to projects within the DTS since the 2019 VGPR was published.

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

1.1 Review of 2019

Total DTS gas consumption during 2019 was slightly higher than in 2018, due to increased gas-powered generation (GPG) for electricity supply for the National Electricity Market (NEM), and was similar to total gas consumption in 2017. DTS system consumption in 2019 was 197 petajoules (PJ), with total consumption of 217 PJ[19]. This is higher than the 193 PJ of system consumption and 203 PJ of total consumption recorded in 2018.

The 2019 Victorian DTS peak demand day occurred on Friday 9 August, which was also the highest ever total demand, at 1,308 terajoules (TJ). This demand comprised 1,194 TJ of system demand and 109 TJ of GPG demand. The Effective Degree Day (EDD)[20] on this day was 15.0.

Total DTS GPG consumption doubled from 10 PJ in 2018 to 20 PJ in 2019, and peaked during the winter and shoulder period from August to October. This increase in DTS GPG consumption was due to the extended outages of the Loy Yang A2 coal-fired generator and Mortlake unit 2 gas-fired generator and other coal generator issues across several units within Victoria and New South Wales during 2019.

Key observations for the peak demand winter period of 2019 include:

- Average system demand was 780 TJ a day (TJ/d), which is slightly below the average 791 TJ/d observed in 2018.
- Cumulative EDD for the period was 1,195, which is below the 2018 value of 1,234.
- Net injections from New South Wales via Culcairn into the Victorian Northern Interconnect (VNI) totalled 12 PJ, which is over three times higher than for the same period in 2018. This is the first time since 2009 that there was an overall net supply from New South Wales via Culcairn. Exports to New South Wales via the Eastern Gas Pipeline (EGP) over the peak period totalled 32.5 PJ, which is below the 41.8 PJ exported in 2018 for the peak period.

[18] The VGPR is required every second year. Recent publications are at https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

[19] System consumption means residential, commercial, and industrial gas usage. Total consumption combines system consumption and consumption by GPG for generating electricity in Victoria.

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

- Net supply from Queensland to the southern states (predominantly New South Wales and South Australia) via the South West Queensland pipeline (SWQP) was 33.2 PJ over the peak demand period, up from 16.7 PJ in 2018 and 5.2 PJ in 2017.
- Longford Gas Plant production was approximately 5% higher in 2019 than in 2018.
- The Iona Underground Storage (UGS) facility was utilised less than in 2018, with 11.0 PJ drawn down from storage in 2019, compared to 14.5 PJ drawn down in 2018.
- Peak shaving liquefied natural gas (LNG) was injected in response to a Threat to System Security on three separate gas days:
  - 20 TJ on 27 May 2019 due to high demand combined with an under delivery from Longford.
  - 12 TJ on 29 May 2019 due to underforecast demand because of colder than forecast temperatures.
  - 12 TJ on 19 June 2019 due to underforecast demand because of colder than forecast temperatures coinciding with higher than forecast GPG due to the unplanned outage of a coal-fired generator.

1.2 The Victorian Declared Transmission System

The DTS supplies natural gas to the majority of households and businesses in Victoria, and in addition, to communities in New South Wales between Moama and Albury. Gas is transported from the Longford and Lang Lang gas plants 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 UGS facility, and to South Australia via the SEA [South East Australia] Gas Pipeline).

Figure 3 provides a high-level map of the Victorian gas transmission network, including the DTS (in blue) and other gas transmission pipelines. The DTS comprises the following six system withdrawal zones (SWZs), defined in Appendix A3: Ballarat; Geelong; Gippsland; Melbourne; Northern; and Western (the Western Transmission System or WTS).

Figure 3 The Victorian Declared Transmission System

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 for the period. 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.

The timing of any capital investment in the DTS is ultimately decided by APA Group. Under the framework set out in the National Gas Law (NGL) and the NGR, APA Group may adjust actual capital expenditure from that assessed by the AER during 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 the planning review as soon as practicable.

In accordance with rule 324 of the NGR, 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 year forecast is defined as a peak day system demand forecast with a 50% probability of exceedance (POE). This means the forecast is expected, on average, to be exceeded once in two years, and is considered the most probable peak day system demand forecast.
- A 1-in-20 year forecast is defined as a peak day system demand forecast for severe weather conditions, with a 5% POE. This means the forecast is expected, on average, to be exceeded once in 20 years. This forecast is used for DTS capacity planning.

System demand does not include supply for GPG[21]. 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 the term "demand" to describe hourly and daily usage of gas, and the term "consumption" to refer to monthly and annual usage of gas.

The *Gas Industry Act 2001* (Vic) and the *Gas Safety Act 1997* (Vic) 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 day demand. This assessment is used to recommend augmentations or additional gas

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

supplies that are required to reduce the risk of an unplanned loss of supply and subsequent risks to public safety.

1.3.3 Gas supply classification definitions

The classifications of gas supply used in the 2020 VGPR Update are defined in Table 1. The gas supply category “prospective”, referred to in the NGR, is now called “anticipated supply” to establish consistent terminology with the Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia. Other supply classifications are unchanged from the 2019 VPGR.

Table 1 also shows the corresponding terms from the Petroleum Resources Management System (PRMS) and GSOO. Full definitions can be found in Appendix A1. Note that the PRMS definition of ‘Development not viable’ is not included in the gas supply classifications.

Table 1 Gas supply classification definitions for VGPR, PRMS and GSOO

VGPR	2020 VGPR description	PRMS	GSOO
Available supply	Comprises developed gas reserves and committed new gas supply projects, including 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.	Reserves: On Production, Approved for Development	Committed supply
Anticipated supply	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 (using existing infrastructure). This supply is discussed in Chapter 3.	Reserves: Justified for Development	Anticipated supply
Potential projects	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 anticipated supply forecast and are discussed in Chapter 4. They are considered less likely than the anticipated supply projects to proceed in the outlook period, due to: • 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.	Contingent Resources: Development Pending, Development on Hold, Development Unclarified	Uncertain supply
Exploration projects	These projects are associated with undiscovered gas resources that are usually mapped using seismic data. These 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 are not included in any of the supply forecasts but are discussed in Chapter 4.	Prospective resources: Prospect/Leads/Plays	

2. Gas usage forecast

Key findings

- Annual system consumption is forecast to remain relatively flat over the outlook period, decreasing from 197 PJ in 2020 to 195 PJ in 2024. This contrasts with the 2019 VGPR, where a slight increase in annual system consumption was forecast.
- The forecast peak system demand for 2020 is:
  - 1,136 TJ for a 1-in-2 year peak system demand day.
  - 1,249 TJ for a 1-in-20 year peak system demand day.
- Tariff D (large customers) consumption is forecast to decrease 3.9% over the outlook period, due to changing behaviours of large commercial and industrial customers.
- DTS-connected GPG consumption is forecast to decrease from 2020, primarily due to new renewable generation that is forecast to come online, however, an increase is predicted following the planned staged closure of the Liddell Power Station between 2022 and 2023. There is high uncertainty around the GPG forecast, due to a number of factors.

Background

The gas usage forecasts in the 2020 VGPR Update were produced using the GSOO demand forecasting methodology[22]. The VGPR forecasts are a subset of the gas usage forecasts for eastern and south-eastern Australia in the 2020 GSOO, also published in March 2020.

Updated monthly peak day GPG demand and peak hourly system demand forecasts are not included in this VPGR Update. Updates to these forecasts will be provided in the 2021 VGPR.

System demand refers to daily gas consumption by residential, commercial, and industrial gas users, including compressor and heater fuel gas usage.

GPG is not included in system demand. Total demand refers to the sum of system demand and GPG demand.

System demand is further classified into Tariff V demand and Tariff D demand, defined as follows:

- Tariff V demand – residential and small commercial customers, each normally consuming less than 10 TJ per year (TJ/y) of gas
- Tariff D demand – large commercial and industrial customers, each 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 heating, which depends on a number of variables. To forecast system demand, AEMO uses a measure known as the EDD, which takes into account the temperature profile, average wind speed, and sunshine hours for the gas day.

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

2.1 Forecast consumption

This section presents the DTS total annual consumption forecasts. Total annual consumption includes:

- System consumption (Tariff V, Tariff D, compressor fuel gas, and unaccounted for gas [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.

2.1.1 Annual consumption

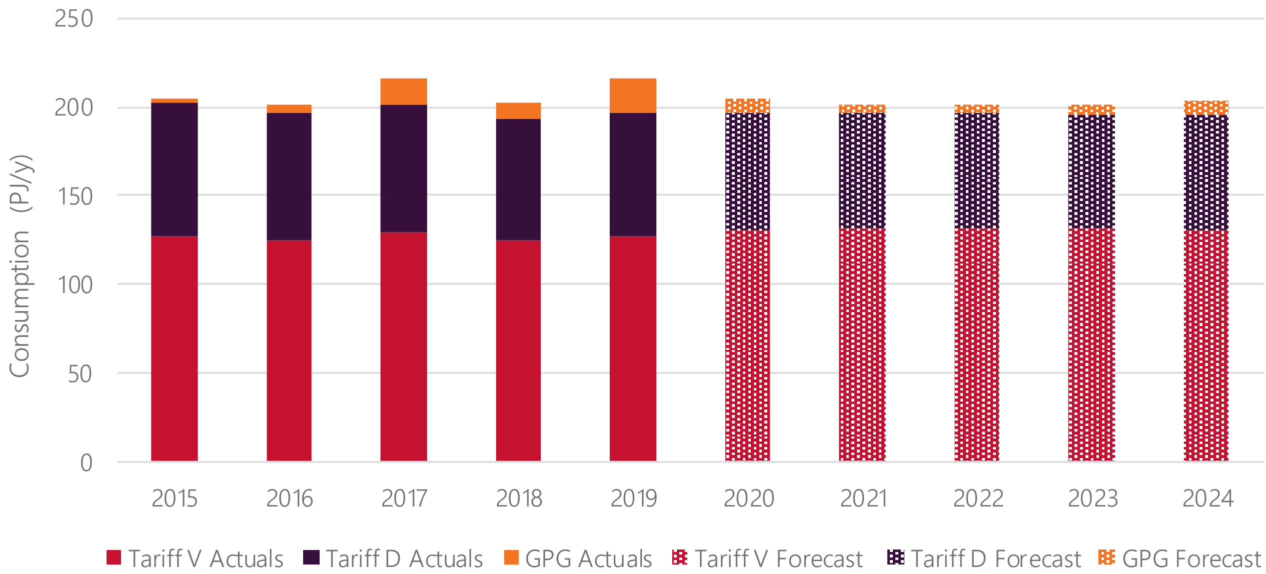
Annual DTS total gas consumption is projected to decrease slightly over the outlook period, from 205 PJ in 2020 to 203 PJ in 2024, as shown below in Table 2 and Figure 4.

Table 2 Total annual gas consumption forecast, 2020-24 (PJ/y)

	2020	2021	2022	2023	2024	Change over outlook
Tariff V	130	131	131	131	131	0.4%
Tariff D	67	65	65	64	64	-3.9%
System consumption	197	196	196	195	195	-1.0%
DTS GPG consumption	8	5	5	6	8	6.5%
Total DTS consumption	205	201	201	201	203	-0.7%
Non-DTS system consumption	1	1	1	2	2	6.1%
Non-DTS GPG consumption	9	6	5	4	3	-65%
Victorian GPG consumption	17	11	10	10	12	-32%
Total Victorian consumption	216	209	208	207	208	-3.5%

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

Figure 4 Total annual DTS consumption, actual 2015-19 and forecast 2020-24 (PJ/y)



This decrease is primarily attributed to a decrease in forecast Tariff D and GPG consumption over the outlook period. It differs from the 2019 VGPR, which projected total consumption increasing to 212 PJ in 2023.

2.1.2 Tariff V consumption

Tariff V consumption (by residential and small commercial customers) is forecast to remain relatively flat, with a predicted increase of just 0.4% over the outlook period. This slight increase is mainly driven by population growth, which is forecast to increase the number of Tariff V connections. The impact of population growth is projected to be offset by decreasing gas consumption per household, as a result of increased energy efficiency and electric appliance use in high density developments.

This increase is lower than the 2% increase projected in the 2019 VGPR. Updated advice from distributors resulted in a lower forecast number of commercial Tariff V connections this year compared to last year.

Table 3 depicts the projected Tariff V consumption by SWZ. It can be seen that demand behaviour varies in the different SWZs:

- In the Melbourne zone, Tariff V consumption is forecast to decrease slightly, as the projected number of new connections is offset by reduced consumption per household, reflecting the greater proportion of high-density developments that generally use electrical appliances.
- In all other 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 mainly gas appliances.

Table 3 Forecast annual Tariff V consumption by SWZ, 2020-24 (PJ/y)

	2020	2021	2022	2023	2024	Change over outlook
Ballarat	8.6	8.8	8.9	9.1	9.2	6.9%
Geelong	11.0	11.2	11.3	11.4	11.6	5.1%
Gippsland	5.6	5.7	5.8	5.9	6.0	7.9%
Melbourne	93.0	93.1	92.7	92.1	91.6	-1.5%
Western	1.4	1.4	1.4	1.5	1.5	6.0%
Northern	10.8	10.9	11.0	11.0	11.1	3.1%
DTS Tariff V system consumption	130.3	131.2	131.2	131.0	130.9	0.4%
Non-DTS Tariff V system consumption	0.47	0.49	0.52	0.54	0.56	19%
Total Victorian Tariff V	130.8	131.7	131.7	131.6	131.5	0.5%

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

2.1.3 Tariff D consumption

Tariff D (large commercial and industrial) consumption, as shown in Table 4, is projected to continue to decline, with a 3.8% reduction over the outlook period. The 2019 VGPR predicted a decline in annual Tariff D consumption of 0.5% over the five-year period. The increased decline is driven by changing behaviour by large industrial consumers, and the 2019 closure of large industrial customer Norske Skog Albury Paper Mill[23].

The forecasting methodology used for Tariff D consumption differs from previous years. In previous years, Tariff D usage was forecast based only from survey information from large industrials. This year, large industrial customer usage was predominately forecast using individual surveys and interviews, whereas smaller customers were forecast using a separate economic aggregate model. This change in methodology has highlighted a long-term trend in smaller Tariff D customers with an increased number of connections but a lower consumption per customer.

