Victorian Gas Planning Report

March 2021

Gas Transmission Network Planning for Victoria

Important notice

PURPOSE

AEMO publishes this Victorian Gas Planning Report (March 2021) in accordance with rule 323 of the National Gas Rules.

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VERSION CONTROL

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Executive summary

The 2021 *Victorian Gas Planning Report* (VGPR) provides information about the supply demand balance over the next five years (2021-25, called the outlook period) in Victoria, and the Victorian Declared Transmission System (DTS). The 2021 VGPR complements AEMO's 2021 *Gas Statement of Opportunities* (GSOO), which assesses the wider gas supply adequacy in eastern and south-eastern Australia.

Key findings

- The threat of winter gas supply shortfalls from winter 2024 that were forecast in the 2020 VGPR Update[1] are expected to be addressed through the commitment from Australian Industrial Energy (AIE) to proceed with the construction of the 500 terajoules per day (TJ/d) Port Kembla liquified natural gas (LNG) import terminal in New South Wales and Jemena's commitment to modify the Eastern Gas Pipeline (EGP) to enable reverse flow from Port Kembla into the DTS.
- AIE and Jemena have advised that these projects will be completed ahead of winter 2023. This will cover the identified supply gaps provided that all construction and commissioning is completed, and that shipping schedules provide reliable cargoes during the winter months.
- Supply forecasts provided to AEMO advise that the depletion of key legacy gas fields that supply the Longford Gas Plant is now expected to occur prior to winter 2023, earlier than previously forecast. These fields enable Victorian monthly production to peak during winter in line with the increased winter gas consumption for heating. The depletion of these key Longford fields will cause gas production to flatten, reducing monthly winter production capacity and peak day supply capacity.
- Overall, annual existing and committed Victorian production is forecast to decline by 43%, from 360 petajoules per year (PJ/y) in 2021 to 205 PJ/y in 2025. The forecast indicates:
  - Gippsland annual production will decline by 52% from 316 PJ/y in 2021 to 153 PJ/y in 2025.
  - Port Campbell annual production will increase by 18% from 44 PJ/y in 2021 to 52 PJ/y in 2025.
- The forecast production decline also reduces peak day supply capacity into the DTS from existing sources by 38%, from 1,585 TJ/d in 2021 to 983 TJ/d in 2025. The Port Kembla LNG import terminal will enable 395 TJ/d of supply from New South Wales, increasing winter 2025 peak day supply capacity to 1,378 TJ/d.
  - Gippsland available peak day supply capacity is forecast to decline from 1,030 TJ/d in 2021 to 443 TJ/d in 2025. Anticipated projects would result in a short-term supply increase to 686 TJ/d in 2023, which is still 32% less than in 2021, before decreasing to 489 TJ/d in 2025.
  - Port Campbell available peak day supply capacity, which includes Iona underground gas storage (UGS), is forecast to increase from 445 TJ/d to 468 TJ/d, following the expected completion of the Western Outer Ring Main (WORM) pipeline in late 2022. This forecast supply capacity is less than the existing and committed production and storage capacity in Port Campbell.

[1] The 2020 VGPR Update forecast a supply shortfall from winter 2024, due to a key Gippsland gas field and several smaller Gippsland fields being forecast to cease production sometime between mid-2023 and mid-2024.

- – New South Wales peak day supply capacity of 395 TJ/d comprises an EGP net supply of 200 TJ/d after suppling demand outside of the DTS and 195 TJ/d supply capacity from the Moomba to Sydney Pipeline (MSP) via the Culcairn interconnection. This supply capacity could be increased by expanding the capacity of the EGP or MSP.
- The declining Victorian production capacity during the outlook period is also expected to reduce system resilience. Peak day supply capacity currently exceeds peak day demand, providing sufficient margin for the operational management of equipment trips, unplanned maintenance, and demand forecast errors. The forecast depletion of the key legacy gas fields supplying the Longford Gas Plant will result in reduced peak day capacity and this capacity margin will no longer be available. This tightening supply demand balance will result in an increased probability that operational issues are unable to be operationally managed, leading to an increased likelihood of threats to system security or curtailment events.
- AEMO relies on the Dandenong LNG storage facility to provide fast response peak shaving gas supply to alleviate threats to system security. The current low contracted storage inventory and available hourly injection capacity are insufficient to manage operational and market responses during periods of high unforecast demand or a supply disruption increasing the risk of customer curtailment. If inventories are reduced to the contracted levels, there will be insufficient inventories to safely manage the DTS during an emergency. AEMO has identified this low Dandenong LNG inventory as a threat to system security and is seeking a market response.

Annual supply adequacy

AEMO is forecasting a 12.7% decrease in Victoria's annual total gas consumption over the next five years. This is due to the forecast increase in new solar and wind generation connections into the National Electricity Market (NEM), the existing Victorian Energy Upgrades (VEU) program[2] to upgrade gas appliance efficiency, and the new Victorian Government policy measures announced in the 2020-21 state budget[3].

Table 1 Victorian gas actual consumption and forecasts (PJ)

	2017	2018	2019	2020	2021	2022	2023	2024	2025
DTS system consumption	201	192	196	201	197	195	192	189	187
DTS GPG consumption	15	10	20	7	3	2	2	2	1
Total DTS consumption	216	202	216	208	200	197	194	191	188
Non-DTS consumption	23	16	16	12	7	5	5	4	3
Total Victorian consumption	239	218	232	220	207	202	199	196	192

In Figure 1, annual production figures provided to AEMO by Victorian producers and the expected 60 PJ/y of supply from New South Wales that will be available due to the 130 PJ/y Port Kembla LNG import terminal development are compared with the AEMO gas consumption forecast in Table 1.

Overall production from existing gas production facilities is forecast to decline each year between 2021 and 2025. Significant declines are expected from the existing fields, predominantly in the Gippsland zone, with the

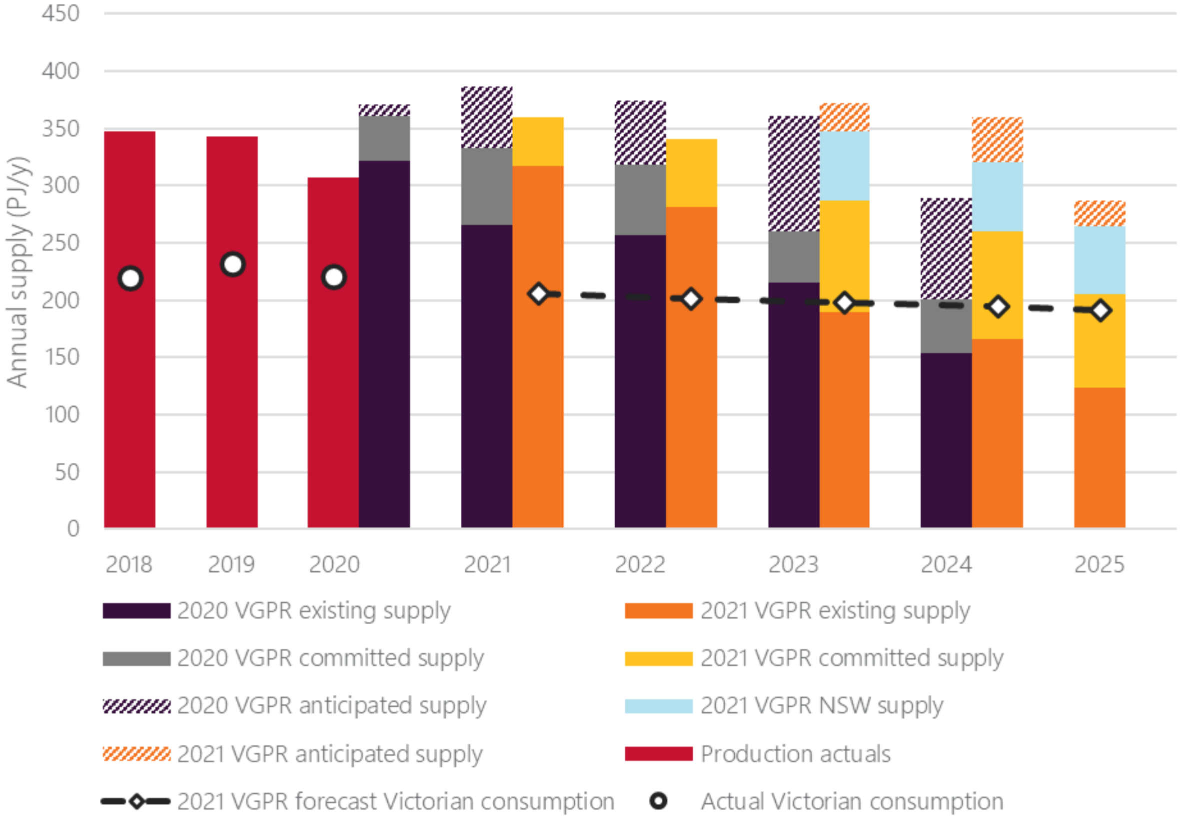
[2] See https://www.energy.vic.gov.au/energy-efficiency/victorian-energy-upgrades.

[3] See https://www.budget.vic.gov.au/clean-energy-power-our-recovery.

largest annual reduction of 72 PJ forecast for 2023. This is mainly due to the forecast reduction of capacity associated with depletion of the large legacy gas fields that supply the Longford Gas Plant prior to winter 2023.

This is earlier than the winter 2024 shortfalls forecast in the 2020 VGPR Update, which advised that a key Gippsland gas field and several smaller Gippsland fields were forecast to cease production sometime between mid-2023 and mid-2024. The commitment of AIE and Jemena to develop the Port Kembla LNG import terminal and modify the EGP to supply gas into the DTS from winter 2023 will provide additional supplies to compensate for the reduced Longford production. The increased New South Wales supply provided by the Port Kembla LNG import terminal is also expected to result in increased winter gas supply into Victoria via the Culcairn interconnection.

Figure 1 Annual production and supply outlook



Forecast production from existing and committed developments[4] in 2021 and 2022 is lower than the sum of existing, committed, and anticipated production that was reported in the 2020 VGPR Update. This is due to some anticipated projects being deferred, as well as some reduction in existing supply. Committed supply forecasts have increased from 2023 onwards as previously anticipated projects transition to becoming committed projects, including some projects deferred from 2021 and 2022. This increase in committed supply from 2023 has reduced anticipated supply[5], which has not been replaced by new anticipated projects.

[4] Committed supply considers 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.

[5] 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.

Potential projects[6] equate to approximately 121 PJ of additional supply over the outlook period, however many of these potential projects are for contingent resources[7], which are expected to have challenging economics and are therefore considered unlikely to be developed within the outlook period.

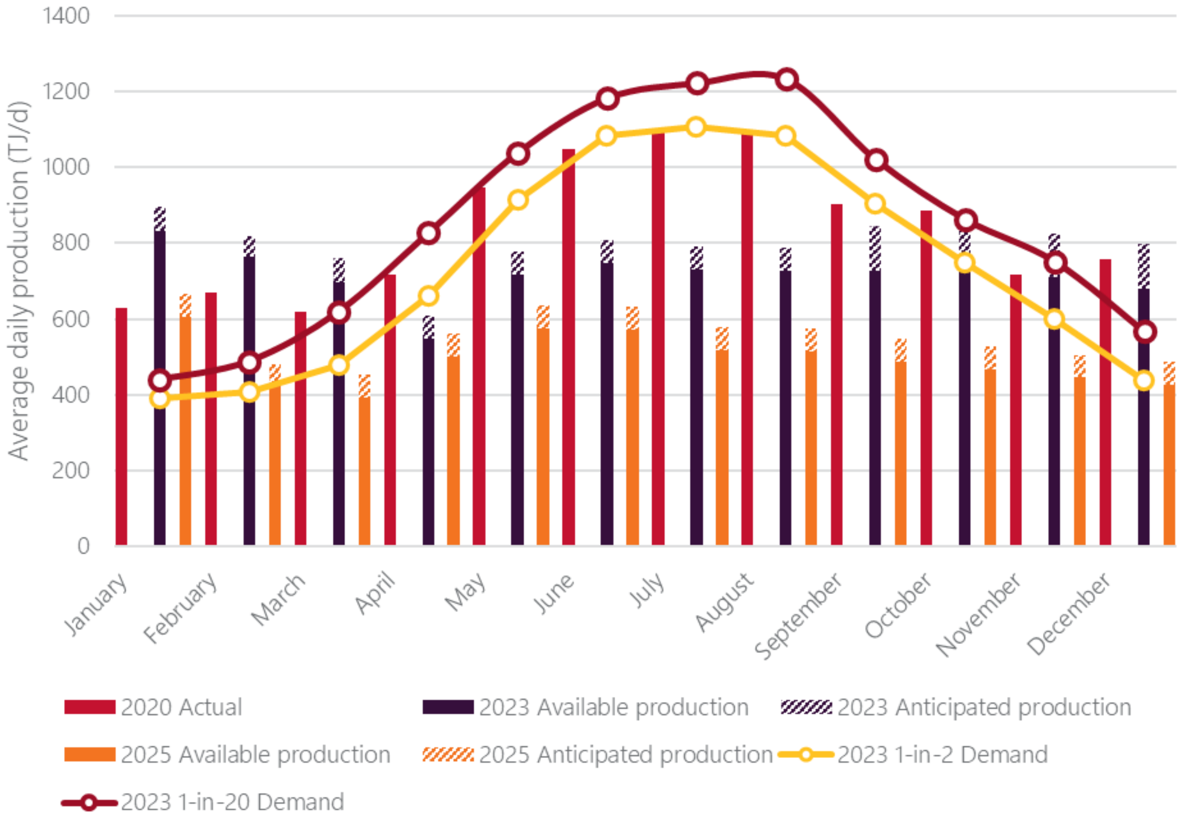
An increasing proportion of annual supply is expected to be reliant on supply from new committed developments. This results in an increased risk to the supply demand balance if developments are not completed on schedule, or do not produce at the expected rate. This includes the risk of ongoing COVID-19 restrictions impacting completion, including the supply of overseas specialist labour and equipment.

Monthly supply adequacy

While Figure 1 suggests that Victorian forecast available[8] annual supply is sufficient to balance forecast annual consumption for each year of the outlook period, the issue is that typical winter consumption is 25-30 PJ per month. This is significantly more than the average monthly production of 17 PJ per month in 2025, when annual Victorian production is forecast to reduce to 205 PJ.

Monthly production has historically peaked during winter. Figure 2 shows that 2020 monthly production was aligned to seasonal system demand. Monthly winter production is forecast to significantly decline and the supply profile will flatten from 2023 due to the forecast reduction of capacity associated with depletion of Longford's large legacy gas fields.

Figure 2 Average monthly production forecast for 2023 and 2025



[6] Potential projects are uncommitted gas supply projects that have not reached FID, which could potentially proceed during the outlook period.

[7] Contingent resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable (Society of Petroleum Engineers).

[8] Available supply comprises existing gas supplies and committed new gas supply projects.

The forecast reduction in flexible production is also expected to increase the winter reliance on storage. As winter storage depletion increases the refilling of storage will also become difficult to manage (and if storage is empty it is also not available to provide peak day capacity). The larger winter utilisation will require a larger refill quantity to be available during the summer and shoulder periods.

After the commissioning of the WORM pipeline, there will be sufficient pipeline capacity for Iona UGS refilling; however, modelling indicates that it could be challenging to support refilling of storage due to the reduced supply surplus outside of winter, including the impact of and requirement to cover production facility maintenance, and if there were extended periods of high gas demand for GPG. The Port Kembla LNG import terminal is expected to increase Victoria's available monthly gas supply by up to 12 PJ per month. While this supply will be critical for supporting the peak winter period, it could also provide an additional supply source to refill storage if anticipated gas supply projects do not proceed.

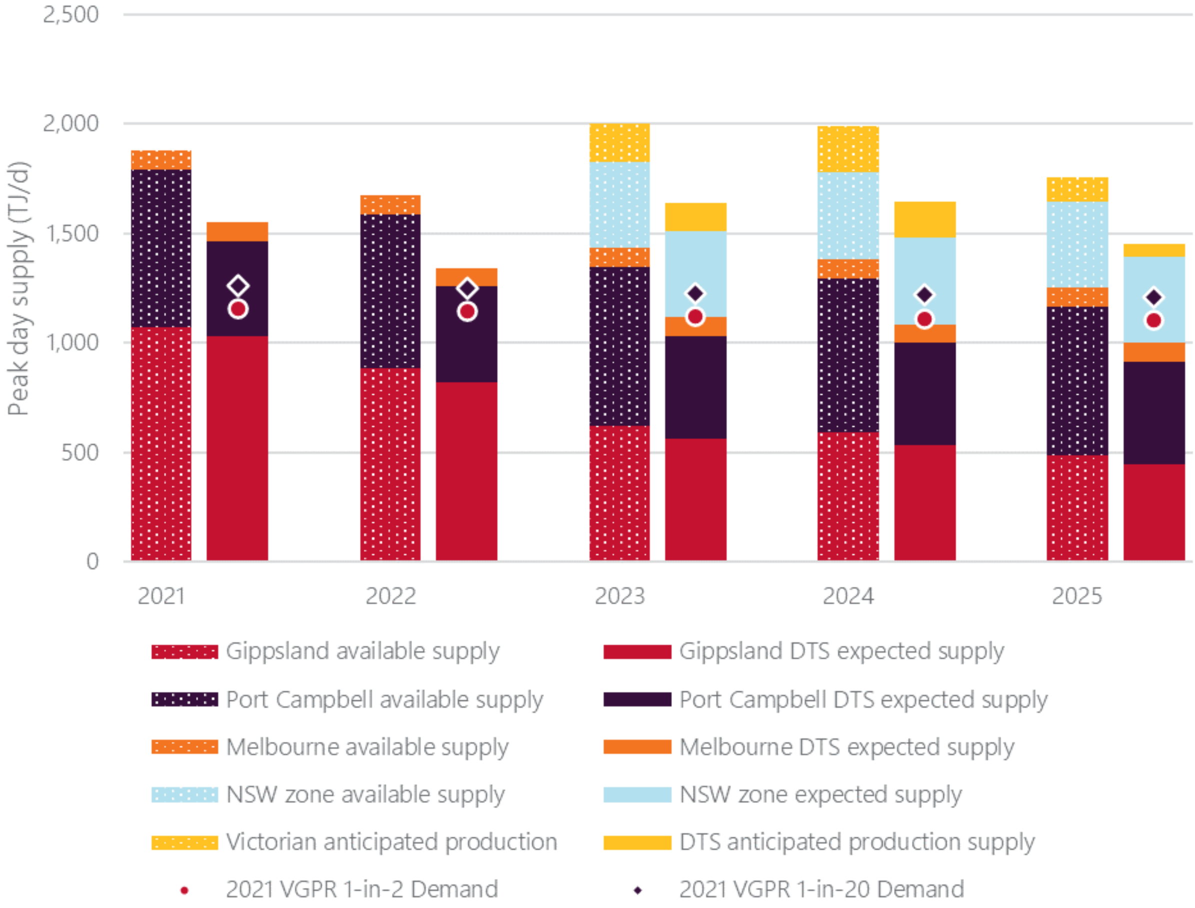
Peak day supply adequacy

The large decline in winter production capacity, due to the forecast reduction of capacity associated with depletion of Longford's large legacy gas fields from 2023, also reduces available peak day supply.

Gippsland production is forecast to decline by 54%, reducing from 1,072 TJ/d in 2021 to 488 TJ/d in 2025. Production capacity in winter 2023 is forecast to be 561 TJ/d without new supply.

Port Campbell peak day supply capacity is forecast to be steady during the outlook period with new committed projects replacing the declining production. Figure 3 shows that the South West Pipeline (SWP) capacity constraint, including the addition of the WORM, limits Port Campbell peak day supply to 468 TJ/d.

Figure 3 Peak day supply and Declared Transmission System adequacy



Note: Includes contribution from storages.

Victorian peak day supply available to the DTS from production and storage is forecast to decline by 36% over the outlook period, from 1,533 TJ/d in 2021 to 983 TJ/d in 2025. By winter 2023, available supply including Dandenong LNG would not even be sufficient to supply a 1-in-2 peak system demand day.

Additional supply capacity of 395 TJ/d is forecast to be available from New South Wales to support Victorian peak days from winter 2023.

- Port Kembla combined with the Orbost Gas Plant production, less gas supply to customers supplied from the EGP and supply to Tasmania, is expected to supply up to 200 TJ/d into the DTS. The EGP supply capacity can be increased by 120 TJ/d with additional compression and an expanded connection at the VicHub connection into the DTS.
- An additional 195 TJ/d of supply into the DTS from the MSP via the Culcairn interconnection is also expected to be available.
- New South Wales GPG demand would reduce the supply available into Victoria, but this is not forecast to be enough of a reduction to result in a Victorian supply shortfall.

Additional supplies during the outlook period

Additional projects that meet the anticipated criteria could also be developed during the outlook period and are summarised in Table 2. Some of these projects however may be less likely to proceed now that the PKGT is a committed project.

Table 2 Anticipated and potential projects

Solutions	Detail	Solution description	Analysis
Anticipated production projects	There are two significant anticipated Gippsland supply projects that are expected to increase the available supply. These are the development of the Golden Beach field and further development of the Kipper gas field that is processed through the Longford Gas Plant.	• The Golden Beach Project[A] is a proposed gas plant to process gas from the Golden Beach field. This would provide additional supply including peak day capacity in 2023 and 2024, prior to possible operation as a new underground gas storage facility following further investment. • The Kipper development does not significantly increase winter 2023 supply, but it reduces the forecast decline in Longford production in 2024 and 2025.	• If the Golden Beach Project is completed prior to winter 2023 it would improve gas supply until 2025. • Kipper provides additional supply from winter 2024 to maintain Longford production closer to 2023 levels, which also assists with refilling Victorian storage facilities.
Victorian LNG import terminals	LNG import terminals could bring gas from Australian export facilities (acting like a virtual pipeline) or from international supply sources. There are three public proposed LNG receiving terminals in Victoria: • The AGL Crib Point project to the east of Melbourne. • The Viva project in Geelong, to the west of Melbourne.	• The Crib Point terminal would connect to the Longford to Melbourne Pipeline, which has sufficient capacity to accommodate this supply. The Crib Point project includes the construction of a 57 km pipeline from Crib Point to Pakenham. • The west of Melbourne terminals would connect to the SWP at Lara/Avalon, which would increase the SWP capacity due to the higher-pressure gas supply (but would reduce the supply of Port Campbell gas including Iona UGS into the DTS). Duplication of the pipeline from Lara to the start of the WORM (Plumpton), along with additional compression and	• All terminals would require approximately 60 km of new pipeline (with the western terminals also requiring additional SWP compression and DTS upgrades). • The Crib Point pipeline has been proposed as part of the project, however expansion of the DTS is not proposed as part of the western terminal projects and may need to be funded by APA Group as an Australian Energy Regulator (AER)-approved DTS upgrade within the 2023 Access Arrangement.

Solutions	Detail	Solution description	Analysis
	• The Vopak project at Avalon, also to the west of Melbourne. The Crib Point project has been announced as being available prior to winter 2023, while the two projects west of Melbourne are not expected to be available until some time during 2024.	city gate expansions to increase the overall capacity, would be required to make up for further forecast gas production reductions (depending on other projects progressing).	
SWP expansion	Port Campbell has additional peak day supply that is currently not available due to the SWP capacity constraint, despite the expected commissioning of the WORM in late 2022.	Additional compression or pipeline looping on the SWP, in addition to the WORM, would increase the peak day supply capacity.	This solution would provide additional peak day supply capacity. It would not provide sufficient monthly winter gas to replace the reduced Gippsland production capacity.
Increased supply capacity from outside Victoria	There are proposed pipeline projects outside of Victoria that could increase supply into south-east Australia.	These possible projects include: • Increased supply from the PKGT through additional compression at Port Kembla to increase the EGP southbound capacity. • Expansions of existing pipelines from Queensland. • A new pipeline from Queensland.	Incremental pipeline expansions could provide additional capacity in approximately two years. A new pipeline is a more substantial undertaking.
Distributed gas supply	There has been increased interest in hydrogen and biogas projects in Australia in recent years which could provide an alternate source of supply.	There are several projects proposed in Victoria to supply either biogas or hydrogen to end use customers. The most notable of these is the Hyp Murray Valley[B] project, an electrolyser proposed by Australian Gas Infrastructure Group (AGIG) which would produce hydrogen for injection into the Albury-Wodonga gas distribution network.	While the transition to biogas and hydrogen is expected to play an important role in decarbonisation, they are not expected to be able to produce significant quantities of gas within the outlook period. The GSOO includes further discussion in the longer term potential for hydrogen.

A. See https://gbenergy.com.au/ for more information.
B. See https://www.agig.com.au/media-release---hydrogen-proposal-in-albury-wodonga for more information.

As Australia transitions to a lower emissions future, striking a balance between the investment required to prevent shortfalls, and avoiding long-term stranded assets, will be critical. Investments that would appear to find this balance include hydrogen-ready pipelines or assets, investments with a low amount of required capital, or the utilisation of existing pipelines or assets where little expansion is required.

Supply resilience

Resilience can be described as the ability of an energy system to limit the extent, severity, and duration of system degradation following an abnormal event[9]. The "system" can be the DTS, or a complex production system such as the Longford Gas Plant including its offshore facilities.

The forecast capacity reduction from Longford's large legacy gas fields is expected to degrade the current high resilience of the plant's production system. Currently, any supply disruptions that occur can often be

[9] CIGRE Working Group C4.47 description of a resilient power system.

smoothed out using the flexible production capacity these fields provide. The absence of these fields would increase the risk that equipment trips and unplanned outages cannot be quickly resolved, resulting in reduced supply into the DTS. This shortfall would need to be covered by another supply facility.

The Port Kembla LNG import terminal provides a new source of DTS supply flexibility that compensates for the forecast reduction in Longford supply capacity into the DTS from 2023. The import terminal will use a floating storage and regassification unit (FSRU), which is an LNG storage ship that has an onboard regassification plant capable of vaporising the stored LNG for supply into a gas pipeline. LNG supplies to Port Kembla will be dependent on shipping schedules to provide reliable cargoes during winter months. Inventory will need to be carefully managed as the FSRU will need to be close to empty when a refill ship arrives, but not at such a low level that would reduce supply capacity.

Flexible sources of supply are essential for covering unplanned plant outages, equipment trips, coincident southern gas demand peaks, or unforecast demand changes that may otherwise result in a threat to system security or a curtailment event. This includes the risk of a prolonged unplanned outage of a coal-fired power station, which could increase GPG demand when there is insufficient gas supply to support this.

Dandenong LNG

The Dandenong LNG storage facility is an essential source of fast response peak shaving gas supply that AEMO utilises to quickly respond to incidents that threaten system security. During winter 2020, a total of 119 TJ of Dandenong LNG supply was utilised on four occasions in response to a threat to system security.

The contracted storage Dandenong LNG storage inventory has declined to only 80 TJ, which is 12% of its 680 TJ capacity. The 4.5 TJ/hr of injection capacity from winter 2021 is less than the firm capacity of 5.5 TJ/hr.

Due to reduced contracted levels, AEMO's ability to manage the DTS during peak winter demand is severely impacted, which increases the risk of gas curtailment in the DTS if peak shaving LNG is not available at firm rates of 5.5 TJ/hr.

Threat to system security

AEMO is required to inform Registered participants if it believes that a threat to system security is indicated by the VGPR[10]. A threat to system security includes, in AEMO's reasonable opinion, that there:

- is a threat to the supply of gas to customers; and
- are insufficient assets available within the DTS to provide the capacity to meet forecast gas supply and demand conditions.

There is forecast to be insufficient Dandenong LNG inventory available to manage operational and market responses during periods of high unforecast demand or a supply disruption, which increases the risk of AEMO curtailing supply to customers. The forecast inventory is also insufficient to safely manage the DTS during an emergency.

Consistent with the criteria above, AEMO has identified this low Dandenong LNG inventory as a threat to system security and is seeking a market response.

[10] NGR 341

Contents

Executive summary **3**

1. Introduction **16**

1.1 Review of 2020 16

1.2 The Victorian Declared Transmission System 18

1.3 Gas planning in Victoria 20

2. Gas usage forecast **22**

2.1 Annual consumption 23

2.2 Monthly consumption in 2021 26

2.4 GPG forecast 31

3. Gas supply forecast adequacy **35**

3.1 Annual supply-demand balance 37

3.2 Monthly supply-demand balance 41

3.3 Peak day supply-demand balance 44

4. Future supply sources **51**

4.1 Anticipated supply projects 51

4.2 LNG import terminals 52

4.3 Other supply sources 53

5. Declared Transmission System adequacy **56**

5.1 Western Outer Ring Main (WORM) system augmentation 56

5.2 Port Kembla LNG import terminal 60

5.3 Victorian LNG import terminals 60

5.4 Peak day system adequacy 64

5.5 Gas-powered generation supportability 64

6. Declared Transmission System pipeline capacities **67**

6.1 Longford to Melbourne Pipeline 67

6.2 South West Pipeline 68

6.3 Victorian Northern Interconnect 70

A1. DTS pipeline capacity charts **73**

A1.1 Longford to Melbourne Pipeline 73

A1.2 South West Pipeline 74

A1.3 Victorian Northern Interconnect 75

A2. Gas demand forecast data by system withdrawal zone **76**

A2.1 Annual consumption and demand 76

A2.2 Monthly consumption and demand for 2021 79

A3. Gas supply forecast 82
A3.1 Victorian supply sources 82
A3.2 Annual production by SWZ 83
A3.3 Monthly production by SWZ 85
A3.4 Peak day production by SWZ 86
A3.5 Storage facility operating parameters 87
A4. System operating parameters 88
A4.1 Critical system pressures 88
A5. DTS service provided assets, maintenance and system augmentations 92
A5.1 Critical DTS assets 92
A5.2 DTS service provider proposed maintenance schedule 93
A5.3 Other proposed maintenance 96
A6. Victorian gas planning approach 97
A6.1 DTS system withdrawal zones 97
A6.2 Victorian gas planning criteria 97
A6.3 Victorian gas planning methodology 99
A6.4 Planning assumptions 100
Measures, abbreviations and glossary 107

Tables

Table 1 Victorian gas actual consumption and forecasts (PJ) 4
Table 2 Anticipated and potential projects 8
Table 3 Total annual gas consumption forecast, 2021-25 (PJ/y) 23
Table 4 Annual Tariff V consumption by SWZ, 2021-25 (PJ/y) 25
Table 5 Annual Tariff D consumption by SWZ, 2021-25 (PJ/y) 26
Table 6 Forecast monthly gas consumption for 2021 (PJ/m) 27
Table 7 Annual 1-in-2 peak day system demand forecast, 2021-25 (TJ/d) 28
Table 8 Annual 1-in-20 peak day system demand forecast, 2021-25 (TJ/d) 28
Table 9 Forecast monthly peak day demand for 2021 (TJ/d) 29
Table 10 GPG consumption forecast, 2021-25 (PJ/y) 32
Table 11 Gas supply classification definitions 36
Table 12 Victorian annual available and anticipated supply balance, 2021-25 (PJ/y) 41
Table 13 Forecast peak winter June to August supply-consumption balance, 2021-25 (PJ) 43
Table 14 Peak day maximum daily quantity (MDQ) capacity by SWZ, 2021-25 (TJ/d) 45

Table 15	DTS capacities and expected supply on a 1-in-20 peak demand day, 2023 (TJ/d)	47
Table 16	DTS capacities and expected supply on a 1-in-20 peak demand day, 2025 (TJ/d)	48
Table 17	Summary of DTS pipeline capacities	67
Table 18	Annual system consumption by SWZ (Tariff V and D split) (PJ/y)	76
Table 19	Annual 1-in-2 peak daily demand by SWZ (TJ/d)	77
Table 20	Annual 1-in-20 peak daily demand by SWZ (TJ/d)	77
Table 21	Annual peak hourly demand by SWZ (TJ/hr)	78
Table 22	Annual 1-in-2 DTS and non-DTS peak day demand forecast (TJ/d)	79
Table 23	Annual 1-in-20 non-DTS peak day demand forecast (TJ/d)	79
Table 24	Monthly gas consumption for 2021 by SWZ (PJ/m)	79
Table 25	Monthly GPG consumption in 2021 by SWZ (TJ/m)	80
Table 26	Monthly peak daily demand in 2021 by SWZ (TJ/d)	80
Table 27	Forecast hourly peak day demand for 2021 (TJ/hr)	80
Table 28	Monthly peak hourly demand in 2021 by SWZ (TJ/hr)	81
Table 29	Victorian facilities by SWZ	82
Table 30	Annual Victorian production by SWZ, 2021-25 (PJ/y)	83
Table 31	Victorian annual available and anticipated supply balance by SWZ, 2021-25 (PJ/y)	84
Table 32	Victorian monthly production by SWZ, 2021-25 (PJ/m)	85
Table 33	Peak day maximum daily quantity (MDQ) supply capacity by SWZ, 2021-25 (TJ/d)	86
Table 34	LNG operating parameters	87
Table 35	Iona UGS operating parameters	87
Table 36	Critical location pressure in the Declared Transmission System	88
Table 37	Total operating hours by compressor station, 2020	91
Table 38	Critical DTS assets	92
Table 39	Planned maintenance for 2021, as at 18 February 2021	94
Table 40	Gas planning methodology summary	99
Table 41	Gas DTS supply modelling assumptions	101
Table 42	Gas DTS modelling heating values	101
Table 43	Gas DTS demand modelling assumptions for 1-in-20 peak system demand day	101
Table 44	Impact of operational factor modelling assumptions	102
Table 45	SWP capacity modelling assumptions both with and without the WORM	103
Table 46	Northern capacity modelling assumptions and conditions	104
Table 47	Eastern LNG receiving terminal modelling assumptions	105
Table 48	Western LNG receiving terminal modelling assumptions	106

Figures

Figure 1	Annual production and supply outlook	5
Figure 2	Average monthly production forecast for 2023 and 2025	6
Figure 3	Peak day supply and Declared Transmission System adequacy	7
Figure 4	Actual 2020 monthly maximum system demands compared to the 1-in-2 and 1-in-20 forecast peak demands	17
Figure 5	The Victorian Declared Transmission System	19
Figure 6	Historical and forecast total annual gas consumption, 2016-25 (PJ/y)	24
Figure 7	Historical and forecast DTS Tariff V connections, 2013-25	24
Figure 8	Forecast average daily 2021 demand compared to 2021 peak day system demand (TJ/d)	27
Figure 9	Historical peak day maximum system demand and forecast peak day system demand, 2012-25 (TJ/d)	28
Figure 10	Average hourly winter profile for 2020 and forecast peak day system demand profile for 2021 (TJ/hr)	29
Figure 11	Average weekday winter system demand profile in 2019 and 2020	30
Figure 12	Top: Average 2020 demand profile where system demand was greater than 1,075 TJ Bottom: Impact on system linepack for a perfectly forecast, 1,100 TJ day for 2019 and 2020 demand profiles – the '2020 under-forecast' represents a 60 TJ forecast error at 6.00 am	31
Figure 13	Monthly DTS-connected GPG consumption, actual 2019-20 and forecast 2021 (TJ/m)	32
Figure 14	Victorian electricity generation, actual 2016-20 and forecast 2021-25, (GWh/year)	34
Figure 15	Peak forecast monthly DTS and non-DTS GPG demand, 2021-26 (TJ/d)	34
Figure 16	Annual supply, actual 2018-20 and 2020 VGPR Update vs. 2021 VGPR forecasts	37
Figure 17	Monthly production forecast, 2021-25 (PJ)	42
Figure 18	Average monthly production forecast, 2023 and 2025 (TJ/d)	43
Figure 19	Forecast peak day supply and Declared Transmission System supply adequacy, 2021-25 (TJ/d)	46
Figure 20	Historical Dandenong LNG storage utilisation, 2007/2019/2020 (TJ)	49
Figure 21	APA compressor locations for proposed MSP and SWQP expansion	54
Figure 22	SWP injection capacity to Melbourne with the WORM (TJ/d)	58
Figure 23	SWP withdrawal capacity to Port Campbell with the WORM (TJ/d)	58
Figure 24	Modelled VNI and SWP capacity with the WORM on a 400 TJ system demand day (TJ/d)	59
Figure 25	Iona CPP withdrawal capacity with Eastern LNG site (TJ/d)	61
Figure 26	SWP injection capacity with Western LNG injections and WORM (TJ/d)	62
Figure 27	SWP withdrawal capacity with Western LNG injections and WORM (TJ/d)	63
Figure 28	DTS peak day system capacity (TJ/d)	64
Figure 29	Daily DTS-connected GPG demand for 2018, 2019 and 2020 (TJ)	65

Figure 30	Modelled peak GPG demand profile	66
Figure 31	Longford CPP injection capacity with varying conditions (TJ/d)	68
Figure 32	SWP injection capacity (including WTS demand) to Melbourne (TJ/d)	69
Figure 33	SWP withdrawal capacity to Port Campbell (TJ/d)	70
Figure 34	Victorian Northern Interconnect export capacity (TJ/d)	71
Figure 35	Victorian Northern Interconnect import capacity (TJ/d)	72
Figure 36	Total operating hours by compressor station, 2018-20	91
Figure 37	System withdrawal zones in the DTS	98
Figure 38	Gas planning methodology overview	99

1. Introduction

The *Victorian Gas Planning Report* (VGPR) is published every two years and 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. Due to material changes to the DTS and new gas production forecast information, a VGPR Update was published in March 2020[11].

