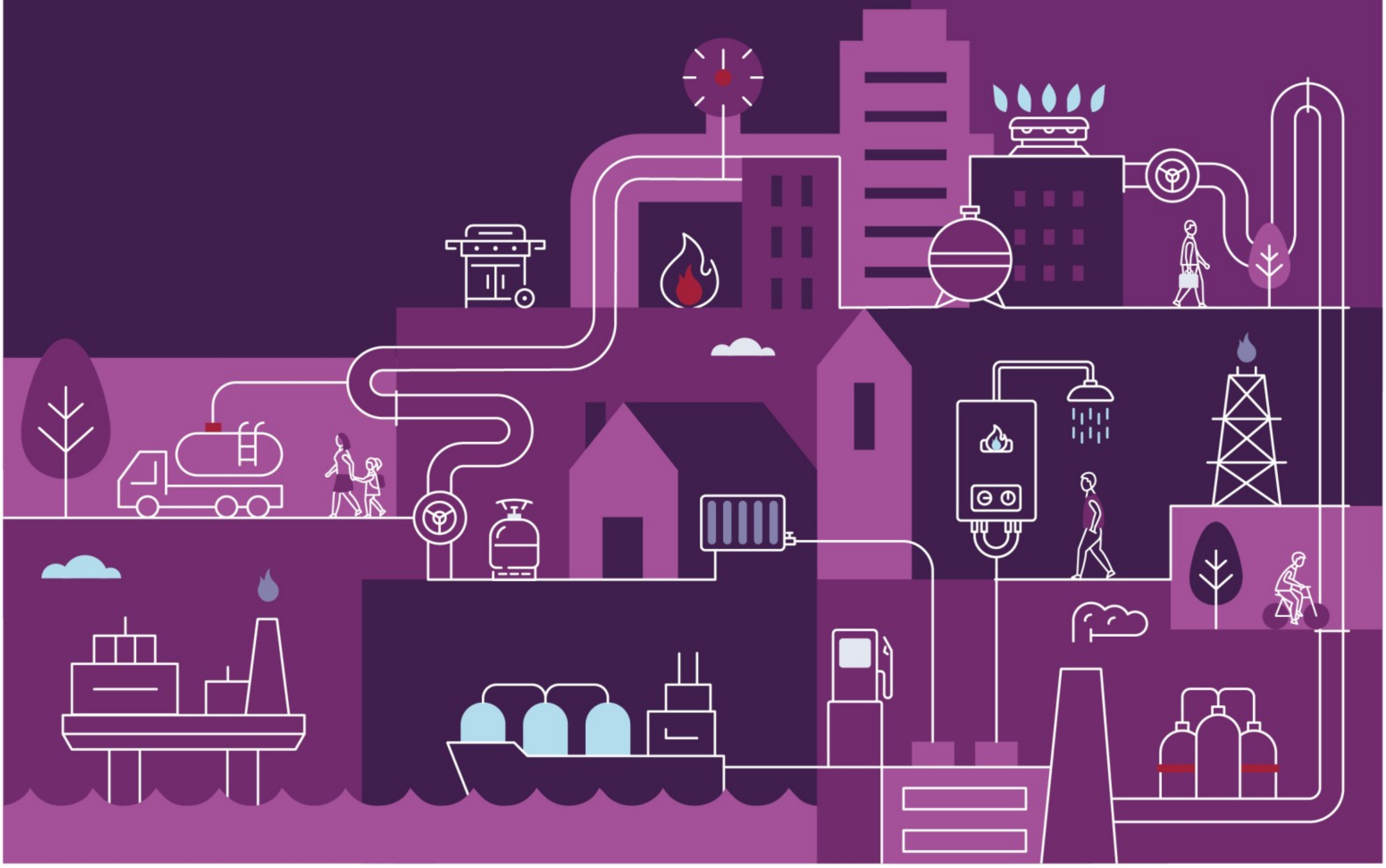
# Victorian Gas Planning Report Update

March 2022

Gas transmission network planning for Victoria



# Important notice

## Purpose

AEMO publishes this Victorian Gas Planning Report Update (March 2022) in accordance with rule 323 of the National Gas Rules.

This publication has been prepared by AEMO using information available at 1 March 2022. Information made available after this date may have been included in this publication where practical.

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## Acknowledgement

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


### Version control

| Version | Release date | Changes |
|---|---|---|
| 1 | 29/3/2022 | Initial release |

# Executive summary

The 2022 *Victorian Gas Planning Report* (VGPR) Update provides information about the supply demand balance over the next five years (2022-26, called the outlook period) in Victoria, and the Victorian Declared Transmission System (DTS). The 2022 VGPR Update complements AEMO's 2022 *Gas Statement of Opportunities* (GSOO), which assesses the wider gas supply adequacy in eastern and south-eastern Australia.

## Key findings

- **Uncertainty about future gas needs** impacts adequacy assessments – consumption and demand forecasts, and the level of risk to adequacy of supply, vary across plausible scenarios as early as next year.
- Demand uncertainty is reflected in the market's **unwillingness to contract for future supply**. In the 2021 VGPR and GSOO, the 500 terajoules per day (TJ/d) Port Kembla Energy Terminal (PKET) project was classified as a committed project, with supply available from the start of winter 2023. AIE and Jemena have advised that while they remain committed to the construction of the wharf and associated pipeline infrastructure, the project works will now not be completed until late 2023. AEMO currently considers PKET as anticipated supply for winter 2024, due to the uncertainty that sufficient capacity will be contracted to justify the relocation and operating expenses of the floating storage and regasification unit (FSRU).
- **Risks to peak day supply adequacy have increased for winter 2022, and peak day and seasonal adequacy risks are forecast to emerge as soon as 2023.**
  - 2022 peak day supply is sufficient to meet forecast peak day demand, although forecast supply capacity is lower than for winter 2021. There is also an increased probability of outages at the Longford Gas Plant due to equipment retirement at the end of 2021.
  - Winter 2023 peak day supply capacity (including firm rate Dandenong liquified natural gas [LNG] and assuming no net imports from New South Wales) is just above the forecast 1-in-20-year peak day system demand under both the *Step Change* and *Progressive Change* scenarios. The 2022 GSOO forecasts that extreme gas demand (including gas generation) in severe cold weather may exceed supply available in Victoria and New South Wales from winter 2023.
  - Unplanned capacity reductions of production, storage or transmission facility capacity, higher gas generation demands than forecast due to co-incident or prolonged coal-fired generator outages, or the delayed completion of the Western Outer Ring Main (WORM) project may result in insufficient peak day or seasonal supply capacity from 2023.
  - There are no anticipated supply solutions that can be developed prior to winter 2023. Duplication of the Winchelsea compressor on the South West Pipeline (SWP) may be possible. In the absence of higher than forecast Longford gas production, options to mitigate the peak day shortfall risk are limited to demand response, including curtailment.
  - Although available annual Victorian production is sufficient to meet forecast annual DTS demand in 2026, the seasonal winter demand may exceed available production and storage capacity.
  - Development of anticipated supply projects from 2024 helps mitigate peak day, seasonal and annual supply risks.

- **Although the supply outlook has improved since the 2021 VGPR, Victorian production continues to decline**, with a large forecast reduction in capacity prior to winter 2023. Total available (existing plus committed) production is forecast to reduce from 360 petajoules (PJ) in 2022 to 243 PJ in 2026. Total available peak day supply capacity is forecast to reduce from 1,552 TJ/d in 2022 to 1,125 TJ/d in 2026.
- **Timely completion of the WORM** is also required to support declining resilience in the DTS and peak day supply adequacy, and to manage locational supply issues that emerge in late 2023 due to a planned one day complete outage of the Longford Gas Plant, and longer future full plant outages of up to one month.
- AEMO has observed **that participant contracted volumes of Dandenong LNG services have remained low,** and are insufficient to respond to both operational and emergency scenarios. If market participants do not increase their contracted quantities to cover expected operational requirements, there is a high likelihood of curtailment being required, particularly on high demand days or when there is unforecast gas generation. **AEMO has identified this low Dandenong LNG inventory as a threat to system security and is seeking a market response.**
- The system capability modelling for determining the amount of capacity certificates available for allocation under the new Declared Wholesale Gas Market (DWGM) entry and exit capacity certificate regime is included in this report.