[23] Norske Skog, "Norske Skog announces sale and closure of Albury Mill", 3 October 2019, at https://www.norskeskog.com/About-Norske-Skog/Press-room/Press-releases/English-press-releases/Norske-Skog-announces-sale-and-closure-of-Albury-mill?Action=1&PID=4123.

Recent high gas prices have resulted in manufacturers and industrial users looking to gas use reduction strategies to decrease operating costs. In some cases, customers have expanded overseas operations instead of increasing Australian operations, and explored fuel switching, energy efficiency, or waste-to-energy technologies[24]. In extreme cases, manufacturers have announced intentions to shut down. This includes Dow Chemicals in Altona, Melbourne, which cited rising gas prices as one of the main factors in its decision to close[25].

Table 4 Forecast annual Tariff D consumption by SWZ, 2020-24 (PJ/y)

	2020	2021	2022	2023	2024	Change over outlook
Ballarat	1.6	1.6	1.5	1.5	1.5	-2.3%
Geelong	11.8	11.1	11.1	10.9	10.9	-7.9%
Gippsland	8.5	8.3	8.1	7.9	7.7	-9.2%
Melbourne	34.4	34.0	33.8	33.4	33.7	-2.2%
Western	2.6	2.6	2.5	2.5	2.5	-4.8%
Northern	7.7	7.8	7.8	7.8	7.8	0.7%
DTS Tariff D system consumption	66.6	65.2	65.0	64.0	64.0	-3.9%
Non-DTS Tariff D system consumption	0.97	0.98	0.98	0.98	0.97	-0.1%
Total Victorian Tariff D	67.6	66.2	65.9	65.0	65.0	-3.8%

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

2.1.4 Annual GPG consumption

Victorian gas usage for power generation is driven by events and conditions in the NEM. For example, in 2017, GPG consumption increased to 15 PJ/y, 500% above the 2016 demand, due to the March 2017 closure of the Hazelwood Power Station.

Total DTS GPG consumption doubled from 10 PJ in 2018 to 20 PJ in 2019. This was largely due to a 16% reduction in brown coal generation, with the main cause being extended outages of the Loy Yang A2 coal-fired generator. Other contributing factors included the extended outage of the Mortlake unit 2 gas-fired generator and coal issues across several units within Victoria and New South Wales.

The GPG forecasting methodology assumed generation and transmission assets are developed in line with the Central scenario detailed in the Draft 2020 *Integrated System Plan* (ISP), which provides a least-cost-based engineering optimisation plan for the NEM transmission system[26].

As shown in Table 2, Victorian DTS GPG consumption is forecast to decrease by 32% over the outlook period. The initial decrease in all Victorian GPG is driven by an increase in the amount of renewable generation forecast to be commissioned over the outlook period. However, this trend is forecast to slow and then reverse slightly with the staged closure of the coal-fired Liddell Power Station in New South Wales across 2022 and 2023[27].

Figure 5 shows monthly DTS GPG consumption for 2018 and 2019, and the predicted monthly forecast for 2020. Monthly GPG consumption can be significant during the winter and shoulder periods, and has the potential to coincide with a 1-in-2 or 1-in-20 peak winter demand day.

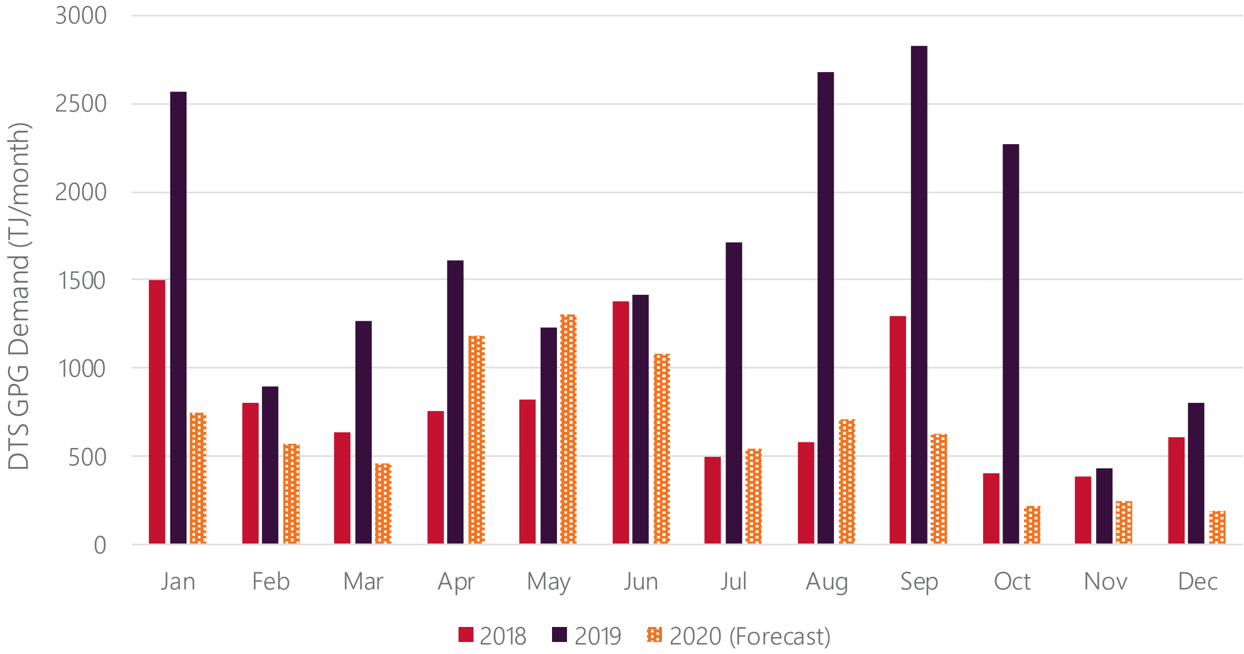
[24] The Australian Competition & Consumer Commission, Gas Inquiry 2017-2025 Interim Report, January 2020, at https://www.accc.gov.au/system/files/Gas%20inquiry%20January%202020%20interim%20report.pdf.

[25] The Sydney Morning Herald, "Altona site to shit: Union sounds jobs alarm on gas crisis", 28 May 2019, at https://www.smh.com.au/business/companies/altona-site-to-shut-union-sounds-jobs-alarm-on-gas-crisis-20190528-p51s2s.html.

[26] AEMO, *Draft 2020 Integrated System Plan*, 2020, at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/draft-2020-integrated-system-plan.pdf?la=en.

[27] AGL, *Schedule for the closure of AGL plants in NSW and SA*, 2 August 2019, at https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa.

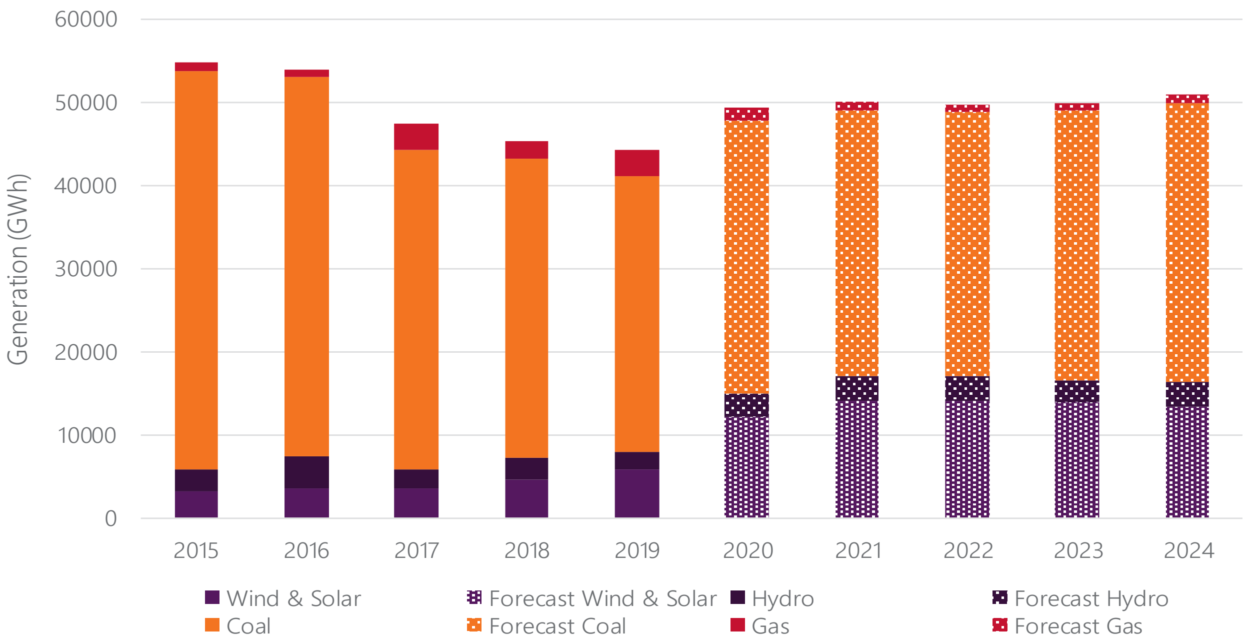
Figure 5 Monthly DTS-connected GPG consumption, actual 2018-19 and forecast 2020 (TJ/month)



These DTS GPG consumption forecasts are subject to a range of uncertainties.

First, the Draft 2020 ISP (Central scenario) forecasts a large amount of additional renewable generation in Victoria over the next decade, to meet the Victorian Renewable Energy Target (VRET)[28,29]. As shown in Figure 6, utility-scale solar and wind generation is forecast to substantially increase from 2019 to 2021 in Victoria. If forecast investments in renewable energy generation are delayed or do not proceed, GPG consumption is likely to be higher than the forecast in Table 2.

Figure 6 Victorian electricity generation, actual 2015-19 and forecast 2020-24 (GWh/year)



[28] AEMO, *Draft 2020 Integrated System Plan*, 2020, at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/draft-2020-integrated-system-plan.pdf?la=en.

[29] Victoria State Government, Victoria's Renewable energy targets, at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

Second, as outlined in the 2020 GSOO, annual GPG gas consumption is forecast to be increasingly sensitive to year-on-year variations in weather conditions. Weather patterns (rainfall, wind, and solar) affect not only consumer demand for electricity, but also the output of renewable generation in the NEM, which subsequently impacts the amount of gas required for GPG.

Other factors that may result in GPG demand varying from forecasts include:

- The reliability of coal-fired generators in the NEM.
- Changes to the expected closure dates of coal-fired generators.
- Gas prices varying from projected levels.
- Delays in any electricity transmission investments that were assumed to proceed in the Draft 2020 ISP.

Additionally, a 220 megawatt (MW) gas-fired power station at Dandenong, proposed by APA Group, has been selected as one of two projects to progress to the next stage of the Federal Government's Underwriting New Generation Investments (UNGI) program[30]. No details have been provided on when the plant is likely to be operational, however, if it progresses during the outlook period, this may also affect the GPG consumption forecast.

2.2 Peak day demand forecast

This section reports:

- Annual DTS peak day system demand forecasts over the five-year outlook period from 2020.
- Monthly peak day gas demand forecasts from January 2020 to December 2020.

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 A2A2.1.

2.2.1 Peak day system demand

Peak day system demand is primarily driven by Tariff V gas usage for space heating, which significantly increases as temperature decreases.

The 1-in-2 year and 1-in-20 year peak day system demand forecasts, summarised below in Table 5 and Table 6 respectively, show a projected decrease in Tariff D peak day demand, while Tariff V peak day demand is forecast to remain relatively stable. The total peak day system demand is forecast to remain flat over the outlook period, decreasing by just 0.4%.

This contrasts to the 2019 VGPR, which projected an increase in Tariff V peak day forecast over the outlook period. The slight decrease in peak day consumption is largely due to the predicted decrease in Tariff D consumption, as discussed in Section 2.1.3.

Table 5 1-in-2 year peak day system demand forecasts, 2020-24 (TJ/d)

	2020	2021	2022	2023	2024	Change over outlook
Tariff V	903	909	908	907	908	0.5%
Tariff D	233	227	228	224	224	-3.9%
System demand	1,136	1,136	1,135	1,131	1,131	-0.4%

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

[30] APA, "APA project selected for government power scheme", 24 December 2019, at https://www.apa.com.au/news/media-statements/2019/apa-project-selected-for-government-power-scheme/.

Table 6 1-in-20 year peak day system demand forecasts, 2020-24 (TJ/d)

	2020	2021	2022	2023	2024	Change over outlook
Tariff V	1,009	1,016	1,018	1,015	1,015	0.6%
Tariff D	240	235	234	230	231	-3.8%
System demand	1,249	1,252	1,252	1,245	1,246	-0.3%

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

2.2.2 Monthly peak day forecast

Table 7 shows the forecast peak day system demand for each month during 2020. The peak day system demand is expected to occur during the winter period, from June to September. Monthly peak day system demand is influenced by weather conditions and seasonal industrial demand changes.

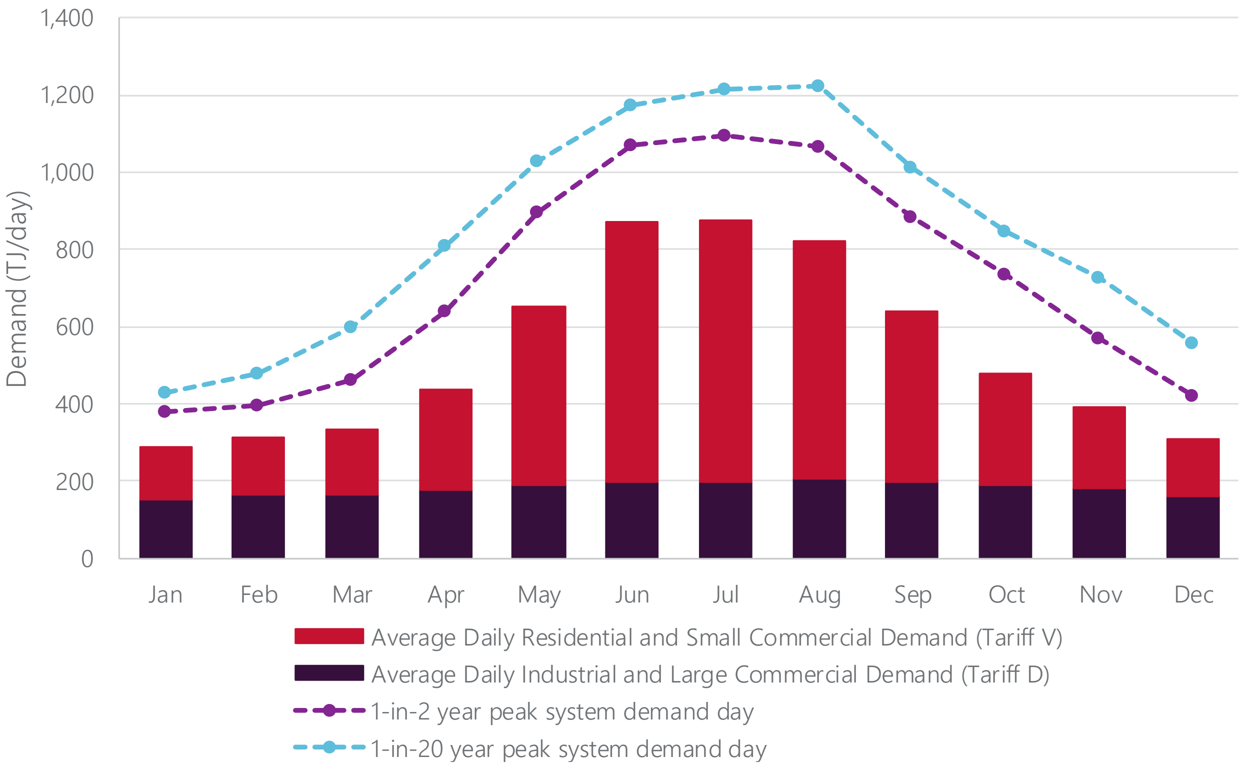
Figure 7 shows the forecast peak day system demand compared to the forecast average daily system demand for each month in 2020.