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

1.1 Review of 2020

The Victorian DTS consumption in 2020 was the highest since 2017, driven by the coldest May since 2006, close to average mean temperatures in June and July, and several strong cold fronts passing through the state in August and September[12].

System consumption[13] in 2020 was 201 petajoules (PJ), which is higher than the system consumption of 197 PJ recorded in 2019 and 193 PJ recorded in 2018.

The 2020 Victorian DTS peak demand day occurred on Tuesday 4 August 2020. The total demand on this day was 1,241 terajoules (TJ), which comprised 1,213 TJ of system demand and 28 TJ of demand for gas-powered generation of electricity (GPG). The Effective Degree Day (EDD)[14] on this day was 15.2.

Gas consumption of DTS-connected GPG during 2020 was 6.7 PJ, which is 66% less than the 19.6 PJ consumed in 2019[15]. In 2020, coal-fired generator reliability increased, there was increased generation from wind and solar, and electricity demand in the National Electricity Market (NEM) decreased due to COVID-19, leading to a reduced requirement for GPG.

Key observations for the winter peak demand period[16] of 2020 include:

- The average system demand was 795 TJ per day (TJ/d), which is higher than the average system demand of 780 TJ/d in 2019, and equal to the average demand observed in 2018.
- Cumulative EDD for the period was 1,252, which is higher than the 2019 and 2018 values of 1,195 and 1,234 respectively.
- Net supply from Queensland to the southern states (predominantly New South Wales and South Australia) via the South West Queensland Pipeline (SWQP) was 33.9 PJ over the winter peak demand period, increasing from 33.2 PJ in 2019, and 16.7 PJ in 2018[17].
- Total Victorian production decreased from 343 PJ in 2019 to 307 PJ in 2020.

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

[12] See http://www.bom.gov.au/climate/current/annual/vic/archive/2020.summary.shtml.

[13] System consumption means residential, commercial, and industrial gas usage. Total consumption combines system consumption and consumption by gas-powered generation (GPG) for generating electricity in Victoria.

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

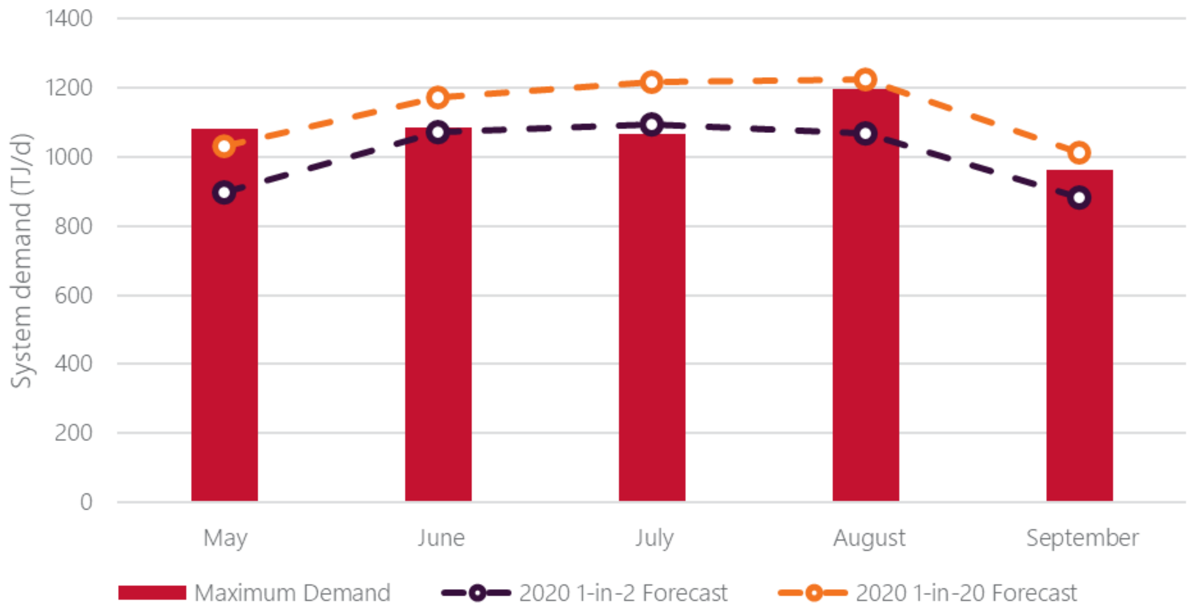
[15] 2019 GPG demand was driven by extended outages of Loy Yang A coal-fired generator and the Mortlake Unit 2 gas-fired generator (a non-DTS connected GPG unit), and a high number of outages at the Yallourn coal-fired power station.

[16] The winter peak demand period is defined as the months of May to September inclusive.

[17] Commissioning of the Northern Gas Pipeline (NGP) in the Northern Territory connecting My Isa to Tennant Creek in 2019 supported increased flows from Queensland to the southern states by supplying gas to Mt Isa that would otherwise have been supplied by the Carpentaria Gas Pipeline, which is supplied by the SWQP.

- The utilisation of the Iona underground gas storage (UGS) facility was much lower than in 2019, with only 3.2 PJ drawn down from storage over the peak winter period in 2020, compared to 8.8 PJ in 2019. This occurred despite lower Port Campbell production, and was supported by lower flows along the South East Australia Gas (SEA Gas) Pipeline due to a reduction in South Australian GPG consumption.
- There were several high demand days during winter where supply from the Iona close proximity point (CPP)[18], plus flow through the Brooklyn Compressor Station, was only just sufficient to meet demand in the Geelong and Western zones. If Iona CPP supply had been lower on these days, a Notice of a Threat to System Security would have been issued, and out-of-merit-order injections would have been scheduled at Iona CPP to resolve the supply-demand imbalance. The commissioning of the Western Outer Ring Main (WORM) pipeline (as discussed in Chapter 5) is expected to reduce the dependence of the Geelong and Western zones on Iona CPP injections.
- Figure 4 shows that the actual maximum system demand day during May exceeded the 2020 forecast 1-in-20 system demand[19], and August was close to this level. The actual maximum system demand days during June, August and September were higher than the 2020 forecast 1-in-2 system demand for those months.

Figure 4 Actual 2020 monthly maximum system demands compared to the 1-in-2 and 1-in-20 forecast peak demands



- AEMO issued a Notice of a Threat to System Security[20] on five occasions during winter 2020:
  - 1 June – caused by colder than forecast weather conditions that drove a large demand increase during the middle of the day, which resulted in 34 TJ of operational response Dandenong liquified natural gas (LNG) being injected in response to the threat. AEMO also constrained Iona CPP withdrawals to 0 TJ/hr to maximise South West Pipeline (SWP) injections.
  - 3 July – caused by higher than forecast system demand. A request for a market response was issued, and no operational response by AEMO was required.
  - 4 August – caused by lower than forecast temperatures during the middle of the day and very high demand (total demand 1,241 TJ). Profiled Longford injections had been scheduled in anticipation of the

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[18] Iona CPP consists of the Iona UGS, Mortlake, Otway and SEA Gas injection and withdrawal points.

[19] See definitions in Section 1.3.2 for 1-in-2 and 1-in-20 system demand forecasts.

[20] This list does not include threats to system security due to routine APA maintenance of the Brooklyn Compressor Station.

high demand and impact of COVID-19 restrictions on the demand profile. In response to the threat, 10 TJ of operational response LNG was injected, and injections at Iona UGS were also profiled.

  – 7 August – caused by lower than forecast temperatures between 7.00 am and 12.00 pm, which resulted in higher than expected demand, particularly during the middle of the day; 55 TJ of operational response LNG was injected in response to the threat.
  – 22 August – caused by lower than forecast temperatures for the first 12 hours of the day driving higher than expected demand throughout the day, particularly when a cold front reached Melbourne which resulted in a sharp temperature decline prior to the 6.00 pm schedule; 20 TJ of operational response LNG was injected in response to the threat.

- Due to this increased requirement for operational response LNG to respond to threats to system security including the impact of COVID-19 restrictions, LNG utilisation almost doubled during winter 2020 in comparison to 2019, with cumulative injections of 694 TJ in 2020 and 350 TJ in 2019.

The impact of COVID-19 on system demand is discussed in Chapter 2.

1.2 The Victorian Declared Transmission System

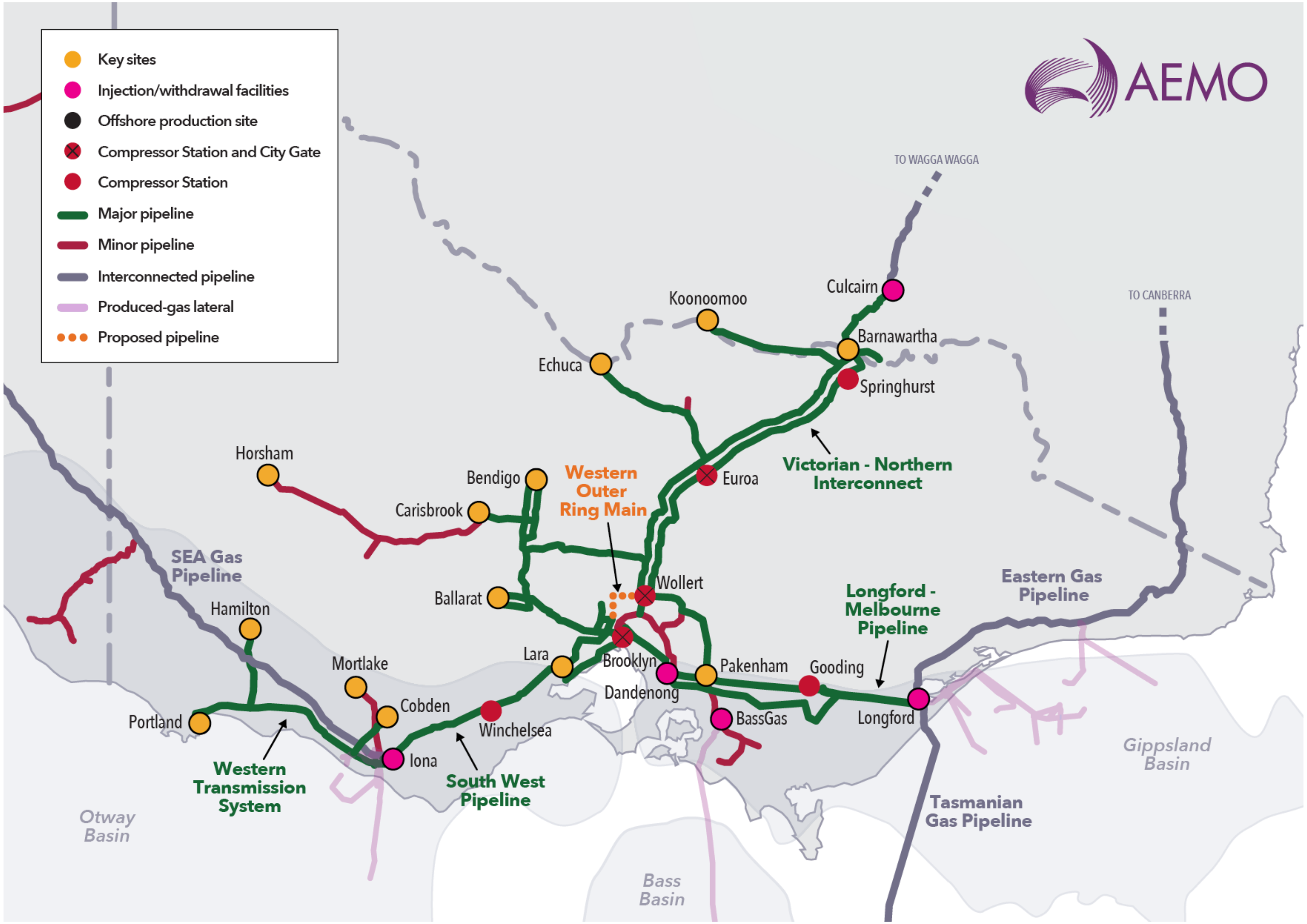
The DTS supplies natural gas to most of the connected households and businesses in Victoria, as well as to communities in New South Wales between Moama and Albury. Gas is transported from the Longford and Lang Lang gas plants in the east, to and from Culcairn in the north (connecting to the New South Wales gas transmission system) and Port Campbell in the west (connecting to the Otway and Athena[21] gas production facilities, the Iona UGS facility, and to South Australia via the SEA Gas Pipeline).

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

The DTS is divided into six system withdrawal zones (SWZs), defined in Appendix A6.

[21] Minerva Gas Plant was renamed to Athena Gas Plant in 2020; see Cooper Energy media release at https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2020.07.20-Athena-Gas-Plant-FID.pdf.

Figure 5 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 Group must submit an Access Arrangement proposal to the Australian Energy Regulator (AER) every five years, which contains its 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 National Gas Rules (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 and 1-in-20 peak system demand day over the outlook period:

- A 1-in-2 forecast is defined as a peak day system demand forecast with a 50% probability of exceedance (POE). 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 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[22]. Under rule 323(3), AEMO is also required to assess the impact of GPG demand on 1-in-2 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

[22] 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 Threat to System Security

AEMO operates the DTS to maintain connection pressure obligations across the system, where flows are within the limits specified in the relevant connection deed and agreement schedules. As gas demand increases, however, there is a risk that critical minimum pressures may be breached, potentially requiring customer curtailment to return the system to a secure state.

The DTS is in a secure state with the following conditions:

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

Under NGR rule 341, AEMO is required to inform registered participants if it believes that a threat to system security is indicated by the VGPR. A threat to system security indicates that, in AEMO's reasonable opinion:

- There is a threat to the supply of gas to customers; and
- There are insufficient assets available within the DTS to provide the capacity to meet forecast gas supply and demand conditions.

2. Gas usage forecast

Key findings

- Annual system consumption is forecast to decrease by 5.1% over the outlook period, from 197 PJ in 2021 to 187 PJ in 2025. This is in contrast with the 2020 VGPR Update, where annual system consumption was forecast to remain relatively flat.
- The forecast peak day system demands are:
  - 1,155 TJ for a 1-in-2 year system demand day in 2021, reducing by 4.5% to 1,103 TJ in 2025.
  - 1,263 TJ for a 1-in-20 year system demand day in 2021, reducing by 4.2% to 1,210 TJ in 2025.
- Tariff V (residential and small commercial customers) and Tariff D (industrial and large commercial customers) consumption is forecast to decrease by 4.6% and 5.0% respectively over the outlook period.
- Forecast reductions in peak day demand and annual consumption are the result of existing Victorian Government energy efficiency programs and new policy measures announced in the 2020-21 budget.
- The COVID-19 pandemic is forecast to continue to impact the system demand profile on high demand days in 2021, resulting in greater linepack depletion throughout the day.
- DTS-connected GPG consumption is forecast to decrease from 2021, primarily due to new committed grid-scale variable renewable energy (VRE) generation projects and distributed solar photovoltaics (PV). Peak GPG demand is expected to remain high as GPG continues to play a critical role in meeting peak electricity demand, particularly during periods of low VRE generation or prolonged coal-fired generation outages.

Background

The gas usage forecasts in the 2021 VGPR were produced using the *Gas Statement of Opportunities* (GSOO) demand forecasting methodology[23]. The VGPR forecasts use the GSOO "Central scenario", which is AEMO's best (central) view of future uncertainties impacting the gas usage forecasts for eastern and south-eastern Australia. The 2021 GSOO is also published in March 2021[24].

System demand refers to daily gas usage by residential, commercial, and industrial gas users. It includes DTS 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.

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[23] AEMO, *Gas Demand Forecasting Methodology Information Paper*, 2020, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/gas-demand-forecasting-methodology.pdf?la=en.

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

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 several variables. To forecast system demand, AEMO uses a measure known as the EDD, which considers the temperature profile, average wind speed, and sunshine hours for the gas day.

2.1 Annual consumption

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

- System consumption (Tariff V and Tariff D customers, compressor and heater fuel gas, and unaccounted for gas [UAFG][25]).
- 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.
- Non-DTS GPG consumption at Bairnsdale and Mortlake.

Annual DTS total gas consumption is forecast to decrease by 5.8% over the outlook period, from 200 PJ in 2021, to 188 PJ in 2025, as shown in Table 3 and Figure 6.

The forecast decrease in DTS total gas consumption is driven by decreases in all consumption categories over the outlook period. This is a greater decline than was forecast in the 2020 VGPR Update, which projected total consumption decreasing to 203 PJ in 2024.

AEMO's analysis showed that the COVID-19 pandemic had an insignificant impact on annual consumption, and it was not included as a long-term variable in the consumption forecasts.

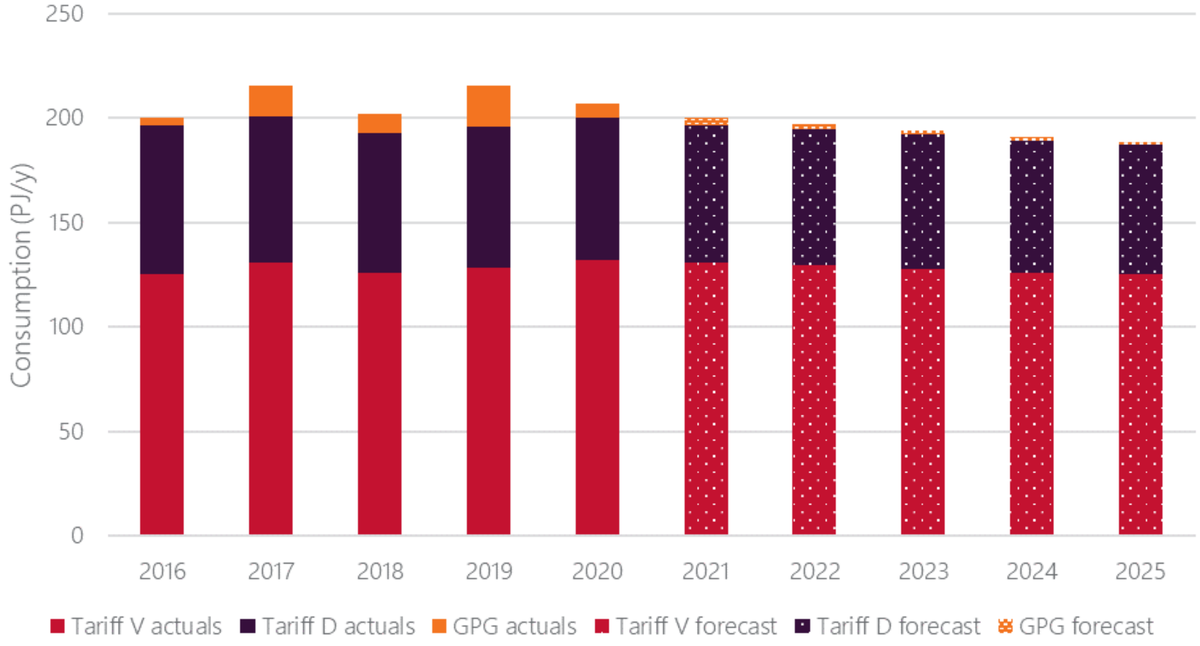
Table 3 Total annual gas consumption forecast, 2021-25 (PJ/y)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V	131	130	128	126	125	-4.6%
Tariff D	65.6	65.3	64.5	63.6	62.4	-5.0%
System consumption	197	195	192	189	187	-4.7%
DTS GPG consumption	3.19	2.19	1.90	1.77	0.92	-71.1%
Total DTS consumption	200	197	194	191	188	-5.8%
Non-DTS system consumption	1.40	1.41	1.42	1.42	1.41	1.2%
Non-DTS GPG consumption	5.38	3.36	3.13	2.99	1.69	-68.6%
Victorian GPG Consumption	8.57	5.55	5.03	4.76	2.61	-69.5%
Total Victorian consumption	207	202	199	196	192	-7.4%

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

[25] UAFG is the difference between the metered amount of gas entering the DTS and the amount of gas delivered to consumers.

Figure 6 Historical and forecast total annual gas consumption, 2016-25 (PJ/y)

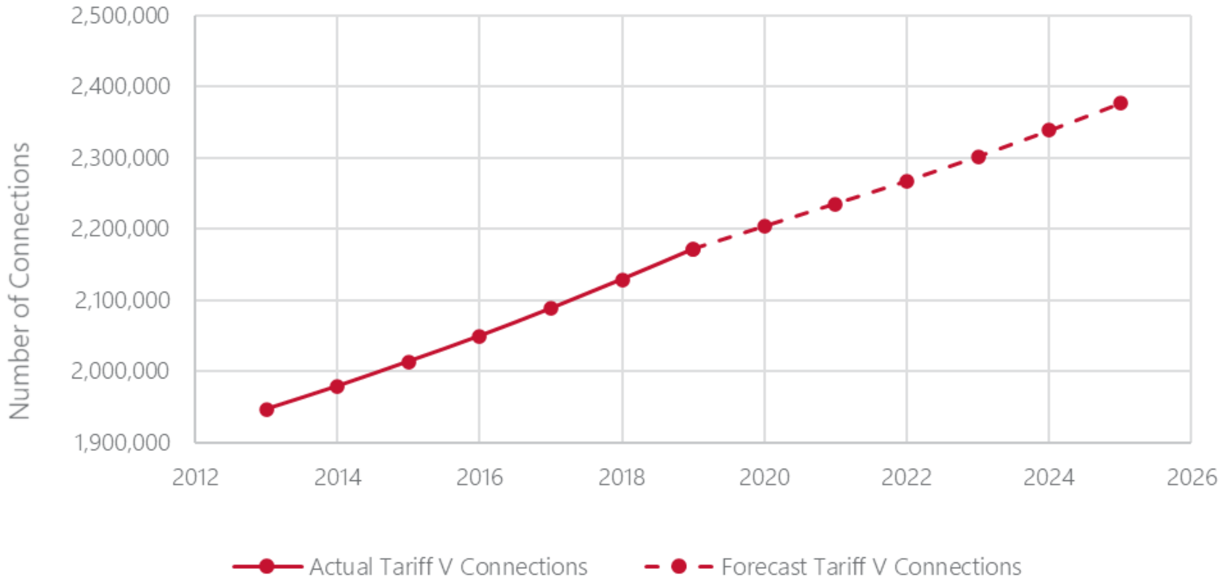


Tariff V and Tariff D gas consumption forecasts are discussed in sections 2.1.1 and 2.1.2 below. Section 2.4 discusses drivers and uncertainties related to forecasts for DTS and non-DTS GPG consumption of gas.

2.1.1 Tariff V consumption

Tariff V consumption (residential and small commercial customers) is forecast to decrease by 4.6% over the outlook period. This forecast decrease is a result of decreasing gas consumption per connection, due to increased energy efficiency and the use of electric appliances in new high-density developments. Population growth, resulting in an increased number of connections (as shown in Figure 7), is projected to offset these reductions slightly.

Figure 7 Historical and forecast DTS Tariff V connections, 2013-25



This forecast is different to the 0.4% consumption increase projected in the 2020 VGPR Update. The difference is driven by increased certainty and updated expectations around energy savings from:

- Existing energy efficiency programs, such as the Victorian Energy Upgrades (VEU) program[26] which aims to upgrade the efficiency of various gas appliances.
- New Victorian Government policy measures announced in the 2020-21 Victorian budget[27]. Areas targeted by these budget measures include:
  - Replacement of heaters for 250,000 low income households to heaters of a more efficient type.
  - Energy efficiency upgrades to 35,000 social housing properties.
  - Upgrades to the minimum energy efficiency standards of rental homes, including the requirement to replace old gas hot water and space heaters with more energy efficient models

Table 4 depicts the projected Tariff V consumption by SWZ. The behaviour varies between SWZs:

- In the Melbourne zone, Tariff V consumption is forecast to decrease substantially, as the projected number of new connections is greatly offset by forecast reduced consumption per connection. This trend is driven by the improved energy efficiency measures described above.
- 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 and regional towns that are expected to continue to install mainly gas appliances.

Table 4 Annual Tariff V consumption by SWZ, 2021-25 (PJ/y)

	2021	2022	2023	2024	2025	Change over outlook
Ballarat	8.9	9.0	9.0	9.0	9.2	2.9%
Geelong	11.5	11.6	11.6	11.6	11.7	1.5%
Gippsland	5.9	5.9	5.9	6.0	6.0	2.9%
Melbourne	92.2	90.5	88.5	86.7	85.6	-7.2%
Western	1.3	1.3	1.3	1.3	1.3	-1.1%
Northern	11.3	11.3	11.3	11.3	11.4	0.3%
DTS Tariff V system consumption	131.1	129.6	127.6	125.9	125.1	-4.6%
Non-DTS Tariff V system consumption	0.49	0.50	0.50	0.51	0.52	6.8%
Total Victorian Tariff V	131.6	130.1	128.1	126.4	125.7	-4.5%

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

2.1.2 Tariff D consumption

The Tariff D forecasting methodology has been updated in 2021 to consider the impact of historical trends more thoroughly, and to consider forecast energy savings driven by government policies on forecast consumption.

Tariff D (large commercial and industrial) consumption is projected to continue to decline, with a 5% reduction over the outlook period, as shown in Table 5. This reduction is greater than forecast in the 2020 VGPR Update, which projected a decline in annual Tariff D consumption of 3.9% over the 2020-24 outlook

[26] See https://www.energy.vic.gov.au/energy-efficiency/victorian-energy-upgrades.

[27] See https://www.budget.vic.gov.au/clean-energy-power-our-recovery.

period. This change is driven by increased certainty in energy savings from the Victorian Energy Upgrades (VEU) program, the Large Energy Users (LEU) program[28], and the change in methodology mentioned above.

The Australian Competition and Consumer Commission's (ACCC's) Gas Inquiry report noted that while several industrial users reported an easing of contracted gas prices, these lower prices were viewed as a short-term improvement, with longer-term high gas prices threatening the viability of many industrial users' operations[29]. If gas prices increase above forecast levels, Tariff D consumption is likely to be lower than the forecast in Table 5.

The Tariff D forecasts may also be impacted by near-term economic uncertainty driven by the COVID-19 pandemic. The ACCC report noted that the impact of the COVID-19 pandemic on industrial users has varied greatly. Some reported increased demand for their products, while others reported a substantial decrease, also noting that temporarily shutting their business may lead to permanent closure[30].

Table 5 Annual Tariff D consumption by SWZ, 2021-25 (PJ/y)

	2021	2022	2023	2024	2025	Change over outlook
Ballarat	1.7	1.6	1.6	1.6	1.6	-8.9%
Geelong	9.1	9.1	8.9	8.8	8.6	-4.5%
Gippsland	8.1	7.9	7.7	7.4	7.1	-12.2%
Melbourne	35.5	35.3	34.9	34.5	33.9	-4.5%
Western	2.7	2.7	2.7	2.7	2.7	0.9%
Northern	8.6	8.7	8.7	8.6	8.5	-1.9%
DTS Tariff D system consumption	65.6	65.3	64.5	63.6	62.4	-5.0%
Non-DTS Tariff D system consumption	0.91	0.91	0.91	0.90	0.89	-1.9%
Total Victorian Tariff D	66.6	66.2	65.4	64.5	63.2	-5.0%

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

2.2 Monthly consumption in 2021

Monthly system consumption forecasts for January to December 2021 are shown in Table 6:

- Maximum monthly system consumption is forecast to be 27.6 PJ per month (PJ/m) during July, with slightly lower amounts during June and August.
- System consumption during summer is forecast to be less than 10 PJ/m, with increased consumption during the shoulder seasons leading into and following winter.
- DTS-connected GPG monthly consumption is forecast to be highest in June 2021 due to high coincident NEM demand, reduced VRE output, and planned maintenance on coal generators.

[28] See https://www.energy.gov.au/business/energy-management-business/large-energy-users.

[29] ACCC, "Gas Inquiry 2017-2025 Interim Report", 17 August 2020, p. 73, at https://www.accc.gov.au/system/files/Gas%20inquiry%20July%202020%20 interim%20report.pdf.

[30] ACCC, "Gas Inquiry 2017-2025 Interim Report", 17 August 2020, p. 74.

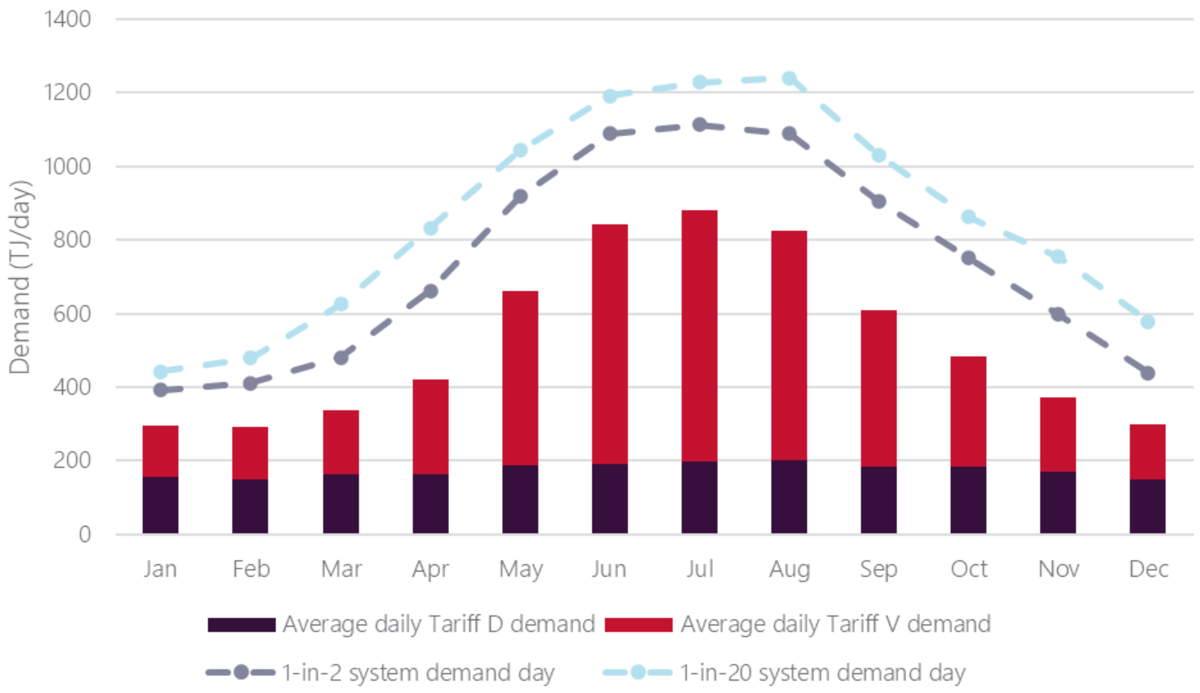
Table 6 Forecast monthly gas consumption for 2021 (PJ/m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System consumption	9.13	9.01	10.44	13.07	20.47	26.11	27.29	25.61	18.86	14.96	11.58	9.27
GPG consumption	0.49	0.23	0.07	0.33	0.46	0.64	0.27	0.39	0.19	0.01	0.05	0.06
Total consumption	9.6	9.2	10.5	13.4	20.9	26.8	27.6	26.0	19.1	15.0	11.6	9.3

These forecasts are reported by SWZ in Appendix A2, Table 24.

Figure 8 shows that the monthly gas consumption is forecast to continue increasing substantially during winter, with the projected average daily July demand of 880 TJ being roughly three times the average daily January demand of 295 TJ. The significant forecast increase during winter is mainly attributed to Tariff V heating demand, while Tariff D demand is forecast to remain relatively constant over the year.

Figure 8 Forecast average daily 2021 demand compared to 2021 peak day system demand (TJ/d)



2.3 Peak day demand

This section reports annual DTS peak day system demand forecasts over the outlook period, and monthly peak day gas demand forecasts for January 2021 to December 2021. An analysis of the impact of the COVID-19 pandemic on the observed demand profile during winter 2020 is also presented.

These forecasts are reported by SWZ in Appendix A2. The non-DTS Victorian 1-in-2-and 1-in-20 peak day system demand forecasts are also included in Appendix A2.

2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 peak day system demand forecasts, summarised in Table 7 and Table 8, show a projected decrease in both Tariff V and Tariff D peak day demand over the outlook period. This is consistent with the trends forecast in annual Tariff V and Tariff D consumption.

This differs from the 2020 VGPR Update, which projected the Tariff V peak day demand forecast to remain relatively stable over the outlook period. This change is due to increased expectations from new and existing energy efficiency schemes (see Section 2.1.1) which are forecast to reduce Tariff V peak day consumption.

Table 7 Annual 1-in-2 peak day system demand forecast, 2021-25 (TJ/d)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V	924	915	898	886	881	-4.7%
Tariff D	230	229	226	224	222	-3.8%
System demand	1,155	1,144	1,123	1,109	1,103	-4.5%

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

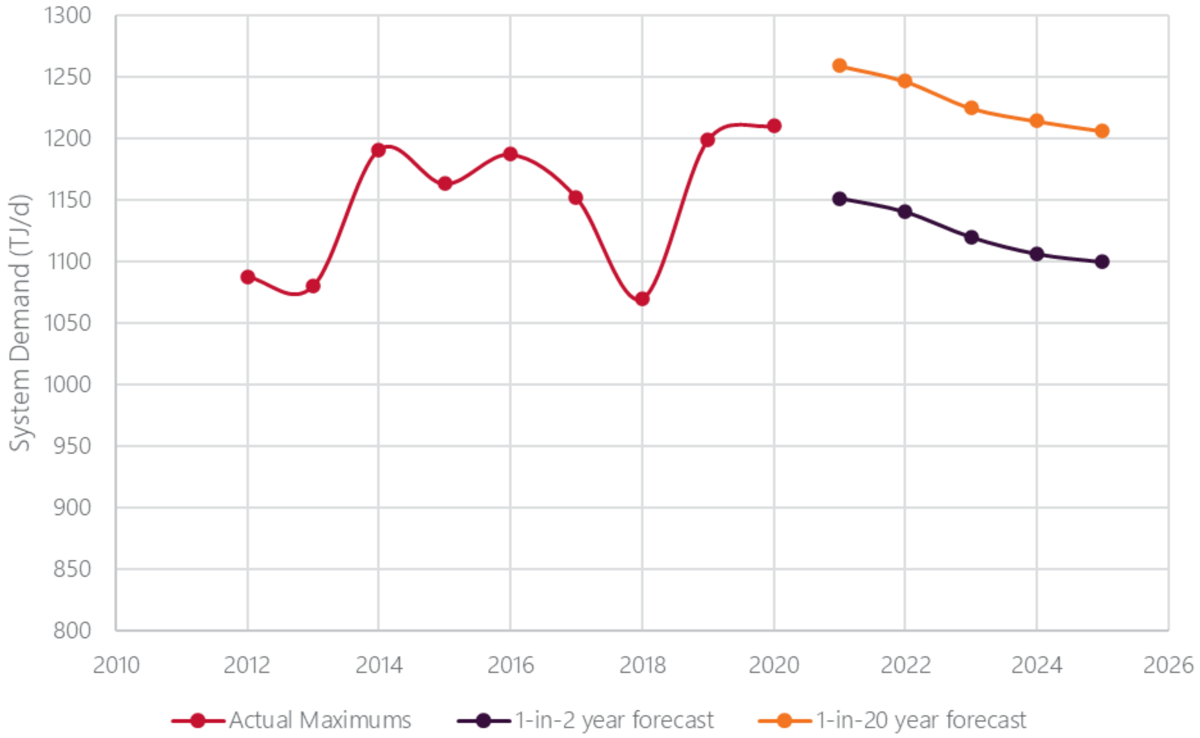
Table 8 Annual 1-in-20 peak day system demand forecast, 2021-25 (TJ/d)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V	1,023	1,012	994	986	981	-4.1%
Tariff D	240	238	234	232	229	-4.6%
System demand	1,263	1,250	1,228	1,218	1,210	-4.2%

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

Shown in Figure 9, the peak day demand forecast aligns with previous historical peak system demand days.