## Gas consumption forecasts

This VGPR Update considers two forecasting scenarios set out in the 2021 *Inputs Assumptions and Scenarios Report* (IASR) – *Step Change* and *Progressive Change*. Both assume net zero emissions by 2050.

The gas consumption forecast diverges across the two scenarios:

- The *Step Change* scenario represents a future with rapid consumer-led transformation of the energy sector, and a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions (including electrification of gas heating load), driven by consumer-led change with a focus on energy efficiency, digitalisation and step increases in global emissions policy above what is already committed. Under this scenario, AEMO is forecasting a reduction of 16.8% in annual gas consumption in the outlook period (**Table 1**), and peak day system demands are forecast to reduce by approximately 18%.

**Table 1 Victorian gas consumption forecast, *Step Change* (PJ)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **System consumption** | 191.8 | 185.3 | 175.4 | 174.9 | 163.7 | -14.6% |
| **DTS gas generation consumption** | 7.8 | 7.1 | 4.0 | 3.5 | 4.4 | -43.0% |
| **Total DTS consumption** | 199.5 | 192.3 | 179.4 | 178.4 | 168.2 | -15.7% |
| **Non-DTS system consumption** | 1.4 | 1.4 | 1.3 | 1.2 | 1.1 | -25.6% |
| **Non-DTS gas generation consumption** | 9.7 | 8.6 | 5.7 | 5.0 | 6.0 | -37.7% |
| **Total Victorian consumption** | 210.6 | 202.4 | 186.4 | 184.6 | 175.3 | -16.8% |

- Under the *Progressive Change* scenario, representing a future that delivers action towards net zero emissions through technology advancements and based on current state and federal government environmental and energy policies, AEMO is forecasting a 1.9% decrease in Victoria's annual total gas consumption over the next five years (**Table 2**), with peak system demand remaining near current levels. Key drivers include energy efficiency savings due to the Victorian Energy Upgrades[1] (VEU) scheme and a continuing increase in the number of new connections during the outlook period.

**Table 2 Victorian gas consumption forecast, *Progressive Change* (PJ)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **System consumption** | 193.1 | 192.0 | 189.9 | 196.4 | 196.4 | 1.7% |
| **DTS gas generation consumption** | 7.8 | 7.1 | 4.0 | 3.5 | 4.4 | -43.0% |
| **Total DTS consumption** | 200.9 | 199.1 | 193.8 | 200.0 | 200.9 | 0.0% |
| **Non-DTS system consumption** | 1.4 | 1.4 | 1.4 | 1.3 | 1.2 | -19.5% |
| **Non-DTS gas generation consumption** | 9.7 | 8.6 | 5.7 | 5.0 | 6.0 | -37.7% |
| **Total Victorian consumption** | 212.0 | 209.1 | 200.9 | 206.2 | 208.0 | -1.9% |

The most notable change for both scenarios from 2024 is an increase in Tariff D (large commercial and industrial) load in most zones, driven by a forecast uptake in gas consumption for steam methane reforming (SMR), a technology that converts natural gas into hydrogen to support industry, transport, and small amounts of pipeline blending (modelled by the CSIRO[2]).

During consultation for the 2022 *Integrated System Plan* (ISP), stakeholders identified *Step Change* as the scenario they considered to be the most likely pathway for Australia's energy sector. In the absence of significant additional policy commencing, there is also a material risk that in the near term gas use will not reduce in line with the *Step Change* scenario from 2023-26.

The VGPR is primarily a security of supply assessment document, reporting on the forecast supply demand balance and identifying potential risks to that balance. Considering the supply challenges as early as next winter, AEMO has therefore assessed supply adequacy using the both the *Step Change* and *Progressive Change* scenarios in forecasts of consumption and peak demand for the outlook period.

As government policy and electrification of gas heating load progresses, AEMO will refine these scenarios and update its supply adequacy assessments in future reports.

## Annual supply adequacy

Available Gippsland annual production is forecast to reduce from 312 PJ in 2022 and to 200 PJ in 2026. Available Port Campbell production is forecast to increase from 48 PJ in 2022 to 69 PJ in 2023 (2021 actual production was 33 PJ), then forecast to decrease to 42 PJ in 2026.

**Figure 1** shows that:

- Available production (existing and committed[3]) is forecast to reduce each year during the outlook period.
- Forecast available production is higher than the amounts reported in the 2021 VGPR, due to an increase from already producing fields, and newly committed projects, mainly in the Gippsland Zone. This includes further

[1] The VEU program provides Victorian households and businesses with a range of low and no-cost energy saving options such as lighting and draught sealing as well as subsidies for replacing major appliances like energy efficient hot water systems.

[2] See p 25, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf?la=en.

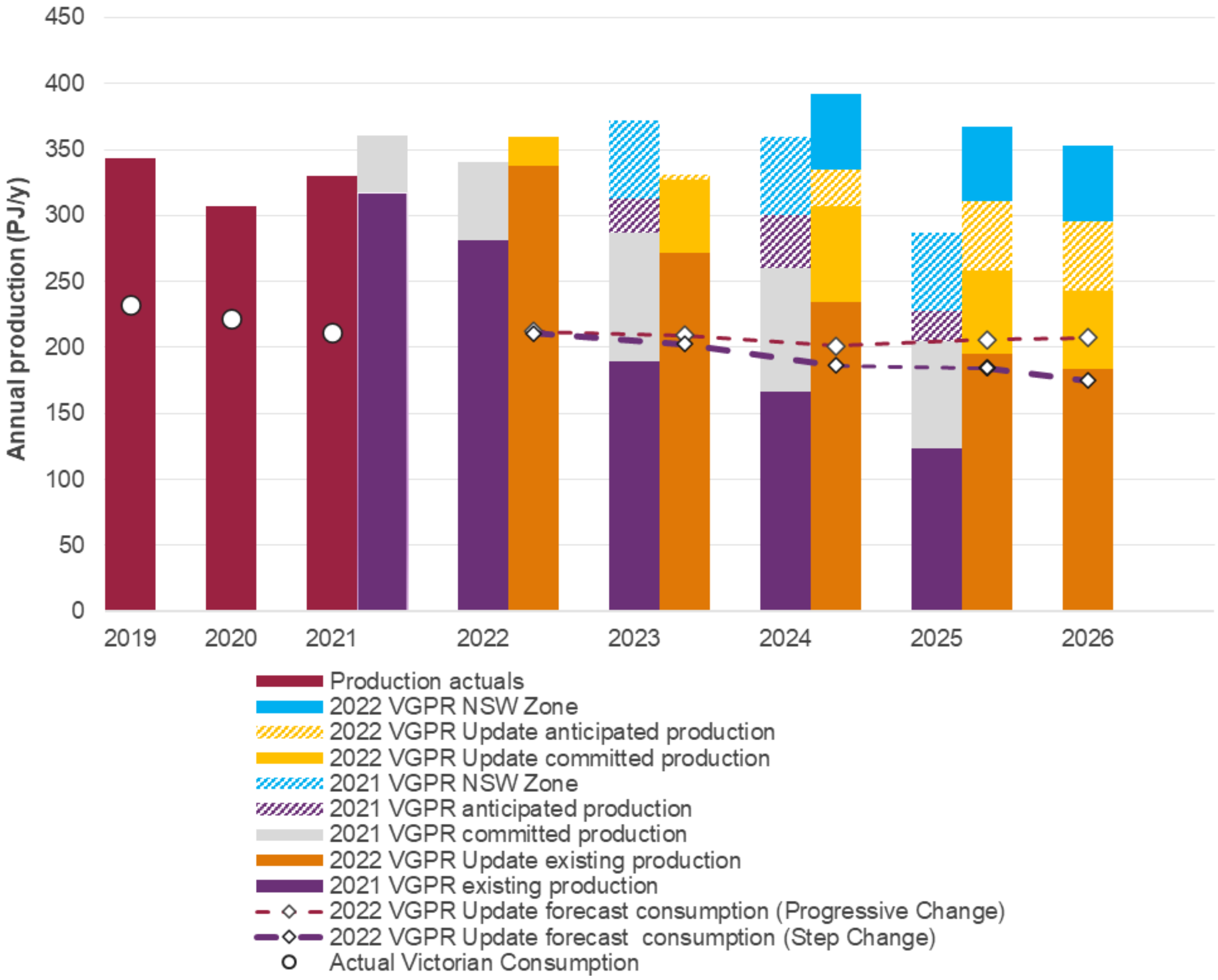
[3] Committed supply considers developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational.

development of the Kipper field (processed through the Longford Gas Plant) that was announced on 17 March 2022[4].