Monthly forecast peak day system demand by SWZ for 2020 is reported in Appendix A2.

Table 7 Forecast monthly peak day system demand, 2020 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 year	378	394	463	638	896	1,070	1,094	1,068	883	734	570	422
1-in-20 year	429	477	598	810	1,029	1,172	1,215	1,224	1,013	846	727	556

Figure 7 Average daily demand compared to peak day system demand forecasts



3. Supply adequacy

Key findings

- Gas production forecasts provided by producers have improved in the short term from 2020 to 2023 compared to the 2019 VGPR, as the Gippsland forecast production output has increased and previously anticipated projects are now committed.
- In 2024, producers forecast a large reduction in the amount of available production. This is driven by a key offshore gas field in the Gippsland Basin being forecast to reach end of life and several other smaller fields in the Gippsland and Otway basins being forecast to cease production. As a result, without additional gas supply, removal of pipeline constraints or an LNG import terminal:
  - There is forecast to be insufficient Victorian production to supply forecast annual Victorian gas consumption from 2024, especially on peak winter days.
  - In 2024, shortfalls are forecast for 1-in-2 and 1-in-20 year peak demand days which may necessitate gas supply restrictions and curtailment.
- There is inherent uncertainty in determining when a gas field will deplete, so there is a risk that the key Gippsland gas field may deplete earlier than forecast, and peak day shortfalls could occur from 2023.
- If the anticipated projects proceed, there is forecast to be sufficient annual supply over the outlook period; however, the majority of these projects are constrained by the capacity of the South West Pipeline (SWP) and hence would not resolve the forecast peak day supply issues.
- No new projects have progressed into the anticipated category since the 2019 VGPR to backfill the projects that have become committed, increasing the risk of future supply shortfalls.

3.1 DTS supply sources

AEMO assesses supply adequacy based on its demand forecast (provided in Chapter 2), and forecast available supply, using data provided to AEMO by producers, facility operators, and market participants.

The methodology used to assess annual and peak day supply adequacy is the same as that described in the 2019 VGPR. Uncommitted gas supply projects that are considered likely to proceed during the outlook period are referred to as anticipated projects and are included in the assessment to determine if they could address forecast supply shortfalls.

Similar to previous years, while the 2020 GSOO is using the same Victorian gas production forecasts as the 2020 VGPR, there are differences in how each document assesses supply adequacy, so the forecast outcomes differ slightly. For more information on supply adequacy in eastern and south-eastern Australia, refer to the 2020 GSOO.

3.1.1 Facility changes since the 2019 VGPR

The Minerva Gas Plant ceased production on 3 September 2019, due to the depletion of the Minerva gas field. The Casino Henry Joint Venture (JV) has acquired the Minerva Gas Plant, with the sales agreements expected to be finalised in January 2020[31]. The JV has stated that the Minerva plant is to be modified to accommodate production from the Casino, Henry, and Netherby fields and any other new gas discoveries. Commissioning is expected to be completed by mid-2021.

The Orbost Gas Plant was previously expected to be operational in 2019, but it has experienced construction delays[32] that pushed the first phase of commissioning to early January 2020. The first supply of Sole gas to the plant was anticipated in February 2020[33], but Cooper Energy announced that, due to the East Gippsland bushfires, production was expected to be delayed until March 2020[34].

Refer to Appendix A3 for further information on production facilities, storage facilities, and interconnected pipelines that have not had a material change from the 2019 VGPR.

3.2 Annual supply demand balance

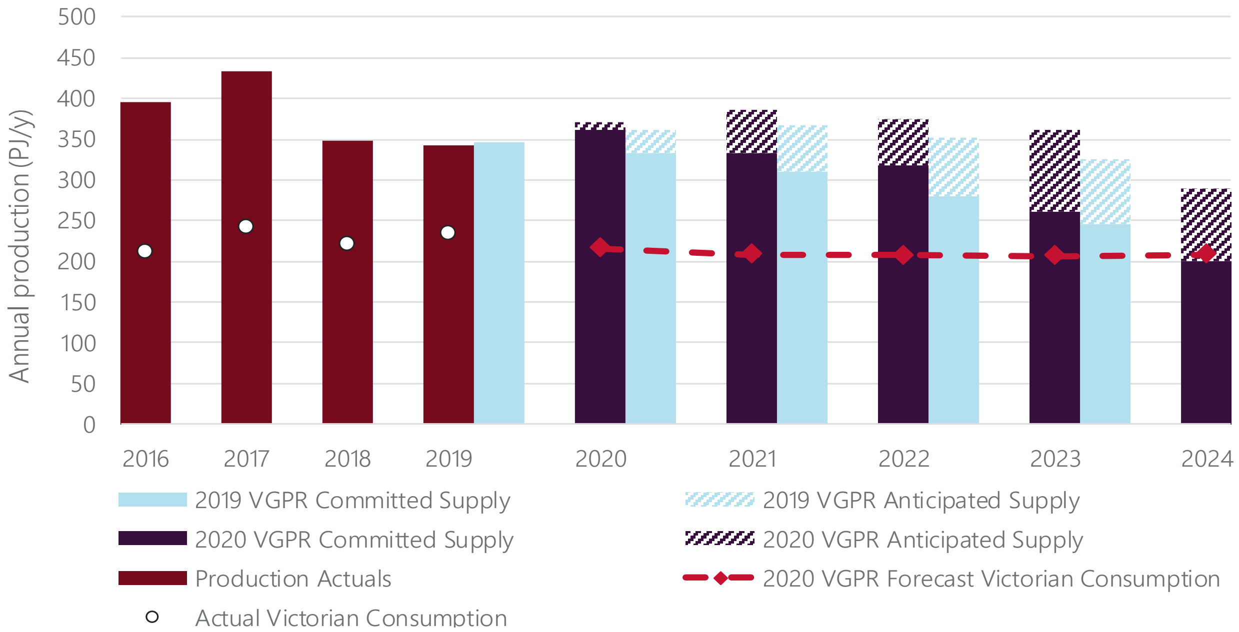
This section discusses forecast annual gas supply and its adequacy during the outlook period.

The forecast does not take into account DTS storage facilities, because these facilities provide seasonal balancing for the peak demand periods and are not expected to provide annual supplies.

3.2.1 Annual production forecasts

The Victorian annual production forecast is shown in Figure 8.

Figure 8 Annual production (PJ per year) and 2019 VGPR vs. 2020 VGPR Update forecasts



[31] Cooper Energy, "Minerva gas field to cease production, triggering acquisition of onshore gas plant", 3 September 2019, at https://www.cooperenergy.com.au/Upload/Minerva-gas-field-and-plant.pdf.

[32] Cooper Energy, "Sole Gas Project update", 10 December 2019, at https://www.cooperenergy.com.au/Upload/2019.12.10-Sole-Gas-Project-update.pdf.

[33] Cooper Energy, "Sole Gas Project Update: East Gippsland Bushfires", 6 January 2020, at https://www.cooperenergy.com.au/Upload/2020.01.06-Sole-project-ASX-update-Bushfires.pdf.

[34] Cooper Energy, "Sole Gas Project Update", 18 February 2020, https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Sole-project-ASX-update-Feb-18.pdf.

Key points are:

- In comparison to the 2019 VGPR, annual production forecasts provided by producers have increased from 2020 to 2023. This is due to increased Gippsland production output over the outlook period and previously uncommitted projects reaching final investment decision (FID) (projects are not included in available supply until they reach FID). This is consistent with the findings in the Australian Competition Consumer Commission (ACCC) Gas Inquiry reports[35,36].
- While there is an improvement in the production forecasts, the projected production decline continues as offshore gas fields further deplete.
- The Otway Basin gas fields are forecast to deplete in 2023, reducing available Port Campbell production from 32 PJ in 2022 to 1 PJ in 2023.
- There is a large reduction in available Gippsland production forecast in 2024. Most of Gippsland's gas was contained in three fields; Marlin, Barracouta, and Snapper. The steep decline in forecast production in 2024 is driven by one of the key Gippsland Basin Joint Venture (GBJV) fields being forecast to reach end of life[37], lowering the available Gippsland supply forecast from 260 PJ in 2023 to 201 PJ in 2024.
- There is inherent uncertainty in predicting when a gas field will decline using current estimation methods, because they are subjective estimates influenced by assumptions and company views[38]. Gas fields' remaining life could extend well past their forecast depletion date, as the Minerva gas field has done[39], or could deplete earlier than forecast, which one of the large original GBJV fields did[40]. If the Gippsland field depletes earlier than forecast, the large decline in available production could potentially occur from 2023.
- The COVID-19 coronavirus is causing disruptions to the global LNG market which have the potential to impact the supply and demand balance across eastern Australia, including Victoria. There has been a substantial drop in international LNG spot prices[41], and while Australia exports few spot cargoes[42], there may be impacts due to oil-linked LNG contracts and further reductions in international LNG demand.
  - In the short term, lower international LNG prices will likely increase supply from Queensland into the domestic market, potentially reducing Victorian production and extending the life of the fields.
  - In the longer term, lower international prices may suppress exploration and development expenditure, reducing the longer term supply outlook.

Anticipated supply includes the uncommitted supply that is considered likely to be brought online from 2020 onwards. No new projects, however, have progressed into the anticipated category since the 2019 VGPR to backfill the projects that have advanced into committed projects. The ACCC inquiry also found that undeveloped gas reserves are "increasingly dependent on more speculative sources of supply"[43]. If all anticipated projects become committed within this timeframe and produce gas as advised, 2024 forecast production would increase from 201 PJ to 289 PJ. The Otway Basin provides 64% of the anticipated supply, with fewer anticipated projects forecast in the Gippsland Basin to backfill the decline.

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[35] Australian Competition and Consumer Commission (ACCC), "Gas inquiry 2017-2020 Interim report", July 2019, at https://www.accc.gov.au/system/files/Gas%20inquiry%20July%202019%20interim%20report.pdf.

[36] Australian Competition and Consumer Commission (ACCC), "Gas inquiry 2017 -2025 Interim report", January 2020, at https://www.accc.gov.au/system/files/Gas%20inquiry%20January%202020%20interim%20report.pdf.

[37] ExxonMobil, "Key gas fields nearing end but news not all bad", 18 October 2019, at https://www.exxonmobil.com.au/Community-engagement/Local-outreach/Esso-community-news/2017/1018_Key-gas-fields-nearing-end-but-news-not-all-bad.

[38] PWC, "Financial reporting in the oil and gas industry", September 2011, at http://www.pwc.com/id/en/publications/assets/eumpublications/financial-reporting-in-the-oil-and-gas-industry.pdf.

[39] BHP, "BHP Operational Review for the quarter ended 30 September 2019", 17 October 2019, at https://www.bhp.com/-/media/documents/media/reports-and-presentations/2019/191017_bhpoperationalreviewforthequarterended30september2019.pdf?la=en.

[40] ACCC, 2017-2020 Gas Inquiry: Interim report, p. 30, at https://www.accc.gov.au/publications.

[41] Reuters, "Global LNG-Asian LNG prices fall to $2.70/mmBtu amid coronavirus outbreak", 14 February 2020, at https://www.reuters.com/article/global-lng/global-lng-asian-lng-prices-fall-to-2-70-mmbtu-amid-coronavirus-outbreak-idUSL4N2AE2BM.

[42] Reserve Bank of Australia (RBA), "Australia and the Global LNG Market", 2015, at https://www.rba.gov.au/publications/bulletin/2015/mar/pdf/bu-0315-4.pdf.

[43] ACCC, Gas Inquiry 2017-2025 Interim Report, January 2020 at https://www.accc.gov.au/system/files/Gas%20inquiry%20January%202020%20interim%20report.pdf.

3.2.2 Annual supply adequacy

Table 8 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 there is sufficient supply over the outlook period. The production forecasts show that:

- At the start of the outlook period, there is sufficient supply to meet forecast annual demand, with approximately 145 PJ of surplus gas available to supply New South Wales, South Australia, and Tasmania. By 2023, this is forecast to reduce to 54 PJ of gas available to support neighbouring jurisdictions.
- Winter monthly gas consumption in Victoria is up to three times summer monthly consumption. 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 from 2023.
- At the end of the outlook period, if anticipated projects do not become committed, there is forecast to be a 7 PJ Victorian supply shortfall in 2024.
  - If Gippsland production declines earlier than the current forecast, there is a risk of a potential shortfall from 2023.
  - If GPG consumption is higher than forecast (risks identified in Chapter 2), this would further tighten the supply demand balance.
- The forecast supply shortfall in 2024 means Victoria would need to source gas from uncommitted projects or from other states. Victoria can currently only import gas via the Moomba to Sydney pipeline (MSP) through the Culcairn interconnection.
- There is 88 PJ of anticipated (uncommitted but likely to proceed) gas production forecast to be available in 2023. If it becomes committed, this would result in a surplus of 81 PJ, and this surplus gas may be used to supply neighbouring jurisdictions.