Figure 9 Historical peak day maximum system demand and forecast peak day system demand, 2012-25 (TJ/d)



2.3.2 Monthly peak day demand for 2021

Table 9 shows forecast peak day system demand for each month during 2021. The peak day system demand is forecast to occur during the three coldest winter months: June, July, and August. Monthly peak day system demand is influenced by weather conditions and seasonal industrial demand changes. Monthly forecast peak day system demand by SWZ for 2021 is shown in Appendix A2.

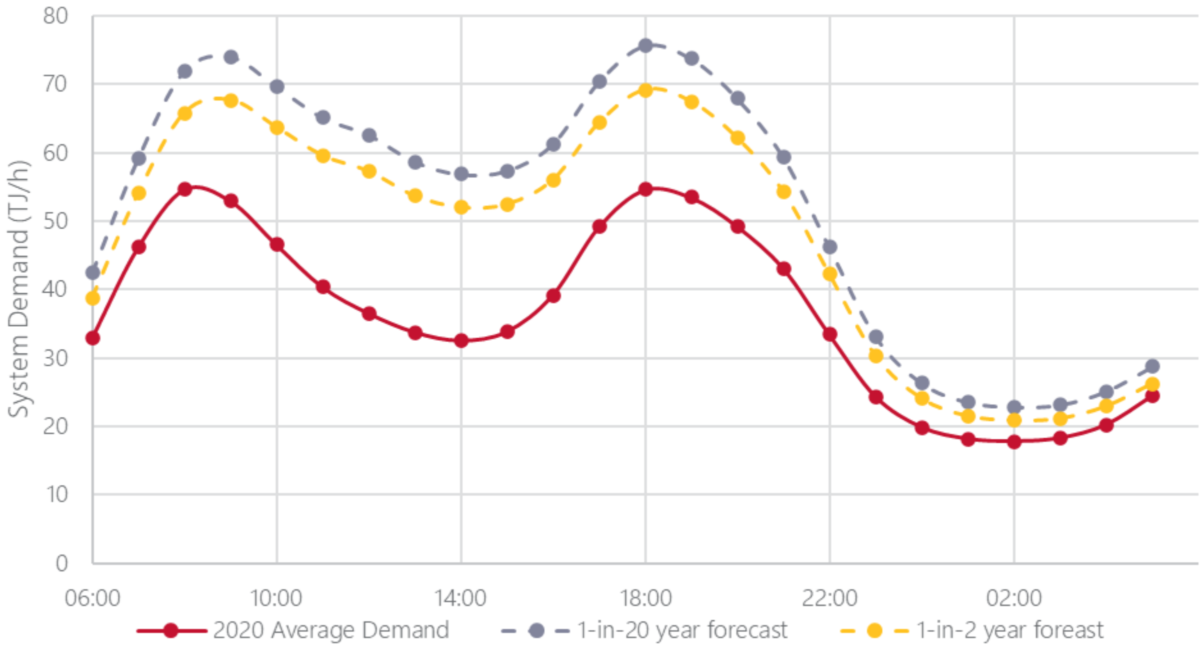
Table 9 Forecast monthly peak day demand for 2021 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	392	411	482	662	918	1,088	1,113	1,089	904	752	598	440
1-in-20	443	479	626	832	1,043	1,192	1,228	1,241	1,030	863	755	579

2.3.3 Hourly peak day demand

The 2021 forecast hourly winter 1-in-2 and 1-in-20 peak day system demand days are shown as dashed lines in Figure 10, with the average hourly demand in winter 2020. This illustrates the substantial increase in hourly demand that is forecast to occur on peak days over the average demand, particularly prior to 10:00 pm. The forecast hourly peak day system demand reflects changes to the demand profile due to the COVID-19 pandemic, as discussed in Section 2.3.4.

Figure 10 Average hourly winter profile for 2020 and forecast peak day system demand profile for 2021 (TJ/hr)



Peak hourly system demand forecasts over the outlook period, and monthly forecasts for January 2021 to December 2021, are presented in Appendix A2.

2.3.4 Impact of COVID-19 on the daily demand profile

Victorian residents and businesses were subject to various levels of movement restrictions due to the COVID-19 pandemic for the entirety of winter 2020. This resulted in:

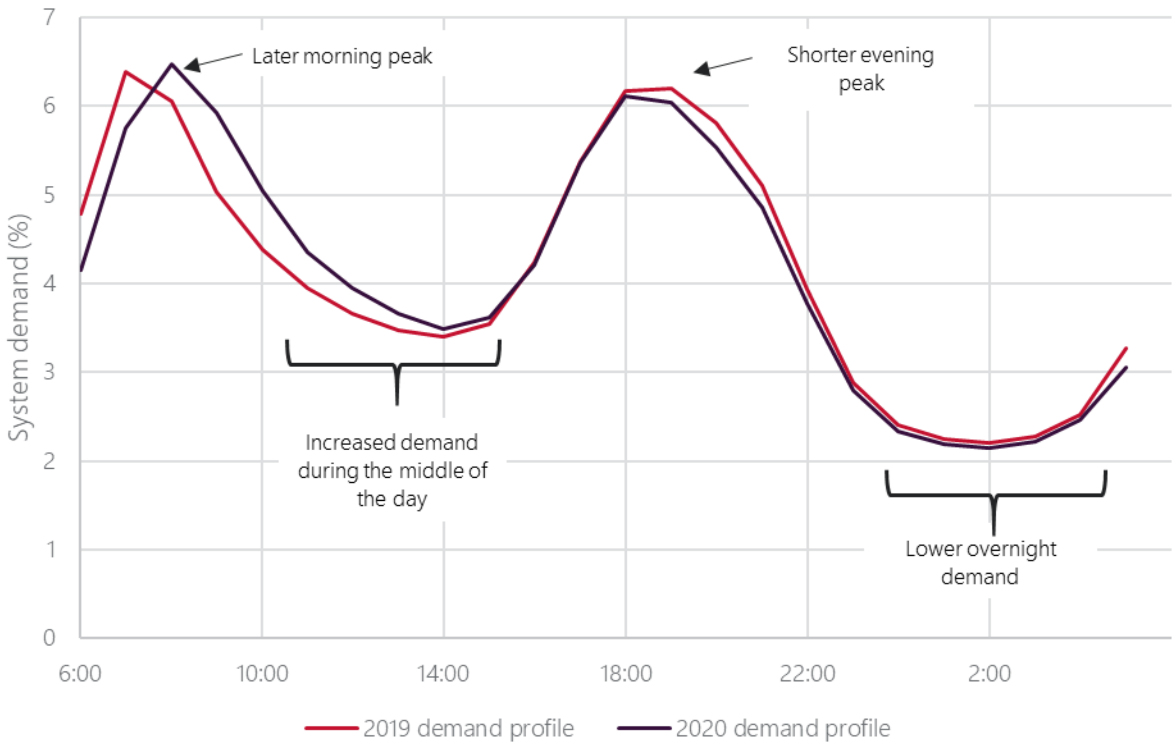
- Reduced commercial and industrial activity.

- Reduced social activity including restaurant dining and sporting matches.
- A large proportion of the population working from home, resulting in a delayed morning peak and increased heating demand during the day.

This impacted the DTS system demand profile and was a large contributing factor in all threat to system security events during winter 2020.

Figure 11 shows the impacts of the COVID-19 restrictions on the average weekday winter system demand profile, by comparing system demand in winter 2020 with system demand during winter 2019, which was a typical year.

Figure 11 Average weekday winter system demand profile in 2019 and 2020



The operational impact of the change in system demand profile on high demand days is demonstrated in Figure 12, which shows:

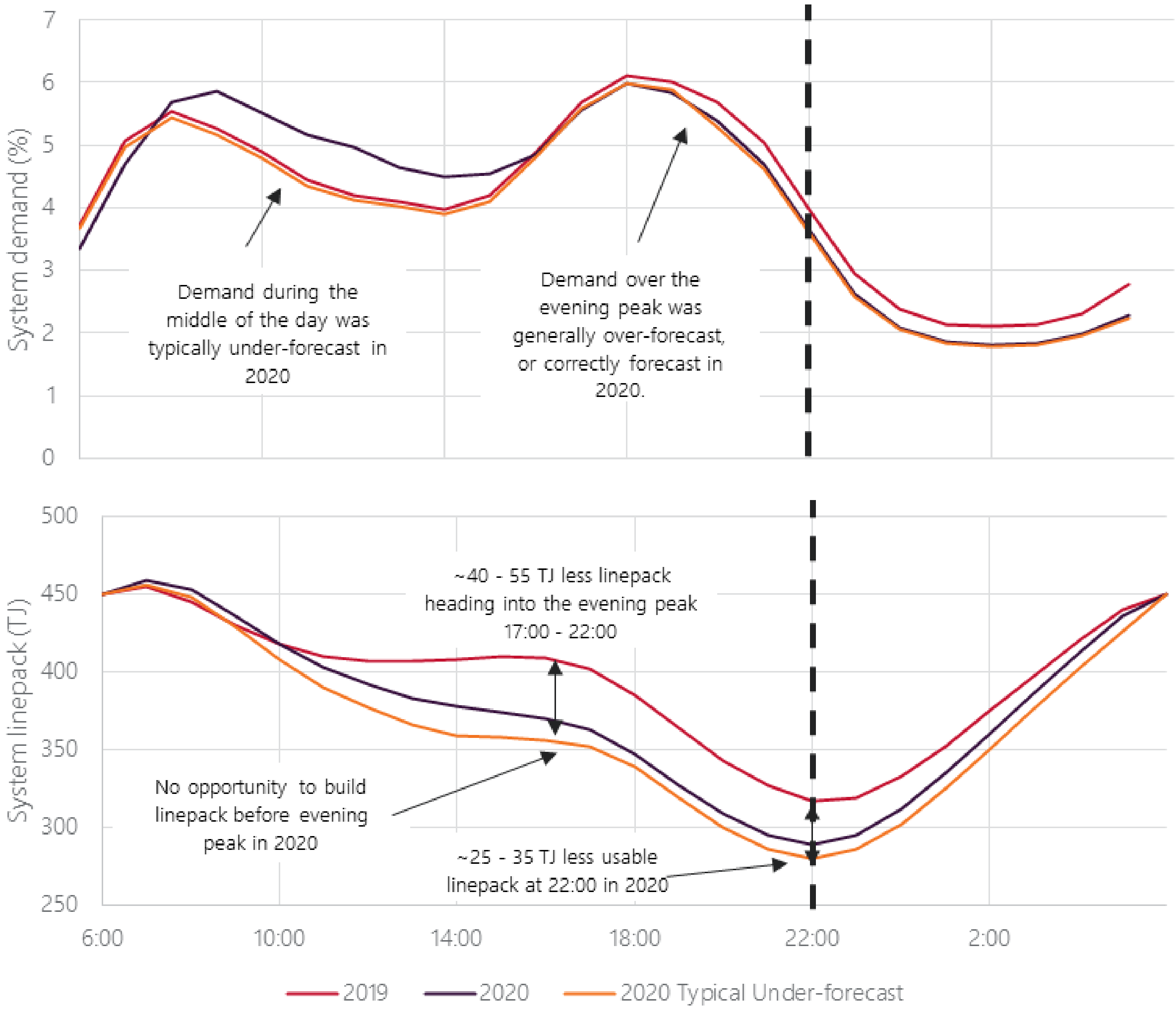
- The aggregate market participant forecast (typically used to schedule the market) was regularly under-forecast during the middle of the day. Consequently, injections scheduled into the market were often lower than if the demand profile had been correctly forecast, reducing usable system linepack heading into the evening peak.
- A greater proportion of daily system demand occurred before 10.00 pm in 2020 than in 2019, which reduced the usable system linepack by 25-35 TJ at 10.00 pm[31] (injections are scheduled flat across the day).
- There was limited ability to build linepack during the middle of the day, even if the demand profile had been perfectly forecast. Typical system linepack levels leading into the evening peaks were 40-55 TJ lower than in 2019, reducing system resilience leading into the evening peak.

[31] This is a critical time operationally, as it corresponds to the time of minimum system linepack, and therefore also minimum system pressure.

AEMO anticipates that, with ongoing 'work from home' arrangements in 2021, the system demand profile (particularly on high system demand days) could be similar to that observed in 2020. AEMO therefore expects that high system demand days will again pose an increased risk to system security.

AEMO will continue to monitor the demand profile on high demand days, and act in accordance with the Demand Override Methodology[32] to minimise interventions by AEMO.

Figure 12 Top: Average 2020 demand profile where system demand was greater than 1,075 TJ Bottom: Impact on system linepack for a perfectly forecast, 1,100 TJ day for 2019 and 2020 demand profiles – the '2020 under-forecast' represents a 60 TJ forecast error at 6.00 am



2.4 GPG forecast

Victorian gas usage for power generation, including for electricity supply on high demand days, is driven by events and conditions in the NEM. GPG can be used to replace generation that is unavailable to meet NEM demand, or for individual NEM participants to balance their portfolio positions.

The GPG forecasting methodology assumed generation and transmission assets were developed in line with the optimal development pathway and the Central scenario detailed in the 2020 *Integrated System Plan* (ISP),

[32] See https://www.aemo.com.au/-/media/files/pdf/demand-override-methodology.pdf.

and incorporated the most recent assumptions on gas prices[33], demand forecasts[34], bidding behaviour, and information on committed generation projects[35].

As shown in Table 10, Victorian GPG consumption is forecast to decrease by 69.5% over the outlook period. This is greater than the reduction of 32% forecast in the 2020 VGPR Update, primarily driven by an increased amount of committed grid-scale VRE generation and distributed solar PV now forecast to be connected.

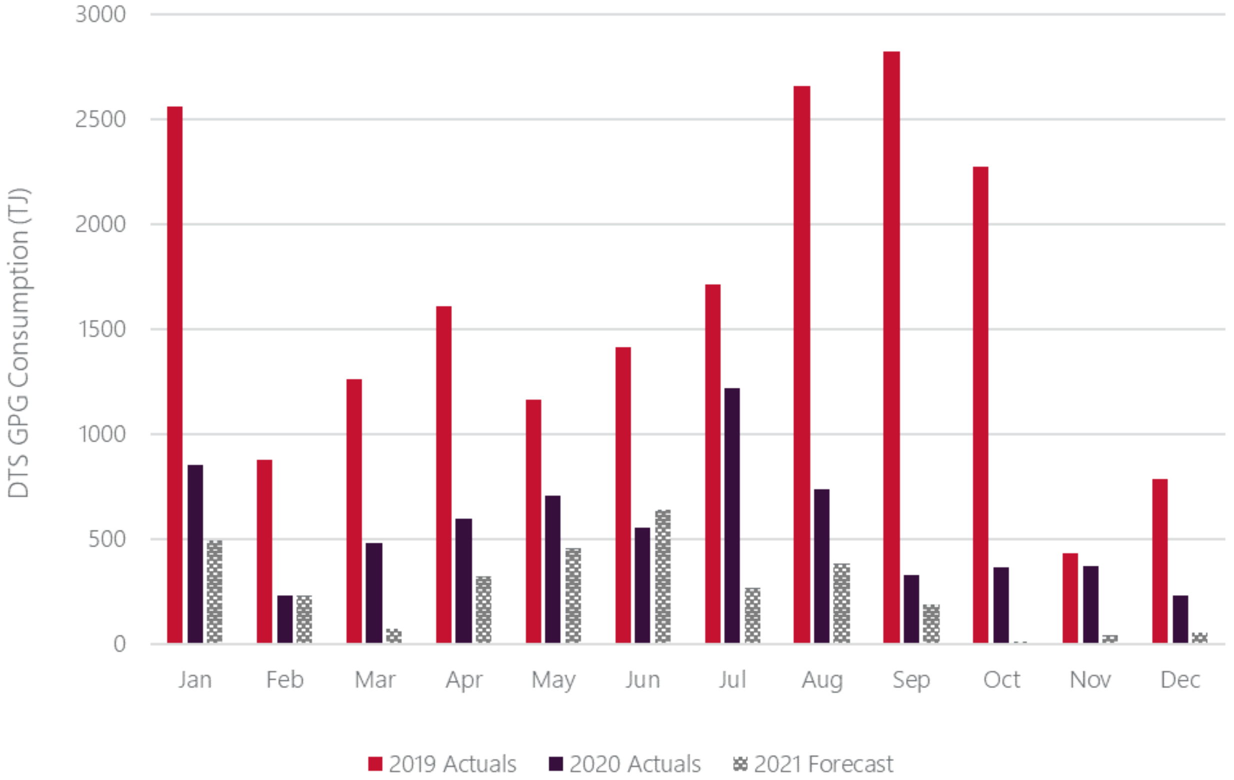
In contrast to the 2020 VGPR Update, the closure of the Liddell Power Station in April 2023[36] is now not forecast to result in an increase in Victorian GPG consumption.

Table 10 GPG consumption forecast, 2021-25 (PJ/y)

	2021	2022	2023	2024	2025	Change over outlook
DTS GPG consumption	3.19	2.19	1.90	1.77	0.92	-71.1%
Non-DTS GPG consumption	5.38	3.36	3.13	2.99	1.69	-68.6%
Victorian GPG Consumption	8.57	5.55	5.03	4.76	2.61	-69.5%

Figure 13 shows monthly DTS-connected GPG consumption for 2019 and 2020, and the predicted monthly forecast for 2021. Monthly GPG consumption can be significant during the winter and shoulder periods, with the potential to coincide with a 1-in-2 or 1-in-20 peak winter demand day.

Figure 13 Monthly DTS-connected GPG consumption, actual 2019-20 and forecast 2021 (TJ/m)



33 AEMO, Draft IASR 2020-21, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx.

34 AEMO, 2020 ESOO demand forecasts, AEMO Forecasting Portal, at http://forecasting.aemo.com.au/. Select 'ESOO 2020' from the drop-down menu.

35 AEMO, Generation Information, November 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2020/nem-generation-information-november-2020.xlsx.

36 See https://www.agl.com.au/about-agl/how-we-source-energy/agl-macquarie.

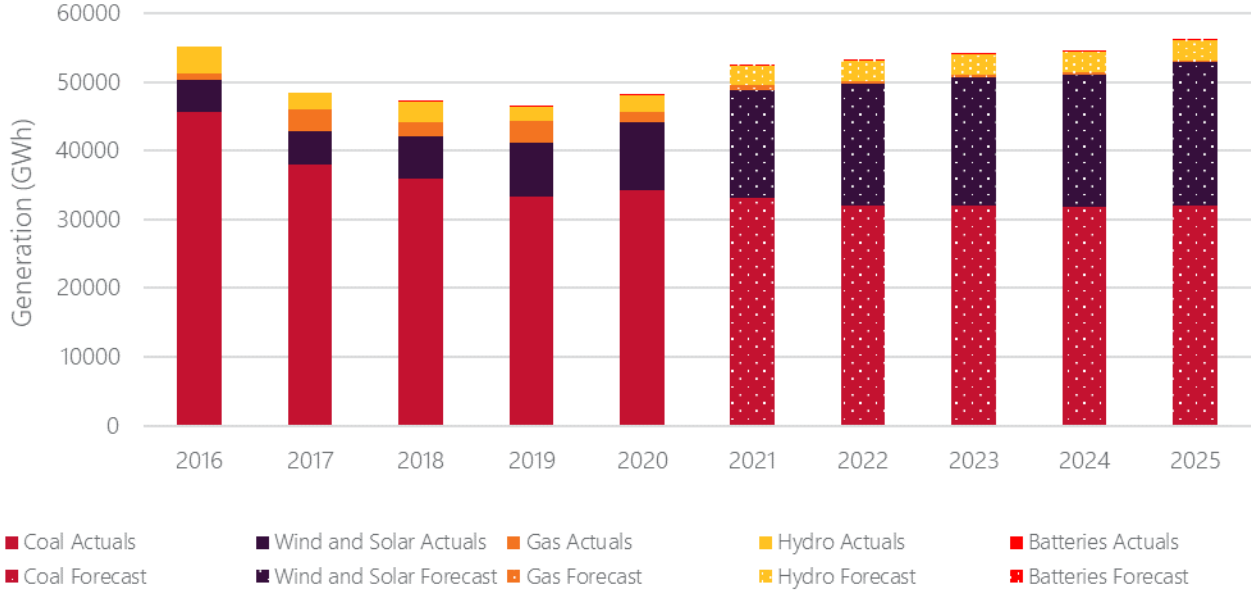
These DTS GPG consumption forecasts are subject to a wide range of uncertainties, including:

- Timing of installation of renewable energy projects – a large amount of VRE is forecast to be commissioned in Victoria from 2020 to 2022, as shown in Figure 14. If forecast investments in VRE generation are delayed or do not proceed, GPG consumption will likely be higher than reported in Table 10.
- Weather variability – GPG gas consumption is highly sensitive to variations in weather conditions. Weather patterns (rainfall, wind, and sun) affect not only consumer demand for electricity, but also the output of renewable (hydro, wind, and solar) generation in the NEM, which subsequently impacts the amount of gas required for GPG.
- Electricity transmission investments – several key electricity transmission projects are required to successfully integrate the large amount of forecast VRE generation into the NEM, and to lessen the impact of planned coal-fired power station retirements. Projects of particular importance are Victoria – New South Wales Interconnector Minor (assumed to be operating from 2022), Project EnergyConnect (connecting South Australia and New South Wales, 2024) and HumeLink (transmission augmentation for the Snowy 2.0 hydroelectric scheme to deliver electricity to New South Wales demand centres, 2025). If the completion of any of these projects is delayed, Victorian GPG consumption will likely be higher than reported in Table 10.
- Major transmission outages – outages of key electricity transmission assets in the NEM can result in increased levels of GPG.
- Early closure of coal-fired generators – the GPG consumption forecasts assume the following closure dates of large coal-fired generators: Liddell in 2023, Yallourn in 2030[37], Callide B in 2029, and Vales Point in 2029. If these closures were to occur earlier in the outlook period, GPG consumption will likely be higher than reported in Table 10.
- Reliability of coal-fired generators – unavailability of coal-fired generators can greatly increase GPG consumption. For example, GPG consumption increased by approximately 10 PJ in 2019 over 2018 levels due to the extended outage of the Loy Yang A2 coal-fired generator and a high number of unplanned outages at the Yallourn Power Station.
- Gas prices – gas prices varying from projected levels may impact the amount of GPG offered into the NEM.

The 2021 GSOO explores the impact of a variety of these events on forecast GPG consumption. Depending on the event and its magnitude, GSOO modelling projects annual Victorian GPG consumption being up to 70% greater than that reported in Table 10.

[37] EnergyAustralia announced on 10 March 2021 that it would now shut down the Yallourn Power Station in mid-2028. The impact of this earlier closure will be analysed in the 2021 ESOO modelling.

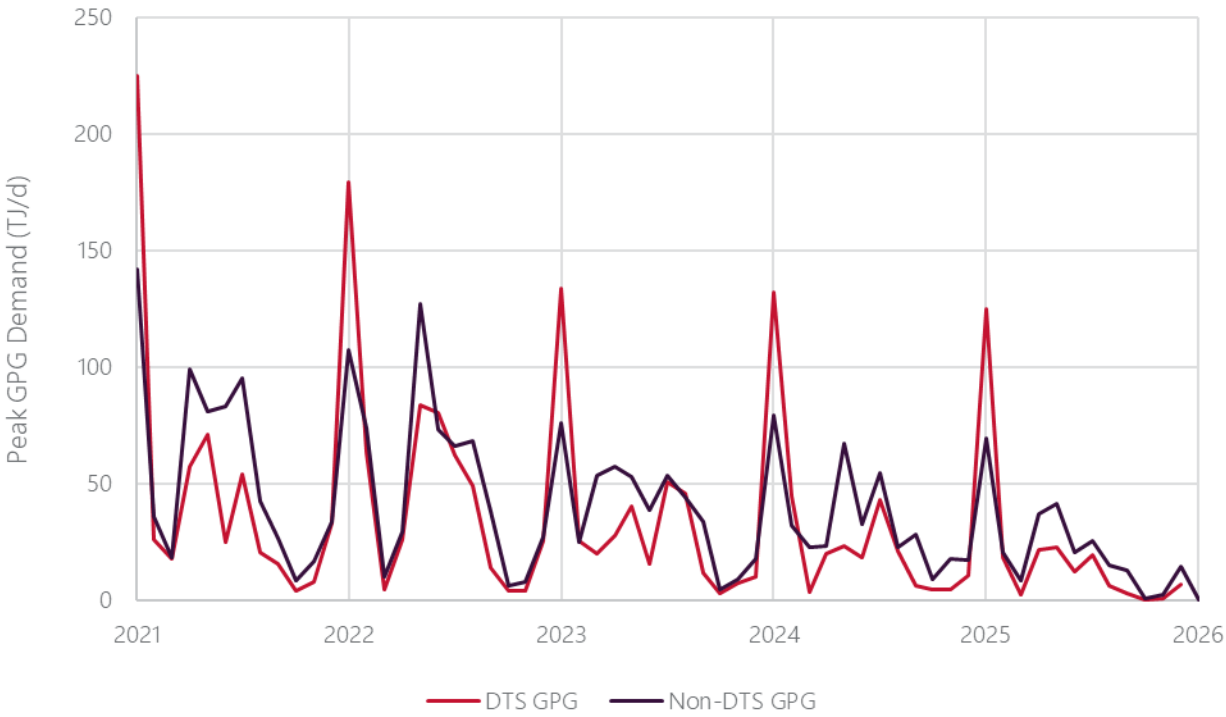
Figure 14 Victorian electricity generation, actual 2016-20 and forecast 2021-25, (GWh/year)



From AEMO, 2020 Electricity Statement of Opportunities (ESOO).

GPG remains an important source of peaking capacity in the NEM, as peak GPG demand[38] (demand on a daily basis) is forecast to decrease slightly, but remain high over the outlook period, as shown in Figure 15. Peak GPG demand may exceed the levels shown in Figure 15 if high NEM demand conditions coincide with generator or transmission line outages or maintenance.

Figure 15 Peak forecast monthly DTS and non-DTS GPG demand, 2021-26 (TJ/d)



[38] Peak GPG demand coincides with high electricity demand conditions in the NEM.

3. Gas supply forecast adequacy

Key findings

- With the binding development agreement executed between Australian Industrial Energy (AIE) and Jemena in March 2021 along with other financial commitments that AIE have made, AEMO now considers the Port Kembla Gas Terminal (PKGT) to have obtained all necessary approvals and there is sufficient evidence that the project has commenced implementation. It is therefore classified as a committed project in the 2021 GSOO and subsequently is considered as available supply for Victoria.
- Provided that projects such as the PKGT are delivered ahead of winter 2023 enabling net supply from New South Wales into the DTS, there is now projected to be sufficient supply to address the forecast shortfall previously outlined in the 2020 VGPR Update.
- While there is projected to be adequate supply, total Victorian available production is declining by 43% from 360 PJ in 2021 to 205 PJ in 2025. This is a slight improvement on the 2020 VPGR Update, with a number of projects transitioning from anticipated to committed.
  - From 2023, Victorian gas production is forecast to flatten, and both the monthly winter peaking production capacity and the associated peak day supply capacity will significantly decrease, increasing the imbalance between winter production and demand.
  - By 2023, 34% of Victoria's gas production is forecast to be from committed projects that are not currently producing. Any delays in these projects could lead to supply shortfalls.
  - By 2025, the imbalance between the available supply and demand during the Victorian winter is forecast to exceed the Dandenong LNG and Iona UGS capacity, whereby the DTS is increasingly reliant on net imports from New South Wales.
- Victorian peak day supply capacity available to the DTS is expected to decline by 38%, from 1,585 TJ/d in 2021 to 983 TJ/d in 2025.
  - Based on current committed projects, the Victorian DTS will rely on net imports from New South Wales from winter 2023 for any demands exceeding a 1-in-2 peak day including any GPG demand above this amount.
  - New South Wales expected supply of 395 TJ/d will be via:
    - The existing route from the Moomba to Sydney Pipeline (MSP) supply via the Culcairn connection point with capacity of 195 TJ/d. The MSP, which will also be expanded to 450 TJ/d, is supplied from the Moomba Gas Plant and Queensland.
    - The Eastern Gas Pipeline (EGP), which will be upgraded to enable reverse flow south into Victoria, and increased supply via the VicHub connection point into the Longford to Melbourne Pipeline (LMP). Supply will be from the PKGT and the Orbost Gas Plant, which also supply Bairnsdale, Tasmania, and Canberra demand.

- Supply from New South Wales will be reliable supply of cargoes to the PKGT during winter months and the reliable operation of key compressors on the MSP and EGP. Very high levels of New South Wales GPG demand may also reduce the supply available to Victoria.

- The Dandenong LNG storage facility is an essential source of fast response peak shaving gas supply that AEMO utilises to quickly respond to incidents that threaten system security. There is forecast to be insufficient Dandenong LNG capacity contracted by winter 2021, limiting AEMO's ability to respond to operational and emergency scenarios. AEMO has identified low Dandenong LNG inventory as a threat to system security and is seeking a market response to increase LNG storage levels prior to winter 2021.

Background

AEMO assesses supply adequacy based on its demand forecasts (see Chapter 2) and the forecast available supply, which is based on data provided to AEMO by producers, storage providers, pipeline operators, and market participants. This assessment includes commentary on supply from interstate through connected pipelines, as modelled for the 2021 GSOO.

Gas supply classification

Table 11 defines gas supply classifications used in the 2021 VGPR, with notes on how these classifications are referred to in the 2021 GSOO and the Petroleum Resources Management System (PRMS)[39].

Table 11 Gas supply classification definitions

VGPR	2021 VGPR description	PRMS	GSOO
Existing supply	Comprises existing gas reserves and projects currently in operation.	Reserves: On Production	Existing supply
Committed supply	Encompasses 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: Approved for Development	Committed supply
Available supply	Incorporates both existing supply and committed supply.	Reserves: On Production, Approved for Development	Existing and 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 4.	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 to proceed than the anticipated supply projects during 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	Contingent Resources: Development Pending, Development on Hold, Development Unclarified	Uncertain supply

[39] The PRMS for defining reserves and resources was developed by an international group of reserves evaluation experts and endorsed by the World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, and Society of Exploration Geophysicists

VGPR	2021 VGPR description	PRMS	GSOO
	• Insufficient gathering pipeline or appropriate gas processing capacity being available; or • The project requiring new infrastructure that currently does not have approved planning permits or environmental approvals.		
Exploration projects	These projects are associated with undiscovered gas resources 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 the GSOO.	Prospective resources: Prospect/Leads/ Plays	

3.1 Annual supply-demand balance

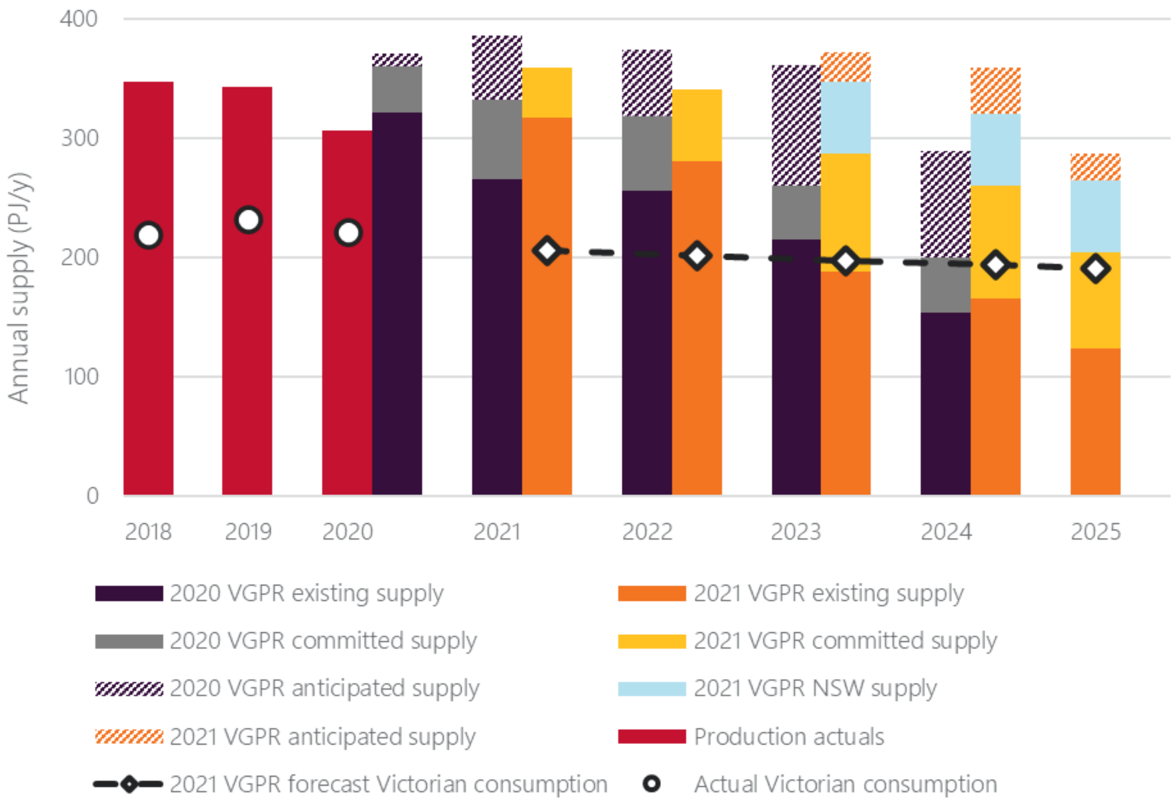
This section discusses the reported Victorian annual gas supply and its adequacy during the outlook period.

The section does not consider DTS storage facilities, because these facilities provide seasonal balancing for peak demand periods and are not expected to provide annual supplies.

3.1.1 Annual production forecasts

Figure 16 shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2020 VGPR Update. The full data set is available in Appendix A3.

Figure 16 Annual supply, actual 2018-20 and 2020 VGPR Update vs. 2021 VGPR forecasts



Gippsland zone[40]

The supply from existing Gippsland fields is forecast to decline 58% from 288 PJ in 2021 to 122 PJ in 2025. Supply from the Sole gas field is now reported as existing supply with the return to service of the Orbost Gas Plant in early 2020.

Available supply (existing plus committed projects) from Gippsland reduces the forecast decline during the outlook period from 58% to 52%. The West Barracouta project is the largest of the region's committed supply projects and is expected to commence production prior to winter 2021 after well development works were completed during 2020[41].

The largest reduction in available Gippsland production is now forecast to occur before winter 2023. This is earlier than reported in the 2020 VGPR Update, which stated that a key Gippsland gas field and several smaller Gippsland fields were forecast to cease production sometime between mid-2023 and mid-2024, resulting in a forecast supply shortfall for winter 2024.

This change is primarily attributed the decline in existing supply from several legacy Gippsland Basin Joint Venture (GBJV) fields, that supply the Longford Gas Plant, occurring earlier than originally forecast. The updated GBJV forecast provided to AEMO advises that production may now cease prior to winter 2023. As these fields approach ultimate depletion, the uncertainty regarding the remaining volume and capacity will improve, but the time available to respond will also be reduced:

- GBJV's large legacy fields are predominantly water-driven. Water-driven reservoirs are characterised by rapid and less predictable production declines at the end of their field life.
- The timing of these legacy field declines will also be a function of the quantity of the gas produced from these fields during 2021 and 2022. Lower production from these fields prior to 2023 could push back the timing of this forecast capacity reduction, while higher production would accelerate it.

Further development of the Kipper Unit Joint Venture (KUJV) Project is an anticipated supply project that is forecast to begin production after winter 2023. This is discussed in Chapter 4.

Port Campbell zone[42]

The 2020 VGPR Update forecast that Port Campbell production would decline from 49 PJ in 2020 to only 1 PJ from 2023. The commitment to redevelop existing fields in the offshore Otway Basin by Beach Energy[43] and Cooper Energy[44] has resulted in a forecast increase in Port Campbell production from 44 PJ in 2021 to 67 PJ in 2023, before declining to 52 PJ in 2025.

This increase in Port Campbell committed production accounts for all developments that were previously classified as anticipated projects, resulting in 0 PJ of anticipated Port Campbell supply forecast during the outlook period.

The recent discoveries of Cooper Energy's Annie field, and Beach Energy's Enterprise and Artisan fields are expected to result in new anticipated production in this region over the next several years. AEMO has not been able to include these discoveries in the 2021 VGPR as anticipated supply projects, because no development timeline has been provided for these fields (due to their recent discovery).

Any increase in production from these fields is expected to be limited by the capacity of Beach Energy's Otway Gas Plant and Cooper Energy's Athena Gas Plant. Peak day supply from these plants along with supply from the Iona UGS facility is expected to be constrained by the capacity of the South West Pipeline (SWP).