As discussed in the 2021 VGPR, the decline in production is being led by existing fields, predominantly from the Gippsland Zone. Total available supply is lower in 2023 than reported last year due to the delay and change in classification of the PKET project.

There are several projects being considered that could add to anticipated supply[5] from 2024 and greatly offset decline over the outlook period. The addition of PKET to New South Wales supply, now anticipated from 2024, is also expected to provide additional gas supply to Victoria in winter via reverse flow on the Eastern Gas Pipeline (EGP) via VicHub. Increased supply via the Culcairn interconnection is also possible.

**Figure 1 Annual production and supply outlook**




Note: The reduction in consumption from 2019 to 2021 shown in Figure 1 was mainly due to reduced gas generation.

[4] ExxonMobil, "Esso Australia to Expand Gas Development in the Gippsland Basin", 17 March 2022, at https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2022/Esso-Australia-to-Expand-Gas-Development-in-the-Gippsland-Basin.

[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.

Although available annual Victorian production is sufficient to meet forecast annual DTS demand in 2026, other jurisdictions require flows from Victoria throughout the year, and the seasonal winter demand may exceed available production and storage capacity. Seasonal adequacy is discussed in the next section.

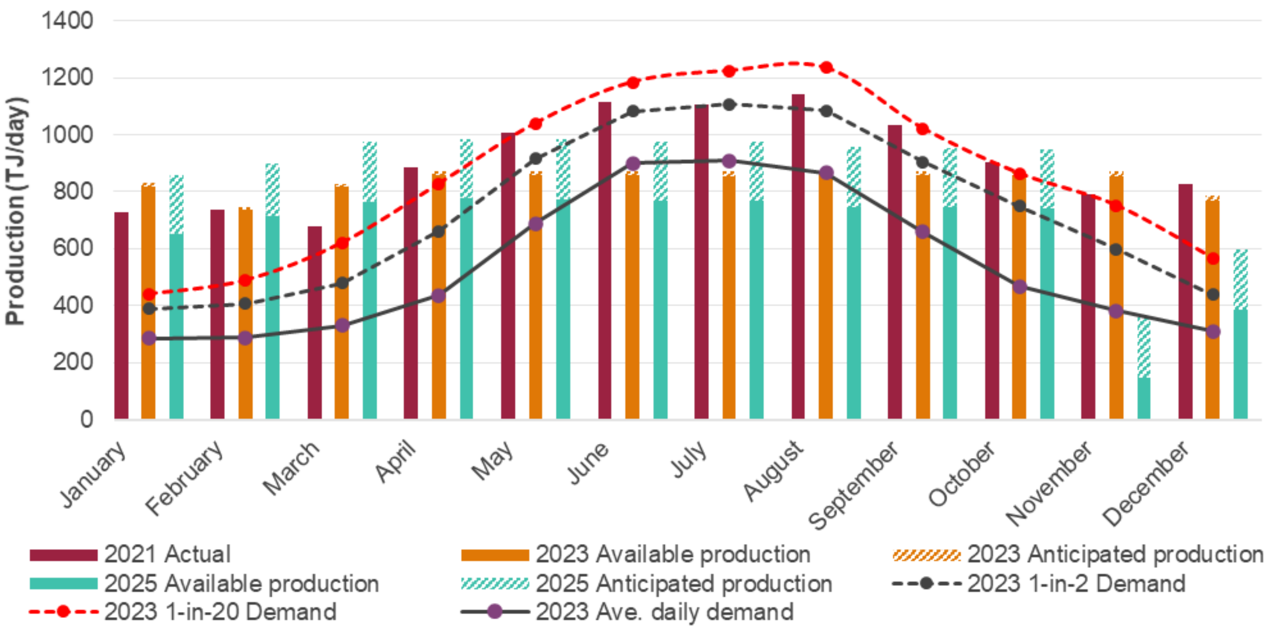
## Monthly supply adequacy

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. This additional gas along with supply from the Iona underground gas storage (UGS) and from Queensland is used to support winter gas use in Victoria and the other southern states. Most other production facilities operate at a flat production rate all year, limited by either the processing capacity of the facility or the supply capacity of connected gas fields.

**Figure 2** shows forecast production in 2023 and 2025, compared to 2021 actuals and the *Progressive Change* demand forecasts for 2023. Demands under the *Step Change* scenario in 2023 are forecast to be approximately 3% lower.

The figure highlights that, from 2023 there is a large reduction in Victorian gas production capacity, particularly during the winter peak demand period due to decreased Longford capacity. Future gas production is forecast to provide a flatter supply profile that will increase the reliance on flexible sources of supply during winter including Iona UGS.

**Figure 2 Average monthly production actuals, 2021, and average monthly production forecasts, 2023 and 2025 (TJ/d)**



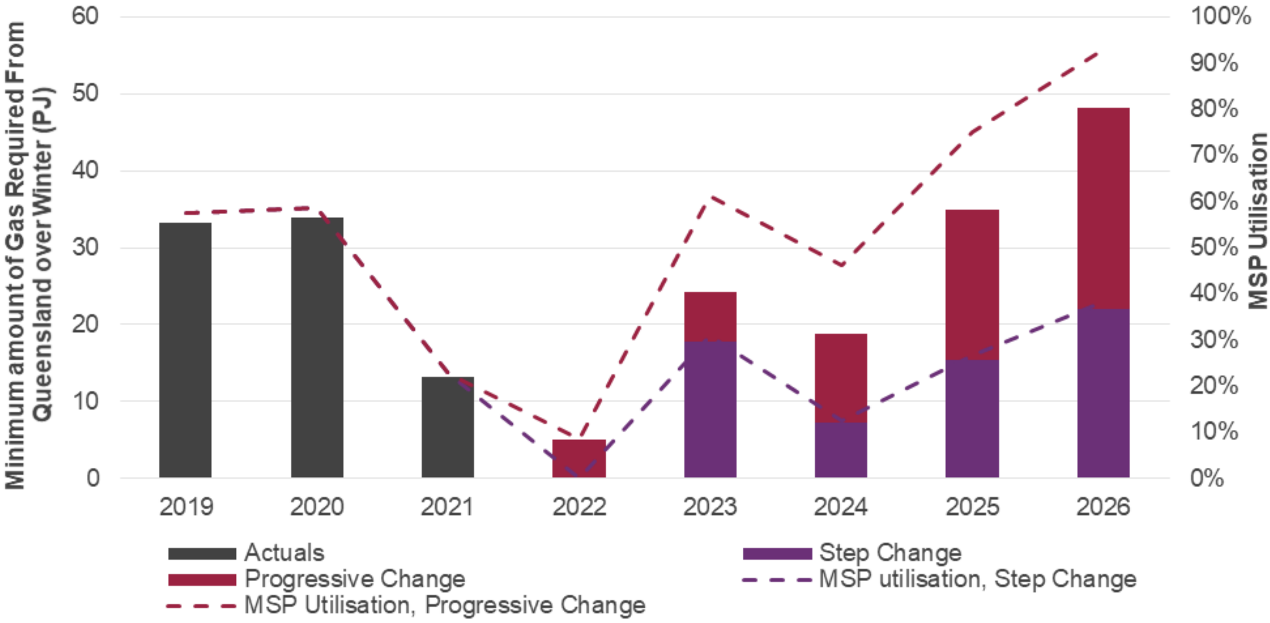

During the winter months, average forecast demand exceeds average production. This means that:

- Supply from Victoria to other jurisdictions will be limited during the winter period.
- Victoria will need to rely on a combination of net imports of gas made available from Queensland and gas held in Iona UGS to satisfy winter seasonal demand, until anticipated projects with sufficient aggregate capacity are developed.