Table 8 Total gas production by SWZ (PJ/y), 2020-2024

	Supply source	2020	2021	2022	2023	2024
Gippsland[A]	Contracted	281	218	216	113	68
	Uncontracted	31	76	71	146	133
	Total available	**312**	**294**	**286**	**260**	**201**
	Anticipated	0	27	30	30	32
	Total available plus anticipated	**312**	**320**	**316**	**290**	**232**
Port Campbell (Geelong)[B]	Contracted	49	24	18	1	1
	Uncontracted	0	16	14	0	0
	Total available	**49**	**39**	**32**	**1**	**1**
	Anticipated	10	27	26	71	56
	Total available plus anticipated	**59**	**66**	**59**	**72**	**57**
Total available		361	333	318	260	201
Total DTS consumption[C]		197	196	196	195	195
Total Victorian non-DTS consumption		11	7	7	6	5
Total Victorian consumption		216	209	208	207	208
Surplus / shortfall quantity		**145**	**124**	**111**	**54**	**-7**
Total anticipated		10	54	56	101	88

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 (up until the field is transitioned to the Minerva gas plant). 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.

Victoria has supplied, on average, 150 PJ/y to South Australia, New South Wales, and Tasmania from its production surplus.

The annual production surplus is forecast to decline from 145 PJ in 2020 to a production deficit of 7 PJ in 2019. If additional production does not eventuate in Victoria, this gas must be supplied from other sources. Not all the additional supply may be able to be sourced from Queensland, because the current maximum physical capacity of gas flow from Queensland to the southern states through existing pipeline infrastructure is 145 PJ/y.

Ensuring continued gas supply to both Victoria and neighbouring jurisdictions will require the progression of potential projects (currently not considered likely to proceed during the outlook period), the expansion of pipelines for importing additional gas supply, or an LNG import terminal. These options for additional supply are discussed in Chapter 4. The impacts of reduced Victorian supplies for other states are explored further in the 2020 GSOO.

3.3 Peak day supply demand balance

Producers have advised AEMO that there is an improvement in the available peak day supply from 2020 to 2023, compared to the 2019 VGPR. A steep decline in available peak day supply is forecast from 2023 to 2024, where total peak day supply (including storage) reduces from 1,431 TJ/d to 1,093 TJ/d:

- Gippsland producers have advised that their maximum daily production capacity will reduce by 41%, from 1,059 TJ/d in 2020 to 629 TJ/d in 2024.
- Port Campbell producers have advised that their maximum daily production capacity will reduce by 84%, from 201 TJ/d in 2020 to 32 TJ/d in 2024.
- There is no change to the Iona UGS and Dandenong LNG peak day supply capacity from the 2019 VGPR.

The production decline is accentuated in the peak day forecast because a large proportion of the remaining fields are only able to produce gas at a constant rate, and the Longford Gas Conditioning Plant, which is required to process gas from higher impurity fields, is limited to a capacity of 427 TJ/d or 150 PJ/y[44].

3.3.1 Forecast peak day supply

Table 9 shows the total forecast available peak day gas supply capacity by supply source.

Table 9 Peak day maximum daily quantity (MDQ) capacity by supply source (TJ/d), 2020-24

SWZ	Supply source	2020	2021	2022	2023	2024
Gippsland[A]	Contracted	942	634	634	351	213
	Uncontracted	117	373	358	616	416
	Total available	**1,059**	**1,007**	**992**	**967**	**629**
	Anticipated	0	73	82	82	87
	Total available plus anticipated	**1,059**	**1,081**	**1,074**	**1,049**	**716**
Port Campbell (Geelong)[B]	Contracted	591	571	553	492	492
	Uncontracted	45	81	71	30	30
	Total available	**636**	**652**	**623**	**522**	**522**
	Anticipated	31	83	92	205	220
	Total available plus anticipated	**667**	**735**	**716**	**727**	**742**
Melbourne	LNG	87	87	87	87	87
Total available (Not including pipeline constraints)		1,781	1,746	1,703	1,576	1,238

[44] 427 TJ/d. BHP media release, "Longford Gas Conditioning Plant Project Approval", 13 December 2012, at https://www.bhp.com/media-and-insights/newsreleases/2012/12/longford-gas-conditioning-plant-project-approval.

Capacity will vary depending on the composition of unprocessed gas and the level of impurities present.

SWZ	Supply source	2020	2021	2022	2023	2024
Total available supply to the DTS including pipeline constraints		**1,508**	**1,457**	**1,442**	**1,431**	**1,093**
1-in-20 year peak system demand		1,249	1,252	1,252	1,245	1,246
DTS surplus/shortfall quantity on 1-in-20 peak day		**259**	**205**	**190**	**185**	**-153**
Total anticipated		31	156	174	287	307
Total balance including pipeline constraints		**259**	**228**	**227**	**249**	**-66**

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

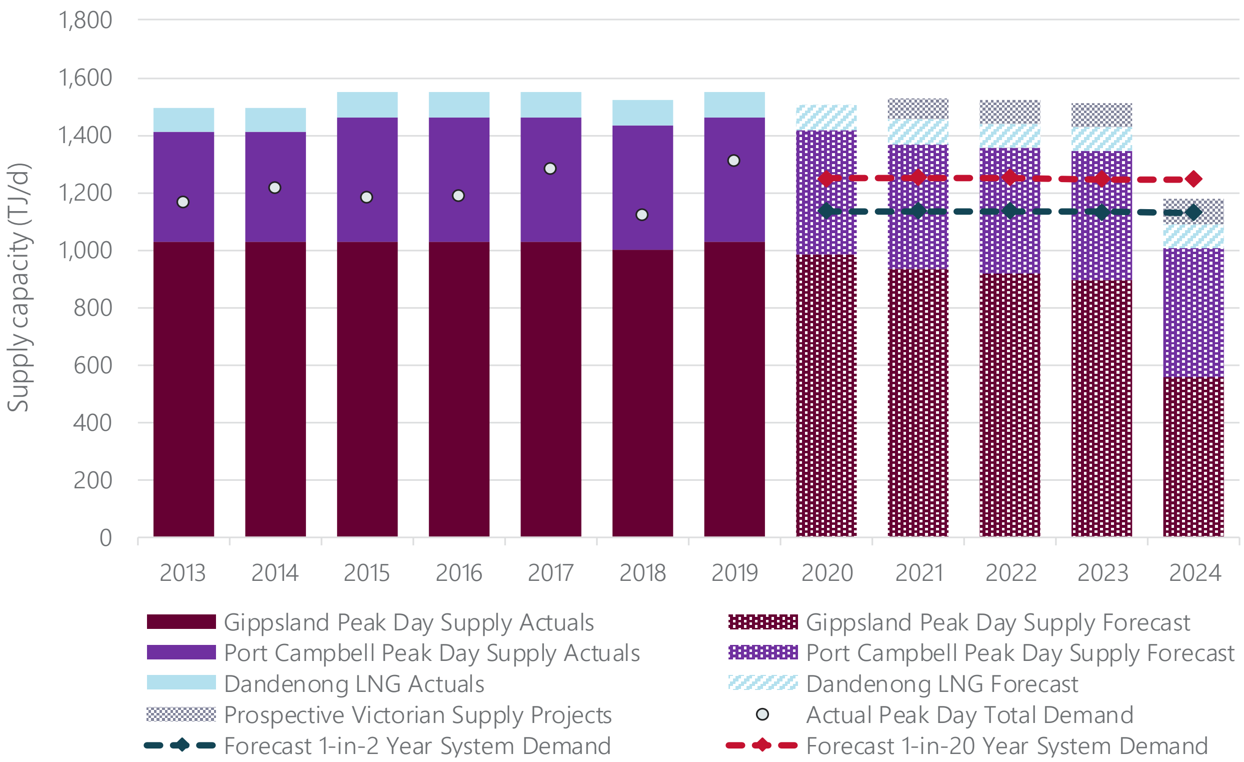
Figure 9 illustrates a shortfall or surplus as the difference between the forecast peak demand day (dotted line) and forecast supply capacity (stacked bar), taking into account pipeline constraints.

It shows that Victorian maximum daily supply capacity is forecast to reduce by 28%, from 1,508 TJ in 2019 to 1,093 TJ in 2023:

- Gippsland maximum daily supply capacity is forecast to reduce by 41%, from 1,059 TJ/d in 2020 to 629 TJ/d in 2024. The Gippsland maximum daily supply capacity is identical to the peak daily production capacity, as the supply is not limited by pipeline capacity.
- Port Campbell maximum daily supply capacity, which includes Iona UGS, is forecast to reduce by 18%, from 636 TJ/d in 2020 to 522 TJ/d in 2024. This remains higher than the South West Pipeline (SWP) capacity, which is forecast to increase from 434 TJ/d in 2019 to 449 TJ/d after the completion of the Western Outer Ring Main (WORM).

A forecast improvement in peak day available capacity from 2020 to 2023 is projected to alleviate the tight supply demand balance that was forecast for 2023 in the 2019 VPGR.

Figure 9 Peak day supply capacity by location (TJ/d)



In 2024, a large production decline is forecast. Without additional gas supply capacity, there is projected to be insufficient gas to supply a 1-in-20 peak winter demand day, and gas supply restrictions or curtailment of GPG would be required to maintain system security.

If the gas fields deplete earlier than forecast, there would be an increased reliance on the Iona UGS facility and Dandenong LNG storage, and increased risk of a supply shortfall and curtailment of GPG from 2023.

The WORM is a planned augmentation of the DTS that will increase the Iona UGS refilling capacity and the peak day supply capacity. In December 2019, the Victorian Government determined that an Environmental Effects Statement (EES) will be required for the WORM project[45]. A delay from APA Group's target mid-2021 completion date has been assumed[46], with AEMO forecasting that the WORM will not be available until mid-2022. Further delays to this project will increase the risk of depleting Iona storage levels and reduce the available peak day supply capacity, further tightening the supply-demand balance in 2023 and 2024.

Gas supplies available for export to New South Wales, Tasmania, and South Australia on a peak demand day will reduce with the tighter supply demand-balance. The 2020 GSOO assesses supply adequacy for those regions.

Assuming all anticipated supply becomes committed in 2024, there is a still a forecast 1-in-20 winter peak day shortfall. Due to the location of gas supplies, transmission constraints, and Victorian non-DTS gas consumption, not all peak day supply capacity is available to the DTS.

The majority of the 307 TJ/d additional anticipated peak day supply capacity is located within the Port Campbell region and hence is limited by the SWP capacity. Only 87 TJ/d of the additional anticipated peak day supply capacity is forecast to be available without further SWP expansions.

2020 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 2020. Table 10 shows that 532 TJ/d of spare capacity is projected to be available to supply DTS-connected GPG demand and to flow to neighbouring jurisdictions.

Table 10 DTS capacities and expected supply on a 1-in-20 peak demand day, 2020 (TJ/d)

		Total plant capacity	Pipeline capacity	DTS potential supply	Expected supply	Remaining supply capacity
Gippsland		1,059	1,030	1,030	900	159
Port Campbell	To Melbourne	636	414	434	349	286
	To WTS		20			
Melbourne	LNG storage	87		87	0	87
Total supply		**1,781**	**1,464**	**1,551**	**1,249**	
1-in-20 year system demand		**1,249**	**1,249**	**1,249**	**1,249**	
DTS surplus/shortfall quantity (TJ/d)		**532**	**215**	**302**		**532**

2024 peak day outlook

Table 11 shows a forecast shortfall of 158 TJ/d on a 1-in-20 winter peak demand day.

All Gippsland daily production is scheduled to supply the DTS, except for 65 TJ which is required to support demand in eastern Victoria via the Eastern Gas Pipeline, southern New South Wales, and Tasmania. As

[45] Victoria Land, Water and Planning, "Reasons for decision under Environment Effects Act 1978", 22 December, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/446979/Reasons-for-Decision.pdf.

[46] APA, "Western Outer Ring Main Pipeline", December 2019, at https://www.apa.com.au/globalassets/documents/our-current-projects/worm/worm_a3_update-01.pdf.

Gippsland is the only source of supply to these regions, this gas cannot be used to supply the DTS without curtailing customers in these locations.

Table 11 DTS capacities and expected supply on a 1-in-20 peak demand day, 2024 (TJ/d)

<table>
<tr><th colspan="2"></th><th>Total plant capacity</th><th>Pipeline capacity</th><th>DTS potential supply</th><th>Expected supply</th><th>Remaining supply capacity</th></tr>
<tr><td colspan="2">Gippsland</td><td>629</td><td>1,030</td><td>629</td><td>564</td><td>65</td></tr>
<tr><td rowspan="2">Port Campbell</td><td>To Melbourne</td><td rowspan="2">522</td><td>429</td><td rowspan="2">449</td><td rowspan="2">449</td><td rowspan="2">73</td></tr>
<tr><td>To WTS</td><td>20</td></tr>
<tr><td>Melbourne</td><td>LNG storage</td><td>87</td><td></td><td>87</td><td>75</td><td>12</td></tr>
<tr><td colspan="2">Total supply</td><td>**1,238**</td><td>**1,479**</td><td>**1,165**</td><td>**1,088**</td><td></td></tr>
<tr><td colspan="2">1-in-20 year system demand</td><td>**1,246**</td><td>**1,246**</td><td>**1,246**</td><td>**1,246**</td><td></td></tr>
<tr><td colspan="2">DTS surplus/shortfall quantity (TJ/d)</td><td>**-8**</td><td>**233**</td><td>**-81**</td><td>**-158**</td><td>**150**</td></tr>
</table>

This forecast assumes that the WORM is commissioned and will provide additional peak day supply from the Port Campbell region. If the WORM is not commissioned by 2024, the peak day supply shortfall will increase.

If neighbouring jurisdictions were to experience gas demand above their state average which coincides with a peak demand day occurring in Victoria, shortfalls would need to be managed among the jurisdictions with arrangements established under the National Gas Emergency Response Advisory Committee (NGERAC)[47].

[47] Council of Australian Governments (COAG) Energy Council, "Gas Emergency Response", at http://www.coagenergycouncil.gov.au/current-projects/gas-emergency-response.