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[40] Gippsland zone includes Longford GBJV, Longford Kipper Project, Sole Gas project, and Lang Lang production facilities. Combined production is gas available to the DTS, EGP, and TGP.

[41] See https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2020/Esso-drilling-for-West-Barracouta-gas.

[42] Port Campbell includes the Otway and Athena gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

[43] See https://www.beachenergy.com.au/wp-content/uploads/2021/02/210216_Beach-Energy_OtwayOffshoreProject_Summary.pdf.

[44] See https://www.cooperenergy.com.au/Upload/Cooper-Energy-Activites-Update-November-2020.pdf.

New South Wales zone

AEMO has introduced the term 'New South Wales zone' for the 2021 VGPR to depict the expected net supply from New South Wales from winter 2023. Winter supply from the MSP via the Culcairn connection point has been increasing in recent years as Queensland gas has been used to supply demand in the southern states. Despite this, Victoria has remained a net exporter of gas with more Gippsland gas, mainly from the Longford Gas Plant, flowing north on the EGP.

The large decrease in Longford production forecast from winter 2023 will require a new source of winter supply. While there are other anticipated and potential projects that could be developed prior to winter 2023, discussed in Chapter 4, the PKGT has been classified as a committed project in the 2021 GSOO and is subsequently considered to be available supply for Victoria

There has been no formal financial investment decision (FID) announcement for the PKGT project. AIE is 100% owned by Squadron Energy[45], which in turn is part of the Tattarang group of companies which hold the private business interests of Andrew Forrest. AEMO has been advised that the entities involved do not intend to make a formal FID announcement regarding this project, but that Tattarang is fully committed to developing the PKGT.

The PKGT will use a floating storage and regassification unit (FSRU), which is an LNG storage ship that has an onboard regassification plant capable of vaporising the stored LNG for supply into a gas pipeline. The import terminal has planning permission for 130 PJ/y of LNG supply. LNG supplies to the PKGT will be dependent on reliable shipping schedules to provide reliable cargoes during winter months. Inventory will need to be carefully managed as the FSRU will need to be close to empty when a refill ship arrives. If the FSRU inventory gets too low or if a shipment is unexpectedly delayed, there could be supply shortfalls if this coincided with peak demands.

AEMO considers the PKGT to be a "committed project" as AIE has made substantial commitments to progress this project, including:

- The FSRU "Höegh Galleon", that will form a key part of this LNG receiving facility, has been constructed and was commissioned in August 2019. This vessel is under an exclusive arrangement between AIE and Höegh LNG and is available to relocate to Port Kembla when AIE calls upon it.
- AIE executed a 25-year lease with Ports NSW in November 2020 that includes a 10-year minimum term. AIE has also committed to the demolition works contract to enable the construction of a new wharf. Contracts for dredging works and the remaining construction are expected to be awarded shortly.
- Separation works from the part of Port Kembla Coal Terminal site that the terminal will occupy have started, with 40-50 people on site working on pre-construction activities, completing approximately 2,000 hours per week.
- All major planning approvals have been granted for the project and the New South Wales Government has designated it as critical state significant infrastructure.
- AIE has 15 personnel in Wollongong working on this project and additional team members in Perth, Sydney and Melbourne, and an overall team (including support staff) which is planned to increase to approximately 50 people by mid-2021.
- AIE and Jemena executed a binding project development agreement in March 2021 that includes the construction of a 12 km pipeline from the Port Kembla wharf to the Eastern Gas Pipeline that will enable at least 500 TJ of regasified LNG to be delivered from the FSRU into the Eastern Gas Pipeline.

The current project plan and timeline provided by AIE to AEMO is for the Höegh Galleon to arrive in Port Kembla in late 2022. This will be followed by a commissioning process for commencement of commercial operations in early 2023.

[45] Legal entity is Squadron Port Kembla Pty Ltd.

Jemena has advised AEMO that that it is committed to pipeline modifications that will enable 200 TJ/d of southern flow from PKGT on the EGP to Victoria. Supply from the Orbost Gas Plant increases this quantity, while demand supplied off the EGP and from VicHub reduces this quantity. The EGP supplies small centres in south-east New South Wales, a portion of Canberra's demand, Bairnsdale including a small power station, and Tasmania. For the planning purposes a net flow of 200 TJ/d into the DTS has been assumed. Supply from the EGP via TasHub would increase this quantity but additional EGP compression at Port Kembla is required.

The capacity of the MSP is also expected to be increased to 450 TJ/d for winter 2021, and the delivery capacity from Young via the Culcairn connection will increase to 195 TJ/d. This capacity via Culcairn is not expected to result in net supply from New South Wales until 2023, as Gippsland gas is expected to continue to flow north on the EGP until 2023. The capacity of the DTS Victorian Northern Interconnection (VNI) to receive this gas is discussed in Chapter 6.

The combined delivery capacity into Victoria for the EGP and the MSP via Culcairn is 395 TJ/d for winter 2023 (unless there is a commitment to further expansion prior to this). A monthly supply of 12 PJ from New South Wales has been assumed for planning purposes.

Further expansions of the EGP and MSP have been proposed. These are discussed in Chapter 4.

3.1.2 Annual supply adequacy

Table 12 shows the annual supply adequacy forecast over the outlook period. The annual supply adequacy assessment indicates that:

- The forecast available Victorian production exceeds forecast consumption for each year of the outlook period. This is an improved position on the forecast shortfall for 2024 as reported in the 2020 VGPR Update, and results from an expected increase in committed supply as producers responded to forecast shortfalls.
- Victoria's annual production surplus is expected to decline over the outlook period, reducing from 154 PJ in 2021 to 14 PJ in 2025. Over the last five years, Victoria has supplied on average 140 PJ/y to South Australia, New South Wales, and Tasmania from its production surplus. The substantial reduction in forecast Victorian production and the reduced quantities Victoria can supply to neighbouring jurisdictions has triggered several proposals to increase gas supplies, including AIE's commitment to develop the 130 PJ/y PKGT.
- The PKGT will enable net supply into Victoria from early 2023. Gas will flow into Victoria from the EGP via VicHub and via the Culcairn interconnection that is supplied from the MSP. An annual supply of 60 PJ/y has been assumed for planning purposes.
- This annual supply assessment does not consider monthly and peak day supply requirements, which are discussed in the following sections.

Table 12 Victorian annual available and anticipated supply balance, 2021-25 (PJ/y)

Supply source		2021	2022	2023	2024	2025
Gippsland[A]	Available supply	316	292	220	202	153
	Anticipated supply	0	0	25	39	22
Port Campbell (Geelong)[B]	Available supply	44	49	67	59	52
	Anticipated supply	0	0	0	0	0
NSW[C]	Available supply	0	0	60	60	60
	Anticipated supply	0	0	0	0	0
Total VIC available supply		**360**	**341**	**287**	**261**	**205**
Total VIC and NSW available supply		**360**	**341**	**347**	**321**	**265**
Total VIC and NSW anticipated supply		0	0	25	39	22
Total Victorian consumption		206	202	198	195	191
Surplus quantity with VIC and NSW available supply		**154**	**139**	**149**	**126**	**74**

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Project, Orbost Gas Plant, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes the Otway and Athena gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.
C. NSW zone include supply from Queensland via Culcairn and PKGT via the EGP through VicHub.

3.2 Monthly supply-demand balance

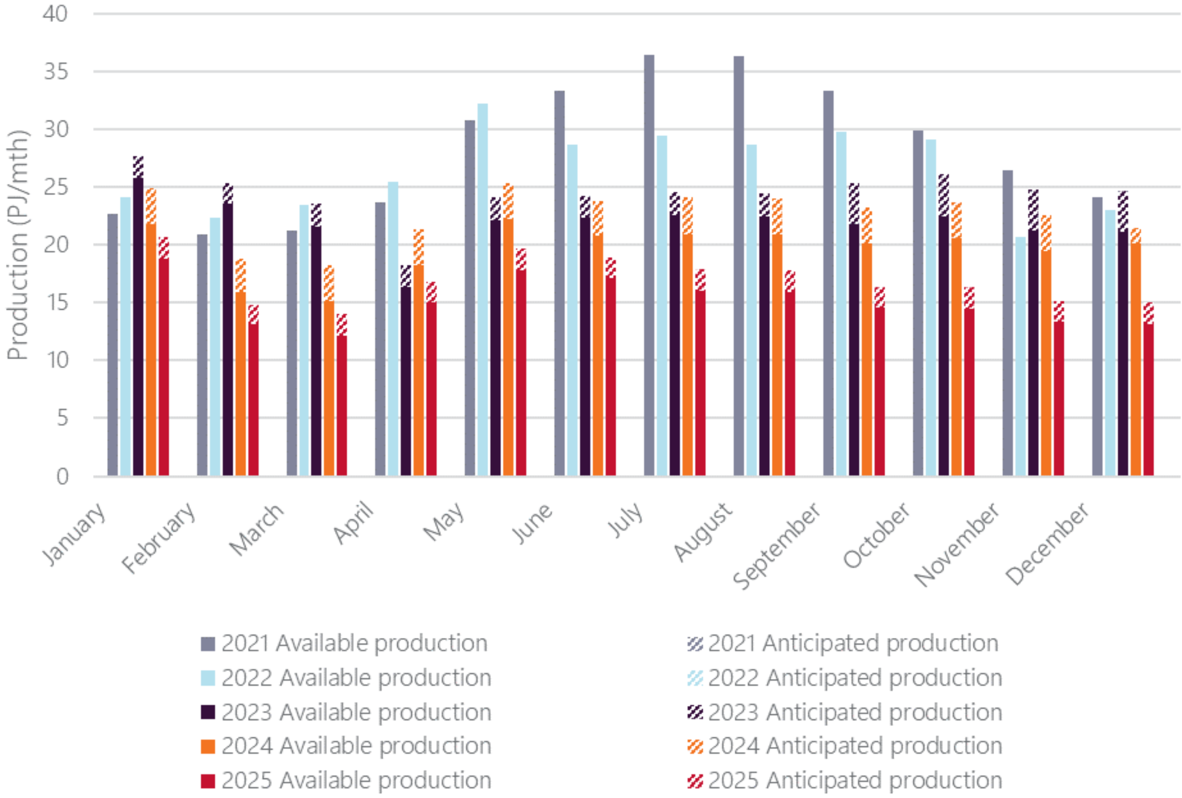
This section discusses the forecast Victorian monthly gas supply for the outlook period, and its adequacy to balance forecast consumption for each month and seasonally over the outlook period. This discussion includes commentary on DTS storage facilities and interstate supply from DTS-connected gas pipelines.

3.2.1 Monthly production forecasts

Figure 17 shows forecast monthly production for the outlook period.

It shows that forecast monthly gas production is forecast to decline further after winter 2021, with a step down for winter 2022 and further reductions for winter 2023 and 2025. When considered against Victoria's monthly consumption – which ranges from 10 PJ/m during summer to 25-30 PJ/m during winter – forecast production is forecast to reduce below monthly production. The full data set is in Appendix A3.

Figure 17 Monthly production forecast, 2021-25 (PJ)



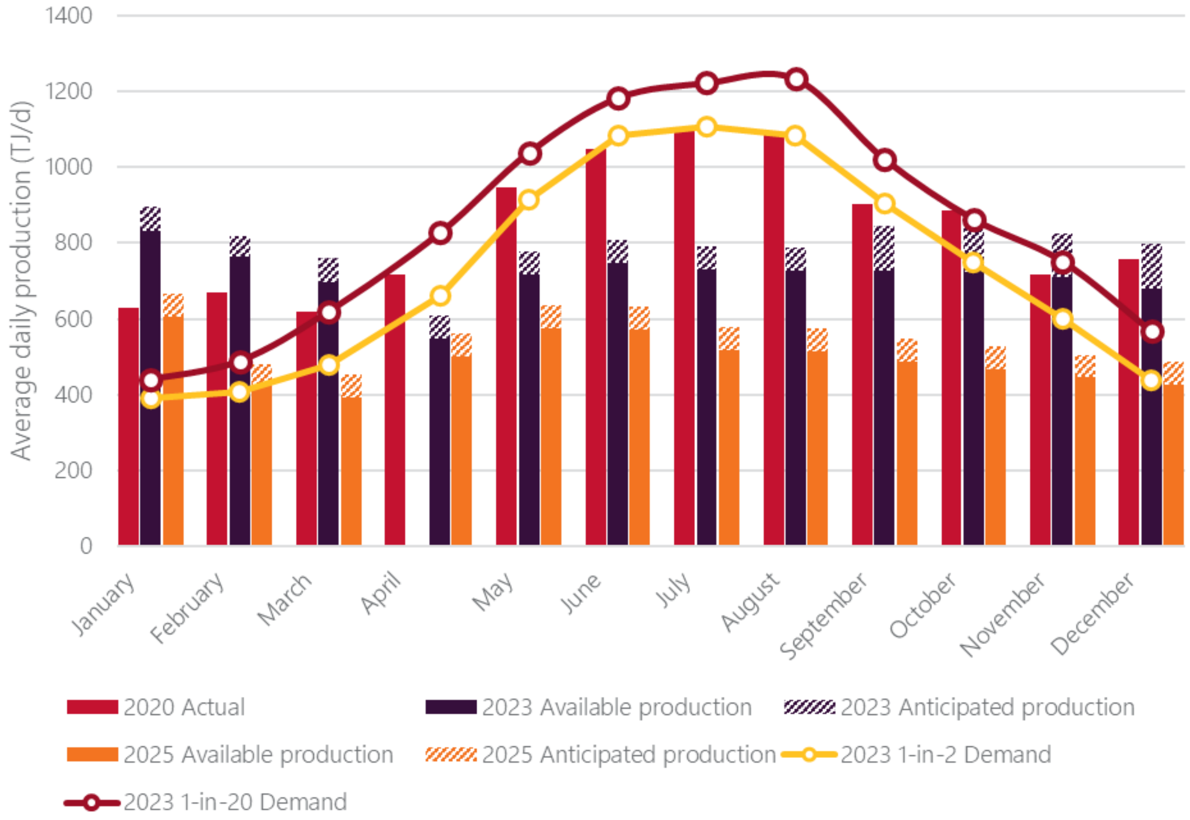
3.2.2 Monthly supply adequacy

Monthly Victorian production has historically peaked during winter, as Longford Gas Plant production has been able to increase in line with the seasonal demand profile. Most other production facilities operate with a flatter production rate all year, with production limited by either the processing capacity of the facility or the supply capacity of the connected gas fields.

Figure 18 shows that 2020 monthly production was generally aligned to Victoria's seasonal system demand. With the forecast reduction in Longford Gas Plant's production capacity and flexibility due to the depletion of legacy gas fields, Victorian monthly winter production is forecast to decline significantly, resulting in a flatter supply profile from 2023.

As Victorian production declines, supply into neighbouring jurisdictions is also expected to decline with Victoria becoming a net importer during winter periods from 2023. Supply will be from the PKGT via the EGP and via Culcairn from the MSP. Being in the southern hemisphere, Victoria's winter does not coincide with winter in north Asia, which is when global LNG demand peaks. Increased supplies from Queensland have occurred during the last few Victorian winters, and winter LNG supplies for the PKGT may be sourced on more favourable terms if north Asia demand is lower.

Figure 18 Average monthly production forecast, 2023 and 2025 (TJ/d)



Reliance on Victorian storage

Table 13 shows the forecast winter production-consumption balance and increasing reliance on Victorian storage capacity during the peak winter period (June to August) to 2025.

A positive 'Net production-consumption balance' means Victoria will produce more than it needs during winter so it can continue to export surplus production during winter.

A negative balance, which is forecast to occur from winter 2023, means that utilisation of Victorian storage (mainly Iona UGS) capacity is necessary to supply winter consumption, even if no production is supplied to neighbouring states. Without the additional supply available from the PKGT, if gas is supplied to other states or winter consumption is higher than forecast (due, for example, to high levels of GPG consumption) or production is lower than forecast (due, for example, to unplanned outages), there is a risk storage consumption will exceed the Iona UGS storage reservoir capacity.

Table 13 Forecast peak winter June to August supply-consumption balance, 2021-25 (PJ)

	2021	2022	2023	2024	2025
Forecast consumption	79	78	77	76	75
Available production	106	87	68	63	49
Net production – consumption	**27**	**9**	**-9**	**-13**	**-26**
DTS total storage capacity	24	24	25	25	25
Surplus / shortfall	**51**	**33**	**16**	**12**	**-1**

This storage adequacy assessment assumes that storage is at full capacity at the start of June, and there is no further increase in Iona UGS storage capacity. If storage is drawn down before this, or it has not been able to refill to its full capacity, this would further increase the risk of a supply shortfall from 2023 without additional gas supply from New South Wales.

Refilling storage relies on production being higher than consumption during the summer and shoulder periods. Historically, this is also when producer maintenance occurs, and there are also increased levels of GPG consumption during hot weather. This reduces gas availability to refill storage and can result in storage depletion during summer if there is high GPG utilisation.

The forecast decline in monthly production will reduce available gas supply for refilling storage. This may result in the refilling of storage becoming reliant on supply from interstate, particularly during production facility maintenance. The prospect of increased Port Campbell production from the recently discovered Annie, Enterprise and Artisan gas fields reduces this risk.

Co-ordination of east coast gas facility maintenance is expected to be increasingly important to ensure refilling of storage can occur and minimise the risk of a supply shortfall during the winter period.

3.3 Peak day supply-demand balance

This section discusses the forecast Victorian peak demand day gas supply over the outlook period. Victorian gas producers have indicated in their submissions for the 2021 VGPR that peak day production is forecast to decline, which places a greater reliance on storage to meet peak day demand.

3.3.1 Forecast peak day supply

The forecast peak day maximum daily quantity (MDQ) capacity by SWZ is shown in Table 14.

Based on advice from gas producers and storage providers, the available Victorian peak day supply capacity is forecast to decline by 35% over the outlook period:

- Gippsland producers have advised that the maximum daily production capacity will reduce by 58%, from 1,012 TJ/d in 2021 to 428 TJ/d in 2025.
  - Esso has advised that the depletion of its large legacy gas fields is the driving factor in the reduction in its forecast peak day capacity.
  - The Golden Beach anticipated supply development, with 125 TJ/d of capacity, is forecast to commence production prior to winter 2023, but it is only expected to produce for an initial two-year period[46]. Peak day supply capacity from Golden Beach as a storage facility is a potential development that could be available from winter 2025.
- Port Campbell producers have advised that the maximum daily production capacity will remain relatively steady, reducing by 6% over the outlook period, with new committed projects replacing declining production. Lochard Energy have advised that Iona UGS capacity will increase to 520 TJ/d for winter 2021.
- Supply capacity from New South Wales into the DTS through the EGP via VicHub and the MSP via Culcairn is expected to provide up to 395 TJ/d on peak days. This supply capacity into Victoria could be impacted by several factors including:
  - Disruptions to LNG shipping schedules that interrupt the reliable supply of cargoes to the PKGT during winter months.
  - Coincident high winter demand in New South Wales and Canberra, combined with high levels of GPG demand following the closure of the Liddell Power Station in April 2023. The MSP supply capacity and the PKGT capacity is expected to exceed the NSW and Canberra demand.

[46] See https://gbenergy.com.au/production.

– Gas generation at any of the following GPG sites will impact the supply available from New South Wales into the DTS.
  - Uranquinty PS, located north of the Culcairn connection point.
  - Tallawarra PS, located south of the PKGT and supplied from the EGP.
  - The proposed Squadron Energy power station[47] or the Snowy proposed gas-fired power plant at Kurri Kurri[48], would be supplied by the PKGT and could reduce the supply available to the DTS from the EGP.

Table 14 Peak day maximum daily quantity (MDQ) capacity by SWZ, 2021-25 (TJ/d)

SWZ	Supply source	2021	2022	2023	2024	2025
Gippsland[A]	**Available**	1,012	822	561	530	428
	Anticipated	-	-	125	165	60
	Total available plus anticipated	**1,012**	**822**	**686**	**695**	**489**
Port Campbell (Geelong)[B]	Available	722	703	726	706	677
	Anticipated	-	-	50	50	50
	Total available plus anticipated	**722**	**703**	**776**	**756**	**727**
Melbourne	**Available**	87	87	87	87	87
NSW[C]	**Available**	0	0	395	395	395
DTS total Victorian supply	**Total VIC and NSW available**	2,076	1,867	1,829	1,778	1,647
	Total VIC and NSW anticipated	0	0	175	215	110
	Total VIC available plus anticipated	**1,821**	**1,612**	**1,549**	**1,538**	**1,303**
	Total VIC and NSW available plus anticipated	**2,076**	**1,867**	**2,004**	**1,993**	**1,758**

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper 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 Athena. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.
C. NSW includes Culcairn injections via. VNI, Orbost Gas Plant via. VicHub, and the PKGT via. VicHub.

3.3.2 Peak day supply adequacy

AEMO's peak day supply adequacy assessment used a mass balance analysis combined with hydraulic pipeline modelling to determine what peak day supply capacity is available to the DTS, and whether this is sufficient to ensure continuity of supply to Victorian customers.

The forecasts shown in Figure 19, and the peak day analysis in Table 15 and Table 16, used the following data and assumptions:

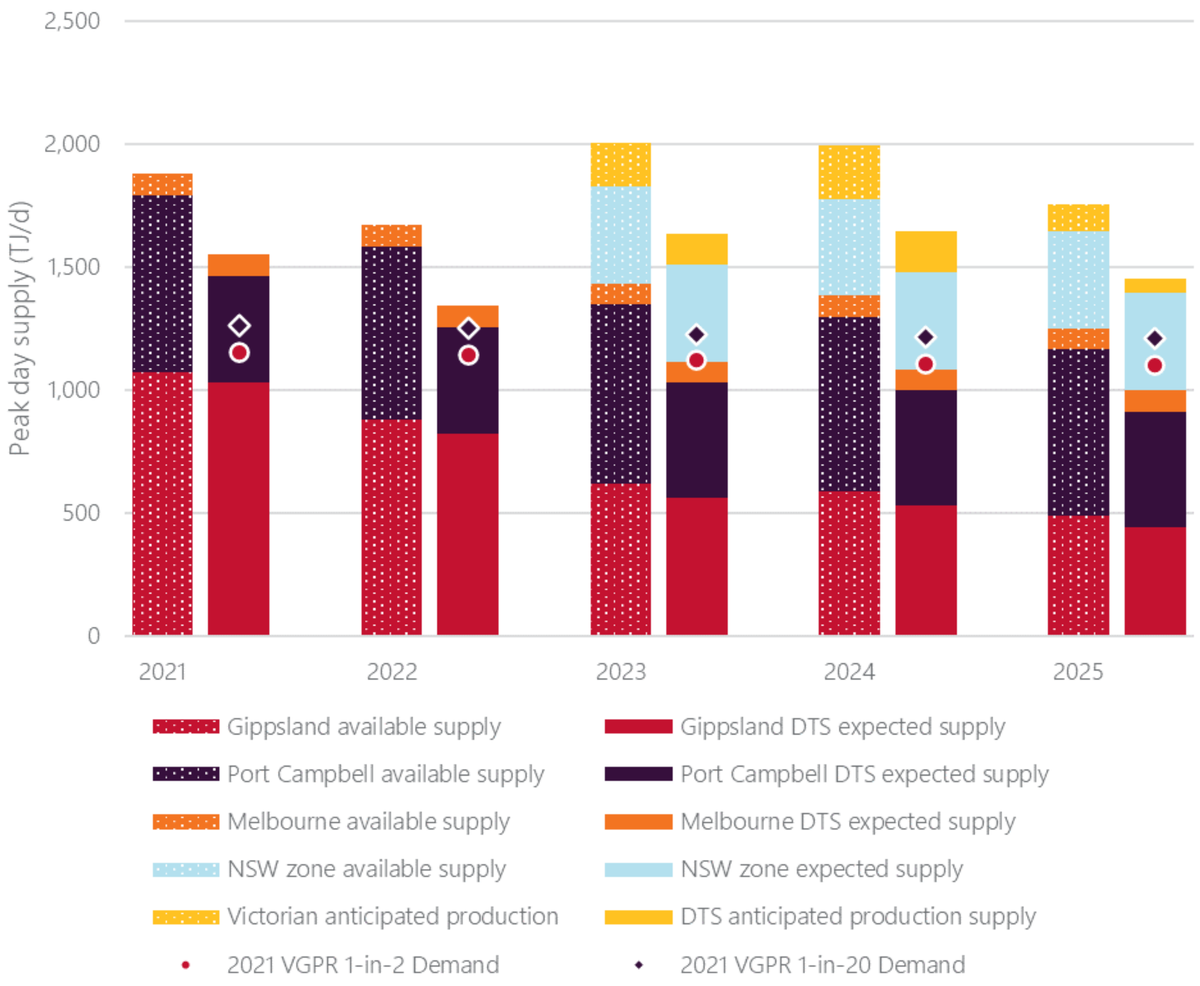
[47] See https://www.afr.com/companies/energy/siemens-boss-says-big-green-hydrogen-power-station-stacks-up-20210317-p57bg3
[48] See https://www.snowyhydro.com.au/hunter-power-project/

- Forecast annual 1-in-2 and 1-in-20 peak day system demands, as discussed in Chapter 2.
- The full capacity of the Iona UGS and Dandenong LNG storage facilities were assumed to be available, and not restricted due to low storage inventories.
- 'DTS expected supply' considered DTS pipeline capacities including approved augmentations, particularly the WORM (discussed in Chapter 5 and 6).
- 'Expected Supply' from the New South Wales supply zone is 395 TJ/d, which includes the supply from MSP via Culcairn, and from the PKGT via VicHub injection point, allowing for Orbost gas plant production and supply to other demand locations supplied from the EGP.

There is forecast to be sufficient available Victorian supply to meet a 1-in-20 system demand day for winter 2021 and 2022. The forecast Victorian peak day supply capacity decline from 2023 has brought forward the risk of a peak day supply shortfall without additional supply to winter 2023, which is earlier than the forecast winter 2024 shortfall in the 2020 VGPR Update.

In the absence of the commitment to develop other anticipated Victorian supply projects prior to winter 2023, Victoria will rely on gas supply from New South Wales to meet a 1-in-2 and 1-in-20 system demand day. Development of anticipated production would alleviate the reliance on New South Wales supply on peak demand days, but in 2025 currently anticipated production is forecast to be insufficient and New South Wales supply is required to support a 1-in-20 system demand day.

Figure 19 Forecast peak day supply and Declared Transmission System supply adequacy, 2021-25 (TJ/d)



The Port Campbell peak day MDQ is expected to continue to be constrained by the SWP transportation capacity limit. This includes the assumption that the supply capacity increases to 468 TJ/d with the expected commissioning of the WORM by winter 2023 (see Chapter 5). Any further delay of the WORM[49] could result in Port Campbell supply capacity being lower than forecast.

2023 peak day outlook

Table 15 shows there is sufficient available supply to support a 1-in-20 peak system demand day in 2023 by utilising supply from New South Wales supply. Without supply from New South Wales the available Victorian supply is insufficient to meet the forecast 1-in-20 peak system demand.

With existing available Gippsland projection committed supply from There is forecast to be surplus pipeline capacity in the Gippsland zone, with up to 269 TJ/d unused pipeline capacity, allowing additional flows at the Longford CPP[50] if additional supply was available including the Golden Beach development.

This forecast also assumes that the WORM is constructed and commissioned by winter 2023, increasing supply from the Port Campbell region to 468 TJ/d. If the WORM is not available, the Port Campbell 'DTS supply capacity' and 'Expected supply' will remain at 445 TJ/d, the existing Port Campbell injection capacity.

Table 15 DTS capacities and expected supply on a 1-in-20 peak demand day, 2023 (TJ/d)

Supply source		Total supply capacity	DTS supply capacity	Expected supply	Remaining DTS capacity	Remaining supply capacity
Gippsland zone	Available supply	561	1,030	561	269[A]	0
	Total available plus anticipated	686	1,030	686	144	0
Port Campbell zone	Available supply	726	468	468	0	258
	Total available plus anticipated	776	468	468	0	308
Melbourne zone	Dandenong LNG	87	87	87	0	0
NSW zone	Available supply	395	395	395	0	0
Total VIC only supply		**1,374**	**1,585**	**1,116**	**-**	**-**
Total VIC and NSW supply		**1,769**	**1,980**	**1,511**		
Total VIC and NSW supply plus anticipated supply		1,944	1,980	1,636	-	**-**
1-in-20 system demand forecast		1,228	1,228	1,228	-	-
DTS surplus / shortfall quantity	VIC and NSW supply	**541**	**752**	**283**	**469**	**258**
	VIC and NSW supply plus anticipated	**716**	**752**	**408**	**344**	**308**

A. Gippsland zone DTS pipeline capacity reduced to account for 200 TJ/d of supply from the PKGT via the EGP

[49] The 2019 VGPR reported that the SWP capacity is forecast to increase in 2021 when the WORM is expected to be available (2019 VGPR page 8).

[50] Longford CPP includes Longford gas plant, VicHub injection point and TasHub injection point.

2025 peak day outlook

Table 16 shows there is sufficient available supply for a 1-in-20 peak system demand day in 2025 by utilising Dandenong LNG and an increased reliance on New South Wales supply.

The development of anticipated and potential Victorian supply projects, including the possible conversion of the Golden Beach development to an UGS facility, would reduce the reliance on supplies from New South Wales.

This forecast also assumes that the SWP capacity, which is expected to be increased through the construction and commissioning of the WORM by winter 2023, has not been increased beyond 468 TJ/d.

Table 16 DTS capacities and expected supply on a 1-in-20 peak demand day, 2025 (TJ/d)

Supply source		Total supply capacity	DTS supply capacity	Expected supply	Remaining DTS capacity	Remaining supply capacity
Gippsland zone	Available supply	428	1030	428	402[A]	0
	Total available plus anticipated	489	1030	489	541	0
Port Campbell zone	Available supply	677	468	468	0	209
	Total available plus anticipated	727	468	468	0	259
Melbourne zone	Dandenong LNG	87	87	87	0	0
NSW zone	Available supply	395	395	395	0	0
Total VIC only supply		**1,192**	**1,585**	**983**	**-**	**-**
Total VIC and NSW supply		**1,587**	**1,980**	**1,378**		
Total VIC and NSW supply plus anticipated supply		1,698	1,980	1,439	**-**	**-**
1-in-20 system demand forecast		1,210	1,210	1,210	-	-
DTS surplus / shortfall quantity	VIC and NSW supply	**377**	**770**	**168**	**602**	**209**
	VIC and NSW supply plus anticipated	**488**	**770**	**229**	**541**	**259**

A. Gippsland zone DTS pipeline capacity reduced to account for 200 TJ/d of supply from the PKGT via the EGP

3.3.3 System resilience

System resilience is defined as the ability of a system to limit the extent, severity, and duration of system degradation following an abnormal event[51]. The "system" could be the DTS, or a complex production system such as the Longford Gas Plant, including its offshore facilities.

[51] Definition of system resilience produced by CIGRE WG C4.47.

Production resilience

The forecast capacity reduction and depletion of Longford's large legacy gas fields is expected to degrade the current high resilience of the Longford production system. Currently, any supply disruptions that occur within the production system can often be smoothed out using the flexible production capacity that the large legacy fields provide. The absence of these fields would increase the risk that equipment trips and unplanned outages cannot be quickly resolved, resulting in reduced supply into the DTS. This shortfall would need to be covered by another supply facility.

DTS resilience

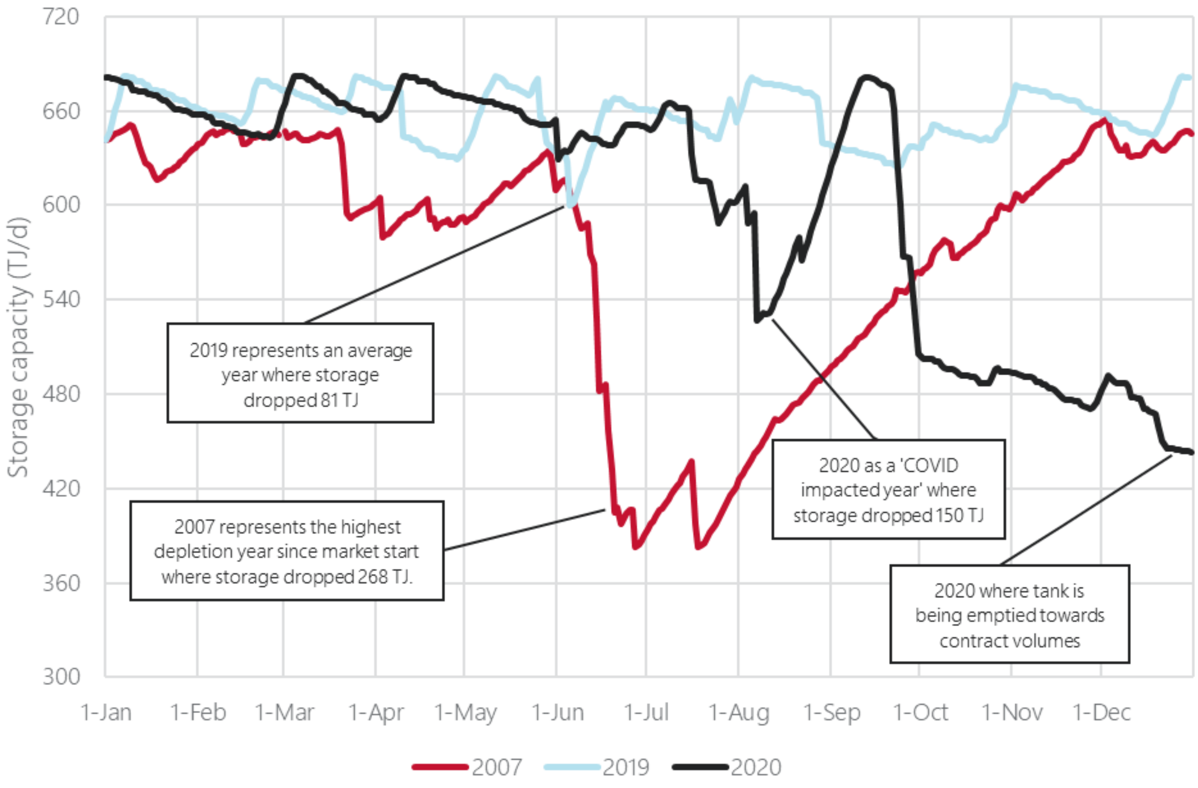
The PKGT provides a new source of DTS supply flexibility that compensates for the forecast reduction in Longford supply capacity into the DTS from 2023. Without this additional supply the DTS would be highly reliant on supply facilities being able operate at their nameplate capacity, and with committed and anticipated developments producing at expected rates on schedule. LNG supplies to Port Kembla will be dependent on shipping schedules to provide reliable cargoes during winter months to prevent supply disruptions.

On high demand days where all facilities are operating at or near maximum capacity, the DTS requires supply flexibility to respond to incidents. Incidents could include unplanned facility outages, equipment trips, under-forecast system demand, coincident gas demand peaks across the southern states, high GPG demand, or an unplanned outage of a coal-fired power station, which could increase GPG demand.

Dandenong LNG

Dandenong LNG has historically been used as an operational response to alleviate threats to system security (discussed in Chapter 1). It is used as a flexible supply source to rapidly respond to incidents such as supply disruptions, equipment outages or failures, unforecast increases in demand, and high GPG.

Figure 20 Historical Dandenong LNG storage utilisation, 2007/2019/2020 (TJ)



AEMO has observed[52] a decline in contracted Dandenong LNG services to only 80 TJ of storage inventory and 4.5 TJ/hr of injection capacity from winter 2021. This has been confirmed in the participant forecasts that were submitted to AEMO.

At these contracted levels, AEMO's ability to manage the DTS during the peak winter demand period is severely impacted, with limited the operational and market responses available leading to increase risk to gas curtailment.

Figure 20 shows several representative years of Dandenong LNG storage utilisation. In 2020 the LNG stock within the Dandenong LNG tank dropped by 150 TJ due to the cooler winter and a higher proportion of people working from home due to COVID-19 restrictions (discussed in Chapter 2).

The largest annual reduction in Dandenong LNG inventory was in 2007 when the tank level dropped by 268 TJ due to very high levels of GPG demand and the severe SWP capacity constraint at that time. Any year similar to those shown in Figure 20 when the tank was heavily drawn upon to manage the system conditions will see the tank emptied and result in gas load curtailments.

3.3.4 Threat to system security

AEMO is required to inform registered participants if it believes that a threat to system security is indicated by the VGPR[53]. A threat to system security includes an assessment that, in AEMO's reasonable opinion, there:

- Is a threat to the supply of gas to customers; and
- Are insufficient assets available within the DTS to provide the capacity to meet forecast gas supply and demand conditions[54].