Estimates of the amount of gas that must be made available from Queensland to the southern states[6] over the winter period (**Figure 3**) show that the volume of gas required under the *Progressive Change* scenario in 2026 almost exceeds the available pipeline transportation capacity, indicating a winter supply shortfall risk under this scenario. The volume of gas required under the *Step Change* scenario is less, delaying the shortfall risk until after the outlook period.

Observed flows from Queensland in 2021 were less than in 2019 and 2020 due to increased Victorian production and high international LNG prices. The minimum volumes required in 2022 are less than the actual volume that flowed in 2021 due to a forecast increase in Port Campbell production and a reduction in assumed levels of gas generation in the southern states. There are supply adequacy risks (outlined later in this section) that may increase the required volume of gas from Queensland.

**Figure 3 Historical levels of Queensland gas supply to the southern states (PJ), 2019-21, and forecast minimum required levels, 2022-26**




## Peak day supply adequacy

Peak day supply capacity reduces in line with annual production over the outlook period.

Gippsland peak day supply capacity is forecast to reduce from 1,018 TJ/d in 2022 to 558 TJ/d in 2026. Supply capacity in 2021 was 1,072 TJ/d. Supply available to the DTS is less due to demand on the EGP and in Tasmania that have no other source of supply. This reduces Gippsland supply to 972 TJ/d in 2022 and to 496 TJ/d in 2026. The reduction in supply capacity is driven by the decline in the large legacy Gippsland Basin Joint Venture (GBJV) fields that supply the Longford Gas Plant, which was first highlighted in the 2018 VGPR Update. These large fields are forecast to cease production prior to winter 2023. This will also reduce the resilience of the Longford production system and increase the reliance on other sources of gas supply during plant upsets and unplanned outages.

[6] "Southern states" includes New South Wales, South Australia, Victoria, ACT and Tasmania.

Esso's recently announced further development of the Kipper field is included in these forecasts[7]. This development lessens the reduction in Gippsland capacity between 2023 and 2024 that was reported in the 2021 VGPR. Esso is also advancing funding decisions on optimisation of the Turrum field. Neither the Kipper development nor Turrum optimisation will replace the capacity lost due to the depletion of GBJV's large legacy gas fields.

Port Campbell available peak day supply, which includes supply from the Iona UGS facility, is forecast to increase from 719 TJ/d in 2022 to 803 TJ/d in 2023, then decrease to 725 TJ/d in 2026. This supply capacity at Port Campbell will continue to be restricted by the capacity of the South West Pipeline (SWP[8]), so there is no additional Port Campbell supply capacity into the DTS for winter 2022 compared to last winter.

Port Campbell supply capacity into the DTS is forecast to increase from 447 TJ/d on a 1-in-20-year peak day in 2022 to 476 TJ/d in 2023 following the commissioning of the WORM. The WORM also increases system linepack, which reduces the likelihood of Dandenong LNG being required to support high hourly gas demands including gas generation.

In **Figure 4**, "NSW Zone expected supply" is the expected supply via the Culcairn interconnect into Victoria on peak demand days, as informed by east-coast mass balance and GSOO modelling. It is expected that on peak demand days injections into the DTS via Culcairn will offset Victorian supply to New South Wales via the EGP, resulting in zero net flow between Victoria to New South Wales.

Figure 4 shows that:

- Although there is sufficient peak day supply for winter 2023, the supply demand balance is tight for both the *Step Change* and *Progressive Change* scenarios. Dandenong LNG injections are required to satisfy a 1-in-2-year system demand with moderate gas generation, or a 1-in-20-year system demand[9]. There is likely to be insufficient capacity to support high levels of gas generation on a peak day. The system is unlikely to be able to support the record total demand of 1,308 TJ on 9 August 2019 and may not support the 1,243 TJ of total demand on 4 August 2020 without the curtailment of gas generation. The increased reliance on Dandenong LNG increases the risk of inventory depletion.
- No anticipated supply or DTS augmentations projects are expected to be able to be implemented prior to winter 2023 to improve the supply outlook. Duplication of the Winchelsea compressor, if it was able to be completed prior to winter 2023, would increase SWP capacity by a further 52 TJ/d to 528 TJ/d.
- The supply demand balance for winter 2024 and 2025 is also tight under *Progressive Change*, with Dandenong LNG required to support peak days. Projected falls in Gippsland production capacity are offset by forecast reductions in peak day demand. The supply demand balance tightness is reduced under the *Step Change* scenario with Dandenong LNG less likely to be required on peak days.
- The development of anticipated supply projects is important to provide additional supply to support coincident gas generation, and to respond to unplanned production, storage or transmission outages that coincide with peak demand conditions.

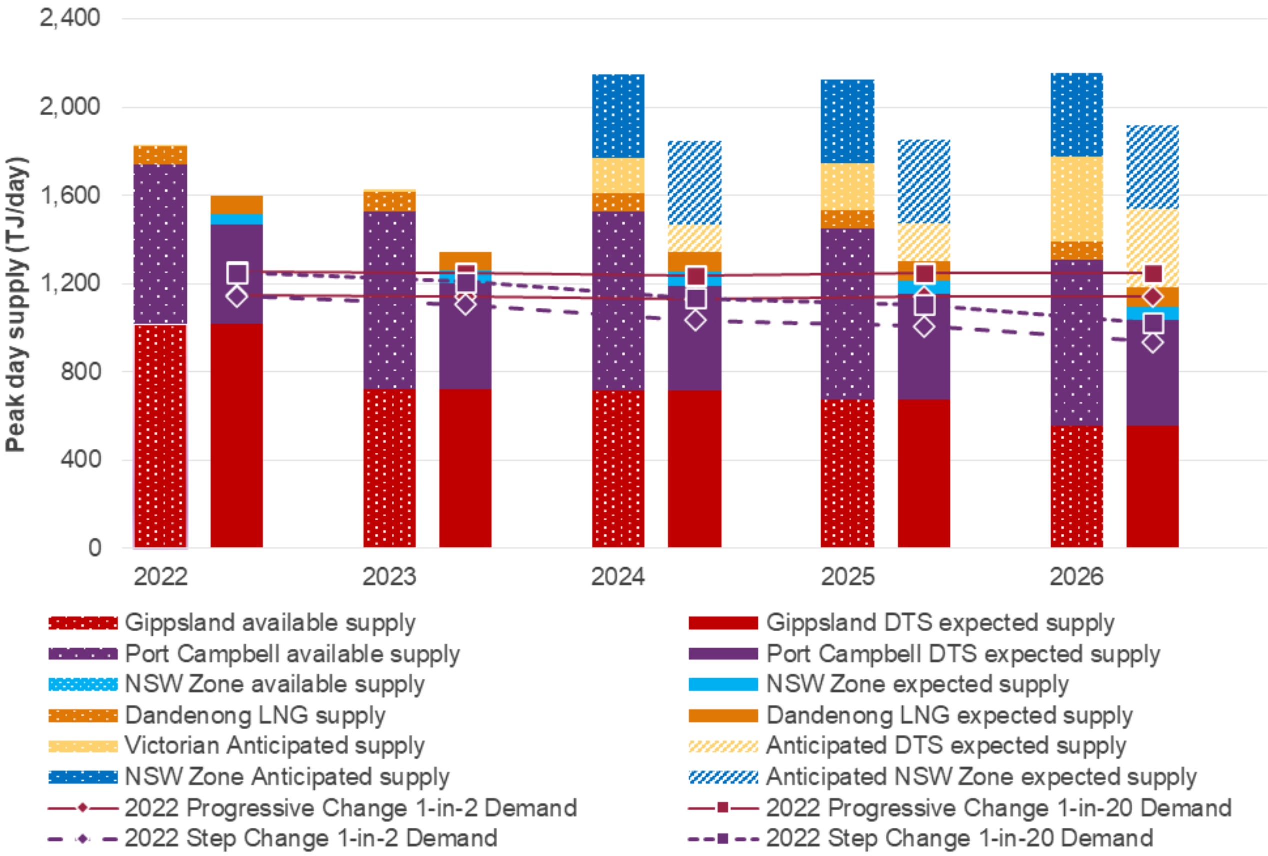
[7] ExxonMobil, "Esso Australia to Expand Gas Development in the Gippsland Basin", 17 March 2022, at https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2022/Esso-Australia-to-Expand-Gas-Development-in-the-Gippsland-Basin.