4. Potential future gas supply sources

Key findings

Projects remain largely unchanged since the 2019 VGPR, with these updates:

- In the Gippsland Basin, Kipper Stage 1B reserves have been upgraded by 60 PJ following the completion of technical studies.
- In the Otway Basin, there was a new gas field discovery at Annie (estimated 55 PJ).
- Potential LNG import terminal projects:
  - Australian Industrial Energy (AIE) has increased the planned capacity of the Port Kembla LNG import terminal to 500 TJ/d. The previously scheduled timing (production start in 2020) has been delayed.
  - The proposed AGL LNG import terminal at Crib Point in Victoria has also experienced delays from its original schedule (construction now expected to start in 2021).
  - ExxonMobil has shelved plans for an LNG import terminal.
- The Victorian Gas Program, in its fourth progress report, has concluded that the most likely prospective resource estimate (which are undiscovered accumulations) for onshore Victorian conventional gas is 547 PJ.

This chapter provides information on projects that have had a material change since the publication of the 2019 VGPR. For information on projects that have not had a material change, refer to the 2019 VGPR.

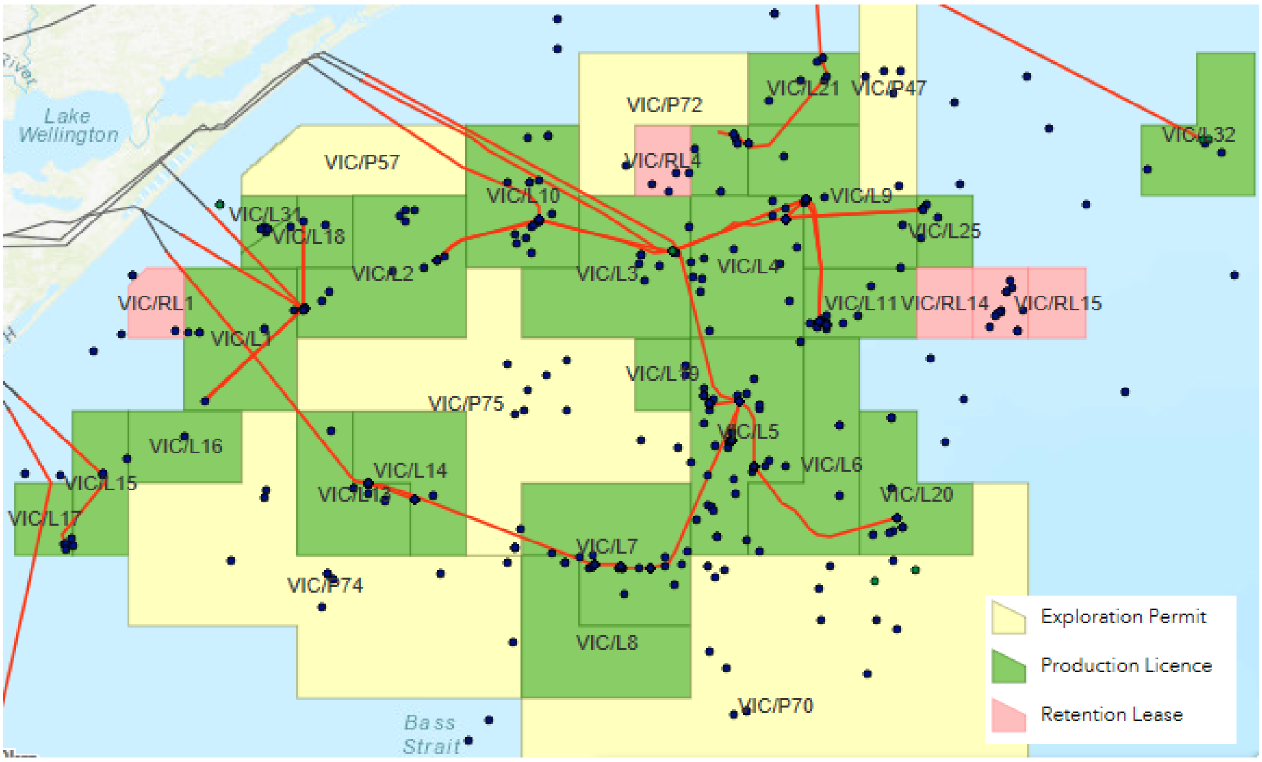
4.1 Anticipated supply

Anticipated supply projects consist of undeveloped 2P reserves[48] which are anticipated by producers to be developed during the outlook period. All the anticipated supply projects are included in the anticipated supply forecast.

[48] 2P reserves- sum of proved and probable reserves typically regarded as the best estimate of recoverable gas

Gippsland Basin

Figure 10 Gippsland Basin titles map



National Offshore Petroleum Titles Administrator (NOPTA), Interactive map, at https://www.nopta.gov.au/maps-and-public-data/interactive-map.html.

Kipper Stage 1B

Title holder Kipper Unit Joint Venture

Operator Esso Australia Resources Pty Ltd

Permit/Lease VIC/L9 & VIC/L25 (Production Licenses)

Discovered 1986

Estimated reserves Not available

Planned production date 2021[49]

The expected timing of production from Kipper Stage 1B remains unchanged from the 2019 VGPR. Kipper field resources were estimated at 654 PJ prior to the start of production in 2017[50]. A technical study conducted in FY19 increased the proved undeveloped reserves from Kipper Stage 1B project by 60 PJ[51].

Information about this project was provided to AEMO.

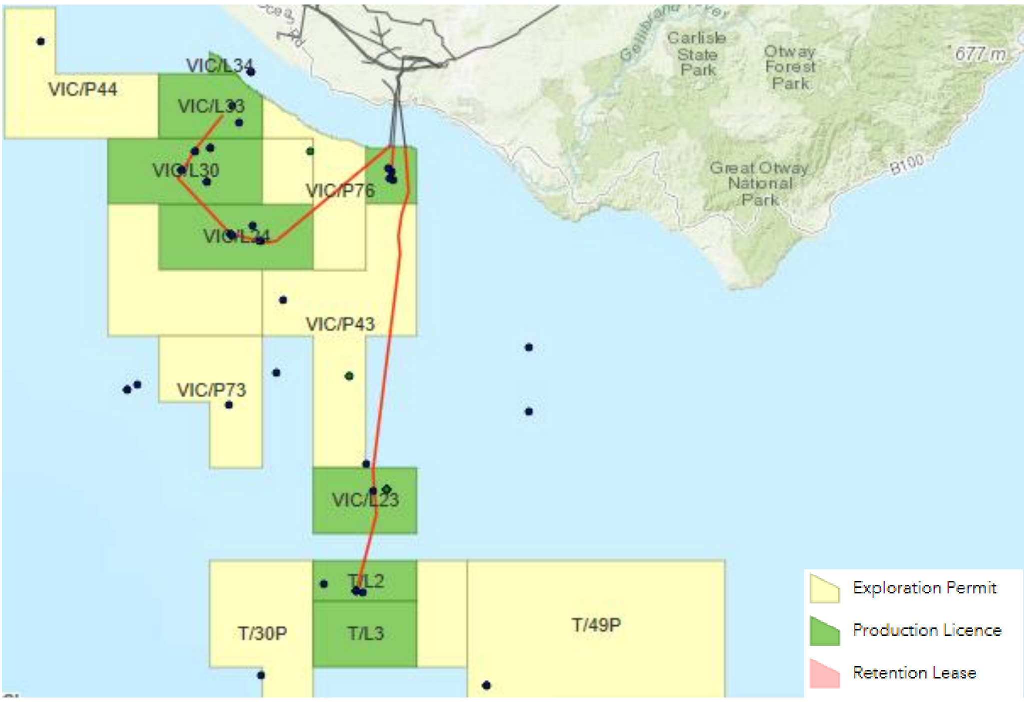
[49] ExxonMobil, "Esso Offshore projects", 4 July 2018, at https://www.exxonmobil.com.au/-/media/Australia/Files/Newsroom/Offshore-projects-fact-sheet.pdf.

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

[51] 10 Million barrels of oil equivalent (Mmboe). BHP Group, "2019 US Annual Report", p 269, at www.asx.com.au/asxpdf/20190917/pdf/448l5pdg5ldj4m.pdf.

Otway Basin

Figure 11 Otway Basin titles map



NOPTA, Interactive map, at https://www.nopta.gov.au/maps-and-public-data/interactive-map.html.

Black Watch

Title holder VIC/L1(v) (Victorian Production License – Beach Energy and OGOG Energy); VIC/L33 & VIC/L34 Cooper Energy, Mitsui)

Operator VIC/L1(v) – Beach Energy; VIC/L34 – Cooper Energy

Permit/Lease VIC/L1(v) (Victorian Production License – Beach Energy and OGOG Energy); VIC/L33 & VIC/L34 Cooper Energy, Mitsui)

Discovered 2005

Estimated reserves 17 PJ[52] (2P)

Estimated production date 2020[53]

Beach Energy spudded the Black Watch well on 6 January 2020, with production planned for Q2 2020[54].

This field straddles a permit boundary, with Beach Energy and OGOG on one side and Cooper Energy and Mitsui on the other. The production licences owned by Cooper and Mitsui were awarded in 2019[55]. It is not clear whether Beach Energy and the adjacent tenure holders have reached a commercial agreement and so the project is still included in anticipated supply.

Information about this project was provided to AEMO.

[52] Beach Energy, *Annual Report 2019*, at https://www.beachenergy.com.au/wp-content/uploads/2019/08/BeachEnergy_AnnualReport2019.pdf.

[53] Beach Energy, "FY20 Half Year Results Presentation", 11 February 2020, at https://www.asx.com.au/asxpdf/20200211/pdf/44dzjwmpgtlzcf.pdf.

[54] Beach Energy, "Quarterly report for the period ended 31 December 2019", 29 January 2020, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1199433/BPT_Quarterly_report_for_the_period_ended_31_December_2019.pdf.

[55] Cooper Energy, "Quarterly Report for 3 months to 30 September 2019", 15 October 2019, at https://www.cooperenergy.com.au/Upload/Q1-FY20-.pdf.

4.2 Potential projects

Potential projects are considered less likely than anticipated supply projects to be developed during the outlook period, due to either:

- The discovered gas field being classified as a contingent resource; or
- Insufficient gas gathering or processing infrastructure.

Gippsland Basin

Golden Beach

Title holder GB Energy

Operator GB Energy

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

Discovered 1967

Estimated resources 70 PJ[56] (2C)[57]

Planned production date 2022

Initially the Golden Beach gas field is expected to produce up to 100 TJ/d over 18 months, before being used as a storage reservoir. The project requires pipeline installation and construction of a new gas processing facility. An independent review of the project economics found that this project was commercial and Golden Beach are currently fundraising for investments to the project[58]. A project team is conducting engineering studies and seeking regulatory and land access approvals, with FID planned for second quarter 2020, drilling in 2021, and production in 2022[59].

Information about this project was provided to AEMO but was not included in the anticipated supply forecast because the project requires new gas processing infrastructure and is seeking funding.

Judith

Title holder Emperor Energy

Operator Emperor Energy Limited

Permit/Lease VIC/P47 (Exploration Permit)

Discovered 1989

Estimated resource 158 PJ (2C)[60]

Emperor Energy issued an updated independent resource report in 2019, upgrading the contingent resource (2C) estimate to 158 PJ based on reprocessing data from the Judith-1 drilled in 1989. Emperor Energy is seeking potential partners for an exploration and appraisal well drilling program planned to commence in

[56] 69 billion cubic feet (bcf). This report uses a conversion factor of 1.055 PJ/bcf, unless otherwise stated.

[57] Golden Beach, "Golden Beach Gas Production and Infrastructure Project", October 2019, at https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5dca3b0d5d270f270df14665/1573534481506/Golden+Beach+Gas+Production+and+Infrastructure+Project.pdf.

[58] GB Energy, *2019 Annual Report*, at https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5db8d642888fb410bd2689b8/1572394577064/GB+Energy+2019+Annual+Report.pdf.

[59] GB Energy, *http://www.coagenergycouncil.gov.au/current-projects/gas-emergency-response*, at https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5db8d642888fb410bd2689b8/1572394577064/GB+Energy+2019+Annual+Report.pdf.

[60] Emperor Energy Ltd, "Independent Resource Statement – Judith Gas Field", 11 July 2019, at https://www.asx.com.au/asxpdf/20190711/pdf/446k2gpmy4xhfv.pdf.

2021. A pre-Front End Engineering Design study, focussing on possible pipeline and processing assets, is planned for 2020. Completion of this study will inform a future project feasibility study[61].

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

Manta

Title holder Cooper Energy

Operator Cooper Energy

Permit/Lease VIC/RL13 (Retention Lease)

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

Prospective resource 121 PJ (2C)[62]

Planned production date Unknown

A technical study of the Manta gas field conducted in 2019 resulted in an upgrade of the contingent resource from 106 PJ to 121 PJ[63]. Manta is being considered as a follow-on development to Sole, with the capability to produce approximately 18 PJ/year. If Manta was to be brought online prior to the depletion of Sole, this would require an expansion of Orbost Gas Plant.

An appraisal well is required prior to a development decision. Drilling of this well, Manta-3, is targeted for 2021, subject to rig availability. The appraisal well will also present an opportunity to test the Manta Deep prospect, discussed in Section 4.3.

Information about this project was provided to AEMO.

Longtom

Title holder SGH Energy VICP54

Operator SGH Energy VICP54

Permit/Lease VIC/L29 (Production License)

Discovered 1995

Estimated reserve 80 PJ[64] (2C)

Estimated production date 2022

The Longtom gas field is connected by a gas gathering system to the Orbost Gas Plant. Negotiations are underway for access to the pipeline and processing infrastructure required to recover gas from the field, and technical studies have commenced into the feasibility of alternative options, such as using stand-alone infrastructure[65].

An environmental plan for the Longtom field was submitted in 2019. This plan included a proposed third subsea development well, Longtom-5, that would tie back to existing infrastructure[66]. Combined with the existing wells, the recoverable reserve estimate has increased to a total of 80 PJ.

AEMO could not request information about this field, because SGH Energy is not a registered participant.

[61] Emperor Energy Ltd, "Update on Memorandum of Understanding with APA Group", 23 December 2019, at https://www.asx.com.au/asxpdf/20191223/pdf/44cv3w232gnw7d.pdf.

[62] Cooper Energy, *2019 Annual Report*, at https://www.asx.com.au/asxpdf/20191008/pdf/4498x78d966d3l.pdf.

[63] Cooper Energy, *2019 Annual Report*, p 19.