From the information provided by participants and modelling conducted for the 2021 VGPR, there is forecast to be insufficient Dandenong LNG inventory available for all operational and emergency scenarios, leading to an increased risk of curtailment during winter 2021 onwards unless the LNG inventory stored within the tank is higher than current contracted levels.

AEMO has identified the low Dandenong LNG inventory as a threat to system security and is seeking a market response.

AEMO is currently engaging with APA, market participants and the Victorian Government to assess the options available to mitigate this gas supply and safety risk.

[52] See the AEMO Gas Bulletin Board for uncontracted capacity information https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb.

[53] NGR 341

[54] Wholesale Market System Security Procedures (Victoria) December 2015, Chapters 3 and 4.

4. Future supply sources

Key findings

- There are several anticipated and potential projects that could provide additional DTS supplies during the outlook period. However, these projects:
  - Have uncertainty regarding their development timeframes.
  - Are pending governmental planning approvals.
  - With the exception of the LNG import terminals, these projects are typically short-term solutions that will require additional projects in later years.
- As Australia transitions to a lower emissions future, it will be critical to strike a balance between the investment required to prevent shortfalls and avoiding long-term stranded assets.
  - Investments that are likely to find the right balance include hydrogen ready pipelines or assets, investments with a low amount of capital required, or the utilisation of existing pipelines or assets where expansion is expected to be faster and cheaper than the development of new pipelines.

To address declining production from existing production developments and to mitigate the risk to Victorian consumers' gas supplies, projects that maintain or improve winter seasonal supply need to be developed to reduce peak day supply shortfall risks and improve the supply resilience.

4.1 Anticipated supply projects

The anticipated supply projects in the Gippsland and Otway regions are expected to increase annual gas supplies, while the Golden Beach development will also increase peak day supply.

Golden Beach

The Golden Beach Project involves the development of the Golden Beach gas field in the Gippsland Basin, with a forecast supply of 43 PJ[55] over two years from 2023, and an initial capacity of up to 125 TJ/d. There are proposed plans to transition the field and facility into a storage facility in 2025 to provide approximately 12.5 PJ of storage.

The project is currently pending environmental assessment planning approvals[56]. Once approved and FID is made, the project will need to construct the gas plant and pipelines, drill the offshore wells, and commission all facilities. This could be challenging to complete prior to winter 2023 in the current COVID-19 environment.

Kipper gas field

The Kipper Unit Joint Venture has indicated the Kipper Phase 1B and 2 development is progressing[57], with anticipated supply from late 2023. This project is intended to maintain Kipper production at close to its

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[55] See https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5fbdab396457125654f61002/1606265669237/GB+Energy+Holdings+Limited+-++Annual+Report+2020+-+Final.pdf.

[56] See https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/golden-beach-gas-project.

[57] See https://www.exxonmobil.com.au/Community-engagement/Local-outreach/Esso-community-news/Going-back-for-future-Bass-Strait-gas.

current rates. Gas from the Kipper field is processed through the Gas Conditioning Plant at the Longford Gas Plant.

The forecast provided to AEMO advises that this additional Kipper gas would reduce a forecast further decline in Longford Gas Plant production by providing additional supply from 2024 onwards. It cannot replace the production capacity of Longford's large legacy gas fields.

Iona UGS Project 570

Lochard Energy are continuing to progressively expand the Iona UGS facility towards 570 TJ/d of capacity. Supply capacity will increase to 520 TJ/d for winter 2021, and Lochard have advised of an anticipated project to increase capacity to 570 TJ/d in 2022.

Enterprise gas field development

Beach Energy drilled the Enterprise-1 well in November 2020 and announced in February that the recently discovered field contains 161 PJ[58] of 2P reserves[59]. Beach Energy has not been able to provide a definitive production forecast for this field, although it is expected that the gas will be processed at the Otway Gas Plant, which has a nameplate capacity of 205 TJ/d.

Beach Energy also discovered gas when it drilled the Artisan-1 well during March 2021[60], which will be cased and suspended as a future producer for processing through the Otway Gas Plant. Cooper Energy also had a discovery when it drilled the Annie-1 well in September 2019[61].

With many Port Campbell zone fields in steep decline, the Enterprise gas field could improve the annual and monthly supply-demand balance for Victoria, including reducing the risk of Iona UGS inventory depletion. The development of this field, along with other Port Campbell fields, is not expected to increase peak day supply, because Port Campbell production and Iona UGS capacity are expected to remain constrained by the SWP transportation capacity limit.

4.2 LNG import terminals

In additional to the committed PKGT development, there are three well progressed publicly announced potential Victorian LNG import terminals which would provide a further increase to the monthly gas supply and the maximum daily quantities in the proposed regions.

The adequacy of the DTS to support the proposed LNG import terminals is discussed in further detail in Chapter 5.

Crib Point LNG import terminal

The proposed AGL Crib Point project is east of Melbourne, with potential supply by winter 2023[62]. The Crib Point terminal would connect to the Longford to Melbourne Pipeline, which has sufficient capacity to accommodate this supply. The project includes the construction of a 57 km pipeline from Crib Point to Pakenham.

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58 See https://www.nsenergybusiness.com/news/beach-energy-enterprise-gas-field-2p-reserves/.

59 Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with developing them. Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations, and proved and probable (2P) is considered the best estimate of commercially recoverable reserves.

60 See https://themarketherald.com.au/beach-energy-asxbpt-discovers-gas-at-artisan-1-well-2021-03-22/

61 See https://www.energynewsbulletin.net/exploration/news/1370961/otway-basin-back-as-cooper-makes-discovery-at-annie

62 See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/june/update-on-crib-point-gas-import-project.

If it is developed, AGL is forecasting a maximum daily quantity of 520 TJ/d[63] that would be transported via the greenfield Crib Point pipeline and injected into the existing high-pressure Longford to Melbourne Pipeline at Pakenham[64]. The project is currently pending environmental assessment planning approvals[65].

Viva LNG import terminal

The proposed Viva project, located adjacent to the Geelong refinery, is expected to be available from 2024[66] and would connect to the SWP at Lara[67]. This would increase the SWP capacity to Melbourne, due to the supply point being at a high pressure and closer to the Melbourne demand, but it would back out other Port Campbell supply including Iona UGS. The terminal is forecast to supply 140 PJ/y, have an MDQ capacity of 500-600 TJ/d[68], and is forecast to be operational and available to the market from 2024[69]. This project is in its early stages of the environmental assessment planning approvals[70].

To fully support the system when there are low Gippsland supplies and to not back off the Port Campbell supply, significant DTS augmentation will be required.

Vopak LNG import terminal

Vopak has recently announced[71] that it is seeking to develop an FSRU off the shoreline of Avalon in Port Phillip Bay. The offshore FSRU would be connected to the SWP near Lara or Avalon via a subsea pipeline.

As discussed above for the Viva terminal, this project would require significant augmentation of the DTS to provide additional DTS supply capacity.

Collectively, the Viva and Vopak terminals are discussed as the western LNG import terminals in Chapter 5 with regards to their potential impacts on the DTS.

4.3 Other supply sources

Constrained Port Campbell supply

As discussed in Chapter 3, the forecast increase in peak day supply at Port Campbell would not be available to the DTS, due to the physical SWP transportation constraint. The SWP will be constrained to 468 TJ/d upon completion of the WORM expansion, which is expected to be available from late 2022. Construction of the WORM is currently in the early stages of environmental assessment planning approvals[72].

Despite the capacity increase provided by the completion of the WORM, gas supplies from the Enterprise gas field development and expanded Iona UGS facility are still expected to be limited at times during the outlook period.

To access unutilised Port Campbell peak day supply, augmentation – such as an additional in-line compressor, or pipeline looping of the SWP – would increase the daily transportation capacity. However, this option on its own would not provide sufficient monthly winter gas supply to replace the reduced Gippsland production capacity (discussed in Chapter 3), but it could improve system resilience for managing supply disruptions.

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[63] See https://www.agl.com.au/-/media/aglmedia/documents/about-agl/how-we-source-energy/crib-point/document-updates-120918/epbc-referral---agl-gas-import-jetty-project.pdf?la=en&hash=278FFD93A1AFDE43B2707460A59B9937.

[64] See https://www.apa.com.au/about-apa/our-projects/crib-point-to-pakenham-pipeline/.

[65] See https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/crib-point.

[66] See https://www.vivaenergy.com.au/operations/geelong/geelong-energy-hub/viva-energy-gas-terminal-project.

[67] See https://www.vivaenergy.com.au/ArticleDocuments/877/Viva%20Energy%20Gas%20Terminal%20Pipeline%20Factsheet.pdf.aspx?Embed=Y.

[68] See https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/495876/Viva-Energy-Gas-Terminal-Project-EES-Referral.pdf.

[69] See https://www.offshore-energy.biz/viva-energy-brings-in-partners-for-geelong-lng-facility/.

[70] See https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/viva-energy-gas-terminal-project.

[71] See https://www.afr.com/companies/energy/vopak-vies-for-coveted-lng-import-terminal-licence-20210315-p57avc.

[72] See https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/western-outer-ring-main-gas-pipeline.

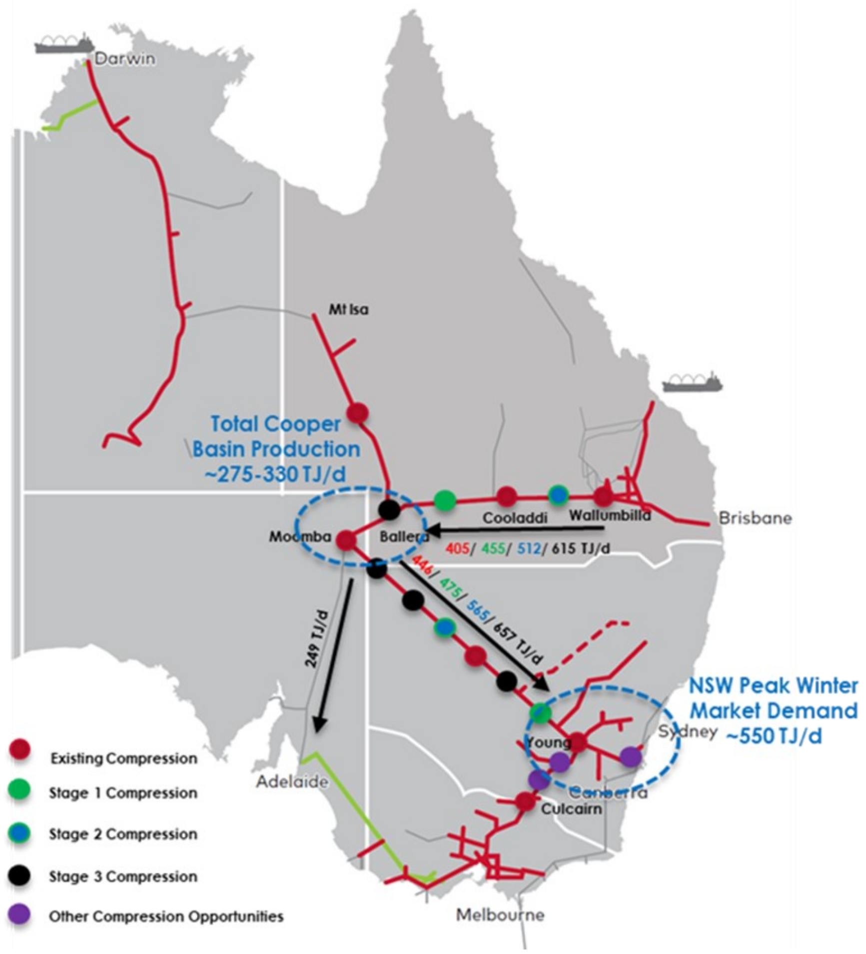
Increased supply from PKGT

Jemena has currently committed to upgrade the EGP to flow 200 TJ/d south from the PKGT. An additional compressor at Port Kembla would provide an extra 120 TJ/d capacity increasing the southern flows from the PKGT to 320 TJ/d, which is in line with the reported 390 TJ/d Victorian supply capacity[73] when supply from the Orbost Gas Plant is added.

Increased supply capacity from Queensland

In addition to the committed project to increase the MSP capacity to 450 TJ/d for winter 2021, APA has announced a possible $700 million project to increase the gas transportation capacity from Queensland to the southern states, including the potential to increase the supply capacity into Victoria by 200 TJ/d[74,75] via Culcairn. This project would increase the capacity of both the SWQP and the MSP to enable increased supply to New South Wales and Victoria.

Figure 21 APA compressor locations for proposed MSP and SWQP expansion



Supplied by APA Group.

APA has advised that other options exist to expand the MSP and the South West Queensland Pipeline (SWQP) by an approximately 300 TJ/d and 200 TJ/d respectively, through the addition of more compression capacity although the projects have not yet reached FID.

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73 See https://www.afr.com/companies/energy/jemena-in-130m-spend-as-forrest-s-lng-imports-firm-20210317-p57bhx

74 See https://www.afr.com/companies/energy/apa-widens-us-acquisition-hunt-despite-loss-20210222-p574tl

75 See https://www.apa.com.au/news/media-statements/2020/apa-response-to-2020-gsoo/

These proposed compression projects could expand the capacity of the MSP up to 750 TJ/d and the capacity of the SWQP up to 600 TJ/d. This could be undertaken as a single project or in staged increments as required.

APA has advised that this could be completed as early as 2023 or otherwise in around 18 to 24 months from FID.

This project is analysed and further explored in the 2021 GSOO.

Distributed gas supply

There has been increased interest in hydrogen and biogas projects in Australia in recent years, which could provide an alternate source of supply.

Several projects are proposed in Victoria to supply either biogas or hydrogen to end use customers. The largest is the Hydrogen Park Murray Valley (HyP Murray Valley) project proposed by Australian Gas Infrastructure Group (AGIG). The project would develop an electrolyser that would produce hydrogen and blend this into the Albury-Wodonga gas distribution network[76].

While the transition to biogas and hydrogen is expected to play an important role in the decarbonisation of Australia's energy sector, these distributed supplies are not expected to be able to produce sufficient gas to replace the current declining Victorian production. Current anticipated projects in this category are expected to produce less than 100 TJ per year prior to the end of the outlook period.

From 2025 to 2030, there is potential for this quantity to increase up to 4-5 PJ per year. The GSOO includes further discussion about the longer-term potential for hydrogen.

[76] See https://www.agig.com.au/media-release---hydrogen-proposal-in-albury-wodonga.

5. Declared Transmission System adequacy

Key findings

- AEMO has assessed the WORM system augmentation that is expected to be commissioned by winter 2023. Modelling results of the design, as at publication, indicate that the WORM will have the following impact on SWP transportation capacity:
  - On a 1-in-20 system demand day, the Iona CPP injection capacity increases to 468 TJ/d. Additional compression on the SWP would increase the injection capacity further.
  - On a 300 TJ system demand day, Iona CPP withdrawal capacity increases to 316 TJ/d. SWP withdrawals are achievable across all system demand days once the WORM is commissioned.
  - The WORM increases SWP pipeline capacity, across all demand days, and can fully support DTS system demand in summer.
- The DTS has sufficient capacity to receive the expected 200 TJ/d of imports from the PKGT via the EGP and VicHub as well as an increase to 195 TJ/d of supplies from the MSP via Culcairn.
- The proposed Victorian LNG import terminals connecting to the DTS were assessed:
  - An eastern LNG terminal, connecting at Pakenham, is projected to further increase Iona CPP withdrawal capacity to 335 TJ/d on a 300 TJ system demand day.
  - A western LNG terminal, connecting at Lara, is projected to increase Iona CPP withdrawals for all system demand days to: 431 TJ/d on a 300 TJ system demand day, and 200 TJ/d on a 1-in-20 system demand day. The SWP transportation capacity is also projected to increase to 741 TJ/d on a 1-in-20 system demand day with 600 TJ/d of western LNG terminal injections.
  - AEMO is investigating the operational impacts of the proposed eastern LNG and western LNG import terminals. Either location could require augmentation to the DTS in addition to the WORM to improve DTS capacity and system resilience.
- The DTS peak day system capacity is 1,560 TJ/d with Dandenong LNG, and 1,472 TJ/d without Dandenong LNG. The DTS capacity with sufficient supply is expected to support forecast peak system demand days during the outlook period (supply adequacy is discussed in Chapter 3).
- The DTS is projected to have sufficient capacity to be able to support all forecast GPG over the outlook period. Peak shaving Dandenong LNG injections may be required on 1-in-20 system demand days to support critical system pressures.

5.1 Western Outer Ring Main (WORM) system augmentation

The WORM is a planned augmentation of the DTS that will connect the SWP/Brooklyn–Lara Pipeline (BLP) at Plumpton and LMP at Wollert. 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 Environmental Effects Statement (EES) would be required for the WORM project[77]. The WORM project is currently in the EES Scoping phase[78].

Benefits of the WORM include:

- Increased system supply capacity, reliability and security.
- Increased Iona UGS refill capability and reduced dependency on Longford CPP injections.
- Improved operability of the DTS by increasing available system linepack and adding the ability to transfer linepack between pipelines that are currently disconnected.
- Reduced dependency on Brooklyn Compressor Station (CS).
- Provide capacity for future growth in Melbourne's west and north, to facilitate new offtakes into distribution systems, or new GPG sites along the WORM.

APA is targeting a mid-2022 completion date for the WORM project[79], however there is some uncertainty on the commissioning date while the EES is still in the scoping phase. Because of this, AEMO only included the WORM in modelling from winter 2023. See Chapter 3 for detailed discussion of supply adequacy.

5.1.1 South West Pipeline to Melbourne

Figure 22 shows the indicative SWP injection capacity (inclusive of Western Transmission System [WTS] demand) with the WORM.

This modelling was performed using the same assumptions as described in Appendix A6, with the addition of:

- 51 km of 500 mm pipeline connecting the Plumpton PRS to Wollert.
- A new PRS at Wollert, from the WORM to flow into the Pakenham to Wollert pipeline.
- A third Centaur 50 compressor at Wollert CS B.

The modelled SWP injection capacity with the WORM is significantly higher than the current configuration, especially at lower demand levels. In summer, with the WORM and low Culcairn withdrawals, system demand can be fully supplied by the Iona CPP, improving system resilience and reducing the reliance on Longford CPP injections. On low demand days, the SWP injection capacity is limited by the ability to move gas to the far eastern end of the LMP, particularly to Sale City Gate (CG), which has a higher minimum pressure than elsewhere on the LMP.

On high demand days, the ability to move gas through the SWP and WORM to the rest of the DTS is limited by the SWP between Port Campbell and Lara. Even with this limitation, the WORM will still greatly improve operability and system security on high demand days by adding linepack close to the Melbourne demand zone, even if the improvement in peak day capacity is less dramatic.

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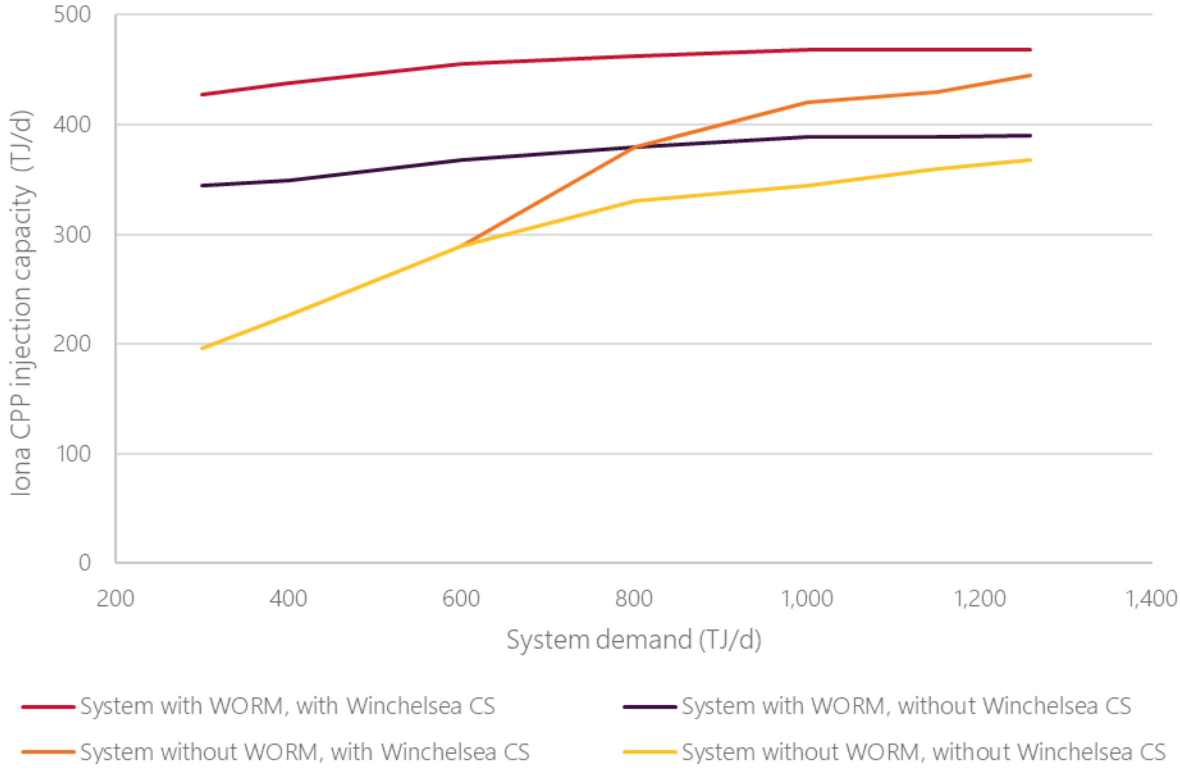
[77] State Government of Victoria Department of Environment, Land, Water and Planning, "Reasons for Decision Under Environmental Effects Act 1978", 22 December 2019, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/446979/Reasons-for-Decision.pdf.

[78] State Government of Victoria Department of Environment, Land, Water and Planning, "Western Outer Ring Main Gas Pipeline", at https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/western-outer-ring-main-gas-pipeline.

[79] APA, "Western Outer Ring Main - January Community Update", 22 January 2021, at https://www.apa.com.au/globalassets/documents/our-current-projects/worm/worm2021-communityupdate-a3-210122-final_3.pdf.

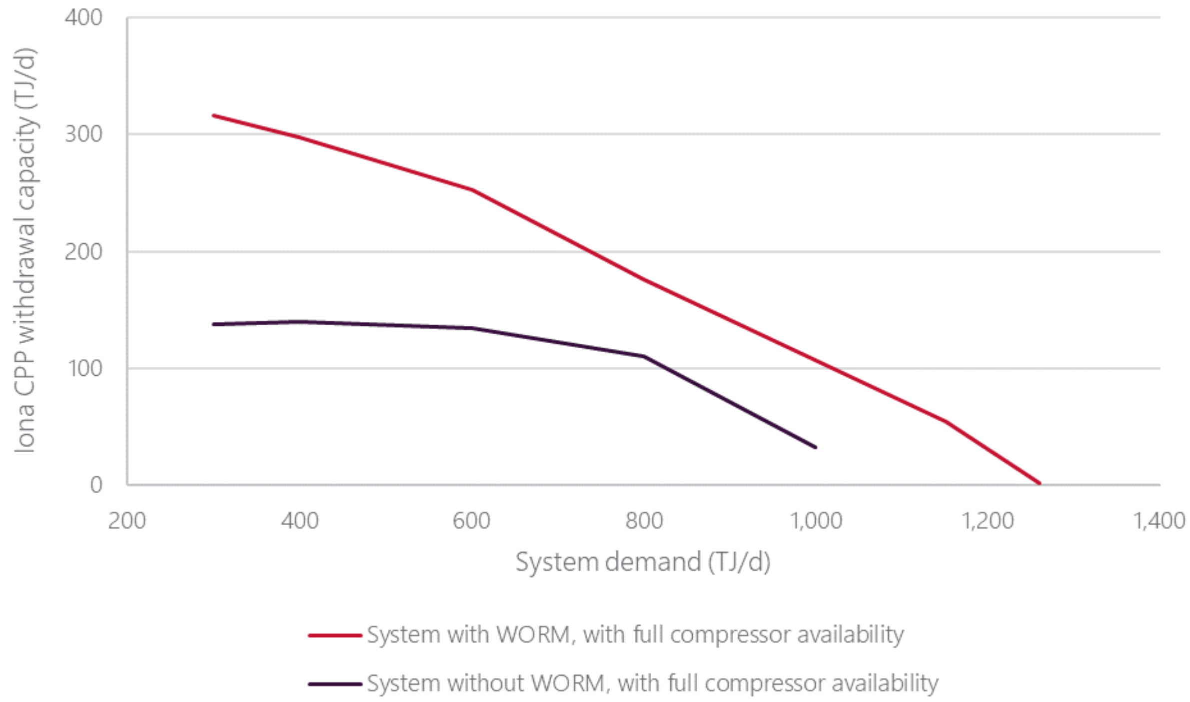
Figure 22 SWP injection capacity to Melbourne with the WORM (TJ/d)



5.1.2 South West Pipeline to Port Campbell

Figure 23 shows the indicative SWP withdrawal capacity with the WORM. This modelling was performed using the same assumptions as in Section 5.1.1.

Figure 23 SWP withdrawal capacity to Port Campbell with the WORM (TJ/d)



The modelled SWP withdrawal capacity with the WORM is more than double the current capacity on lower system demand days compared to the existing configuration. The majority of Iona UGS refilling is undertaken when demand is less than 800 TJ. Withdrawal capacity is constrained by the ability of Wollert CS and Winchelsea CS to move gas away from the Longford–Melbourne Pipeline (LMP).

At higher demands, the WORM has less impact on the withdrawal capacity, as the system is constrained by the ability to move gas to Wollert. The gas moving through Wollert must then be shared between supporting VNI demand, SWP demand, and SWP withdrawals. Increased linepack with the completed WORM allows for SWP withdrawals to be sustained on high demand days, and with sufficient supply from other injection points even on 1-in-2 and 1-in-20 system demand days.

Without Winchelsea CS, the withdrawal capacity is reduced by 5-20 TJ depending on the system demand. The impact of Brooklyn CS availability is limited, only reducing the capacity by around 10 TJ when the full Brooklyn CS is not available.

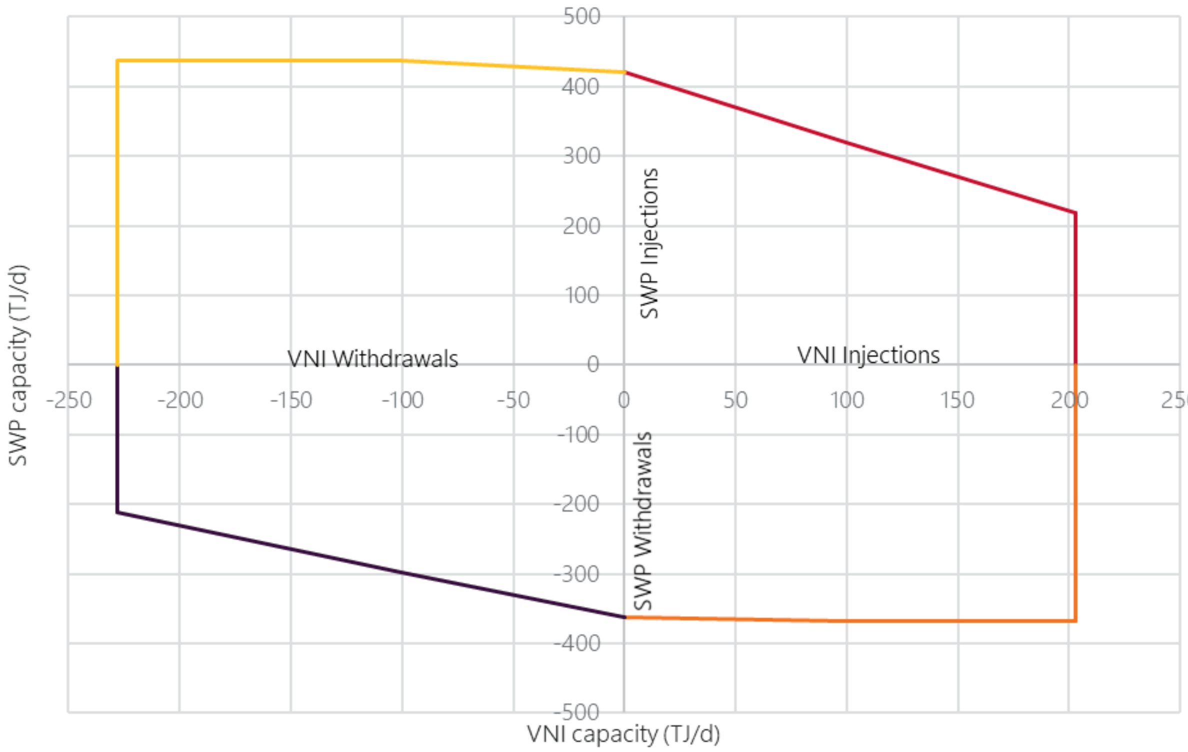
5.1.3 South West Pipeline and VNI Capacity Interaction

The completion of the WORM will link together all three major DTS pipelines at Wollert. This includes the linking of the VNI and SWP capacities, which are relatively independent of each other in the existing DTS configuration.

Figure 24 shows the results of modelling performed to demonstrate the interaction between the SWP and VNI capacity after the completion of the WORM. This chart refers to capacities for a 400 TJ system demand day. This modelling was performed using the same assumptions as in Section 5.1.1.

This chart shows the VNI import capacity of the DTS; it does not consider the injection capacity of the New South Wales transmission system north of Culcairn.

Figure 24 Modelled VNI and SWP capacity with the WORM on a 400 TJ system demand day (TJ/d)



This modelling indicates that the VNI and SWP capacities will mostly be independent of each other at this demand level unless both pipelines are simultaneously withdrawing. When both pipelines are withdrawing, the SWP withdrawal capacity decreases as the VNI withdrawals increase. This occurs because Wollert compression must be shared between both pipelines.

VNI injections and VNI withdrawals are independent of the SWP at this demand level because these capacities are both limited by the power of Euroa CS and Springhurst CS, not the ability to move gas to or from the VNI.

The capacities when both pipelines are injecting are only dependent at this system demand level as demand can be fully supplied by these pipelines alone with no Longford CPP injections.

AEMO will continue to assess this effect, including at higher system demands, and any market implications it may have.

5.2 Port Kembla LNG import terminal

As discussed in Chapter 3, AEMO considers that the PKGT is a committed project that will supply gas into the DTS from early 2023. Supply from this facility will be via the EGP and the VicHub facility connected to the Longford to Melbourne Pipeline (LMP).

The 200 TJ/d of supply from the PKGT would effectively replace Longford Gas Plant supply, and total injections at the Longford CPP – including anticipated production from the Golden Beach development – are not expected to exceed the capacity of the LMP. AEMO will undertake further assessments of LMP capacity to assess further potential supply from at the Longford CPP, including increased EGP supply capacity from PKGT and the development of Golden Beach as a storage facility.

The PKGT is also expected to result in more supply from the MSP via Culcairn. The forecast supply capacity of 195 TJ/d is less than the 226 TJ/d import capacity of the VNI, meaning that this supply can be accommodated.

The capacity of the DTS pipelines is discussed further in Chapter 6.

5.3 Victorian LNG import terminals

As discussed in Chapter 4, there are three proposed Victorian LNG import terminals that could increase supply to the DTS. AEMO has assessed the DTS adequacy to support the three proposed LNG projects which would connect directly into the DTS:

- Eastern LNG terminal – AGL Crib Point project at Pakenham.
- Western LNG terminal – Viva project at Lara, and Vopak project at Avalon.

5.3.1 Eastern LNG terminal

The proposed Crib Point LNG import terminal, referred to the eastern LNG terminal in this section, was assessed based on the latest information available to AEMO. The connection would be located on the LMP east of Pakenham, with a maximum injection capacity of 520 TJ/d.

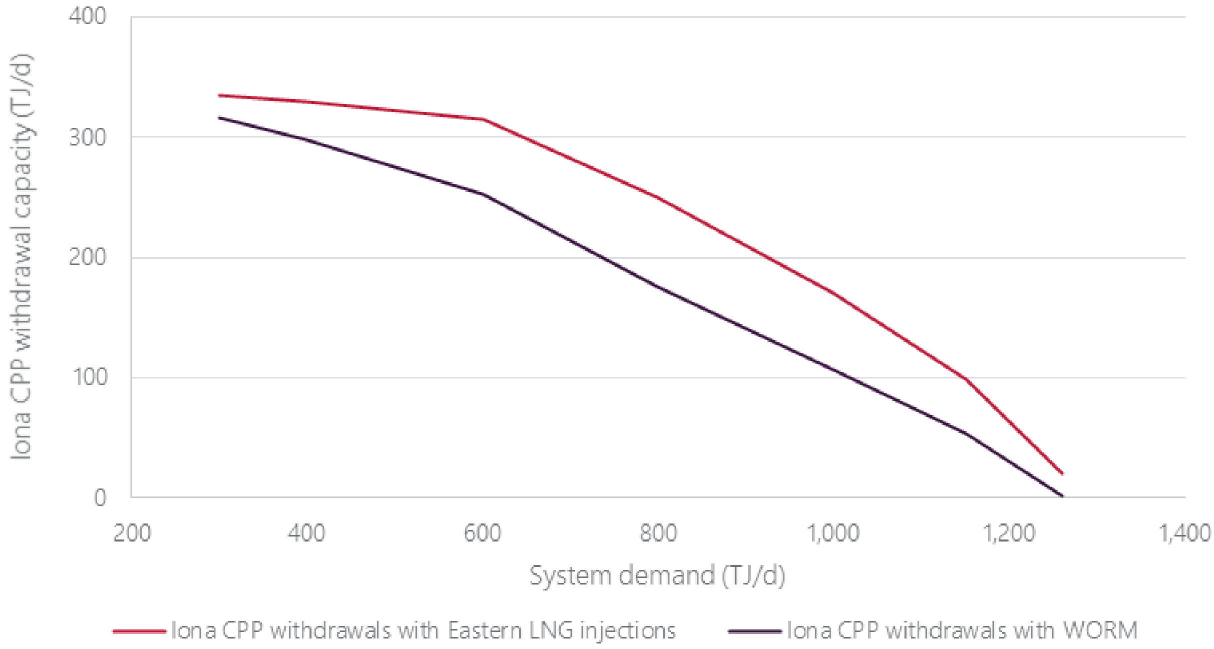
Assumptions made by AEMO to complete the assessment were:

- Maximum injection pressure of 6,750 kPa.
- Minimum injection pressure of 4,500 kPa.
- Flat injection profile as per the AEMO modelling methodology (see Appendix A6).
- The WORM is in operation, as discussed in Section 5.1.

SWP withdrawal capacity

The indicative SWP withdrawal capacity with the WORM (discussed in Section 5.1) would increase further with eastern LNG terminal injections of 520 TJ/d, as shown in Figure 25. The increase in SWP withdrawal capacity is due to the increased inlet pressure for Wollert compression into the SWP.

Figure 25 Iona CPP withdrawal capacity with Eastern LNG site (TJ/d)



The SWP withdrawal capacity may be impacted if Culcairn injection or withdrawal on the gas day differs from those assumed. The interaction between SWP and VNI capacities is discussed in Section 5.1.3.

5.3.2 Western LNG terminal

The term western LNG terminal refers to the two proposed LNG import terminals that would connect to the SWP near Geelong, which are discussed in Chapter 4.

AEMO conducted a system adequacy assessment based on one LNG receiving terminal connecting to the SWP, with a maximum injection capacity of 600 TJ/d.