[8] The SWP includes the Brooklyn to Lara pipeline (BLP)

[9] System demand includes gas use by industry, business and household consumers. Forecasts with a 1-in-20 probability of exceedance are statistically expected to be met or exceeded one in every 20 years. This represents more extreme weather than the average weather conditions assumed in a 1-in-2 forecast, which is expected to be met or exceeded one in every two years.

- Development of anticipated supply, including from the New South Wales Zone[10], is required to avert shortfalls on peak system demand days in 2026 under *Progressive Change*. Under *Step Change* there is no forecast peak system demand day shortfall in 2025 or 2026, with a small amount of Dandenong LNG required on a 1-in-20-year day.

**Figure 4 Peak day supply and DTS adequacy**




## System resilience

### Longford Gas Plant

Esso retired the inlet section of Gas Plant 1 at the end of 2021 to align Longford's operating footprint with system capacity, among other things. The capacity of Gas Plants 2 and 3 inlets is sufficient to accommodate Longford's gas capacity. While an Esso review of Gas Plant 2 and 3 inlet systems showed high historical uptime performance, if one of the two remaining inlet sections was unavailable (for example, due to unplanned maintenance), the Longford Gas Plant capacity would reduce to approximately 500-650 TJ/d, depending on the gas system conditions at the time. An outage on a peak demand day is likely to result in a threat to system security, which may require operational response LNG to manage, and could result in curtailment in the event of very high gas demands.

[10] The New South Wales Zone encompasses flows from New South Wales in the DTS via either the Culcairn interconnect, or southern flow on the EGP via the VicHub facility.

The Longford production system produces an ethane by-product stream that is used by a downstream customer. Periods of reduced customer ethane offtake may constrain Longford production during winter 2022. AEMO is working collaboratively with Esso to minimise the impact on Longford operations and gas supply into the DTS.

As reported in the 2021 VGPR, the forecast capacity reduction from Longford's large legacy gas fields is expected to degrade the current high resilience[11] of the plant's production system from early 2023. Currently, any supply disruptions that occur can often be 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 increases the risk to supply at both a seasonal and peak day level. Esso is continuing to monitor the performance of its production fields and is expected to provide an update on expected production capacity in late April 2022.

Esso has also advised AEMO that as part of production decline and reduced redundancy, full plant outages at Longford Gas Plant are being planned as significant maintenance activities are carried out both onshore and offshore. Based on Esso's preliminary long-term maintenance plans, a full day outage of Longford Gas Plant is expected as early as the fourth quarter of 2023 and a longer shutdown of one month is currently expected in late 2025. Existing supply sources can support these outages under low demand conditions, but the WORM is needed to provide a reliable supply of gas from Port Campbell to eastern Victoria. The capacity to support coincident gas generation will be limited.

The anticipated supply from PKET and the Golden Beach facility for winter 2024 would also assist with managing future Longford Gas Plant outages.

### Dandenong LNG

The Dandenong LNG facility has historically been used as an "operational response" to alleviate threats to system security and for "emergency response" to support demand during the implementation of customer curtailment. Its location enables the facility to be used as a flexible high capacity supply source to rapidly respond to supply disruptions, equipment outages or failures, unforecast increases in demand and high gas generation.

AEMO has contracted 60 TJ of Dandenong LNG storage capacity after AEMO issued a Notice of a Threat to System Security following the publication of the 2021 VGPR and the market response was not sufficient to increase storage capacity to 250 TJ (including 140 TJ for an emergency response and an additional 110 TJ to minimise the likelihood of curtailment)[12].

AEMO's modelling has indicated that the required quantity of Dandenong LNG has increased to 268 TJ for winter 2022. This includes 140 TJ for an emergency reserve and 128 TJ to minimise the likelihood of curtailment, based on a 1-in-20 year probability of exceedance. This requirement is more than the capacity currently contracted by market participants and AEMO for winter 2022.

If market participants do not increase contracted supplies, AEMO intends to respond to ensure that there is sufficient capacity for emergency response. If there is insufficient capacity for operational response there is a risk of increased curtailment, particularly of gas generation.

[11] 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.

[12] See https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-er-21-004-winter-2021.pdf?la=en for more information.

### 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[13]. 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 from 2022 (including currently contracted AEMO volumes) to manage operational and emergency responses during periods of high unforecast demand or a supply disruption, which increases the risk of AEMO curtailing supply to customers.

This risk has increased compared to the 2021 VGPR, because of the increased possibility of reduced Longford Gas Plant capacity due to the retirement of the Gas Plant 1 inlet section. The risk increases further in 2023 in line with the projected reduction in available supply, which presents a material risk of gas generation curtailment on peak demand days.

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.

## Risks to supply adequacy

Under both the *Step Change* and *Progressive Change* scenarios, the peak day and seasonal supply demand balance is tight from winter 2023 and for the remainder of the outlook period without additional gas supply. The increased risks to supply that may lead to peak day and seasonal shortfalls from 2023 include:

- **Delay to WORM construction** – the WORM is a key infrastructure project that increases supply capacity, reliability and security. The Environment Effects Statement for the WORM was approved by the Victorian Planning Minister on 26 January 2022. There is limited time to complete construction and commissioning prior to winter 2023. Construction of the WORM is contingent on a pipeline licence being issued (expected late April 2022).
- **Increased gas generation** – weather conditions and coal-fired generation outages can result in increased gas generation. In 2017, 2019 and 2021 there was increased gas generation in Victoria to due coal-fired generator outages or closures, which coincided with peak demand conditions.
- **Production facility outages** – as well as the Longford decline and reduced resilience discussed above, other production facilities are also aging, so unplanned outages may occur more frequently and there will be limited spare capacity to cover them.
- **Transmission facility outages** – unplanned outages at single-unit compressor stations such as Winchelsea and Springhurst will significantly reduce peak day pipeline capacity.
- **Production lower than forecast** – accurately forecasting the rate and expected duration of production, as reservoirs approach their end of life, can be challenging. Deviations can, and occasionally do, occur.
- **Reduced gas offered from Queensland to southern states** – volumes offered by Queensland LNG producers may be reduced due to lower production or favourable international LNG prices which may attract

[13] National Gas Rules (NGR) 341

surplus production. Unplanned outages impacting APA's transmission pipelines from Queensland are also a risk, along with possible delays to the expansion that is forecast to be completed prior to winter 2023.

- **Unavailability of Dandenong LNG capacity** – retailer-contracted volumes at Dandenong LNG are low, and there is a risk that storage will be depleted and capacity unavailable on peak demand days.
- **Mismanagement of Iona UGS inventory** – the tight supply demand balance from winter 2023 requires prudent management of participants' Iona UGS inventories to ensure that maximum injection capacity is maintained during the winter peak demand period.