[64] SGH, Result Release – Full year Ended 30 June 2019, at https://www.asx.com.au/asxpdf/20190821/pdf/447pgkbcn8446s.pdf.

[65] SGH, *Annual Report 2019*, at https://www.asx.com.au/asxpdf/20190821/pdf/447nmc3fs942tf.pdf.

[66] SGH Energy, Longtom Environment Plan, at https://docs.nopsema.gov.au/A691371.

Otway Basin

Annie

Title holders Cooper Energy, Mitsui

Operator Cooper Energy

Permit/Lease VIC/P44

Discovered 2019[67]

Prospective resource 55 PJ[68] (2C)

Estimated production date 2021[69]

Cooper Energy drilled an exploration well in 2019, successfully discovering gas in the Annie field. The field is located near the Casino, Henry, and Netherby field gas gathering infrastructure and could be processed through the newly acquired Minerva Gas Plant. Well results and data analysis are ongoing and will inform a development decision. A favourable decision on field development could result in the commencement of production from the Annie gas field in the latter half of 2021.

Information about this project was provided to AEMO. It was not included in anticipated supply, because Cooper Energy is yet to release a reserve statement following the exploration drilling.

La Bella

Title holder Beach Energy and OGOG

Operator Beach Energy

Permit/Lease Vic/P73

Discovered 1993

Estimated reserves 40 PJ (2P)[70]

Estimated production date 2022[71]

NOPTA approved a seabed survey for the La Bella field, which commenced in September 2019[72]. Beach Energy has proposed drilling a production well in the La Bella field from 2022, subject to the outcome of other exploration drilling results. It is anticipated that this field would be tied back to existing Geographe and Thylacine gas gathering infrastructure, for processing at the Otway Gas Plant. Historically, the field's relatively small reserves (40 PJ) and high carbon dioxide levels have been an impediment to development[73].

Information about this project was provided to AEMO.

Henry

Title holder Casino Henry Joint Venture

Operator Cooper Energy

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[67] Cooper Energy, "New gas field discovery at Annie", 6 September 2019, at https://www.cooperenergy.com.au/Upload/New%20gas%20field%20discovery%20at%20Annie.pdf.

[68] Cooper Energy, "Contingent Resource announcement: Annie gas field", 24 February 2020, at https://www.asx.com.au/asxpdf/20200224/pdf/44fcdpmkqg8838.pdf.

[69] Cooper Energy, "New gas field discovery at Annie", 6 September 20196 September 2019, at https://www.cooperenergy.com.au/Upload/New%20gas%20field%20discovery%20at%20Annie.pdf.

[70] Beach Energy, *Annual Report 2019*, athttps://www.beachenergy.com.au/wp-content/uploads/2019/08/BeachEnergy_AnnualReport2019.pdf.

[71] Beach Energy, U.S. and Canada roadshow presentation, 29 October 2019, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1182757/BPT_US_and_Canada_Roadshow_Presentation.pdf.

[72] NOPSEMA, "Environment Plan Otway Development Drilling and Well Abandonment", 29 August 2019, at https://docs.nopsema.gov.au/A690628.

[73] BHP, "Well Completion Report Interpretive Data", at http://er-info.dpi.vic.gov.au/documentation/scratch/hyp_of/SCANS_REEDITED_IMAGES/raw/wells/otw_off/final/az/labl1/pe900368__((_LA_BELLA-1_WCR_Vol.2__interpretive__))_.pdf.

Permit/Lease Vic/L30

Discovered 2005

Estimated reserve 48 PJ (2C)[74]

Estimated production date 2021

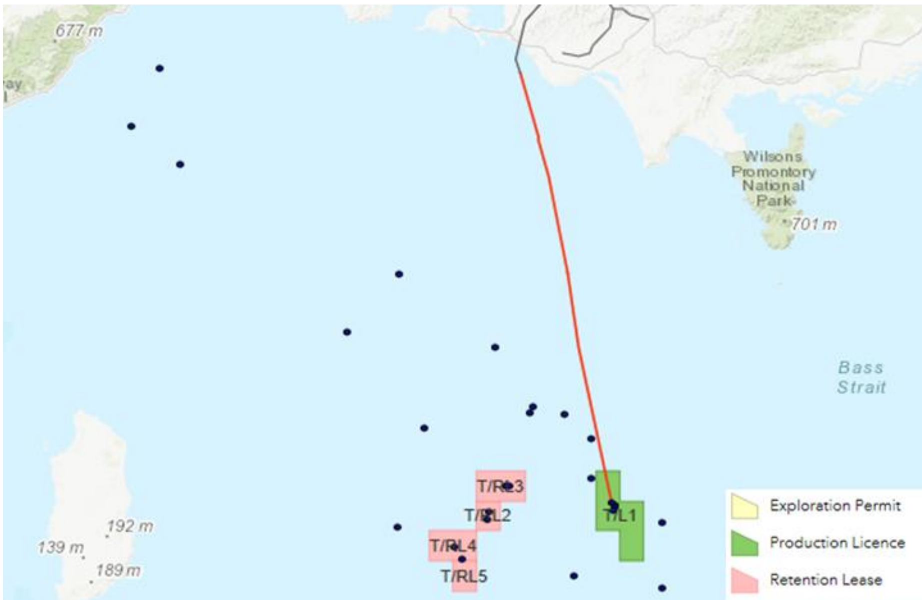
Cooper Energy has proposed the redevelopment of the Henry field, subject to rig availability and Joint Venture approval. If approved, drilling of a new well could commence in 2021, for immediate production.

A project is underway to connect the Henry field and nearby Casino and Netherby fields to the Minerva Gas Plant to enable gas production at lower operating pressure, enabling the remaining Henry reserves to be developed[75].

Information about this project was provided to AEMO.

Bass Basin

Figure 12 Bass Basin titles map



NOPTA, Interactive map, at https://www.nopta.gov.au/maps-and-public-data/interactive-map.html.

Trefoil

Title holder Beach Energy, Mitsui and Prize Petroleum

Operator Beach Energy

Permit/Lease T/RL2 (Retention Lease)

Discovered 2004

Estimated reserve 60 PJ (2P)[76]

Planned production date Unknown

Evaluation conducted in 2018-19 demonstrated the potential producibility of the field. As a result, it has been reclassified from a contingent resource to an undeveloped reserve[77]. Beach Energy is currently completing the

[74] Cooper Energy, Investor Pack, 16 October 2019, at https://www.asx.com.au/asxpdf/20191016/pdf/449jyq93pvxlmd.pdf.

[75] Cooper Energy, Investor Pack, 22 July 2019, at https://www.cooperenergy.com.au/Upload/July-investor-pack-update-.pdf.

[76] Beach Energy, *Annual Report 2019*, at https://www.asx.com.au/asxpdf/20190819/pdf/447l49dzlyp6wh.pdf.

[77] Ibid.

concept selection phase of the project. The current development plan is to drill two near horizontal wells and tieback to the existing nearby Yolla platform, with gas processing from the Lang Lang gas plant.

Information about this project was provided to AEMO. It was not included in anticipated supply, as it is still in the concept selection phase of the project lifecycle.

4.3 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

Drilling of the very deep-water Sculpin-1 at 2,300 m within the VIC/P70 permit area was completed in 2020[78]. No announcement has been made on the outcome of this work.

No information has been received by AEMO concerning this field.

West Longtom and West Remora

Title holder Cooper Energy

Operator Cooper Energy

Permit/Lease VIC/P72 (Exploration Lease)

Prospective resource Unknown

Two prospects, West Longtom and West Remora, have been identified in the VIC/P72 permit area. Subsurface studies and well design will be conducted to identify candidate prospects for drilling in 2021 [79].

No information has been received by AEMO concerning this field.

Pointer

Title holder Carnarvon Hibiscus, 3D Oil Limited

Operator Carnarvon Hibiscus

Permit/Lease VIC/P57 (Exploration Lease)

Prospective resource 248 PJ (2C)[80]

[78] Energy News Bulletin (Pay wall), "Drilling at Scuplin-1 well complete: Exxon confirms", 7 February 2020, at https://www.energynewsbulletin.net/development/news/1380570/drilling-at-sculpin-1-complete-exxon-confirms%C2%A0.

[79] Cooper Energy, *2019 Annual Report*, at https://www.asx.com.au/asxpdf/20191008/pdf/4498x78d966d3l.pdf.

[80] 3D Oil Limited, "Taylor Collision 2019 East coast Gas Day", at http://www.openbriefing.com/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20190411%2F02095390.pdf.

The Joint Venture is currently in the process of farming out the license to drill a proposed exploration well in either 2021 or 2022[81].

Otway Basin

Nestor

Title holder Cooper Energy, Mitsui

Operator Cooper Energy

Permit/Lease VIC/P76

Discovered N/A (Prospective Resource)

Estimated resource Unknown

Cooper Energy was awarded the new exploration permit VIC/P76 in September 2019. It contains the play Nestor, which shows similar characteristics to the adjacent gas field Annie[82]. Cooper is currently completing subsurface analysis, with exploration drilling currently planned for 2021[83].

No information has been received by AEMO concerning this field.

T/30P

Title holder Beach Energy

Operator Beach Energy

Permit/Lease T/30P

Discovered N/A (Prospective Resource)

Estimated resource Unknown

Estimated production date Unknown

Beach Energy has scheduled an exploration well within the T/30P permit area in 2021[84], however the exact location of the well is yet to be determined[85]. The T/30P permit area is situated on either side of the T/L2 and T/L3 permits which contains the currently producing Thylacine gas field.

4.4 Onshore projects

The *Resources Legislation Amendment (Fracking Ban) Act 2017* (Vic) came into operation on 16 March 2017 and imposed a moratorium on conventional exploration and production in the onshore areas of Victoria. It was due to expire on 30 June 2020[86].

The Victorian Gas Program[87] scope includes scientific research and related activities to assess the potential for onshore conventional gas in Victoria. Progress Report No. 4[88] of the three-year program concluded that:

- An onshore conventional gas industry would not compromise the state's environmental and agricultural credentials and should be allowed to recommence.

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[81] Hibiscus Petroleum, "An insight into Malaysia's First Listed Pure Play Oil and Gas Exploration Company", at https://12363a36-44cf-4eaa-9a8a-f70c19fbe556.filesusr.com/ugd/6a7e03_6a45d4d3ba954e00bc5f69f96421c511.pdf.

[82] Oil & Gas Journal, "Cooper Energy awarded new permit near Annie discovery", 18 September 2019, at https://www.ogj.com/exploration-development/article/14040168/cooper-energy-awarded-new-permit-near-annie-discovery.

[83] Cooper Energy, "Investor Update 2019", October 2019, at https://www.cooperenergy.com.au/Upload/Investor-Update-October-2019.pdf.

[84] Beach Energy, "Victorian Otway Basin site visit", at https://www.asx.com.au/asxpdf/20190924/pdf/448tfv5hcg18mm.pdf.

[85] Beach Energy, "Environmental Plan, Otway Geophysical and Geotechnical Seabed Assessment", at https://www.nopsema.gov.au/assets/epdocuments/A681252.pdf.

[86] Victorian Government, Restrictions on onshore gas, at https://earthresources.vic.gov.au/geology-exploration/oil-gas/restrictions-on-onshore-gas.

[87] Victorian Government, Victorian Gas Program, at https://earthresources.vic.gov.au/projects/victorian-gas-program.

[88] At https://earthresources.vic.gov.au/__data/assets/pdf_file/0005/524489/VGP_PR04-120320-Low-Res.pdf.

- The onshore Otway Basin low (P90) prospective resource estimate is 317 PJ and the high (P10) estimate is 715 PJ. Prospective resources are quantities of gas that are estimated to be potentially recoverable from undiscovered accumulations.
- The onshore Gippsland Basin low (P90) prospective resource estimate is 38 PJ and the high (P10) estimate is 115 PJ.
- The most likely prospective resource estimate (P50) is 547 PJ.
- The additional gas that could be produced in the state would contribute to gas supply but would not address Victoria's forecast peak day shortfalls unless pipeline constraints are also addressed.
- The additional gas would improve energy security by increasing the diversity of gas supply. It would also benefit industrial users, particularly in regional areas, by providing new options for local gas supplies.

To manage the restart of the onshore conventional gas industry and implement the relevant regulations, the moratorium on exploration will be lifted on 1 July 2021[89]. The timing and quantity of any new supply that may become available are still unclear.

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.

Golden Beach underground gas storage facility

The Golden Beach gas reservoir discussed in Section 4.2 has also been proposed for development into an underground gas storage facility, to supply peak period demand by injection of gas into the DTS at the Longford close proximity point (CPP).

The scope of this proposal is unchanged from the 2019 VGPR. Since the 2019 VGPR, Golden Beach Energy has announced that the storage capacity is expected to be 12.5 PJ, with a maximum DTS injection rate of 250 TJ/d[90].

4.6 Imports into the DTS

Narrabri Gas Project

The Santos Narrabri Gas Project is a 200 TJ/d proposed project in the Gunnedah Basin of New South Wales. Regulatory approvals are expected in the first half of 2020[91], and a non-binding memorandum of understanding for supply from the project references commencement of operation no earlier than 2023[92].

The scope of possible associated pipelines – the Western Slopes Pipeline and Hunter Gas Pipeline – remains unchanged from the 2019 VGPR.

4.7 LNG import terminals

At the start of 2019, there were five potential LNG import terminal projects around the south-east coast of Australia.

[89] Victorian Government, at https://www.premier.vic.gov.au/backing-the-science-protecting-farmers-and-boosting-jobs/.

[90] Golden Beach Energy, *GB Energy 2019 Annual Report*, 29 October 2019, at https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5db8d642888fb410bd2689b8/1572394577064/GB+Energy+2019+Annual+Report.pdf.

[91] The Australian, "Santos eyes Narrabri approvals, lifts output', at https://www.theaustralian.com.au/business/mining-energy/santos-lifts-2019-production-by-28pc/news-story/ed2986cbdc9deac4e5c5f2a85d9afdd8.

[92] Santos, Second Quarter Activities Report, at https://www.asx.com.au/asxpdf/20190718/pdf/446psnm0dghmvz.pdf.

ExxonMobil has since shelved plans to build a terminal on the Victorian Gippsland coast, citing insufficient interest from potential customers[93]. The remaining four projects have all suffered delays from their original schedule. Of these four projects, two could provide additional peak day capacity to Victoria:

- AGL Energy, Crib Point LNG Import Terminal, Victoria.
- AIE, Port Kembla Gas Terminal, New South Wales.