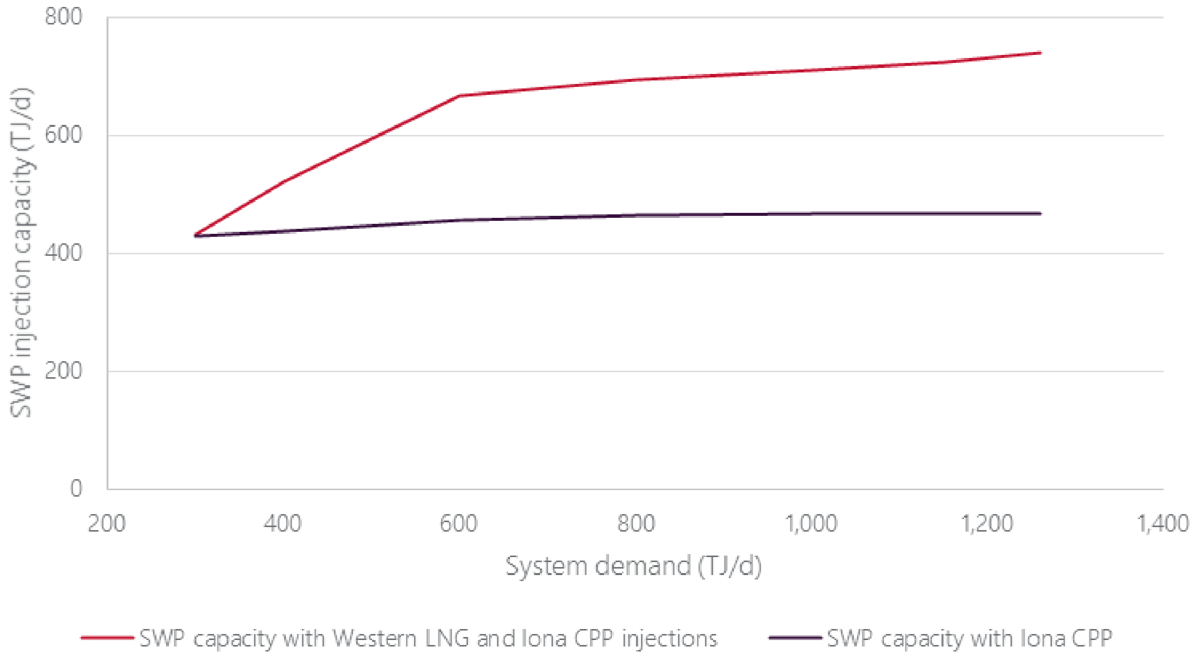
Specific assumptions made by AEMO to complete the assessment were:

- Connection on the SWP, west of Lara PRS inlet.
- Maximum injection pressure of 9,500 kPa.
- Minimum injection pressure of 4,500 kPa.
- Flat injection profile as per the AEMO modelling methodology, see Appendix A6.
- The WORM is constructed and operational, as described in Section 5.1.

SWP injection capacity

The indicative SWP injection capacity with a western LNG terminal, shown in Figure 26, was modelled to maximise western LNG injections up to the western LNG terminal supply capacity of 600 TJ/d, with the remainder of SWP injections from Iona CPP.

Figure 26 SWP injection capacity with Western LNG injections and WORM (TJ/d)



The SWP can support large injections from the western LNG terminal, even without additional compression, due to its location close to the Melbourne demand zone and high injection pressure. This increases the SWP transportation capacity up to 741 TJ/d on a 1-in-20 system demand day, an increase of 273 TJ/d compared to the modelled capacity with the WORM.

The SWP capacity with western LNG injections is limited by the Brooklyn CG maximum flow limit and Sale CG minimum pressure requirements. For demands above 400 TJ/d, minimum Longford CPP injections are required to maintain Sale CG pressure, which leads to less injections from the SWP to satisfy the supply-demand balance.

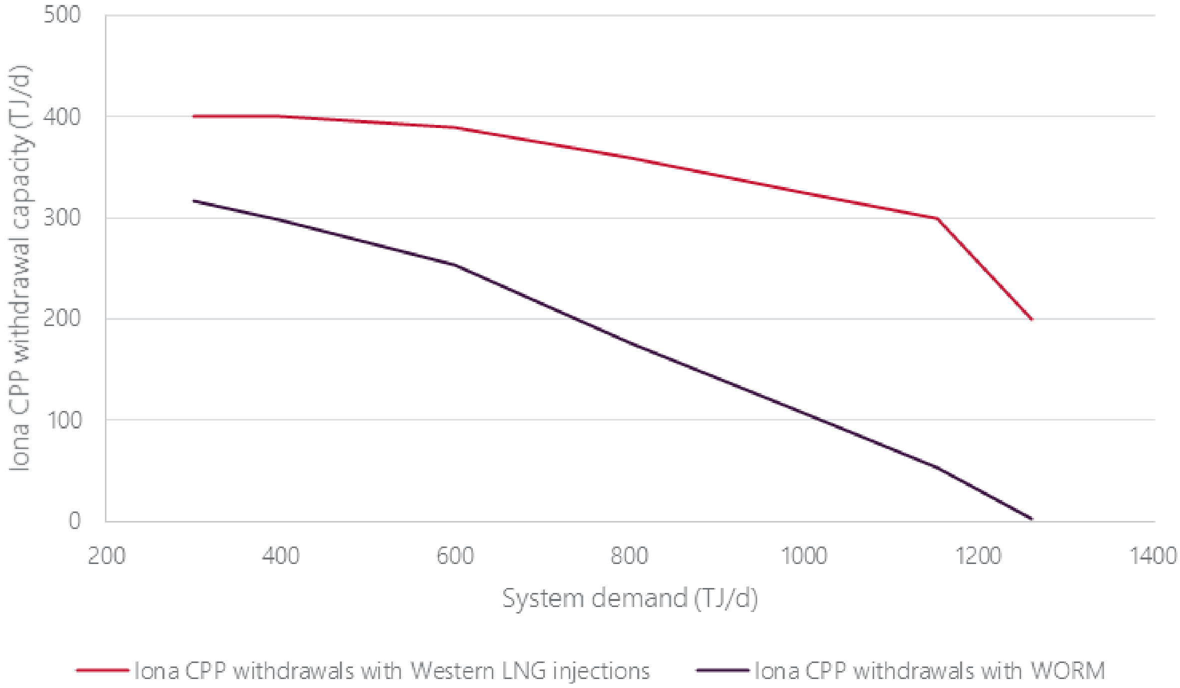
Initial analysis shows that if western LNG injections are maximised, then Iona CPP will not be able to also inject at maximum capacity due to allowable pipeline pressures; on a 1-in-20 system demand day, the achievable Iona CPP injection is 141 TJ/d without exceeding SWP pressures. To achieve the maximum Iona CPP injections discussed in Section 5.1.1 of 468 TJ/d, as well as western LNG injections, additional pipeline augmentations would be required to further increase SWP capacity, discussed in Section 5.3.3.

Further analysis and consultation will be conducted to determine the interaction between Iona CPP and western LNG injections for scheduling purposes.

SWP withdrawal capacity

The indicative Iona CPP withdrawal capacity, shown in Figure 27, is significantly increased when there are sufficient western LNG injections (the modelled results are with 600 TJ/d). The increase is due to its proximity to Iona CPP and supports withdrawals for all system demands including a 1-in-20 system demand day.

Figure 27 **SWP withdrawal capacity with Western LNG injections and WORM (TJ/d)**



SWP withdrawals on peak days require sufficient injections and linepack in the system, which is aided by the WORM. This modelled outcome may be impacted if Culcairn injections or withdrawals on the gas day differ from those assumed. The interaction between SWP and VNI capacities is discussed in Section 5.1.3.

5.3.3 DTS requirements with Victorian LNG terminals

The DTS was originally designed to transport large volumes of gas from the Longford CPP to the demand centre in Melbourne, then throughout western and northern Victoria to locations such as Ballarat, Bendigo, Shepparton, and Geelong. Over time, the DTS has evolved to receive supply from other sources such as Port Campbell, Culcairn, and Lang Lang, but it still receives the majority of its supply from the Longford CPP.

The decline in Gippsland production and the potential for the majority of peak day supply to come from the western side of the system would bring a fundamental shift in the way the DTS would be configured and operated.

AEMO is currently investigating the impacts of both eastern LNG and western LNG import terminals. Either location could require augmentation to the DTS in addition to the WORM to improve DTS capacity and system resilience in response to changing DTS operations, such as:

- Increase to Brooklyn CG flow capacity.
- Reduction of the Sale CG minimum operating pressure.
- Automation of Gooding CS line valve to allow free-flow west to east.
- Compression eastbound on the LMP or at Wollert.

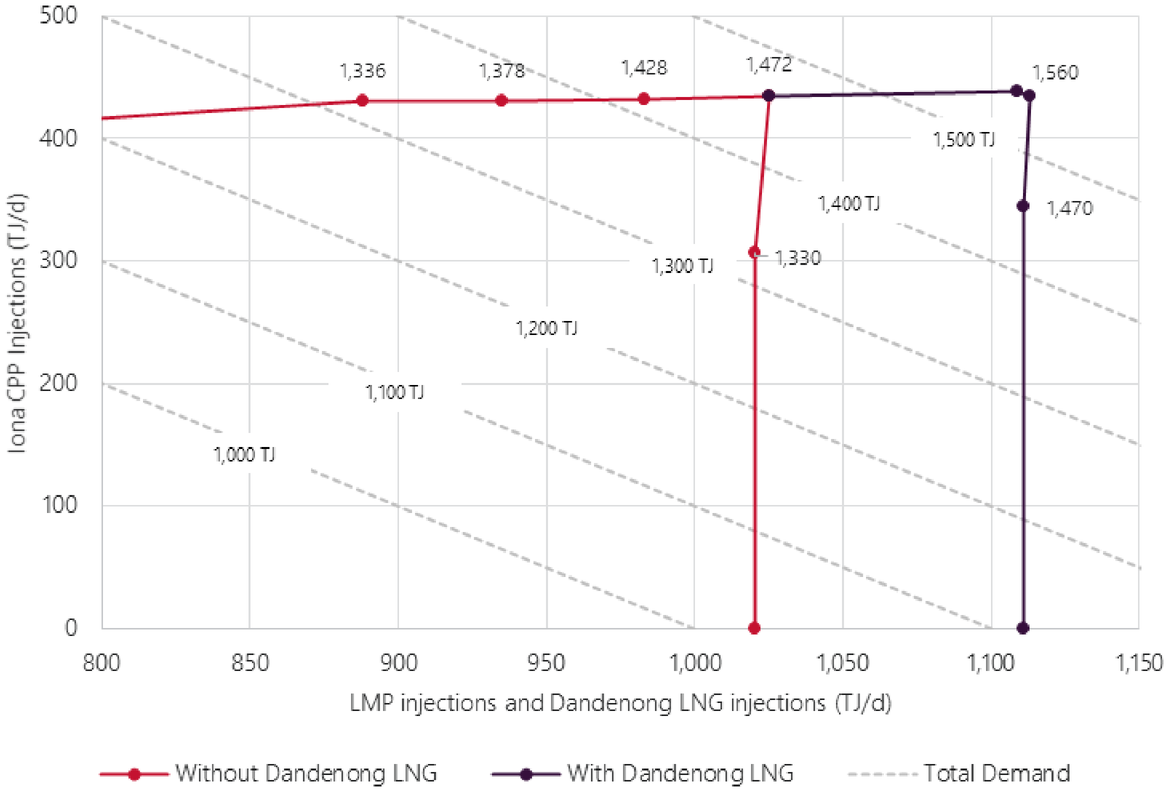
Augmentations to mitigate the impacts on the Iona CPP injection MDQ with western LNG injections could include:

- Pipeline looping of the SWP.
- Mid-line compression between Lara and Wollert.

5.4 Peak day system adequacy

Peak day system capacity[80], shown in Figure 28, quantifies the main sources of DTS supply – the LMP[81], Iona CPP, and Dandenong LNG injections – required to meet total DTS demand (including GPG). The area under the curve represents the feasible operating envelope of the DTS, assuming sufficient gas supply is available.

Figure 28 DTS peak day system capacity (TJ/d)



Key observations are:

- The maximum DTS capacity of 1,560 TJ/d is achieved with Dandenong LNG injecting at its maximum firm rate of 87 TJ/d, and 1,472 TJ/d without Dandenong LNG.
- The LMP and SWP can operate close to their respective maximum capacities coincidently, due to changes modelled operating methodology at Wollert being optimised to support northern zone demand and the utilisation of VNI linepack over the evening peak. This change in methodology is responsible for the increase peak day system capacity from 1,504 TJ/d (as reported in the 2019 VGPR) to 1,560 TJ/d.
- Culcairn injections or withdrawals are not included in system capacity modelling. With the current DTS configuration, Culcairn injections are equivalent to LMP injections, and would effectively offset LMP injections, achieving the same system capacity.

5.5 Gas-powered generation supportability

DTS-connected GPG units typically operate as peaking generators during times of high electricity demand, or when supply from other generation sources is limited. Figure 29 shows historical DTS-connected GPG usage.

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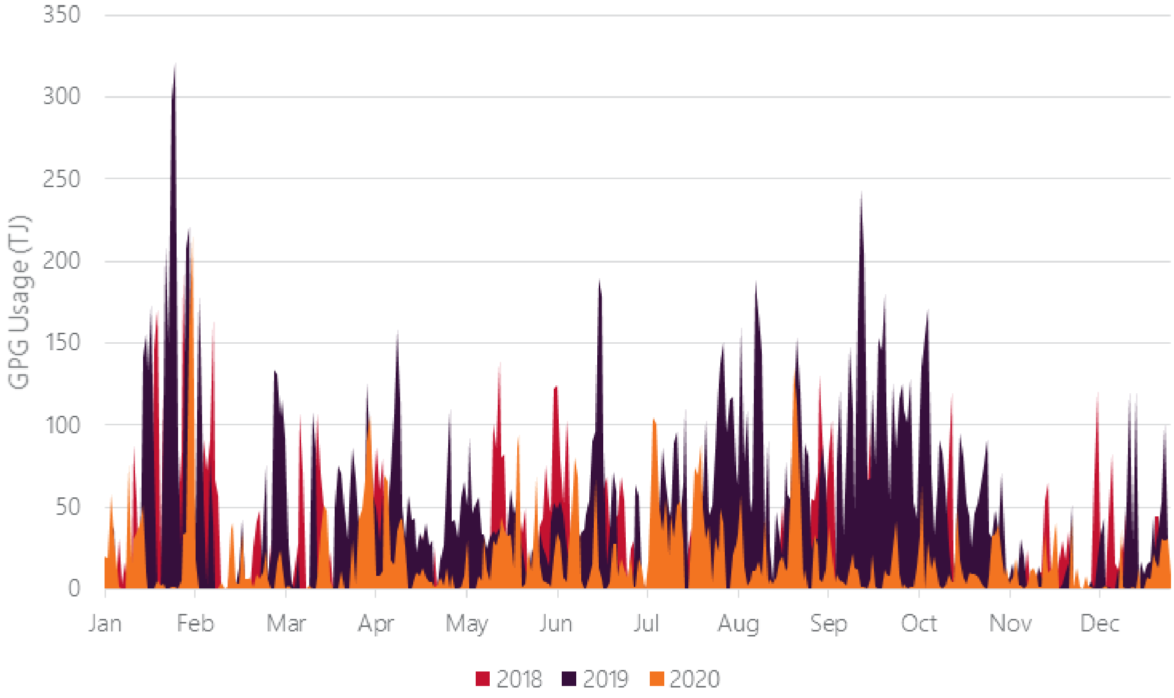
80 Peak day system capacity includes system demand, 25 TJ/d of GPG demand, and system compressor fuel gas.

81 LMP injection facilities include Longford CPP and Lang Lang Gas Plant.

Figure 29 Daily DTS-connected GPG demand for 2018, 2019 and 2020 (TJ)



As reported in Chapter 2, although annual GPG consumption is forecast to decrease over the outlook period, peak consumption is forecast to remain high to satisfy peak NEM demand. An assessment of the ability of the DTS to support DTS-connected GPG demand therefore remains critical.

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

- The DTS has low usable linepack in comparison to the demand on the network.
- Instantaneous GPG hourly demand can be high and can reduce linepack levels quickly, particularly during the morning and evening peak demand periods.

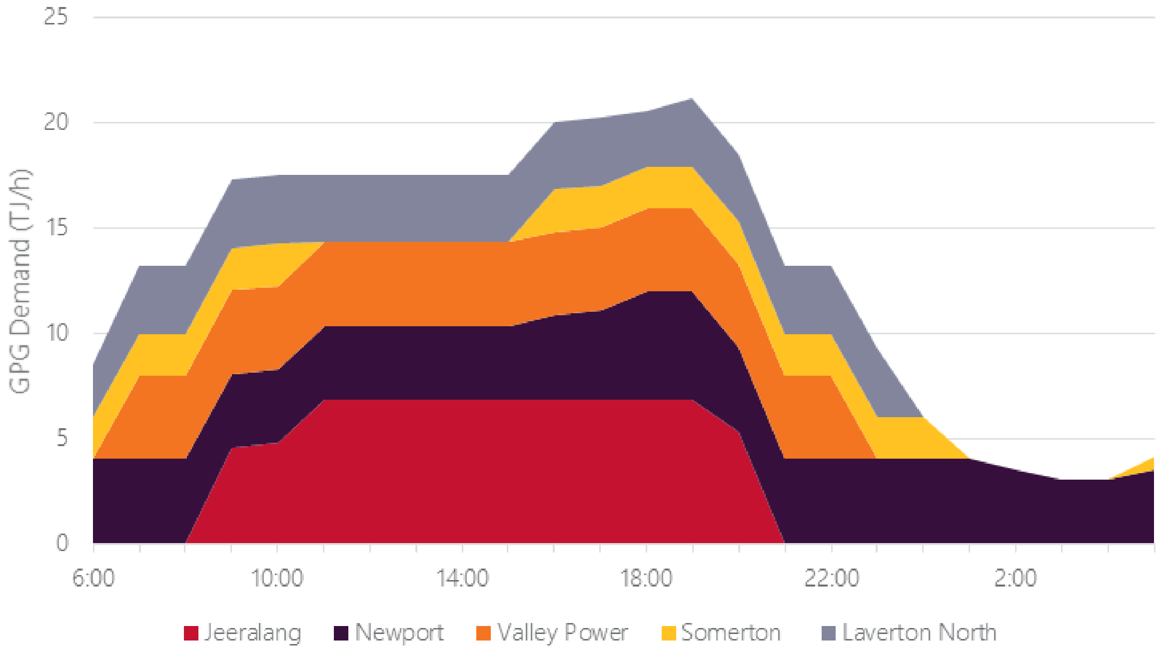
To better manage the uncertainties of GPG demand, the AEMO gas control room:

- Monitors forecast GPG in both the Declared Wholesale Gas Market (DWGM) demand forecasts and NEM pre-dispatch.
- Seeks confirmation and updates from market participants that operate GPG units supplied from the DTS.
- Communicates regularly with AEMO's NEM control room and its support teams regarding forecast electricity demand, NEM reserve levels, and generator outages.

AEMO has assessed the ability of the current DTS configuration (without WORM) to support forecast demand for DTS-connected GPG by modelling a GPG demand of 317 TJ[82], profile shown in Figure 30, occurring in both summer and winter 2021.

[82] GPG demand of this magnitude may occur if there is significant electricity demand in the NEM, coinciding with NEM transmission line outages and/or low NEM generation reserves.

Figure 30 Modelled peak GPG demand profile



Peak GPG demand in summer

This scenario modelled the peak GPG demand of 317 TJ occurring on a 400 TJ system demand day. Modelling for this scenario indicated:

- The system can support the modelled GPG demand profile, by maximising the LMP capacity with Longford CPP and BassGas injections.
- SWP withdrawals of up to 91 TJ/d can be supported. The reduction in the SWP withdrawal capacity occurs due to Laverton North and Newport gas demand.
- Culcairn withdrawals of up to 120 TJ/d can be achieved without the use of Dandenong LNG. Quantities above this level are possible if Dandenong LNG is used to support Wollert inlet pressures during the afternoon to evening GPG demand peak.
- Significant volumes of Dandenong LNG are required if the GPG demand is not correctly forecast from the beginning of the gas day.

Peak GPG demand in winter

This scenario modelled the peak GPG demand of 317 TJ occurring on a 1,155 TJ 1-in-2 peak system demand day resulting in a total demand of 1,472 TJ. Modelling for this scenario indicated:

- Although this is the same demand as the maximum system capacity without LNG in Figure 28, in this case 40 TJ of Dandenong LNG is required to support Dandenong CG inlet pressures. This is due to the peakier GPG demand profile shape, which depletes linepack more than a normal system demand profile even if the GPG demand is correctly forecast.
- Culcairn injections were required to support the GPG demand, which also allows greater utilisation of VNI linepack. A reduction in Culcairn injections, or any Culcairn withdrawals, would increase the required Dandenong LNG injections.

If the GPG demand is not correctly forecast at the beginning of the gas day, non-firm rate LNG would likely be required for a sustained period, and some GPG demand could not be supported.

6. Declared Transmission System pipeline capacities

Key findings

- There are no significant changes to pipeline capacities for this outlook period. The pipeline capacities are summarised in Table 17.
- These pipeline capacities will be used for the application of constraints in the DWGM, and to inform the assessment of any proposed DTS service provider and facility operator maintenance plans.

This section outlines the DTS pipeline capacities as at report publication.

Table 17 Summary of DTS pipeline capacities

Pipeline		Maximum capacity (TJ/d)	Comment
Longford to Melbourne	Injections only at Longford CPP	990	
	Injections at Longford CPP and Pakenham CPP	1,030	
South West Pipeline[A]	To Melbourne	426	Excludes WTS demand of 19 TJ/d, total Iona CPP injections are 445 TJ/d.
	To Port Campbell	140	Reduction from 2020 VGPR Update due to increased Melbourne zone demand.
Victorian Northern Interconnect	To Melbourne	226	Limited to 195 TJ/d due to capacity constraints in the New South Wales transmission network.
	To New South Wales via Culcairn	223	193 TJ/d on a 1 in 20 system demand day.

A. SWP capacities will increase with the commissioning of the WORM, discussed in Chapter 5.

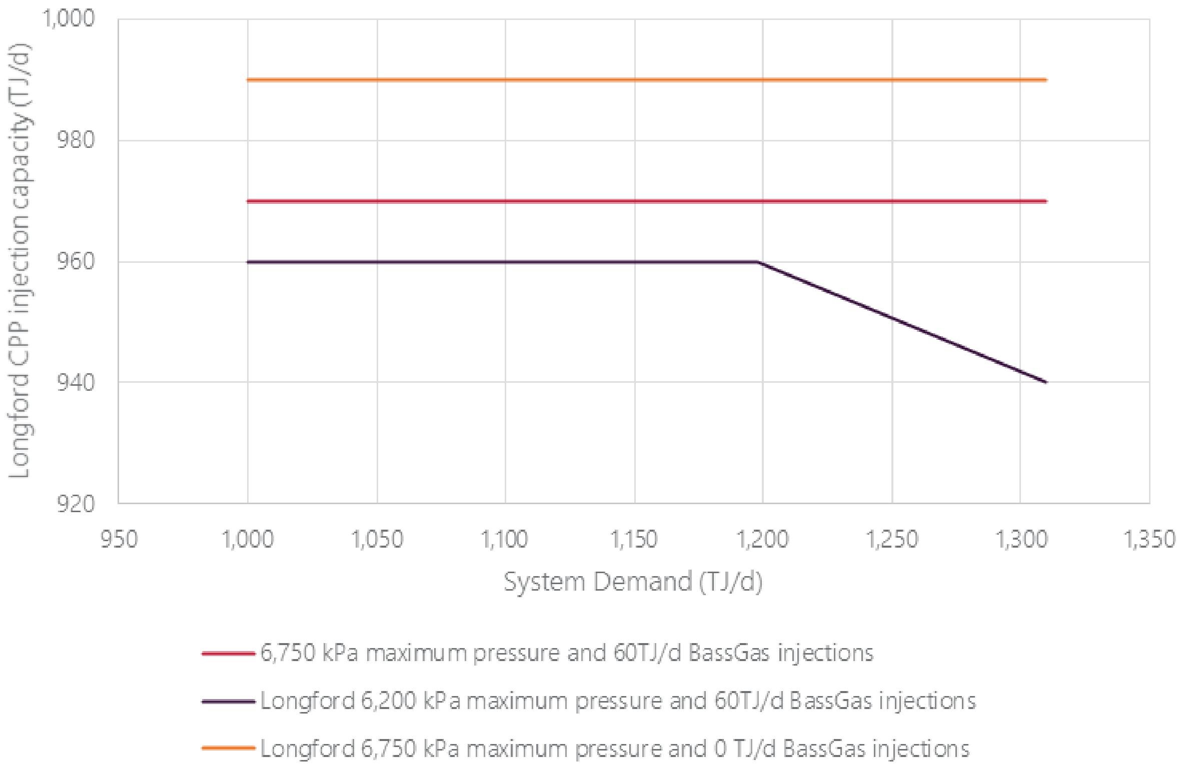
6.1 Longford to Melbourne Pipeline

The LMP runs from the Longford Gas Plant and VicHub connection point, which will supply gas from PKGT via the EGP, to Dandenong City Gate (DCG), which is the main supply point into the Melbourne inner ring-main.

The pipeline is supplied by the Longford CPP[83] and the BassGas connection point. The maximum pipeline capacity of 1,030 TJ/d is achieved with 970 TJ/d injections at the Longford CPP and 60 TJ/d injections at BassGas, as shown in Figure 31.

Further analysis on the LMP capacity will be conducted after the WORM design is finalised, and after any proposed Victorian LNG import terminals have reached FID.

Figure 31 Longford CPP injection capacity with varying conditions (TJ/d)



6.2 South West Pipeline

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

The SWP is typically used to:

- Transport gas from the Port Campbell production and Iona UGS facilities (Iona CPP[84]) towards Melbourne during periods of high gas demand.
- Support Iona UGS reservoir refilling, and supply to the Mortlake Power Station and to South Australia via the SEAGas Pipeline[85], during periods of lower gas demand in the summer and shoulder seasons.

The planning assumptions for SWP capacity are outlined in Appendix A6.

6.2.1 South West Pipeline to Melbourne

The SWP injection capacity (including WTS demand), shown in Figure 32, is dependent on system demand and is maximised on peak demand days. The Winchelsea CS is typically operated to increase the

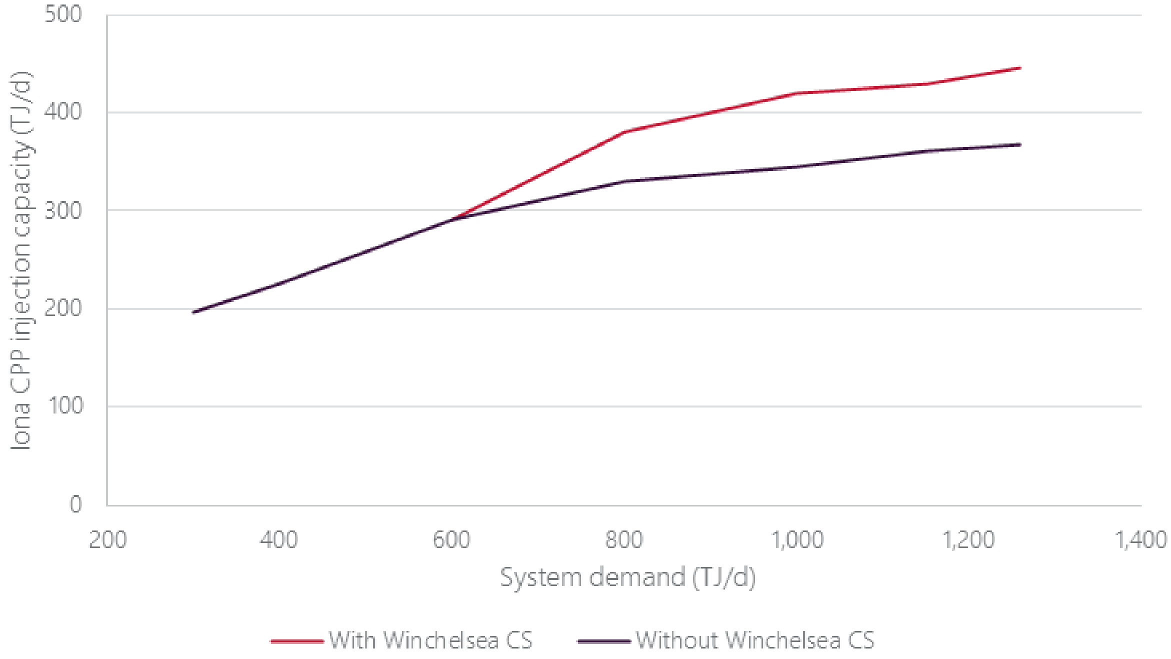
[83] Longford CPP includes the Longford, VicHub and TasHub injection points.

[84] Iona CPP includes the Iona, SEAGas, Mortlake, and Otway injection and withdrawal points.

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

transportation capacity and shift the linepack closer to Melbourne on system demand days of 800 TJ and above. The SWP injection capacity has increased from 434 TJ/d in 2019 to 445 TJ/d in 2020 on a 1-in-20 system demand day, driven by an increase in demand in the Geelong zone by 6 TJ/d.

Figure 32 SWP injection capacity (including WTS demand) to Melbourne (TJ/d)



6.2.2 South West Pipeline to Port Campbell

The SWP transportation capacity to support SWP withdrawals and WTS demand is shown in Figure 33. The withdrawal capacity is maximised on low system demand days when Winchelsea CS is available and Brooklyn CS Units 11 and 12 are compressing into the BLP.

Under these conditions, the maximum SWP withdrawal capacity is 140 TJ/day when system demand is 400 TJ/day. This has reduced from the capacity of 145 TJ/d reported in the 2019 VGPR, due to increased demand in the Melbourne region.

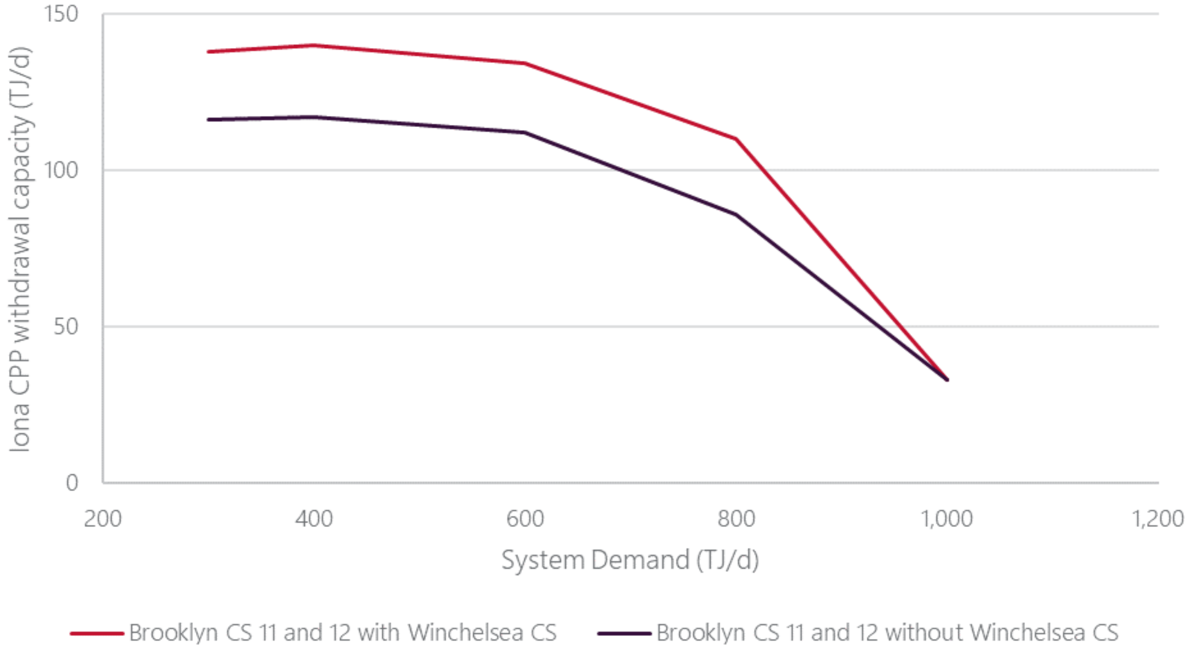
To support SWP withdrawals during the shoulder season and mild winter days, Brooklyn CS Unit 8 or Unit 9 is required to support Geelong morning and evening peak demand via the Brooklyn to Corio Pipeline. The unavailability of Brooklyn CS Unit 8 and Unit 9 on a shoulder or mild winter demand day increases the amount of gas taken from the BLP to support the Geelong region, resulting in a SWP to Port Campbell transportation capacity reduction of approximately 40 TJ/day.

Due to the location of the Laverton North and Newport power stations, and their high offtake rate, SWP transportation capacity towards Port Campbell is impacted by the operation of these generators.

The impact of Laverton North Power Station operation on the SWP withdrawal capacity will vary depending on its offtake rate and operating hours.

The SWP withdrawal capacity reduces by 1 TJ/d for every 13 TJ/d of Newport Power Station demand.

Figure 33 SWP withdrawal capacity to Port Campbell (TJ/d)



6.3 Victorian Northern Interconnect

The VNI runs between Wollert and Culcairn and encompasses three pipelines:

- T74 (300 mm) Wollert to Wodonga 7,400 kPa and 8,800 kPa Maximum Allowable Operating Pressure (MAOP) pipeline supporting Northern Zone demand including Bendigo via Wandong PRS, and the Echuca and Koonoomoo laterals.
- T119 (400 mm) Wollert to Barnawartha 10,200 kPa MAOP pipeline supporting exports to and imports from NSW; and also support Northern Zone demand into the T74 via the Wollert, Euroa, and Barnawartha PRSs.
- T99 (450 mm) Barnawartha to Culcairn 10,200 kPa MAOP pipeline supporting exports to and imports from New South Wales.

The planning assumptions for VNI capacity are outlined in Appendix A6.

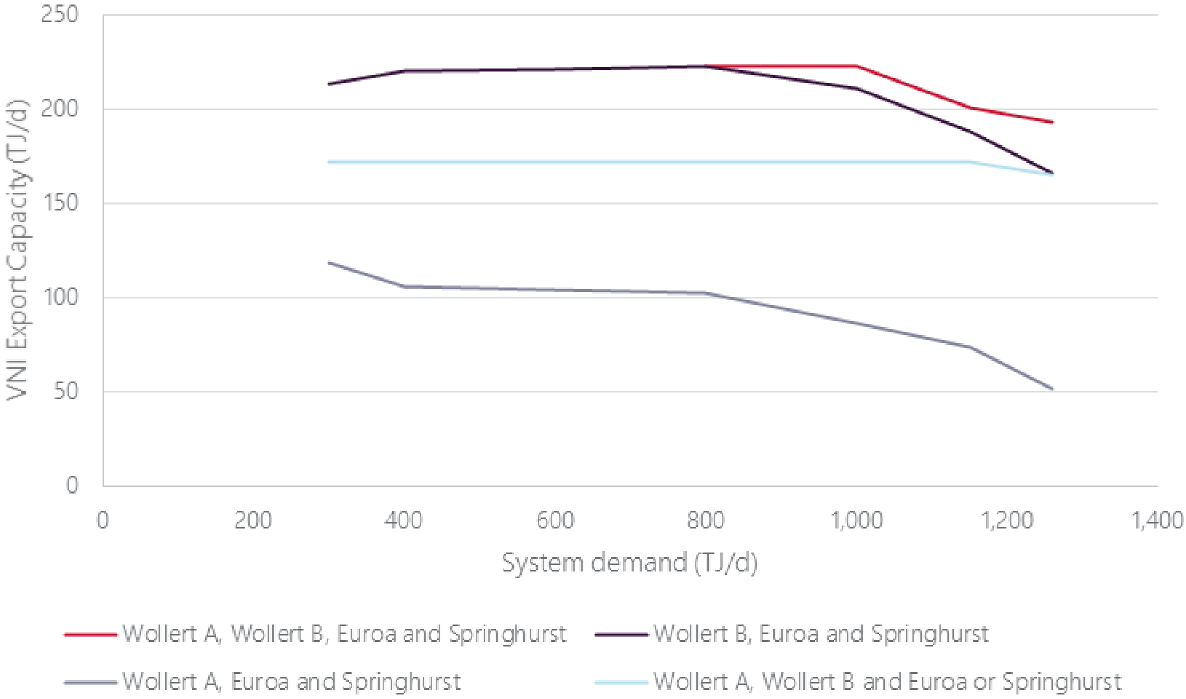
6.3.1 Victorian Northern Interconnect export capacity

The VNI export capacity, shown in Figure 34, is dependent on the availability of the Wollert, Euroa, and Springhurst compressor stations, and the capacity varies with different compressor configurations, the capacity is the higher of either:

- The DTS maximum export capacity when the DTS supply pressure to Culcairn is greater than 8,600 kPa, or
- Up to 172 TJ/d when the DTS supply pressure is lower than 8,600 kPa and all three Culcairn compressors[86] are operating.

[86] Culcairn compressors are located outside of the DTS, and are operated by the facility operator of the NSW transmission system.

Figure 34 Victorian Northern Interconnect export capacity (TJ/d)



On peak system days, the T74 pipeline cannot support the Northern zone demand with Wollert CS A compression alone and additional gas must be supplied to it from the T119 pipeline via Wollert CS B compression. Supply to the T74 from the T119 is through the Wollert, Euroa, and Barnawartha PRSs.