## Additional supplies during the outlook period

Additional supply projects that meet the anticipated criteria could be developed during the outlook period, although none are expected to be able to be developed prior to winter 2023. These, and potential projects, are summarised in **Table 3**.

**Table 3 Anticipated and potential projects**

| Solutions | Detail | Solution description | Analysis |
|---|---|---|---|
| **Anticipated production projects** | There are anticipated supply projects in the Gippsland and Port Campbell zones that are expected to increase the available supply.<br>Projects already identified in the 2021 VGPR are the development of the Golden Beach field, the Enterprise gas field, and further development of the Kipper gas field that is processed through the Longford Gas Plant.<br>Projects are also being progressed for the Yolla and Trefoil fields that supply the Lang Lang Gas Plant (BassGas). | • The Golden Beach Project[14] is a proposed gas plant to process gas from the Golden Beach field. This would provide additional supply including peak day capacity in 2024 and 2025, prior to operation as a new underground gas storage facility. Golden Beach Energy received $32m from the federal government in 2022 to accelerate development of the project[15].<br>• The Kipper development would be undertaken in two stages; with committed production from 2024[16], and anticipated ongoing evaluation and preparation for future Phase 1B drilling. The additional production will offset the decline in other gas fields that are processed through at Longford.<br>• Following successful drilling of the Enterprise-1 well in November 2020, Beach Energy is targeting to reach FID on the Enterprise pipeline project in the second half of financial year 2022. This is expected to assist in returning the Otway Gas Plant to its nameplate capacity of 205 TJ/d.<br>• Work on existing wells in the Yolla field anticipated in Q3 2022, with Trefoil supply anticipated from 2025. | • Completion of the Golden Beach Project prior to winter 2024 would increase gas supply until 2025. It could continue to support demand if it commences operation as a storage facility.<br>• The Kipper and BassGas projects maintain and restore gas supply capacity that has reduced due to field decline. |
| **Potential Victorian LNG import terminals** | LNG import terminals could bring gas from Australian export facilities (acting like a virtual pipeline) or from international supply sources.<br>There are two publicly proposed LNG receiving terminals in Victoria:<br>• The Viva project in Geelong, to the southwest of Melbourne, has announced that it is | • These terminals to the southwest 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 simultaneous supply of Port Campbell gas including Iona UGS into the DTS). | • Both terminals would require a new pipeline to connect them to the DTS.<br>• The connection of a new supply source into the SWP near Geelong would increase the SWP transportation capacity from the current 468 TJ/d to above 700 TJ/d with the WORM, due to its closer proximity to Melbourne, but simultaneous supply capacity from Port Campbell |

[14] See https://gbenergy.com.au/ for more information.

[15] The Hon Angus Taylor MP, "Unlocking critical local gas production and storage", 21 March 2022, at https://www.minister.industry.gov.au/ministers/taylor/media-releases/unlocking-critical-local-gas-production-and-storage.

[16] See https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2022/Esso-Australia-to-Expand-Gas-Development-in-the-Gippsland-Basin for more information.

| Solutions | Detail | Solution description | Analysis |
|---|---|---|---|
| | working towards delivering first gas in 2024[17].<br>• The Vopak project is at Avalon, also to the southwest of Melbourne. | | would be reduced to as low as 150 TJ/d.<br>• Further expansion of the SWP would be required to support simultaneous supply from the Port Campbell facilities at current capacities. |
| **Potential 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 2023.<br>Iona UGS is proceeding with an expansion that will increase the facility capacity to 570 TJ/d. An additional expansion beyond this to 670 TJ/d is also being considered. | Two expansion projects are being proposed to increase SWP capacity:<br>• Increasing Port Campbell injection capacity from 476 TJ/d to 528-570 TJ/d by augmenting SWP (compression and possible looping)<br>• Increasing Port Campbell injection capacity from 570 TJ/d to 670 TJ/d by augmenting SWP (additional looping and/or compression) | These proposed expansion projects could:<br>• Increase peak day supply.<br>• Mitigate the risk of peak day shortfalls.<br>• Improve system resilience. |
| **Potential increased supply capacity from outside Victoria** | A two-stage expansion project has been approved to increase southbound transmission capacity on the South West Queensland Pipeline (SWQP) and Moomba – Sydney Pipeline (MSP).<br>Several other possible projects are being developed to improve supply and transmission capacity in south-eastern Australia. | Construction of additional compression facilities will expand southbound capacity from Queensland to south-eastern Australia by 25% (approx. 120 TJ/d capacity increase on MSP):<br>• Stage 1, which is committed, increases MSP capacity by 30 TJ/d, completed in Q1 2023,<br>• Stage 2, yet, to reach FID, provides a 59 TJ/d increase in capacity to the southern markets, completed in Q1 2024,<br>Other potential projects include:<br>• Increased supply from the PKET through additional compression at Port Kembla to increase the EGP southbound capacity from 200 TJ/d to 320 TJ/d.<br>• Two other public proposed LNG terminals that may increase supply in South Australia (Venice Energy) and New South Wales (Newcastle GasDock)<br>• Narrabri Gas Project with FID expected in late 2023. | Incremental pipeline expansions could provide additional capacity in approximately two years. A new pipeline is a more substantial undertaking.<br>The Venice Energy and Newcastle GasDock are unlikely to increase DTS gas supply due to existing pipeline capacity constraints.<br>While supply projects from outside Victoria may contribute to DTS peak day supply, there would be no net increase as the current and forecast transportation capacities in south-east Australia become a limiting factor. |
| **Distributed gas supply** | Hydrogen and biogas injections into distribution networks could provide a future 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[18] project, with an electrolyser proposed by Australian Gas Infrastructure Group (AGIG) that would produce hydrogen for injection into the Albury-Wodonga gas distribution network from 2024. | Technologies are still in the early stages of trial and adoption. These projects are not expected to produce significant quantities of gas within the outlook period.<br>The GSOO includes further discussion on the longer term potential for hydrogen. |

## System capability modelling to support new entry and exit capacity certificate regime

On 12 March 2020, the Australian Energy Market Commission (AEMC) published the final rule change that replaces the DWGM authorised maximum daily quantity (AMDQ) regime with an entry and exit capacity certificate regime[19]. The new regime allocates system injection point and system withdrawal points to capacity certificate zones. The system capability modelling for determining the amount of capacity certificates available for allocation under this regime is included in this report.

[17] See https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project for more information.

[18] See https://www.agig.com.au/media-release---hydrogen-proposal-in-albury-wodonga for more information.

[19] AEMC, "DWGM improvement to AMDQ regime", 12 March 2020, at https://www.aemc.gov.au/rule-changes/dwgm-improvement-amdq-regime.

# Contents

# Tables

# Figures

# 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 2021.

Where AEMO becomes aware of any information that materially alters the most recently published VGPR, the National Gas Rules (NGR) require AEMO to update the report as soon as practicable. The material changes since the 2021 VGPR was published that prompted this VGPR Update are:

- Updated gas production and consumption forecasts.
- Updates to projects within the DTS since the 2021 VGPR was published.
- Updates to some pipeline capacities within the DTS since the 2021 VGPR was published.