As potential projects they are excluded from the anticipated supply forecast.

AGL Cribb Point LNG Import Terminal

The proposed scope and supply capacity remain unchanged from the 2019 VGPR. AGL expects the outcome of the EES to occur no earlier than the first half of 2020, subject to and following which AGL expects to reach FID on the project. AGL have advised that the timing is likely to be impacted by increased complexity with first gas now expected in 2022-23[94].

Port Kembla Import Terminal

The New South Wales Government declared this project Critical State Significant Infrastructure in June 2018 and awarded it Development Consent in April 2019.

The project scope was subsequently modified to permit seasonal variability in demand through an increase in capacity up to 500 TJ/d, which could potentially lead to an increase in the frequency of LNG shipments from 24 to 52 per year[95]. A re-approval process commenced in the second half of 2019, and no revised proposed first gas date has been announced.

4.8 Distributed gas supply

Decarbonisation of gas distribution networks through biogas and hydrogen can utilise existing networks to deliver low carbon energy. While these technologies are not expected to materially impact DTS supply and demand during the 2020 VGPR Update outlook period, AEMO will continue to monitor developments and provides the summaries below for information.

4.8.1 Hydrogen

The Australian Government's *National Hydrogen Strategy*, published in November 2019[96], identifies a number of coordinated strategic actions for governments to enable use of clean hydrogen in Australian gas networks. These strategic actions encompass technical, regulatory, and community workstreams to potentially enable 100% hydrogen in natural gas distribution networks.

A review commissioned as part of the National Hydrogen Working Group's development of the Strategy found that, providing the hydrogen in the natural gas mixture is homogenous, the addition of 10% hydrogen to natural gas has no significant impacts or implications on gas quality, safety and risk aspects, materials, network capacity, or blending[97].

The Victorian Government released a discussion paper in November 2019 requesting stakeholder input into the development of a green hydrogen sector as part of the Victorian Hydrogen Investment Program (VHIP).

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[93] Sydney Morning Herald, "ExxonMobil shelves Victorian gas import terminal", at https://www.smh.com.au/business/companies/exxonmobil-shelves-victorian-gas-import-terminal-plan-20191201-p53fri.html.

[94] AGL Energy, Update on Crib point gas import terminal project, at https://www.asx.com.au/asxpdf/20190628/pdf/44660ztgbgw6ls.pdf.

[95] Australian Industrial Energy, *Environmental Assessment*, at https://ausindenergy.com/file/2019/12/MOD-Environmental-Assessment-r.pdf.

[96] COAG Energy Council 2019, *Australia's National Hydrogen Strategy*, at https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy.

[97] GPA Engineering 2019, *Hydrogen in the Gas Distribution Networks*, at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-hydrogen-in-the-gas-distribution-networks-report-2019_0.pdf.

The outcomes of the discussion paper will inform an Industry Development Plan for Victoria's green hydrogen producers and users[98].

There are four projects underway in South Australia, New South Wales, and Queensland investigating hydrogen blending in natural gas, and a Clean Energy Innovation Hub in Western Australia that will investigate the potential role of hydrogen and biogas in the future energy mix[99].

While there are currently no hydrogen blending in natural gas projects planned in Victoria, demonstration projects such as the Hydrogen Energy Supply Chain (HESC) pilot project are expected to provide critical learnings to strengthen Victoria's green hydrogen supply chain capabilities.

4.8.2 Biogas

Biogas is a source of energy that can be converted into heat or electricity. The *Biogas Opportunities for Australia*[100] report released in 2019 estimates that Victoria's biogas potential represents up to 27% of the state's gas consumption from the existing natural gas network. The Australian biogas industry is emerging, with waste-to-energy feasibility studies and projects in the development stage.

[98] The State of Victoria Department of Environment, Land, Water and Planning 2019, at https://engage.vic.gov.au/vhip.

[99] Energy Networks Australia, *Gas Vision 2050*, October 2019, at https://www.energynetworks.com.au/resources/reports/gas-vision-2050-hydrogen-innovation/.

[100] ARENA, March 2019, *Biogas Opportunities for Australia*, at https://arena.gov.au/assets/2019/06/biogas-opportunities-for-australia.pdf.

5. Declared Transmission System adequacy

Key findings

- APA has completed the Warragul lateral duplication and subsequently the threat to system security relating to peak day supply to Warragul custody transfer meter (CTM) has ended.
- VNI import capacity has increased to 170 TJ/d, with the capacity still subject to Uranquinty Power Station operation and operating conditions on the Moomba – Sydney pipeline.

5.1 System augmentations

5.1.1 Western Outer Ring Main

The WORM is a planned augmentation of the DTS which will connect the SWP/ Brooklyn to Lara Pipeline (BLP) to the VNI and Longford to Melbourne Pipeline (LMP). The project will also include the installation of additional compression at Wollert and a new pressure reduction station (PRS) which will enable flow from the WORM into the Pakenham to Wollert pipeline.

In December 2019, the Victorian Government determined that an EES will be required for the WORM project[101]. The Victorian Government has yet to issue scoping requirements for the WORM EES (these are unique for each project and outline what is to be investigated and documented), so the impact of the EES process on the project timeline is still unknown. AEMO has assumed a delay from asset owner APA Group's target mid-2021 completion date[102], and that the WORM will not be available until mid-2022.

5.1.2 Warragul looping project

In the 2017 VGPR, AEMO identified a threat to system security for the supply to the Warragul 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 the demand supplied by the Warragul CTM would exceed the existing infrastructure capacity and increased supply would be required.

In 2019 APA duplicated the Warragul lateral by constructing a 4.8 km 150 mm diameter pipeline which predominantly follows the existing pipeline route. The duplication was completed in August 2019, increasing the supply capacity to the Warragul CTM. AEMO subsequently notified the market that the threat to system security has been averted. A detailed report outlining the event is available on AEMO's website[103].

[101] Victoria Land, Water and Planning, "Reasons for decision under Environment Effects Act 1978", 22 December, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/446979/Reasons-for-Decision.pdf.

[102] APA, "Western Outer Ring Main Pipeline", December 2019, at https://www.apa.com.au/globalassets/documents/our-current-projects/worm/worm_a3_update-01.pdf.

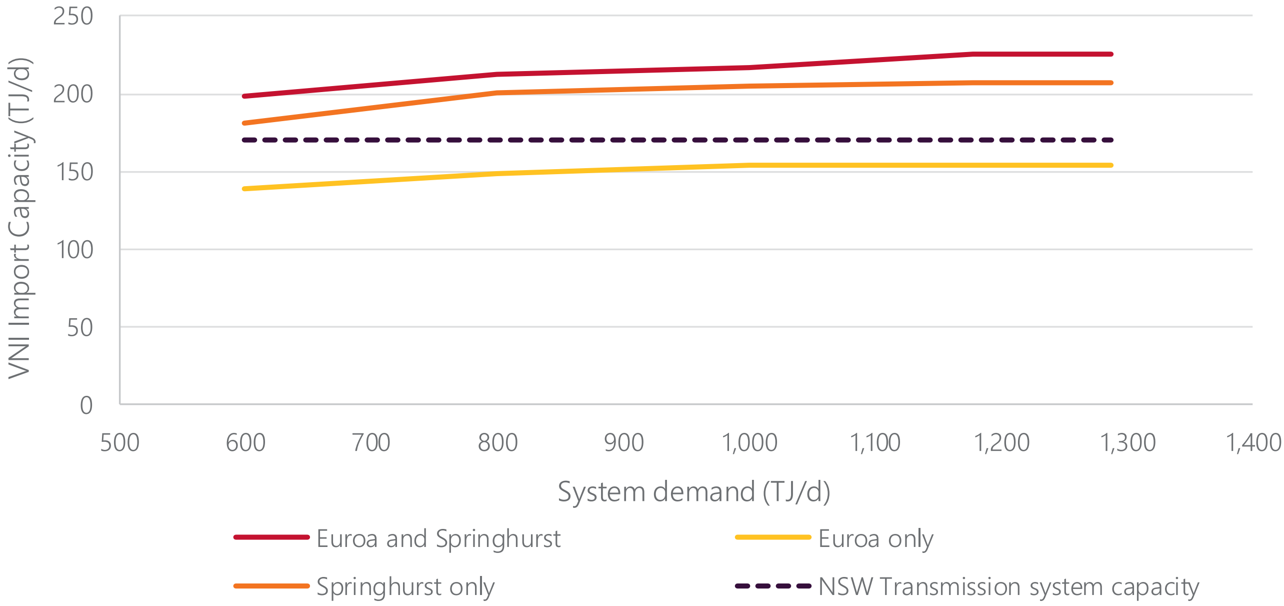
[103] AEMO, "Declared Wholesale Gas Market – Intervention Report", September 2019, at https://aemo.com.au/-/media/files/gas/dwgm/2019/dwgm-er-19-004-30-august-2019.pdf?la=en&hash=32E497C93257323061B5AFDBC12B9F05.

5.1.3 Culcairn injection capacity increase

The operator for the New South Wales transmission system north of Culcairn has advised AEMO that the import capacity into the DTS has increased from 150 TJ/d to 170 TJ/d[104]. The capacity increase was enabled by the completion of work in the New South Wales transmission system.

The increased supply capacity is within the existing DTS import capacity through the VNI, which is unchanged from the 2017 VGPR, at 226 TJ/d. Figure 13 shows the modelled import capacity of the VNI, as reported in the 2019 VGPR update, with the New South Wales transmission system capacity increased to 170 TJ/d.

Figure 13 Victorian Northern Interconnect import capacity



5.1.4 Clyde North

The Clyde North CTM is supplied off the Lurgi Pipeline and is one of three meters feeding the Cranbourne region within Melbourne's South East growth corridor[105]. This region is experiencing significant residential growth historically averaging 1,750 new gas connections per year. Distribution network operator, Australian Gas Networks (AGN) identified that without major augmentation in this region there would be a risk of losing supply to end-use customers[106].

Recent information provided to AEMO indicates that new connections in this region have exceeded forecasts exacerbating this risk. This is a recent development, and further detailed modelling needs to be completed and investigations conducted with AGN and APA Group. The intent of this work is to determine whether the proposed and approved program of works in the AGN Access Arrangement would be sufficient to maintain supply within this distribution area or if additional system augmentations and new CTMs are required.

[104] The import capacity is reduced if the Uranquinty Power Station is operating, or during cold weather that results in higher system demand on this pipeline.

[105] Victorian Planning Authority - https://vpa.vic.gov.au/wp-content/Assets/Files/GCP%20-%20Chapter%205%20North%20Corridor%20Plan.pdf

[106] AGN Access Arrangement Business Case Capex V28 H07 Cranbourne - https://www.aer.gov.au/system/files/AGN%20-%20Attachment%208.6%20-%20Business%20Cases%20-%20December%202016%20-%20Public%5B1%5D.pdf

A1. Gas supply classifications definitions

Table 12 GSOO gas supply classifications definitions

GSOO	Description	VGPR	PRMS
Committed	All necessary approvals have been obtained and implementation is ready to commence or is underway.	Available Supply	Reserves
Anticipated	The project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and that there are reasonable given expected commercial conditions, and there is a reasonable expectation that all necessary approvals, such as regulatory approvals and final investment decisions.	Anticipated	Contingent Resources
Uncertain	Those projects that are more uncertain or at early stages of development.	Exploration	Prospective Resources

Table 13 PRMS gas supply classifications definitions

PRMS	Description
Reserves	Quantities anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market. The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development projects is ready to begin or is underway. The project must not be subject to any contingencies.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Quantities estimated to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclarified	A discovered accumulation where justification as a commercial development is unknown based on available information
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.
Prospective Resources	Quantities that are estimated to be potentially recoverable from undiscovered accumulations.

PRMS	Description
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Definitions taken from Petroleum Resources Management System, June 2018.

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

SWZ		2020	2021	2022	2023	2024	Change over outlook
Ballarat	Tariff V	8.6	8.8	8.9	9.1	9.2	6.9%
	Tariff D	1.6	1.6	1.5	1.5	1.5	-2.3%
	SWZ Demand	**10.2**	**10.3**	**10.5**	**10.6**	**10.7**	**5.5%**
Geelong	Tariff V	11.0	11.2	11.3	11.4	11.6	5.1%
	Tariff D	11.8	11.1	11.1	10.9	10.9	-7.9%
	SWZ Demand	**22.8**	**22.3**	**22.5**	**22.3**	**22.4**	**-1.7%**
Gippsland	Tariff V	5.6	5.7	5.8	5.9	6.0	7.9%
	Tariff D	8.5	8.3	8.1	7.9	7.7	-9.2%
	SWZ Demand	**14.1**	**14.0**	**13.9**	**13.8**	**13.7**	**-2.4%**
Melbourne	Tariff V	93.0	93.1	92.7	92.1	91.6	-1.5%
	Tariff D	34.4	34.0	33.8	33.4	33.7	-2.2%
	SWZ Demand	**127.4**	**127.1**	**126.5**	**125.5**	**125.2**	**-1.7%**
Northern	Tariff V	**10.8**	**10.9**	**11.0**	**11.0**	**11.1**	**3.1%**
	Tariff D	7.7	7.8	7.8	7.8	7.8	0.7%
	SWZ Demand	**18.5**	**18.7**	**18.8**	**18.8**	**18.9**	**2.1%**
Western	Tariff V	1.4	1.4	1.4	1.5	1.5	6.0%
	Tariff D	2.6	2.6	2.5	2.5	2.5	-4.8%
	SWZ Demand	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**-1.0%**