These export capacities are similar to the 2019 VGPR, with some small changes, including a reduction in 1-in-20 system demand day capacity from 202 TJ/d to 193 TJ/d. These differences can be attributed to a change in demand distribution and different peak-day system demand quantities. Culcairn export capacity modelling for 2021 indicated no difference between export capacity if only Euroa CS or Springhurst CS was available.

6.3.2 Victorian Northern Interconnect import capacity

The VNI import capacity is shown in Figure 35, with varying compressor configurations. The maximum VNI import capacity of 226 TJ/d is achieved on a 1-in-20 system demand day with both Euroa and Springhurst compressors operating. The import capacity is reduced if either compressor is offline, but more so when the Springhurst CS is offline, due to the larger distance from Culcairn to the Euroa CS.

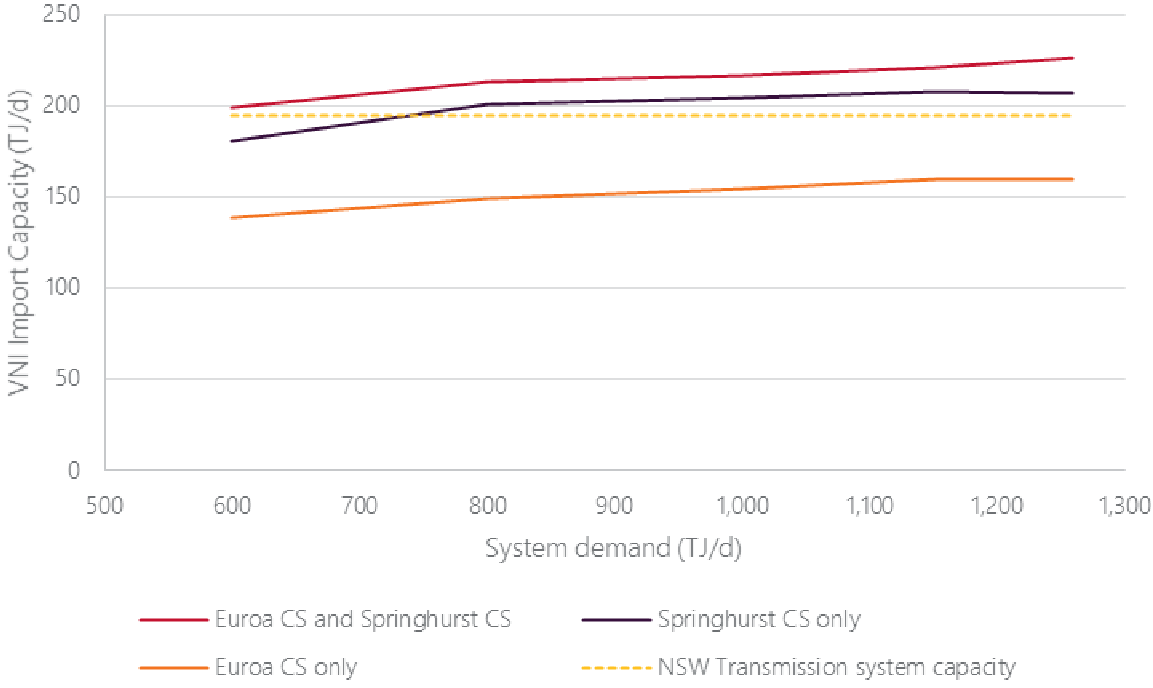
The operator of the New South Wales transmission system north of Culcairn has advised AEMO that up to 195 TJ/d of imports into the DTS can be supported by winter 2021[87,88]. When Springhurst CS is available, the import capacity of the VNI is higher than the Culcairn supply capacity for all demand levels except 600 TJ/d. When Springhurst CS is unavailable, the Culcairn supply capacity is greater than the VNI import capacity for all demand levels.

The VNI import capacities on 1-in-2 and 1-in-20 system demand levels are different from those published in the 2019 VGPR, due to a change in system demand distribution and a change in the peak day system demands.

[87] APA has undergone upgrades of upstream compression at Young compressor station, which supports Culcairn injection capacity.

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

Figure 35 Victorian Northern Interconnect import capacity (TJ/d)

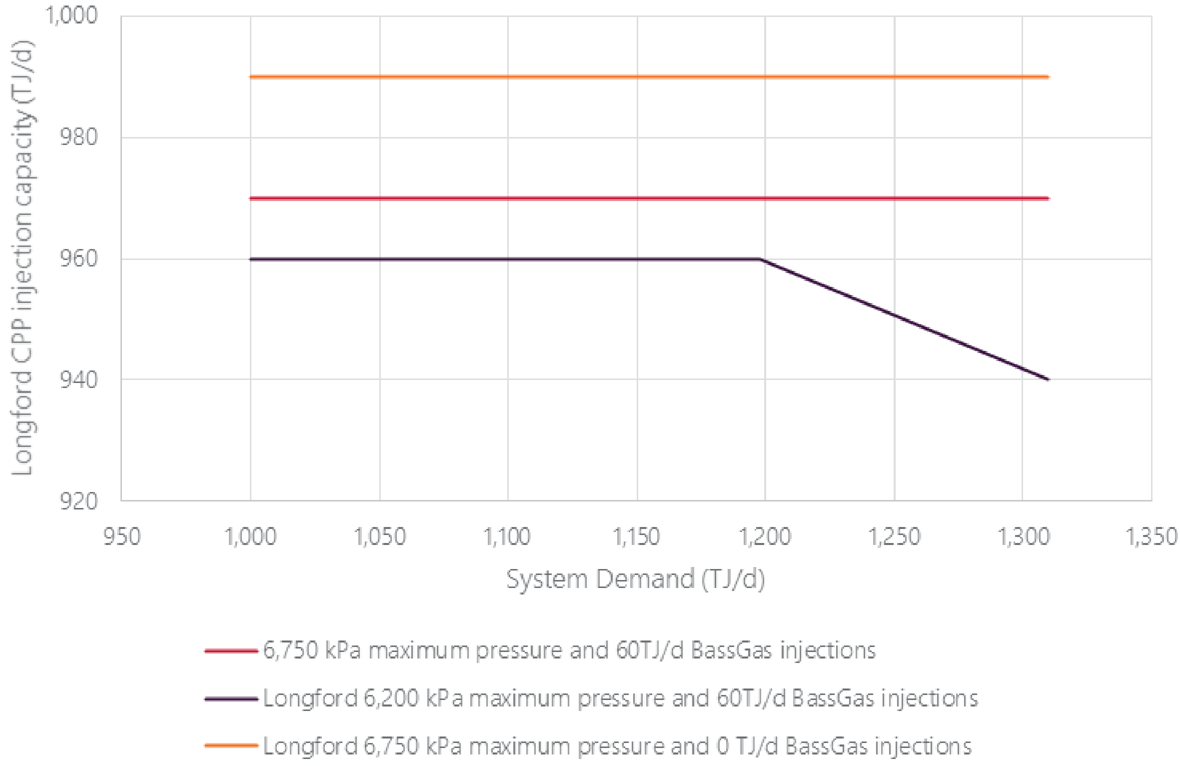


A1. DTS pipeline capacity charts

Note: This appendix summaries the DTS pipeline capacities as at report publication.

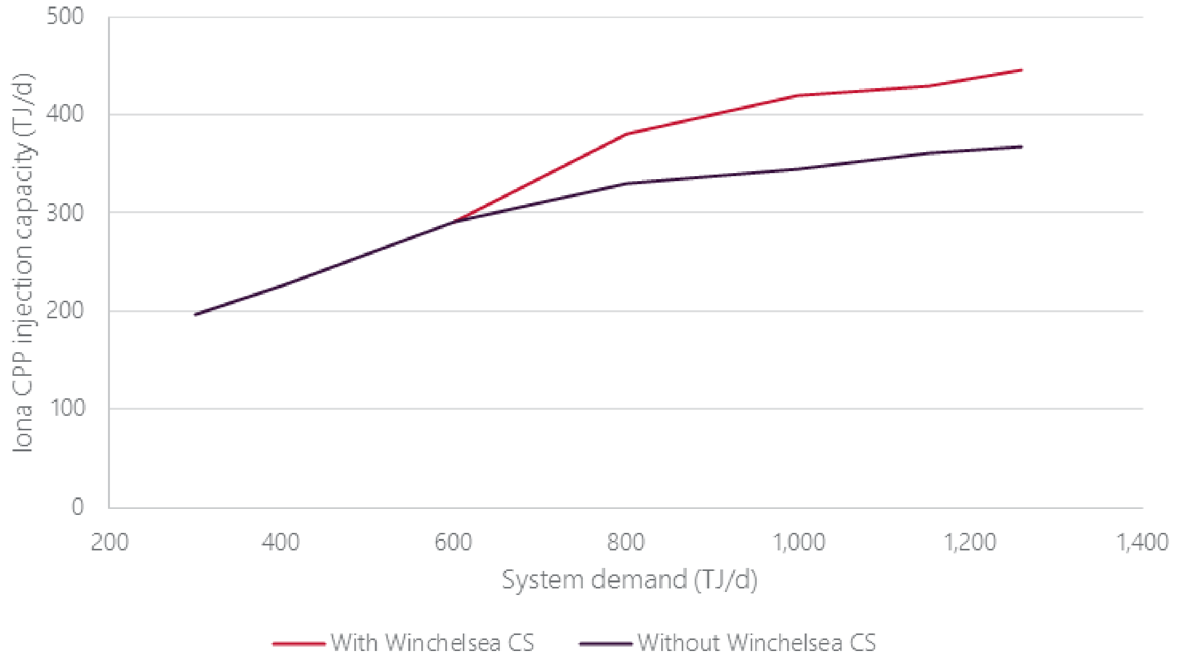
A1.1 Longford to Melbourne Pipeline

Longford CPP injection capacity with varying conditions (TJ/d)

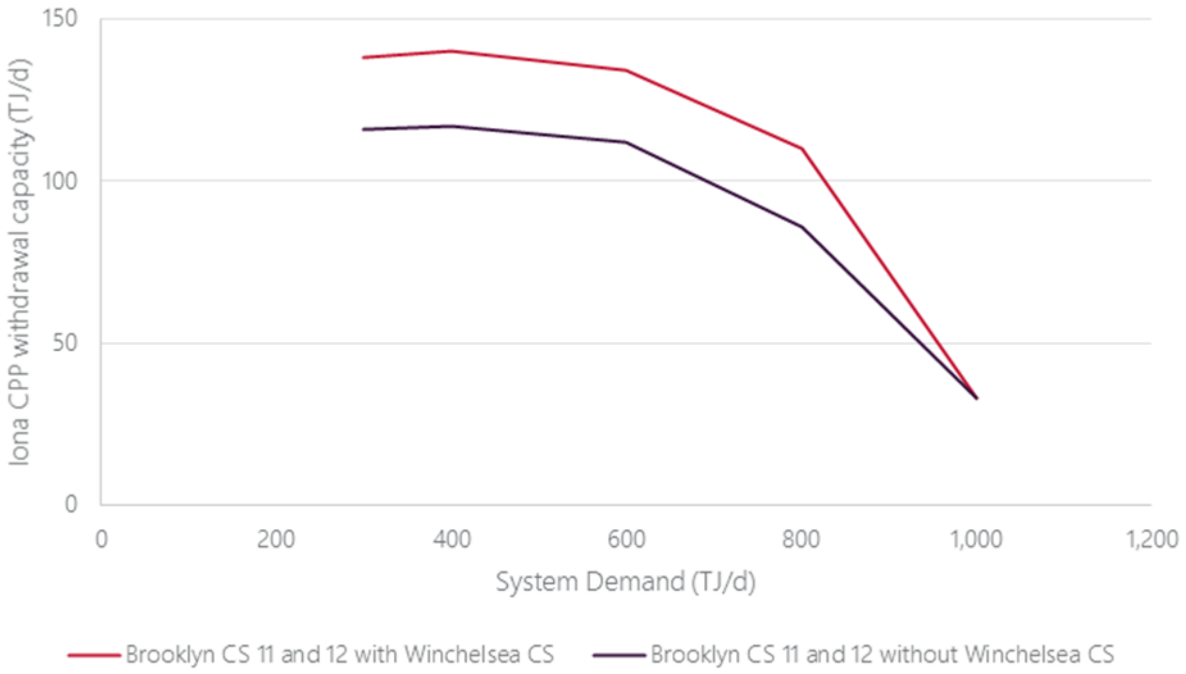


A1.2 South West Pipeline

SWP injection capacity (including WTS demand) to Melbourne (TJ/d)

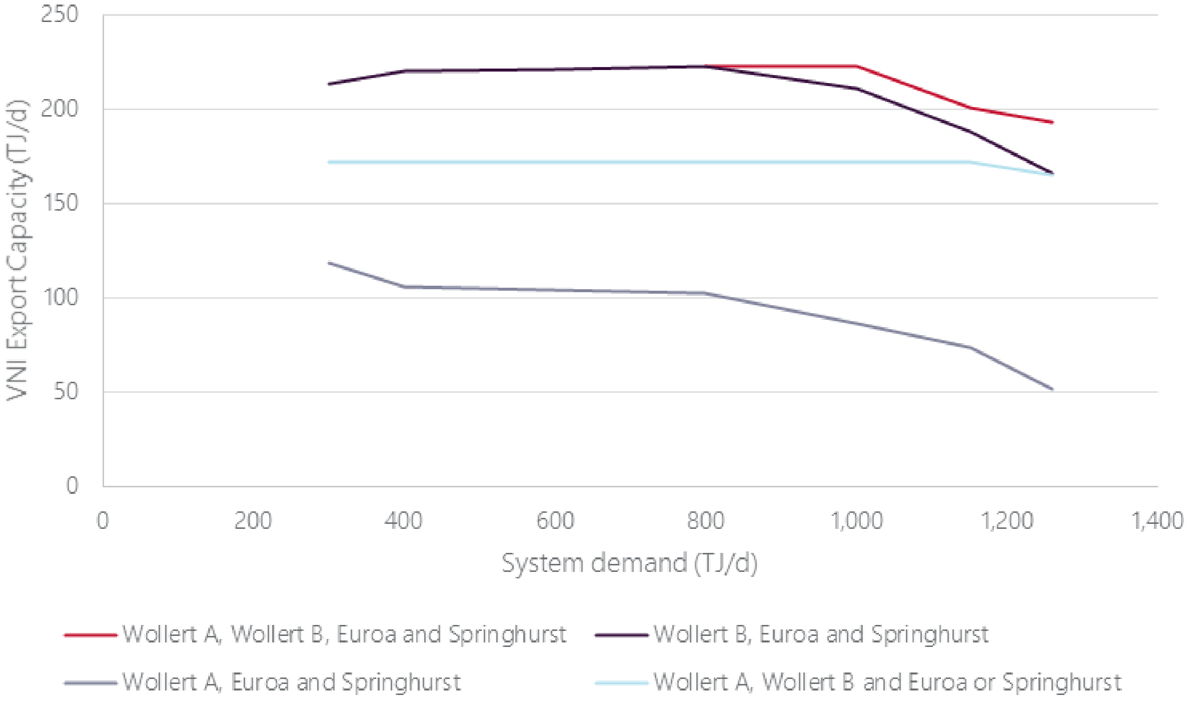


SWP withdrawal capacity to Port Campbell (TJ/d)

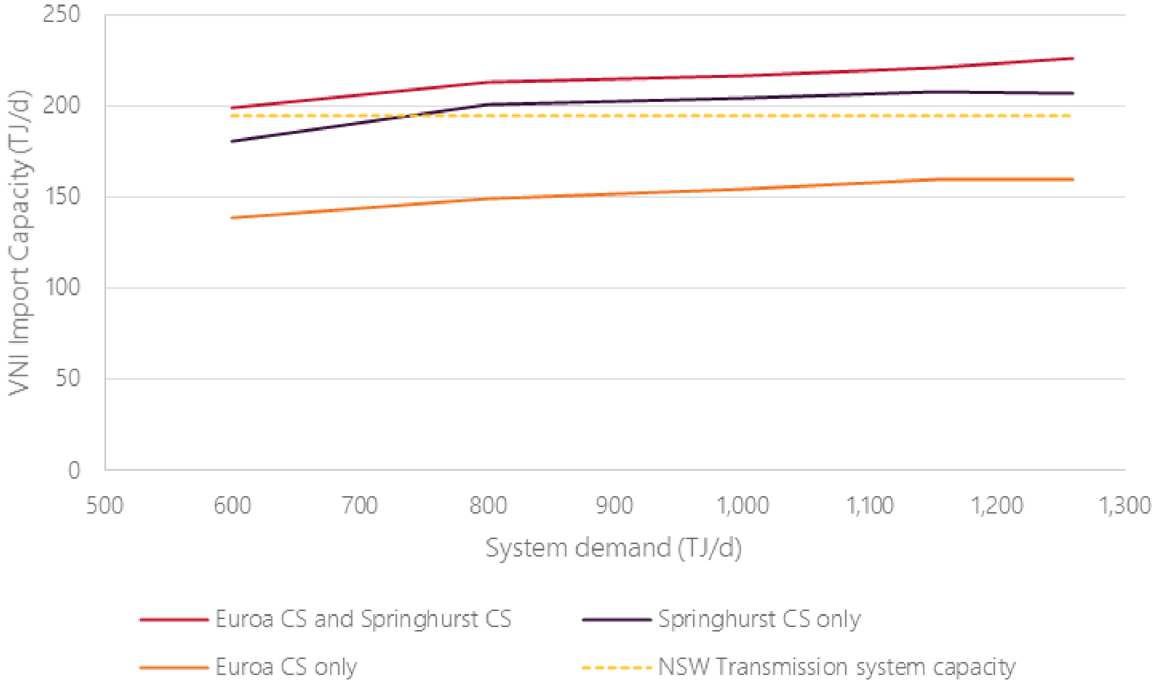


A1.3 Victorian Northern Interconnect

Victorian Northern Interconnect export capacity (TJ/d)



Victorian Northern Interconnect import capacity (TJ/d)



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

SWZ		2021	2022	2023	2024	2025	Change over outlook
Ballarat	Tariff V	8.9	9.0	9.0	9.0	9.2	2.9%
	Tariff D	1.7	1.6	1.6	1.6	1.6	-8.9%
	SWZ total	**10.6**	**10.6**	**10.6**	**10.6**	**10.7**	**1.0%**
Geelong	Tariff V	11.5	11.6	11.6	11.6	11.7	1.5%
	Tariff D	9.1	9.1	8.9	8.8	8.6	-4.5%
	SWZ total	**20.6**	**20.6**	**20.4**	**20.3**	**20.3**	**-1.2%**
Gippsland	Tariff V	5.9	5.9	5.9	6.0	6.0	2.9%
	Tariff D	8.1	7.9	7.7	7.4	7.1	-12.2%
	SWZ total	**14.0**	**13.8**	**13.6**	**13.4**	**13.2**	**-5.8%**
Melbourne	Tariff V	92.2	90.5	88.5	86.7	85.6	-7.2%
	Tariff D	35.5	35.3	34.9	34.5	33.9	-4.5%
	SWZ total	**127.7**	**125.8**	**123.4**	**121.2**	**119.5**	**-6.4%**
Northern	Tariff V	1.3	1.3	1.3	1.3	1.3	-1.1%
	Tariff D	2.7	2.7	2.7	2.7	2.7	0.9%
	SWZ total	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**0.2%**
Western	Tariff V	11.3	11.3	11.3	11.3	11.4	0.3%
	Tariff D	8.6	8.7	8.7	8.6	8.5	-1.9%
	SWZ total	**20.0**	**20.1**	**20.0**	**19.9**	**19.8**	**-0.6%**

Table 19 Annual 1-in-2 peak daily demand by SWZ (TJ/d)

SWZ		2021	2022	2023	2024	2025	Change over outlook
Ballarat	Tariff V	59.0	59.5	59.5	59.9	60.8	3.0%
	Tariff D	5.6	5.3	5.3	5.2	5.2	-7.7%
	SWZ total	**64.6**	**64.8**	**64.8**	**65.1**	**66.0**	**2.0%**
Geelong	Tariff V	78.1	78.6	78.4	78.6	79.4	1.6%
	Tariff D	37.5	37.6	36.6	36.5	36.3	-3.3%
	SWZ total	**115.7**	**116.2**	**115.0**	**115.0**	**115.7**	**0.0%**
Gippsland	Tariff V	41.0	41.4	41.4	41.6	42.2	3.0%
	Tariff D	27.4	26.7	25.9	25.1	24.4	-11.1%
	SWZ total	**68.4**	**68.1**	**67.3**	**66.8**	**66.6**	**-2.7%**
Melbourne	Tariff V	664.7	653.6	637.3	624.8	617.3	-7.1%
	Tariff D	122.2	121.3	119.8	118.9	118.2	-3.3%
	SWZ total	**787.0**	**775.0**	**757.1**	**743.7**	**735.4**	**-6.5%**
Northern	Tariff V	72.9	73.1	72.6	72.6	73.1	0.4%
	Tariff D	28.9	29.2	29.2	29.0	28.8	-0.6%
	SWZ total	**101.8**	**102.3**	**101.8**	**101.6**	**101.9**	**0.1%**
Western	Tariff V	8.5	8.5	8.4	8.3	8.4	-1.1%
	Tariff D	8.7	8.8	8.8	8.9	8.9	2.2%
	SWZ total	**17.1**	**17.2**	**17.2**	**17.2**	**17.2**	**0.6%**

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

SWZ		2021	2022	2023	2024	2025	Change over outlook
Ballarat	Tariff V	65.3	65.8	65.9	66.6	67.7	3.6%
	Tariff D	5.8	5.5	5.5	5.4	5.3	-8.5%
	SWZ total	**71.2**	**71.4**	**71.4**	**72.1**	**73.0**	**2.6%**
Geelong	Tariff V	86.5	87.0	86.8	87.4	88.4	2.2%
	Tariff D	39.0	39.1	38.0	37.9	37.4	-4.1%
	SWZ total	**125.5**	**126.1**	**124.8**	**125.3**	**125.8**	**0.2%**
Gippsland	Tariff V	45.4	45.8	45.8	46.3	47.0	3.6%
	Tariff D	28.5	27.8	26.9	26.1	25.1	-11.8%
	SWZ total	**73.9**	**73.6**	**72.8**	**72.4**	**72.2**	**-2.4%**
Melbourne	Tariff V	735.8	723.4	705.8	695.2	687.3	-6.6%

SWZ		2021	2022	2023	2024	2025	Change over outlook
	Tariff D	127.1	126.1	124.5	123.5	121.9	-4.1%
	SWZ total	**863.0**	**849.5**	**830.3**	**818.7**	**809.2**	**-6.2%**
Northern	Tariff V	80.7	80.8	80.4	80.8	81.4	0.9%
	Tariff D	30.1	30.4	30.3	30.2	29.7	-1.4%
	SWZ total	**110.8**	**111.2**	**110.7**	**110.9**	**111.1**	**0.3%**
Western	Tariff V	9.4	9.4	9.3	9.3	9.3	-0.5%
	Tariff D	9.0	9.1	9.2	9.2	9.1	1.4%
	SWZ total	**18.4**	**18.5**	**18.5**	**18.5**	**18.5**	**0.4%**

Table 21 Annual peak hourly demand by SWZ (TJ/hr)

	SWZ	2021	2022	2023	2024	2025
Max. hourly demand on 1-in-2-year peak demand day	Ballarat	4.8	4.9	4.8	4.9	4.9
	Geelong	6.7	6.7	6.7	6.7	6.7
	Gippsland	4.4	4.4	4.3	4.3	4.3
	Melbourne	51.5	50.7	49.5	48.7	48.1
	Northern	6.4	6.5	6.4	6.4	6.5
	Western	1.1	1.1	1.1	1.1	1.1
	System total	**75.0**	**74.3**	**72.9**	**72.1**	**71.6**
Max. hourly demand on 1-in-20-year peak demand day	Ballarat	5.4	5.4	5.5	5.5	5.6
	Geelong	7.4	7.5	7.4	7.4	7.5
	Gippsland	4.8	4.8	4.8	4.7	4.7
	Melbourne	57.6	56.7	55.4	54.6	54.0
	Northern	7.2	7.2	7.1	7.2	7.2
	Western	1.2	1.2	1.2	1.2	1.2
	System total	**83.7**	**82.8**	**81.4**	**80.7**	**80.1**

Table 22 Annual 1-in-2 DTS and non-DTS peak day demand forecast (TJ/d)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V (non-DTS)	1.3	1.4	1.4	1.4	1.5	14.9%
Tariff D (non-DTS)	2.0	2.0	2.0	2.0	2.0	-0.2%
System demand non-DTS	3.3	3.3	3.4	3.4	3.5	5.8%
System demand DTS	1,154.7	1,143.6	1,123.1	1,109.4	1,102.8	-4.5%
System demand Victoria	1,157.9	1,146.9	1,126.5	1,112.9	1,106.3	-4.5%

Table 23 Annual 1-in-20 non-DTS peak day demand forecast (TJ/d)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V (non-DTS)	1.4	1.5	1.5	1.6	1.7	15.6%
Tariff D (non-DTS)	2.0	2.1	2.1	2.0	2.0	-1.0%
System demand non-DTS	3.5	3.6	3.6	3.7	3.7	5.8%
System demand DTS	1,262.8	1,250.2	1,228.5	1,217.9	1,209.8	-4.2%
System demand Victoria	1,266.3	1,253.7	1,232.1	1,221.5	1,213.5	-4.2%

A2.2 Monthly consumption and demand for 2021

Table 24 Monthly gas consumption for 2021 by SWZ (PJ/m)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SWZ consumption	Ballarat	0.42	0.43	0.53	0.71	1.13	1.50	1.57	1.45	1.07	0.80	0.59	0.43
	Geelong	1.17	1.16	1.27	1.48	1.97	2.48	2.56	2.43	1.91	1.60	1.35	1.19
	Gippsland	0.86	0.82	0.89	1.00	1.36	1.62	1.61	1.51	1.27	1.18	0.99	0.89
	Melbourne	5.56	5.43	6.43	8.34	13.63	17.63	18.51	17.30	12.41	9.56	7.23	5.64
	Northern	0.93	1.00	1.14	1.33	2.11	2.59	2.74	2.61	1.87	1.51	1.20	0.93
	Western	0.25	0.23	0.24	0.26	0.35	0.42	0.44	0.45	0.41	0.37	0.31	0.27
	System consumption	9.18	9.06	10.49	13.11	20.55	26.24	27.43	25.74	18.94	15.03	11.67	9.35

Table 25 Monthly GPG consumption in 2021 by SWZ (TJ/m)

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	67	23	0	13	32	56	21	25	6	0	0	6
Gippsland	106	28	0	3	10	21	7	9	1	0	0	6
Melbourne	321	183	73	312	415	567	241	352	186	11	46	47
Northern	-	-	-	-	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-	-	-	-	-
Total DTS consumption	494	234	73	327	457	643	269	387	193	11	46	59

Table 26 Monthly peak daily demand in 2021 by SWZ (TJ/d)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day demand	Ballarat	16	18	24	34	51	60	64	60	50	41	31	20
	Geelong	53	53	60	69	93	105	109	107	91	78	65	55
	Gippsland	32	33	36	45	56	64	68	65	57	51	44	35
	Melbourne	242	255	303	442	619	743	754	741	608	500	395	280
	Northern	38	43	49	61	86	100	101	99	82	67	49	39
	Western	10	10	10	12	14	16	17	17	17	15	13	11
	System demand	**392**	**411**	**482**	**662**	**918**	**1,088**	**1,113**	**1,089**	**904**	**752**	**598**	**440**
1-in-20 peak day demand	Ballarat	19	22	34	44	59	66	71	70	58	48	41	29
	Geelong	59	58	72	83	103	114	119	119	101	87	78	67
	Gippsland	35	35	42	52	62	70	74	72	63	56	52	41
	Melbourne	277	307	407	565	708	816	834	851	698	578	508	382
	Northern	43	48	60	75	96	109	111	111	92	76	60	48
	Western	11	11	11	14	15	17	18	18	18	17	15	13
	System demand	**443**	**479**	**626**	**832**	**1,043**	**1,192**	**1,228**	**1,241**	**1,030**	**863**	**755**	**579**

Table 27 Forecast hourly peak day demand for 2021 (TJ/hr)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	25	31	36	47	65	73	75	73	64	53	45	33
1-in-20	34	36	44	59	70	80	83	84	69	61	54	44

Table 28 Monthly peak hourly demand in 2021 by SWZ (TJ/hr)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max. hourly demand on 1-in-2 peak demand day	Ballarat	1.16	1.41	1.97	2.57	3.83	4.42	4.51	4.42	3.83	2.97	2.50	1.58
	Geelong	3.23	3.87	4.30	4.73	6.09	6.92	7.07	6.92	6.00	5.40	4.92	4.15
	Gippsland	1.89	2.27	2.55	2.89	3.54	3.93	4.01	3.93	3.41	3.12	3.07	2.54
	Melbourne	16.27	19.82	23.56	31.90	44.68	51.07	52.21	51.09	44.29	36.61	30.64	21.35
	Northern	2.29	3.04	3.47	4.15	5.58	6.11	6.24	6.11	5.29	4.25	3.25	2.87
	Western	0.56	0.69	0.65	0.75	0.93	0.92	0.94	0.92	0.80	0.95	0.87	0.79
Max. hourly demand on 1-in-20 peak demand day	Ballarat	1.56	1.77	2.55	3.33	4.22	4.85	5.00	5.05	4.19	3.94	3.10	2.33
	Geelong	4.19	4.20	4.92	5.68	6.54	7.55	7.77	7.86	6.52	6.10	5.52	4.95
	Gippsland	2.44	2.37	2.80	3.37	3.75	4.27	4.40	4.45	3.69	3.52	3.38	2.84
	Melbourne	21.66	23.89	29.42	40.34	48.81	55.98	57.68	58.30	48.39	41.30	36.92	29.45
	Northern	2.99	3.34	3.99	4.99	5.98	6.67	6.88	6.95	5.77	4.79	3.67	3.42
	Western	0.72	0.73	0.72	0.87	0.98	1.00	1.03	1.04	0.86	1.08	0.95	0.87

A3. Gas supply forecast

A3.1 Victorian supply sources

Table 29 reports Victorian supply sources by SWZ, with facility ownership details[89].

Table 29 Victorian facilities by SWZ

SWZ	Supply source	Project	Project Ownership
Gippsland	Longford Gas Plant	Gippsland Basin Joint Venture	• Esso Australia Resources, 50% • BHP Billiton Petroleum, 50%
		Kipper Unit Joint Venture	• Esso Australia Resources, 32.5% • BHP Billiton Petroleum, 32.5% • Mitsui E&P Australia, 35%
	Lang Lang Gas Plant	BassGas Project	• Beach Energy Limited, 53.75% • Mitsui E&P Australia, 35% • Prize Petroleum International, 11.25%
	Orbost Gas Plant	Sole Gas Project	• Cooper Energy, 100%
Melbourne	Dandenong LNG	Dandenong LNG	• APA Group, 100%
Port Campbell (Geelong)	Otway Gas Plant	Otway Gas Project	• Beach Energy Limited, 60% • O.G Energy, 40%
		Halladale, Black Watch, 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 E&P Australia, 50%
	Athena Gas Plant	Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui E&P Australia, 50%

[89] 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.

A3.1.1 Infrastructure changes since the 2020 VGPR Update

The Orbost Gas Plant commenced production from the Sole gas field in 2020. Supply from this facility is delivered into the EGP and can support Victorian non-DTS demand (Bairnsdale), DTS via VicHub connection point, and interstate gas flow.

The Athena Gas Plant is committed to return to service by mid-2021. This facility will initially process gas from the existing Casino, Henry, and Netherby fields. Supply from these fields are currently processed at the Iona Gas Plant until the Athena Gas Plant commences production.

Iona UGS storage capacity is expected to increase from 23.5 PJ to 24.4 PJ in 2023, and a meter upgrade due in April 2021 is set to increase the facilities injection MDQ from 503 TJ/d to 520 TJ/d.

Further information on production facilities, storage facilities, and interconnected pipelines is in Appendix A3.

A3.2 Annual production by SWZ

Table 30 Annual Victorian production by SWZ, 2021-25 (PJ/y)

SWZ	Supply source	2021	2022	2023	2024	2025	Change over outlook
Gippsland[A]	Existing	288	255	180	164	122	-58%
	Committed	28	37	40	38	31	13%
	Total available	**316**	**292**	**220**	**202**	**153**	**-51%**
	Anticipated	0	0	25	39	22	-
	Total available plus anticipated	**316**	**292**	**245**	**241**	**175**	**-44%**
Port Campbell (Geelong)[B]	Existing	29	27	9	2	2	94%
	Committed	15	22	58	57	50	231%
	Total available	**44**	**49**	**67**	**59**	**52**	**18%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**44**	**49**	**67**	**59**	**52**	**18%**
Total Victorian Production	Existing	317	281	189	166	124	-61%
	Committed	43	60	98	94	81	90%
	Total available	**360**	**341**	**287**	**261**	**205**	**-43%**
	Anticipated	0	0	25	39	22	-
	Total available plus anticipated	**360**	**341**	**312**	**300**	**227**	**-37%**

Table 31 Victorian annual available and anticipated supply balance by SWZ, 2021-25 (PJ/y)

SWZ	Supply source	2021	2022	2023	2024	2025	Change over outlook
Gippsland[A]	Existing	288	255	180	164	122	-58%
	Committed	28	37	40	38	31	13%
	Total available	**316**	**292**	**220**	**202**	**153**	**-51%**
	Anticipated	0	0	25	39	22	-
	Total available plus anticipated	**316**	**292**	**245**	**241**	**175**	**-44%**
Port Campbell (Geelong)[B]	Existing	29	27	9	2	2	94%
	Committed	15	22	58	57	50	231%
	Total available	**44**	**49**	**67**	**59**	**52**	**18%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**44**	**49**	**67**	**59**	**52**	**18%**
Total Victorian production	Existing	317	281	189	166	124	-61%
	Committed	43	60	98	94	81	90%
	Total available	**360**	**341**	**287**	**261**	**205**	**-43%**
	Anticipated	0	0	25	39	22	-
	Total available plus anticipated	**360**	**341**	**312**	**300**	**227**	**-37%**
Total available supply		360	341	287	261	205	-43%
Total Victorian consumption		206	202	198	195	191	-7.9%
Surplus / shortfall quantity		154	139	89	66	14	-
Total anticipated supply		0	0	25	39	22	-

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Unit JV, Orbost Gas Plant, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes the Otway and Athena gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

A3.3 Monthly production by SWZ

Table 32 Victorian monthly production by SWZ, 2021-25 (PJ/m)

SWZ	Year	Supply source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gippsland[A]	2021	Available	21.6	20.0	20.3	22.9	30.3	32.0	33.2	33.3	30.5	27.2	23.7	21.3
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2022	Available	21.7	20.4	21.1	23.2	30.0	26.6	27.3	26.6	27.9	27.2	18.9	21.1
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2023	Available	21.6	20.1	17.6	12.6	18.3	18.8	18.9	18.9	18.4	19.0	18.0	17.8
		Anticipated	1.9	1.8	1.9	1.9	1.9	1.9	1.9	1.9	3.5	3.6	3.5	3.6
	2024	Available	18.6	13.2	12.0	15.3	19.1	17.9	17.9	17.9	17.4	17.6	16.8	17.3
		Anticipated	3.2	2.9	3.2	3.1	3.2	3.1	3.2	3.2	3.1	3.2	3.1	1.2
	2025	Available	16.0	10.8	9.5	12.5	15.2	14.8	13.6	13.5	12.4	12.3	11.3	11.1
		Anticipated	1.9	1.7	1.9	1.8	1.9	1.8	1.9	1.9	1.8	1.9	1.8	1.9
Port Campbell (Geelong)[B]	2021	Available	2.6	2.3	2.6	2.3	2.4	3.1	5.1	5.0	4.7	4.7	4.6	4.7
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2022	Available	4.4	4.0	4.4	4.1	4.2	4.0	4.1	4.1	3.9	3.9	3.8	3.8
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2023	Available	6.2	5.5	6.0	5.7	5.8	5.6	5.7	5.6	5.3	5.4	5.2	5.3
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2024	Available	5.2	4.7	5.1	4.9	5.1	4.9	5.0	5.0	4.8	4.9	4.7	4.8
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2025	Available	4.8	4.3	4.6	4.4	4.5	4.3	4.4	4.3	4.1	4.2	4.0	4.0
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
Total Victorian production	2021	Available	24.2	22.3	22.8	25.2	32.7	35.2	38.4	38.2	35.2	31.9	28.3	26.0
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-
	2022	Available	26.1	24.3	25.4	27.4	34.3	30.6	31.4	30.7	31.8	31.1	22.7	25.0
		Anticipated	-	-	-	-	-	-	-	-	-	-	-	-

SWZ	Year	Supply source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	2023	Available	27.8	25.6	23.6	18.4	24.2	24.3	24.6	24.5	23.8	24.4	23.2	23.1
		Anticipated	1.9	1.8	1.9	1.9	1.9	1.9	1.9	1.9	3.5	3.6	3.5	3.6
	2024	Available	23.8	17.9	17.1	20.3	24.2	22.7	22.9	22.9	22.1	22.5	21.5	22.2
		Anticipated	3.2	2.9	3.2	3.1	3.2	3.1	3.2	3.2	3.1	3.2	3.1	1.2
	2025	Available	20.7	15.1	14.1	17.0	19.7	19.1	18.0	17.8	16.5	16.4	15.3	15.1
		Anticipated	1.9	1.7	1.9	1.8	1.9	1.8	1.9	1.9	1.8	1.9	1.8	1.9

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Unit JV, Orbost Gas Plant, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes the Otway and Athena gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

A3.4 Peak day production by SWZ

Table 33 Peak day maximum daily quantity (MDQ) supply capacity by SWZ, 2021-25 (TJ/d)

SWZ	Supply source	2021	2022	2023	2024	2025	Change over outlook
Gippsland[A]	Available	1,072	882	621	590	488	-54%
	Anticipated	-	-	125	165	60	-
	Total available plus anticipated	**1,072**	**822**	**746**	**755**	**548**	**-49%**
Port Campbell (Geelong)[B]	Available	722	703	726	706	677	-6%
	Anticipated	-	-	50	50	50	-
	Total available plus anticipated	**722**	**703**	**776**	**756**	**727**	**1%**
Melbourne	Available	87	87	87	87	87	0%
DTS total supply	Available	1,881	1,672	1,434	1,383	1,252	-33%
	Anticipated	0	0	175	215	110	-
	Total available plus anticipated	**1,881**	**1,672**	**1,609**	**1,598**	**1,362**	**-28%**

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Unit JV, Orbost Gas Plant, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP.
B. Port Campbell includes the Otway and Athena gas plants, and Casino production via Iona UGS. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

A3.5 Storage facility operating parameters

A3.5.1 Dandenong LNG

The Dandenong LNG storage facility has a capacity of 12,400 tonnes (680 TJ); approximately 10,565 tonnes (580 TJ) of this capacity is available to market participants. Dandenong LNG is usually scheduled for either:

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

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

Table 34 LNG operating parameters

Year	Min hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. down rate (TJ/h/h)	Pressure range (kPa)[A]
2021-25	2.2	9.9	5.5	5.5	2,760-2,700 kPa

A. The minimum and maximum pressure is based on injection in the 2,800 kilopascals (kPa) system.

A3.5.2 Iona Underground Storage

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports GPG demand in South Australia via the SEA Gas Pipeline and can supply the Mortlake Power Station. The current total Iona UGS storage reservoir capacity is 23.5 PJ. The injection capacity into the storage reservoirs is 155 TJ/d[90].