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

## 1.1 Review of 2021

- Victorian DTS consumption in 2021 was 207 petajoules (PJ), slightly lower than 2020 due to milder temperatures and lower consumption from gas generation.
- System consumption (by industrial, commercial and household consumers) in 2021 was 199.6 PJ, similar to system consumption of 201.5 PJ in 2020 and 197 PJ in 2019.
- The Victorian DTS peak total demand day was on Monday 21 June 2021, reaching 1,169 terajoules (TJ). This comprised 986 TJ of system demand (demand from industrial, commercial and household consumers) and 183 TJ of gas generation; the Effective Degree Day (EDD)[20] on this day was 9.9. This is less than the peak total demand in 2020 of 1,241 TJ.
- The peak system demand day was Tuesday 20 July 2021, when system demand reached 1,129 TJ and the EDD was 13.6. This was much milder than the peak system demand days during winter 2019 and 2020. System demand was 1,194 TJ, with an EDD of 15.0 on 9 August 2019, and 1,213 TJ on 4 August 2020, with an EDD of 15.2.
- Gas consumption of DTS-connected gas generation in 2021 was 6.2 PJ, 8% lower than 6.7 PJ in 2020.
- On the supply side, total Victorian production increased from 305 PJ in 2020 to 331 PJ in 2021. The largest increase came from the Longford Gas Plant, which increased by 24 PJ to 276 PJ, assisted by the commissioning of the West Barracouta gas field during April[21].

Key observations for the winter 2021 peak period[22] include:

- The average system demand was 768 TJ per day (TJ/d), which was lower than the average system demand of 795 TJ/d in 2020 and 780 TJ/d in 2019.

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

[21] See https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2021/Esso-Australia-delivers-West-Barracouta-gas-to-the-domestic-market-in-time-for-winter.

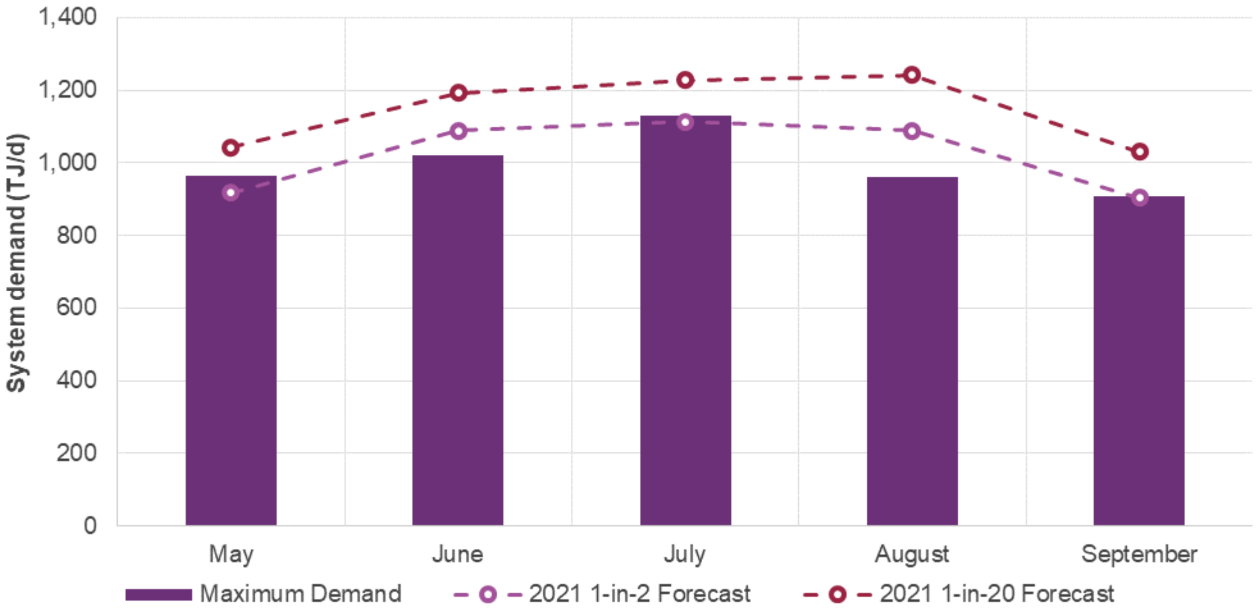
[22] The winter peak demand period is defined as the months of May to September inclusive.

- Cumulative EDD for the period was 1,176, which is lower than the 2020 and 2019 values of 1,252 and 1,195 respectively.
- Net supply from Queensland to the southern states via the South West Queensland Pipeline (SWQP) was 13.1 PJ over the winter peak demand period, significantly less than the 33.9 PJ supplied in 2020 and 33.2 PJ in 2019.
  - On 25 May 2021, the Callide Power Station incident in Queensland resulted in all Callide units being unavailable. Two units returned to service in June 2021, one unit returned to service in July 2021, and the last unit remains unavailable as at publication[23]. The incident resulted in high levels of Queensland gas generation and lower than usual winter gas supply from Queensland to the southern states.
- Gas generation consumption was 5.0 PJ; higher than 3.5 PJ in 2020 but less than 9.8 PJ in 2019.
  - Gas generation consumption in June 2021 accounted for 2.5 PJ (40% of the annual total).
  - This was largely due to the increased use of gas generation to cover for reduced generation at the coal-fired Yallourn Power Station. From 11 June 2021, the Yallourn Power Station mine capacity was reduced to near zero due to flooding risks following heavy rainfall in the region[24], which again resulted in high gas generation consumption. Significant generation capacity was restored on 26 June 2021, and all units were returned to service by 2 July 2021.
  - The Newport gas-fired power station was the main contributor to the increase in gas generation consumption in June 2021, returning from a two-month planned outage and consuming 1.4 PJ compared to 0.25 PJ in June 2020 to cover for the reduced Yallourn generation. Gas consumption at the Jeeralang and Laverton North power stations also increased.
- There was a significant increase in Iona underground gas storage (UGS) utilisation during early winter, compared to 2020 and 2019. Total storage held at the start of May was 24.5 PJ, which is its highest inventory ever. This was quickly drawn down to 9.6 PJ in late July (discussed further in Section 1.2).
- **Figure 5** shows that the actual maximum system demands in May, July and September exceeded the 2021 forecast 1-in-2 peak day system demand for these months.

[23] See https://www.csenergy.com.au/news/latest-news/news.

[24] See https://www.aemo.com.au/-/media/files/major-publications/qed/2021/q2-report.pdf?la=en.

Figure 5 Actual 2021 monthly maximum system demands compared to the forecast 1-in-2 and 1-in-20 peak demands




- AEMO issued a Notice of a Threat to System Security[25] on two occasions during winter 2021:
  – On 10 June 2021[26], due to a trip of the Longford Gas Plant and the potential breach of the minimum operating pressure at Sale City Gate (CG) in the Gippsland System Withdrawal Zone (SWZ). A market response was called for to alleviate the threat to system security by requesting Market Participants to re-evaluate their market bids and offers. During this event no out-of-merit-order injections from the Dandenong liquified natural gas (LNG) facility were required.
  – On 21 June 2021[27], due to a trip of an offshore platform impacting the output of the Longford Gas Plant resulting in a forecast pressure breach at Dandenong CG and Sale CG. AEMO sought a market response and was able to alleviate that threat by profiling injections at the VicHub and TasHub facilities to support Sale CG pressure.

## 1.2 Winter 2021 gas supply challenges

### 1.2.1 Unplanned coal generation and gas facility outages

Winter 2021 presented significant gas supply management challenges for AEMO, due to the unexpected increase in gas generation demand, reduction in gas flows from Queensland to southern states, and capacity reduction at the Longford gas plant, which put additional pressure on Victorian supply (described in Section 1.1).

These outages caused June 2021 gas generation consumption to be the highest across the east coast markets since September 2019, as shown in **Figure 6**. Note that large gas generation consumption in

[25] This list does not include threats to system security due to planned APA maintenance at the Brooklyn Compressor Station.
[26] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2021/dwgm-er-21-002-10-jun-2021.pdf?la=en.
[27] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2021/dwgm-er-21-003-21-june-2021.pdf?la=en.

2019 was due to the extended outage of the Loy Yang A2 coal generator and other coal generator issues across several units within Victoria and New South Wales.