Table 15 Annual 1-in-2 peak daily demand (TJ/d) by SWZ

SWZ		2020	2021	2022	2023	2024	Change over outlook
Ballarat	Tariff V	57.4	58.7	59.6	60.6	61.6	7.4%
	Tariff D	5.6	5.5	5.6	5.5	5.5	-2.5%
	SWZ Demand	**63.0**	**64.2**	**65.1**	**66.1**	**67.1**	**6.5%**
Geelong	Tariff V	73.8	75.2	76.1	77.0	77.9	5.5%
	Tariff D	37.4	35.1	35.4	34.5	34.4	-8.2%
	SWZ Demand	**111.2**	**110.3**	**111.5**	**111.5**	**112.3**	**0.9%**
Gippsland	Tariff V	40.0	41.0	41.7	42.5	43.3	8.3%
	Tariff D	27.6	26.9	26.5	25.8	25.0	-9.5%
	SWZ Demand	**67.6**	**67.9**	**68.2**	**68.2**	**68.3**	**1.0%**
Melbourne	Tariff V	652.8	653.7	649.6	646.0	642.9	-1.5%
	Tariff D	124.2	121.9	122.4	120.5	121.2	-2.4%
	SWZ Demand	**777.0**	**775.6**	**772.0**	**766.5**	**764.1**	**-1.7%**
Northern	Tariff V	70.9	71.9	72.3	72.7	73.3	3.3%
	Tariff D	29.0	29.0	29.4	29.3	29.1	0.5%
	SWZ Demand	**99.9**	**100.9**	**101.6**	**102.1**	**102.4**	**2.5%**
Western	Tariff V	8.1	8.2	8.4	8.5	8.6	6.4%
	Tariff D	8.9	8.7	8.6	8.5	8.4	-5.1%
	SWZ Demand	**17.0**	**16.9**	**17.0**	**17.0**	**17.0**	**0.4%**

Table 16 Annual 1-in-20 year peak daily demand (TJ/d) by SWZ

SWZ		2020	2021	2022	2023	2024	Change over outlook
Ballarat	Tariff V	64.2	65.6	66.8	67.8	68.9	7.5%
	Tariff D	5.8	5.7	5.7	5.7	5.6	-2.3%
	SWZ Demand	**69.9**	**71.4**	**72.5**	**73.4**	**74.6**	**6.7%**
Geelong	Tariff V	82.5	84.1	85.3	86.1	87.1	5.6%
	Tariff D	38.5	36.3	36.4	35.5	35.4	-8.0%
	SWZ Demand	**121.0**	**120.4**	**121.7**	**121.6**	**122.6**	**1.3%**
Gippsland	Tariff V	44.7	45.8	46.8	47.5	48.4	8.4%
	Tariff D	28.4	27.8	27.2	26.5	25.8	-9.3%
	SWZ Demand	**73.1**	**73.7**	**74.0**	**74.0**	**74.2**	**1.5%**
Melbourne	Tariff V	729.8	731.2	728.7	722.8	719.0	-1.5%
	Tariff D	127.9	126.2	125.7	123.9	125.0	-2.3%
	SWZ Demand	**857.7**	**857.5**	**854.4**	**846.7**	**844.0**	**-1.6%**
Northern	Tariff V	79.3	80.4	81.1	81.4	82.0	3.4%
	Tariff D	29.8	30.0	30.2	30.1	30.0	0.7%

SWZ		2020	2021	2022	2023	2024	Change over outlook
	SWZ Demand	**109.1**	**110.4**	**111.2**	**111.5**	**112.0**	**2.6%**
Western	Tariff V	9.0	9.2	9.4	9.5	9.6	6.5%
	Tariff D	9.2	9.0	8.9	8.8	8.7	-4.9%
	SWZ Demand	**18.2**	**18.2**	**18.2**	**18.2**	**18.3**	**0.7%**

Table 17 Annual 1-in-2 Non-DTS and Victoria peak day demand forecast (TJ/d)

	2020	2021	2022	2023	2024	Change over outlook
Tariff V (non-DTS)	2.5	2.6	2.7	2.7	2.8	10%
Tariff D (non-DTS)	2.0	2.0	2.0	2.0	2.0	-0.3%
System demand non-DTS	4.5	4.6	4.7	4.7	4.8	5.4%
System demand DTS	1,136	1,136	1,135	1,131	1,131	-0.4%
System demand VIC	1,140	1,140	1,140	1,136	1,136	-0.4%

Table 18 Annual 1-in-20 Non-DTS peak day demand forecast (TJ/d)

	2020	2021	2022	2023	2024	Change over outlook
Tariff V (non-DTS)	3.0	3.1	3.1	3.2	3.3	10%
Tariff D (non-DTS)	2.0	2.1	2.1	2.1	2.0	-0.2%
System demand non-DTS	5.0	5.1	5.2	5.3	5.3	5.9%
System demand DTS	1,249	1,252	1,252	1,245	1,246	-0.3%
System demand VIC	1,254	1,257	1,257	1,251	1,251	-0.2%

A2.2 Monthly consumption and demand for 2020

Table 19 Monthly gas system consumption (PJ/month) for 2020 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SWZ consumption	Ballarat	0.38	0.40	0.49	0.66	1.07	1.46	1.52	1.39	1.03	0.75	0.57	0.43
	Geelong	1.29	1.34	1.43	1.74	2.11	2.68	2.65	2.57	2.19	1.85	1.53	1.40
	Gippsland	0.85	0.84	0.88	0.95	1.36	1.49	1.56	1.54	1.33	1.18	1.02	0.92
	Melbourne	5.37	5.35	6.30	8.33	13.45	17.72	18.41	17.15	12.51	9.33	7.16	5.65
	Northern	0.83	0.93	1.06	1.24	1.95	2.42	2.53	2.37	1.74	1.36	1.09	0.85
	Western	0.25	0.23	0.23	0.26	0.35	0.42	0.43	0.44	0.41	0.39	0.32	0.28
	System consumption	**8.98**	**9.09**	**10.39**	**13.18**	**20.29**	**26.18**	**27.11**	**25.46**	**19.21**	**14.85**	**11.70**	**9.53**

Table 20 Monthly gas consumption (PJ/month) for 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System consumption	9.0	9.1	10.4	13.2	20.3	26.2	27.1	25.5	19.2	14.9	11.7	9.5
GPG consumption	0.7	0.6	0.5	1.2	1.3	1.1	0.5	0.7	0.6	0.2	0.2	0.2
Total consumption	9.7	9.7	10.9	14.4	21.6	27.3	27.7	26.2	19.8	15.1	11.9	9.7

Table 21 Monthly GPG consumption (TJ/month) in 2020 by SWZ

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	49	22	8	0	0	6	2	2	1	0	0	3
Gippsland	151	79	40	114	146	156	30	46	25	1	9	15
Melbourne	544	467	413	1073	1162	923	512	665	604	221	239	168
Northern	-	-	-	-	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-	-	-	-	-
Total DTS consumption	745	569	461	1,186	1,309	1,085	543	714	630	222	248	186

Table 22 Monthly peak daily demand (TJ/d) in 2020 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day demand	Ballarat	15	16	23	33	48	58	61	58	48	38	30	19
	Geelong	52	52	60	68	89	101	104	104	89	77	62	56
	Gippsland	32	32	35	44	55	64	66	64	56	50	43	35
	Melbourne	233	242	289	423	605	733	746	730	595	490	375	262
	Northern	37	42	47	59	85	99	99	95	80	64	47	39
	Western	10	10	10	12	14	16	17	17	16	15	13	11
	System consumption	**378**	**394**	**463**	**638**	**896**	**1070**	**1094**	**1068**	**883**	**734**	**570**	**422**
1-in-20 peak day demand	Ballarat	17	21	32	44	56	64	68	68	56	45	40	28
	Geelong	57	58	71	82	100	109	115	117	99	87	75	66
	Gippsland	35	35	41	51	61	69	72	71	62	55	51	40
	Melbourne	268	304	386	547	701	806	832	843	689	570	489	363
	Northern	41	48	58	72	96	108	109	107	90	72	57	47
	Western	11	11	11	14	15	17	18	18	18	17	15	12
	System consumption	**429**	**477**	**598**	**810**	**1029**	**1172**	**1215**	**1224**	**1013**	**846**	**727**	**556**

A3. Victorian gas planning approach

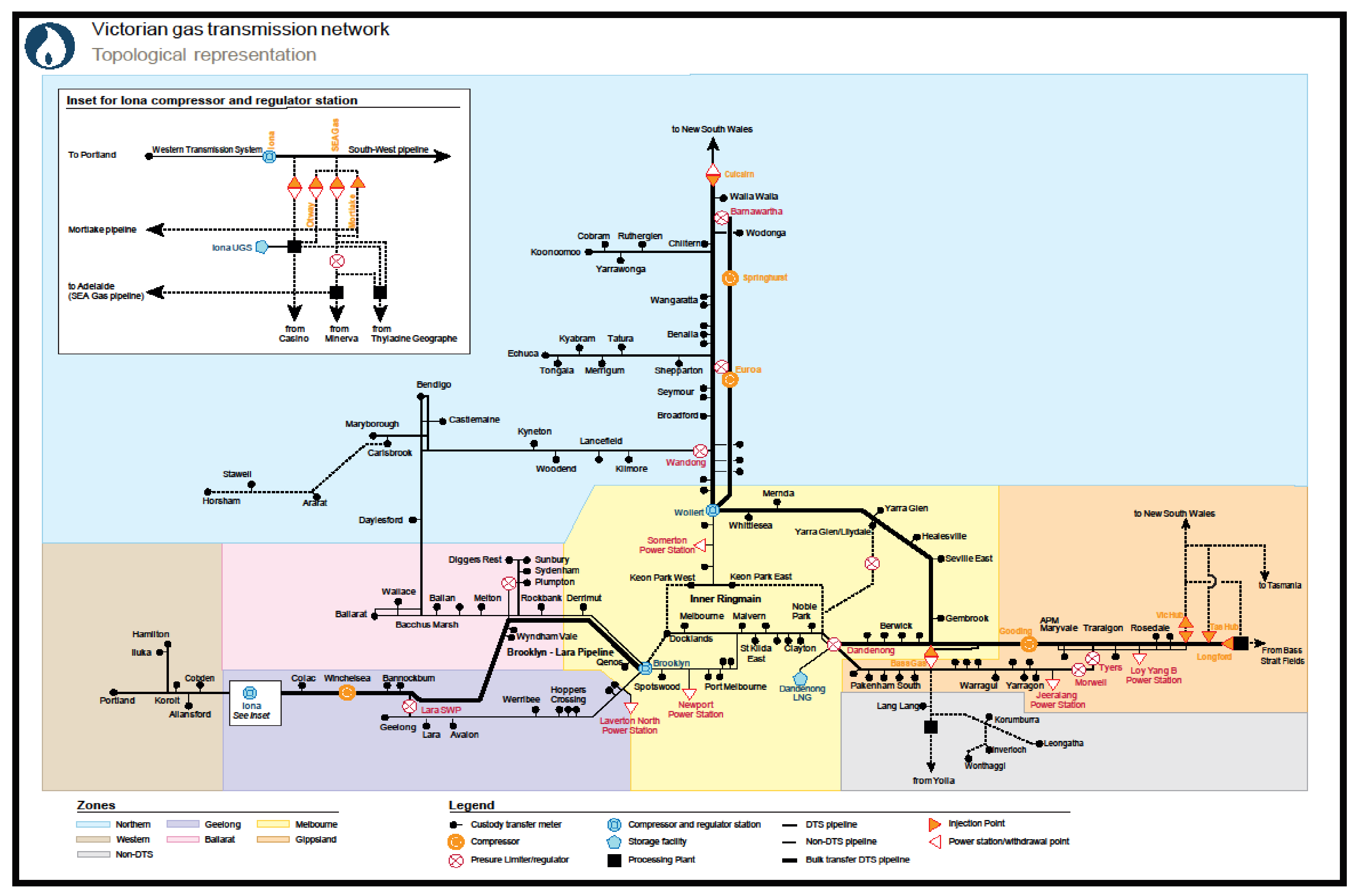
A3.1 DTS system withdrawal zones

The DTS is divided into six zones, as shown in Figure 14:

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

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

Figure 14 System Withdrawal Zones in the DTS



A3.2 DTS supply sources

A3.2.1 Production facilities

DTS production capacity by supply source is reported by SWZ (shown in Table 23, with ownership details[107]).

Table 23 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, 35%
	Lang Lang Gas Plant	BassGas Project	• Beach Energy Limited, 53.75% • Mitsui, 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%
	Iona Gas Plant	Iona UGS	• QIC, 100%
		Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui, 50%
	Minerva Gas Plant	Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui, 50%

5.1.5 Storage facilities

There are two storage facilities in the DTS:

- Iona UGS, located in Port Campbell (Geelong zone).
- Dandenong 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.

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

- https://www.exxonmobil.com.au/en-au/energy-and-environment/energy-resources/upstream-operations/longford-plants
- https://www.exxonmobil.com.au/en-au/energy-and-environment/energy-resources/upstream-operations/kipper-tuna-turrum-KTT
- 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.qic.com.au/knowledge-centre/gi-media-release-20151008
- https://www.cooperenergy.com.au/Upload/Minerva-completion-.pdf
- 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.

The current total Iona UGS storage reservoir capacity is 26 PJ. The injection capacity into the storage reservoirs is 155 TJ/d[108].

The Iona UGS supply capacity has increased in 2019 from 440 TJ/d to 480 TJ/d from 1 May 2019, with a further uncommitted expansion to 520 TJ/d in 2021. Additional information is provided in Chapter 4.

Dandenong LNG storage

The operating parameters for Dandenong LNG storage are unchanged from the 2019 VGPR. The 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 to maintain system security.

5.1.6 Interconnected pipelines

There are four pipelines with connections to the DTS:

- EGP, via the VicHub connection point into the LMP.
- 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).
- SEA Gas Pipeline, which supplies gas into the SWP via the SEA gas, Otway and Mortlake connection points.

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

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
MW	Megawatt
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
AGN	Australian Gas Networks
AIE	Australian Industrial Energy
BCP	Brooklyn to Corio Pipeline

Abbreviation	Expanded name
BLP	Brooklyn to Lara Pipeline
CG	City Gate
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
EDD	Effective Degree Day
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
HESC	Hydrogen Energy Supply Chain
ISP	Integrated System Plan
JV	Joint Venture
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
MGP	Minerva Gas Plant

Abbreviation	Expanded name
MOP	Maximum Operating Pressure
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
NGL	National Gas Law
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
OCGT	Open cycle gas turbine
POE	Probability of Exceedance
PRMS	Petroleum Resources Management System
PRS	Pressure Reduction Station
PV	Photovoltaic
QHGP	Queensland Hunter Gas Pipeline
RBA	Reserve Bank of Australia
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
UNGI	Federal Government's Underwriting New Generation Investments program
VEET	Victorian Energy Efficiency Target
VGPR	Victorian Gas Planning Report
VHIP	Victorian Hydrogen Investment Program
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.
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.
DTS service provider	Service provider for the declared transmission system, currently APA group.
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.

Term	Definition
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.
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.

Term	Definition
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).
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).

Term	Definition
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.