Iona UGS requires two hours' notification to switch between withdrawals to storage and injection into the DTS. The storage operating parameters shown in Table 35, including injection and withdrawal rate and pressures, have been historically and are foreseeably sustainable. These may, however, be impacted by a combination of maintenance, peak demand conditions, and a low total storage inventory.

Table 35 Iona UGS operating parameters

Year	Min hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. hourly withdrawal rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure range (kPa)
2021	1.0	21.7	8.3	5.4	10.8	4,500-10,000
2022	1.0	21.7	8.3	5.4	10.8	4,500-10,000
2023	1.0	23.8	8.3	5.9	11.9	4,500-10,000
2024	1.0	23.8	8.3	5.9	11.9	4,500-10,000
2025	1.0	23.8	8.3	5.9	11.9	4,500-10,000

[90] See https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb.

A4. System operating parameters

A4.1 Critical system pressures

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

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

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

- The system is operating within the requirements of the gas quality procedures, and breaches of the gas quality procedures do not require intervention by AEMO.
- There is no threat to public safety.
- There is no threat to the supply of gas to customers, and system pressures and flows are within, and are forecast to remain within, the agreed operating limits (see Table 36).

Table 36 lists key critical locations and associated pressure obligations (MAOP and minimum operating pressure [MinOP]). This table is required to be published under Rule 323(3)(g), and can also be found in AEMO's Wholesale Market Critical Location Pressures[91].

Table 36 Critical location pressure in the Declared Transmission System

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

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

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of data and comments
Lurgi	2,760	Morwell Porters Rd	2,650	
		Warragul	1,400	AEMO-Distributor Connection Deed
		Pakenham South	1,400	AEMO-Distributor Connection Deed
		Jeeralang GPG	2,500	
Metropolitan Ring Main	2,760	Dandenong Terminal Station	2,650	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Dandenong North	2,500	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Brooklyn (Melbourne side)	1,700 1,800	AEMO-Distributor Connection Deed Brooklyn compressor suction min pressure requirement
		Keon Park	2,200	AEMO-Distributor Connection Deed
		Newport GPG	1,800	
		Somerton GPG	2,000	
Wollert to Euroa	8,800	Wandong PRS inlet	3,700	APA design parameter
Euroa to Wodonga	7,400	Wodonga	2,400	AEMO-Distributor Connection Deed
		Shepparton	2,400	AEMO-Distributor Connection Deed
		Echuca	1,200	AEMO-Distributor Connection Deed
		Rutherglen	2,400	AEMO-Distributor Connection Deed
		Koonoomoo	1,200	AEMO-Distributor Connection Deed
Victorian Northern Interconnect	10,200	Euroa CS Inlet	4,500	APA design parameter
		Springhurst CS Inlet	4,500	APA design parameter
		Culcairn	2,700	Connection Agreement
Brooklyn Corio Pipeline	7,390 5,150 MOP	Corio (Avalon, Lara and Werribee)	2,300 w 1,900 s	7,390 kPa Pipeline licence pressure 2,300 kPa during high flow (winter), 1,900 kPa during low flow (summer), Distributor Connection Deed
		Coogee Methanol	1,800	
		Laverton North GPG	1,700	

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of data and comments
Brooklyn Lara Pipeline	10,200	Qenos	3,800	3,800 kPa approved AEMO-Distributor Connection Deed (Wyndham Vale & Qenos) Usually controlled >4,500 kPa by BLP CG
Brooklyn Ballan Pipeline	7,400	Sunbury	2,000	AEMO-Distributor Connection Deed
		Ballarat	2,100	AEMO-Distributor Connection Deed
		Plumpton PRS	4,500	APA design minimum pressure
South West Pipeline	10,200	Iona	3,800	Connection Agreement Operational maximum pressure of 9,500 kPa applies due to operating limits at the plant
		SEA Gas	3,800	Connection Agreement
		Winchelsea Inlet	4,000	APA Design Parameter
		Colac	3,800	APA Group-Distributor Connection Deed
Western Transmission System	7,400	Iluka	2,500	APA Group-Distributor Connection Deed
		Portland	2,800	AEMO-Distributor Connection Deed
Wandong to Bendigo	7,390	Bendigo	3,000	AEMO-Distributor Connection Deed
		Maryborough	3,000	AEMO-Distributor Connection Deed
		Carisbrook	3,000	AEMO-Distributor Connection Deed

A4.1.1 Compressor utilisation in 2020

Table 37 lists the hours of usage for each DTS compressor station by month for 2020, and 0 compares the total operating hours by compressor stations from 2018 to 2020. Key points are:

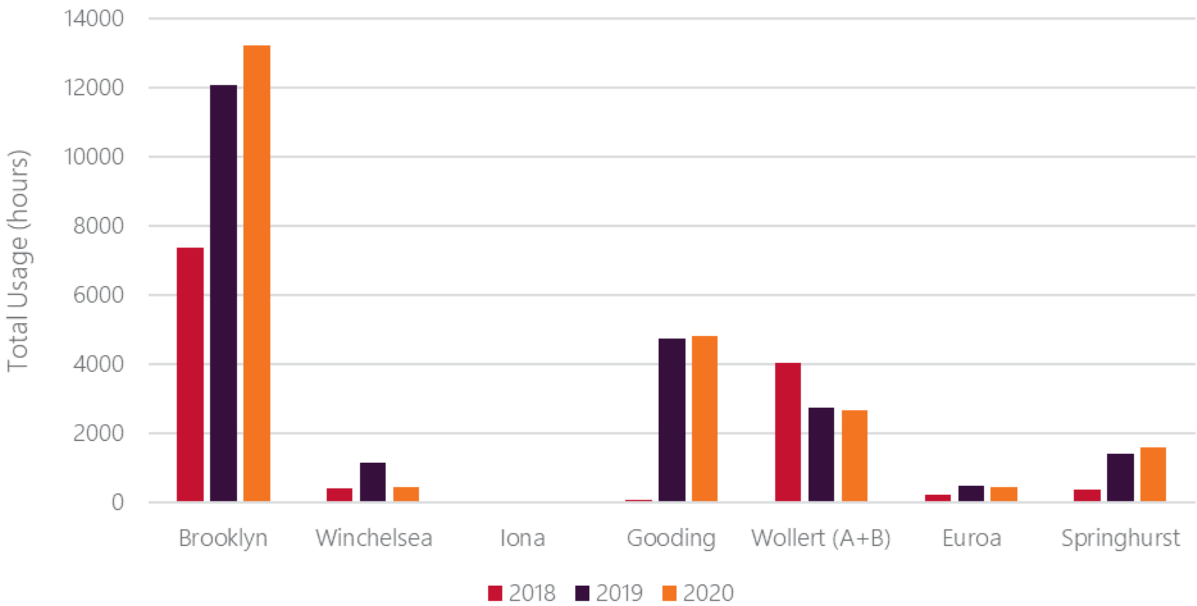
- The most utilised compressors in the DTS in 2020 were the Brooklyn compressors, which have been heavily used to support Iona UGS refill over the lower demand period and are also used to support Ballarat and Geelong demand during winter. Compared to 2018 and 2019, usage of the Brooklyn compressors in 2020 increased, due to a reduction in injections from Iona CPP into the DTS throughout the winter period, and an increased requirement to run Brooklyn compression to maintain supply to the Geelong, Western and Ballarat zones.
- The usage of Wollert compressors has reduced due to less gas being exported from the DTS into New South Wales during the summer period.
- The usage of Springhurst and Euroa compressors[92] has increased, to support an increased level of injections through Culcairn into the DTS during the winter period, which has also resulted in reduced Wollert compression during winter.

[92] Note that the Euroa and Springhurst compressors are bi-directional.

Table 37 Total operating hours by compressor station, 2020

Compressor station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn	1,022	964	780	499	1,134	1,485	1,516	1,606	1,877	794	950	608
Euroa	0	0	0	0	14	51	205	76	25	14	12	71
Gooding	5	2	1	15	583	1,423	1,444	1,230	106	10	0	4
Iona	0	0	2	0	3	18	2	0	8	2	0	1
Springhurst	0	0	2	0	88	416	571	351	87	18	12	45
Winchelsea	0	88	0	0	54	49	21	124	86	23	6	0
Wollert	94	135	206	271	233	87	61	110	101	329	449	608

Figure 36 Total operating hours by compressor station, 2018-20



A5. DTS service provided assets, maintenance and system augmentations

A5.1 Critical DTS assets

Critical assets in the DTS are considered the assets required to maintain system security on peak demand days. Table 38 outlines these assets by SWZ and operational purpose.

Table 38 Critical DTS assets

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

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

A5.2 DTS service provider proposed maintenance schedule

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

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

AEMO, under Rule 326, coordinates maintenance planning of the DTS with the DTS service provider on a weekly basis. The DTS service provider's maintenance schedule for 2019 and the capacity impact is shown in Table 39. The maintenance is scheduled to minimise impacts to DTS capacity. The import and export transmission capacities shown in the table are based on a monthly 1-in-2-year peak system demand day.

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

Table 39 Planned maintenance for 2021, as at 18 February 2021

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
Melbourne	Brooklyn Compressor Station	Unit 10	13-17 September 2021	-	-	Up to five days unit outage, with eight-hour recall time. No impact to capacity – reduced redundancy at Brooklyn CS.
		Unit 12	1-16 March 2021	-	-	Up to two-week unit outage, with no recall time. No impact to capacity – reduced redundancy at Brooklyn CS.
		Full Station	15-19 March 2021	-	0	Total station outages for four days. Recall time of four hours.
		Full Station	8-19 November 2021	-	0	Total station outage for two days, followed by Unit 8,9,10 & 11 outage for 12 days No recall.
	Wollert Compressor Station	Station A and B	12-13 October 2021	-	0	Total station outage for two days over the maintenance period. Recall time of four hours.
		Station B	11-15 October 2021	-	103	Total station outage for five days over the maintenance period. Recall time of four hours.
		Station A	4-8 October 2021	-	223	Total station outage for five days over the maintenance period.
		Unit 4	20-24 September 2021	-	180	Up to five days unit outage, with eight-hour recall.
		Unit 5	27 September to 1 October 2021	-	180	Up to five days unit outage with eight-hour recall.

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
		Station B	12 May	-	103	One day outage, No recall.
Geelong	Winchelsea Compressor Station		3-7 May 2021	249	125	Total station outage for five days over the maintenance period. Recall time of four hours.
			15-19 March 2021	249	125	Total station outage for five days over the maintenance period. Recall time of four hours.
			8-12 November 2021	282	122	Up to five days unit outage, with eight-hour recall time.
Gippsland	Gooding Compressor Station		11 March – 1 April 2021	720	-	Total station outage for 22 days over the maintenance period. No recall time.
Northern	Euroa Compressor Station		1-5 March 2021	181	172	Total station outage for five days over the maintenance period. Recall time four hours.
			13-17 September 2021	202	172	Up to five days unit outage, with eight-hour recall time.
	Springhurst Compressor Station		26-30 April 2021	139	172	Total station outage for five days over the maintenance period. Recall time four hours.
			22-26 November 2021	139	172	Up to five days unit outage, with eight-hour recall.
Western	Iona Connection Point		8-28 April 2021	0	0	APA conducting an upgrade of the Iona Connection point into the DTS, Coincides with the Iona Plant outage. No recall.
	Iona Compressor Station	Unit 1	17-21 May 2021	-	-	Up to five days unit outage, with eight-hour recall time.
		Unit 2	24-28 May 2021	-	-	Up to five days unit outage, with eight-hour recall time.
		Full Station	22-26 November 2021	-	-	Up to five days unit outage, with eight-hour recall time.

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

A5.3 Other proposed maintenance

The DTS service provider will be performing a series of pipeline inspections (pigging) works during 2021:

- T18 (Inner Ring-main) pipeline pigging in March 2021.
- T33 (South Melbourne to Brooklyn) pipeline pigging in April 2021.
- T64 (Newport lateral) pipeline pigging mid-2021.
- T37 (Maryvale lateral) pipeline pigging second half of 2021.
- T63 (Tyers to Morwell) pipeline pigging second half of 2021.

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

A6. Victorian gas planning approach

A6.1 DTS system withdrawal zones

The DTS is divided into six zones, shown in Figure 37:

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

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

A6.2 Victorian gas planning criteria

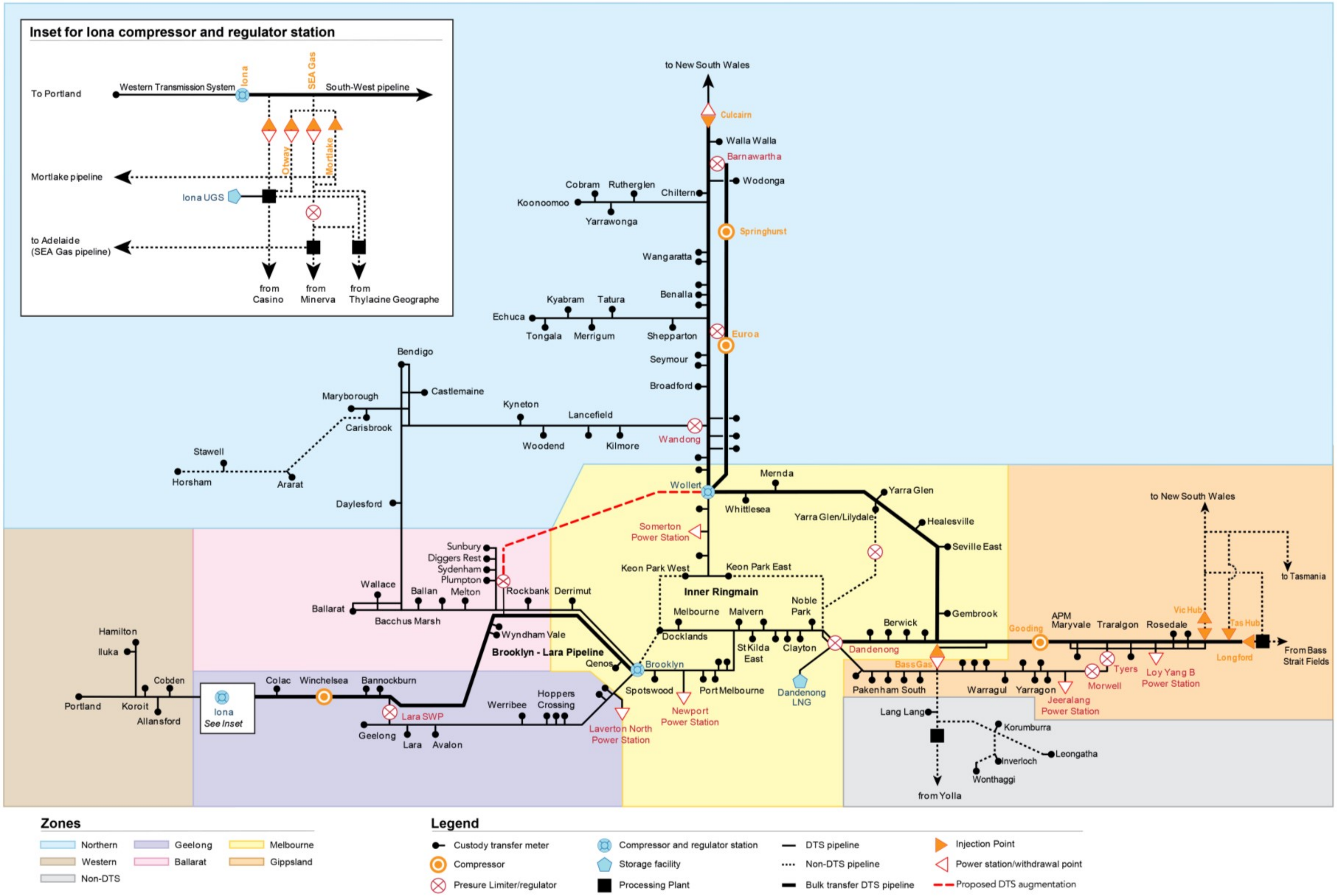
Under Rule 323(1), AEMO must publish a planning review, *"by no later than 31 March 2015 and by 31 March in every second year thereafter"*.

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

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

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

Figure 37 System withdrawal zones in the DTS



A6.3 Victorian gas planning methodology

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

Figure 38 shows an overview of the gas planning methodology, and Table 40 provides more detail for the numbered steps.

Figure 38 Gas planning methodology overview

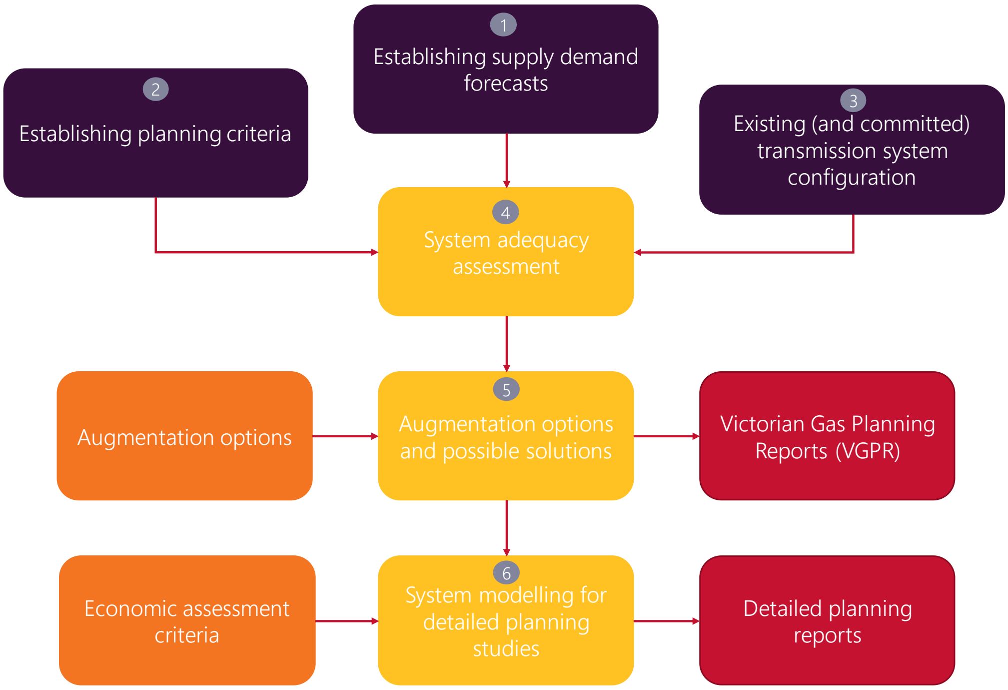


Table 40 Gas planning methodology summary

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

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

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

A6.4 Planning assumptions

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

- Table 41 to Table 44 list the standard modelling assumptions used by AEMO.
- AEMO used assumptions for capacity modelling for SWP (Table 45) and Northern zone export (Table 46).
- An additional modelling assumption reflected known injection point capabilities at each injection point.
- To better reflect real-world conditions, the adequacy of the system to meet peak demand was modelled using typical beginning-of-day (BoD) linepack[93] (lower than the linepack target) and surprise cold weather[94].

Modelled maximum capacities can only be realised with reliable demand forecasting and operating conditions (on the day) that are similar to the model's assumptions. Extreme high demand days that test system capacity are often also surprise cold days, where scheduling is not optimum and maximum capacities cannot be realised. On peak days, the level of linepack and the BoD operating conditions are also critical. Modelled system capacity is based on pressures less than MAOP which optimise operational capabilities.

A6.4.1 Supply assumptions

Table 41 and Table 42 list assumptions relating to the supply of gas to the DTS.

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

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

Table 41 Gas DTS supply modelling assumptions

Supply assumptions and conditions	Notes
Longford injections at flat hourly profile	Normal operating condition.
VicHub and TasHub injections at flat hourly profile	Normal operating condition.
Iona and SEA Gas injection at flat hourly profile	Normal operating condition.
NSW injection at Culcairn at flat hourly profile	Normal operating condition.
Dandenong LNG contracted vaporisation rate at 100 t/h for 16 hours	For peak shaving purposes to support critical system pressures, LNG is effective only up to 10.00 pm. Modelling assumed 16 hours LNG, equivalent to 88 TJ.
LNG receiving terminal injections at flat hourly profile	Applies to both Eastern LNG terminal and Western LNG terminal sites.

Table 42 Gas DTS modelling heating values

Location	Heating value (Megajoules/m^3)
Longford	38.67
BassGas	38.63
Iona (winter)	37.95
Iona (summer)	37.60
NSW injection at Culcairn	37.25
Dandenong LNG	39.11
LNG import terminals	37.52

A6.4.2 Demand assumptions

Table 43 lists assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table 43 Gas DTS demand modelling assumptions for 1-in-20 peak system demand day

Demand assumptions	Notes
Load profiles calculated by AEMO	Calculated from historical flow data for each custody transfer meter.
Load distribution as per AEMO forecasts	Based on historical custody transfer meter data and expected system configuration changes.
Supply to Horsham pipeline at Carisbrook	Carisbrook to Horsham pipeline modelled with demand at Ararat, Stawell, Horsham (connected in 1998). The minimum pressure requirement at Horsham is 1,200 kPa (AusNet design requirement).
Transmission UAFG determined at Longford	Calculated from calibrated model data.
BOC liquefaction operating, let-down gas operating	Full supply to this customer is normally required.
Existing GPG demand (open-cycle gas turbine [OCGT])	A 30 TJ/d total GPG demand profile.

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

Tariff D and Tariff V[95] load changes are based on demand forecasts, existing GPG demand is based on GPG capacity for 1,300 TJ/d with historical load profiles, and future GPG demand is based on known GPG development proposals (which are checked for consistency with the ISP and with the DTS service provider, for any committed connections to the DTS).

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

A6.4.3 Impact of operational factors modelling assumptions

Table 44 lists the assumptions relating to operation of the DTS and assist with the management of linepack and constraints specified in various agreements.

Table 44 Impact of operational factor modelling assumptions

Location	Operational assumptions	Notes
Longford	Maximum pressure is 6,750 kPa.	To conform to normal operating practice. Assumed to peak momentarily at 6,750 kPa before reducing again.
	Minimum pressure is 4,500 kPa.	
Iona	Maximum pressure is 9,500 kPa.	As per pipeline licences, operating agreements and practice.
	Minimum pressure is 4,500 kPa.	
Culcairn	For exports, minimum pressure is 8,600 kPa for free flow cases. For imports, maximum pressure is 6,500 kPa, and minimum pressure is 4,500 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions. For exports below 172 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports.
Brooklyn–Lara Pipeline	Minimum pressure is 4,500 kPa.	Pipeline design requirement for BLP.
Brooklyn CG	Minimum pressure is 3,200 kPa.	Normal operating condition.
Dandenong CG	Minimum pressure is 3,200 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
	Maximum allowable operating pressure (MAOP) and delivery pressures in connection and service envelope agreements not infringed.	Service Envelope Agreement and Connection Deed requirements (for example, a minimum 3,100 kPa at the DCG).
Wollert CG	Minimum pressure is 3,000 kPa.	Normal operating condition.
Other factors	BoD and end-of-day (EoD) linepack are equal.	For capacity modelling, mining of linepack not allowed.
	BoD linepack 20 TJ below target[A].	Used for lateral constraint modelling.
	DTS service provider's pipeline, regulator and compressor assets and operating conditions as specified in the Service Envelope Agreement.	Agreement between the DTS Service Provider and AEMO.

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

Location	Operational assumptions	Notes
	BoD and EoD pressures similar at key network locations.	Required for system security.
	Regulators, compressors, and valves are set to reflect operational guidelines.	Required for operational and system security reasons.
	Gas delivery temperature above 2°C.	Gas Quality Regulations requirement.

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

A6.4.4 Capacity modelling assumptions

Modelling assumptions are listed in Table 45 for SWP capacity (both with and without the WORM), and 0 for Northern capacity. Under different operating conditions on the day, the capacity result may differ.

Table 45 SWP capacity modelling assumptions both with and without the WORM

SWP capacity assumptions		Notes
Injections		For SWP to Melbourne: • Maximum injection from Iona and the rest will be supplied from Longford and/or BassGas for all cases. For SWP to Port Campbell: • Maximum injection from Longford and/or BassGas for all cases. For WORM: • No limit on Longford CPP injection capacity.
GPG demand		Without the WORM: • No GPG demand for all cases at Laverton North and Newport. With the WORM: • GPG demand for all cases varied as agreed between AEMO and the DTS Service Provider.
Dandenong LNG		LNG was required to maintain system security for the 1-in-2 and 1-in-20 system demand day for SWP withdrawal cases with the WORM.
Culcairn flows		Export demand of 100 TJ/d was used for system demand up to 800 TJ/d. Above 800 TJ/d, 50 TJ/d of supply from Culcairn was assumed.
Compressors		For SWP to Melbourne: • For the case with Winchelsea compressor in place, the target compressor outlet was set to 10,200 kPa; compressor would control on maximum power during model runs. For SWP to Port Campbell: • Capacity for varying compressor configurations at Brooklyn was determined to manage outages. With WORM: • Capacity assumed all compressors available, including an additional Centaur 50 at Wollert, unless otherwise stated.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	**Iona**	Maximum pressure is 9,500 kPa. Pressure not allowed to increase over the modelling period. Minimum pressure is 4,500 kPa.
	DCG	Minimum pressure is 3,200 kPa.

SWP capacity assumptions		Notes
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.
	Ballarat CG[A]	Minimum pressure is 2,100 kPa.

Table 46 Northern capacity modelling assumptions and conditions

Northern capacity assumptions		Notes
Injections		Maximum injection from Longford does not exceed 970 TJ/d. The rest will be supplied from Iona and/or BassGas for all cases.
GPG demand		GPG demand for all cases varied as agreed between AEMO and the DTS Service Provider.
Dandenong LNG		LNG was required to maintain system security for the 1-in-20 system demand day case.
Compressors		Capacity for varying compressor configurations was determined, to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Northern zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Culcairn	Modelled minimum pressure is 8,600 kPa for free flow, or 7,000 kPa utilising Culcairn compressors for Northern export capacity modelling cases. Modelled minimum pressure is 4,500 kPa for Northern import capacity modelling cases.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.
	Wandong CG[A]	Minimum pressure is 3,500 kPa.

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

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

- **Beginning-of-day-linepack**.
  - Linepack is the pressurised gas stored in transmission pipelines throughout the DTS. It varies considerably throughout the day, as it is drawn down from the start of the gas day to balance a fairly constant hourly injection rate with the morning and evening demand peaks. Linepack reaches a minimum by around 10.00 pm. Overnight, injections exceed demand and linepack is replenished until the start of the morning peak at around 6.00 am, when linepack is at its highest level.
- **Demand forecast error**.
  - Daily demand forecast errors occur due to changes in the weather, the inherent uncertainty in predicting system demand, large loads varying from the initial forecast (such as GPG), and weather forecast errors.
  - When actual demand is higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system ability to meet demand. When actual demand is lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the injection points, generally only after the 10.00 pm scheduling horizon, to avoid breaching upper operating limits.
- **Delivery pressure**.

- Supply pressure drives gas through a pipeline. The higher the supply pressure, the higher the average level of linepack and effective system capacity.

- **Injection profiles**.
  - For operational reasons, gas production plants generally operate at a constant injection rate.
  - Varying the injection rate to reflect demand throughout the day can increase the ability to supply demand. In particular, an injection profile with a higher injection rate during the first half of the day can increase gas transport capability.
  - Gas sources that can be injected for short periods at times of high demand, such as LNG, can assist overall system capacity.
- **Demand profiles (temporal distribution)**.
  - During winter, peaking demand in the morning and evening (due to temperature-sensitive load) draws down system linepack. More severe demand profiles, including the presence of spike loads such as GPG, will deplete linepack at a faster rate.
- **Spatial distribution of demand**.
  - System capacity is modelled using forecast load distributions across the DTS. If a specific load is located close to an injection point, the gas transport capability is higher than if the load is located further away.

A6.4.5 LNG receiving terminal assumptions

Modelling assumptions specific to the LNG import terminals are summarised in Table 47 and Table 48 respectively. In these models, it was assumed that the WORM and associated compressors and regulators (see Chapter 5) were commissioned and operational.

Table 47 Eastern LNG receiving terminal modelling assumptions

<table>
<tr><th colspan="2">Operational assumptions</th><th>Notes</th></tr>
<tr><td colspan="2">Injections</td><td>Maximum injection from Eastern LNG receiving terminal, with the rest supplied from Longford, Iona and BassGas for all cases</td></tr>
<tr><td colspan="2">Culcairn flows</td><td>Export demand of 100 TJ/d was used for system demand up to 800 TJ/d.
Above 800 TJ/d, 50 TJ/d of supply from Culcairn was assumed.</td></tr>
<tr><td colspan="2">GPG Demand</td><td>GPG demand for all cases varied as agreed between AEMO and the DTS service provider.</td></tr>
<tr><td colspan="2">Dandenong LNG</td><td>LNG was required to maintain system security for the 1-in-2 and 1-in-20 peak system demand day for SWP withdrawals.</td></tr>
<tr><td colspan="2">Linepack</td><td>BoD and EoD linepack are equal for system demand and Geelong zone.
For capacity modelling, mining of linepack not allowed.</td></tr>
<tr><td colspan="2">Compressors</td><td>Capacity determined assumed all DTS compressors are available, including Wollert 6 installed as part of the WORM project.</td></tr>
<tr><td rowspan="4">Critical pressure points</td><td>Eastern LNG</td><td>Maximum injection pressure is 6,750 kPa.
Minimum injection pressure is 4,500 kPa.</td></tr>
<tr><td>DCG</td><td>Minimum pressure is 3,200 kPa</td></tr>
<tr><td>Sale CG</td><td>Minimum pressure is 5,000 kPa.</td></tr>
<tr><td>Wollert CG</td><td>System demand ≤ 1,150 TJ is set to 2,550 kPa.
System demand ≥ 1,150 TJ is set to 2,650 kPa.</td></tr>
</table>

Table 48 Western LNG receiving terminal modelling assumptions

Operational assumptions		Notes
Injections		Maximum injection from Western LNG receiving terminal, with the rest supplied from Longford, Iona and BassGas for all cases. No limit on Longford CPP injection capacity.
Culcairn flows		Export demand of 100 TJ/d was used for system demand up to 800 TJ/d. Above 800 TJ/d, 50 TJ/d of supply from Culcairn was assumed.
GPG Demand		GPG demand for all cases varied as agreed between AEMO and the DTS service provider.
Dandenong LNG		LNG was not required for any system demand cases.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Compressors		Capacity determined assumed all DTS compressors are available, including Wollert 6 installed as part of the WORM project.
Critical pressure points	**Western LNG**	Maximum injection pressure is 9,500 kPa. Minimum injection pressure is 4,500 kPa.
	DCG	Minimum pressure is 3,200 kPa.
	Sale CG	Minimum pressure is 5,000 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.

A6.4.6 Seasonal variations in DTS capacity

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

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

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

Measures, abbreviations and glossary

Units of measure

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

Abbreviations

Abbreviation	Expanded name
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AIE	Australian Industrial Energy
BCP	Brooklyn–Corio Pipeline
BLP	Brooklyn–Lara Pipeline
BoD	Beginning-of-day

Abbreviation	Expanded name
CG	City Gate
CPP	Close proximity point
CS	Compressor Station
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EDD	Effective Degree Day
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
EOD	End-of-day
ESV	Energy Save Victoria
FID	Final Investment Decision
FSRU	Floating storage and regassification unit
GBJV	Gippsland Basin Joint Venture
GJ/hr	Gigajoules per hour
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
ISP	Integrated System Plan
kPa	Kilopascal/s
KUJV	Kipper Unit Joint Venture
LEU	Large Energy Users
LNG	Liquified natural gas
MAOP	Maximum allowable operating pressure
MDQ	Maximum daily quantity/ies
MinOP	Minimum operating pressure
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
PJ	Petajoule/s
PJ/m	Petajoules per month
PKGT	Port Kembla Gas Terminal
POE	Probability of exceedance

Abbreviation	Expanded name
PRMS	Petroleum Resources Management System
PRS	Pressure reduction station
PV	Photovoltaic/s
SEA Gas	South East Australia Gas (pipeline)
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zone
TJ	Terajoule/s
TJ/d	Terajoules per day
TJ/hr	Terajoules per hour
TJ/m	Terajoules per month
TJ/y	Terajoules per year
TTSS	Threat to System Security
UAFG	Unaccounted for gas
UGS	Underground Storage
VEU	Victorian Energy Upgrades
VGPR	Victorian Gas Planning Report
VNI	Victorian Northern Interconnect
VRE	Variable renewable energy
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.
connection point	A gas delivery point, transfer point, or receipt point.
Culcairn	The gas transmission network interconnection point between Victoria and New South Wales.

Term	Definition
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
custody transfer meter	A meter installed at a connection point to measure gas withdrawn from or injected into a transmission system.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the DWGM) or may be registered as market participants in their own right.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the *National Gas (Victoria) Act*, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Transmission System constraint	A constraint on the gas Declared Transmission System.
Declared Wholesale Gas Market (DWGM or market)	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.
distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
Gas Statement of Opportunities	The Gas Statement of Opportunities (GSOO) published annually by AEMO.
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.

Term	Definition
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 (CH_4) (between 95% and 99%) and ethane (C_2H_6).
participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
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 x 10^{15} 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.
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.
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.
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

Term	Definition
	consuming more than 10 TJ of gas per annum). It excludes gas powered generation (GPG) demand, exports, and gas withdrawn at Iona.
system injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas Declared Transmission System (gas DTS) connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
system withdrawal zone	Part of the gas Declared Transmission System (gas DTS) that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Tariff V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial gas consumers.
Tasmanian Gas Pipeline	The pipeline from VicHub (Longford) to Tasmania.
terajoule	Terajoule (TJ). An International System of Units (SI) unit, 1 TJ equals 1 x 10^{12} 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.