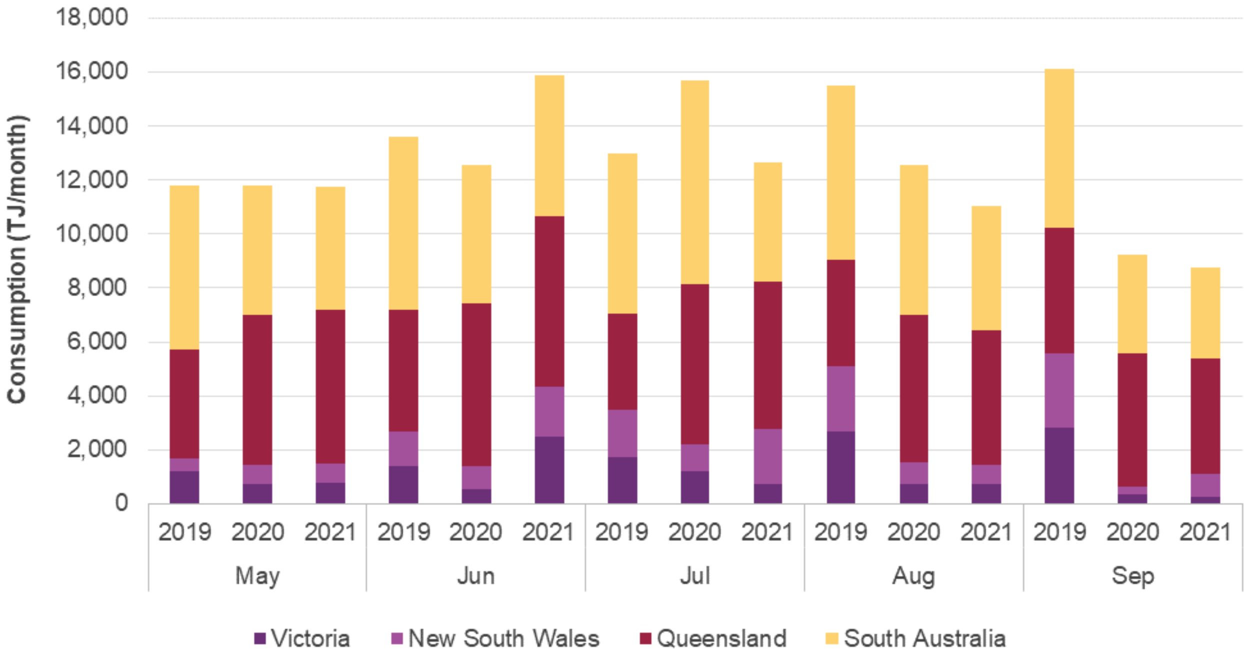
The increase in gas generation consumption driven by these outages, along with the reduction in gas supply made available from Queensland in comparison to previous years, resulted in rapid emptying of the Iona UGS facility.

On 21 June 2021, Lochard Energy, operator of the Iona UGS facility, identified a gas leak on a section of piping at the Iona plant. As a result, Iona required an unplanned outage for repairs. AEMO worked closely with Lochard Energy to determine a date for this outage when demand would be low enough to prevent a supply disruption.

The outage went ahead from noon on 24 June 2021, to reduce market impact, and the plant resumed availability from early morning on 25 June. The resulting temporary repair meant that Iona was unable to refill with gas from the South West Pipeline (SWP) until a subsequent outage occurred.

Shortly after this outage, Esso Australia, the operator of the Longford Gas Plant, advised AEMO on 28 June 2021 of a gas leak on one of its three gas processing trains. An unplanned outage of almost three weeks was required to complete repairs, which reduced plant capacity to 850 TJ/d. Longford returned to full capacity on 17 July 2021.

**Figure 6 East coast gas generation consumption over the 2021 winter period**




While these events are unusual (noting that the Yallourn mine also flooded in 2004 and 2012), the Yallourn and Longford issues narrowly avoided overlapping. Had these issues overlapped it is possible that southern state supply would not have been sufficient to satisfy gas demand.

In the 2021 VGPR, AEMO highlighted reducing system resilience due to a tightening supply demand balance. The report noted that:

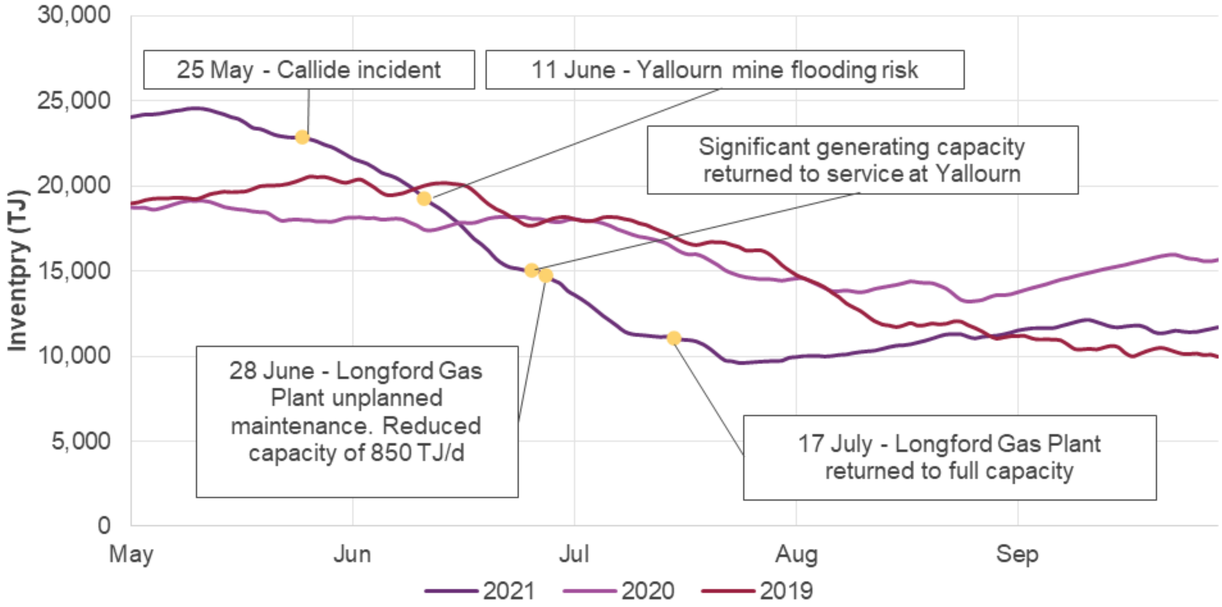
> *"Flexible sources of supply are essential for covering unplanned plant outages, equipment trips, coincident southern gas demand peaks, or unforecast demand changes that may otherwise result in a*

*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 (gas generation) demand when there is insufficient gas supply to support this."*

### 1.2.2 Iona UGS inventory management

There were significant concerns about Iona UGS inventory during winter 2021, despite storage levels reaching a record high of 24.5 PJ on 10 May. Iona UGS was heavily utilised from that point on (see **Figure 7**), with high gas generation demand in Queensland and Victoria, and a reduction in Queensland gas flows south compared to 2020, being contributing factors.

**Figure 7 Comparison of Iona UGS storage levels, 2019, 2020 and 2021**




From 14-20 June 2021, Iona UGS supplied 2.2 PJ from storage, a weekly record that was mainly driven by high Victorian gas generation demand in response to the Yallourn Power Station coal mine flooding risk. Lochard Energy highlighted an increased risk of supply restrictions from the facility due to the rate of storage reservoir depletion. AEMO asked market participants to consider sourcing increased gas supply from Queensland and formally requested updated gas supply and demand forecasts as well as Iona UGS storage balance projections from participants.

Iona began July 2021 at its lowest storage levels since reporting of storage levels began in October 2016. This rapid emptying continued into July, with Iona heavily utilised because of the Longford outage, cold weather, and high gas generation. Iona fell to its lowest level of 9.6 PJ on 25 July.

Reduced system demand then allowed Lochard Energy to schedule an Iona outage on 31 July, to complete a permanent repair that enabled Iona to refill with gas from the SWP.

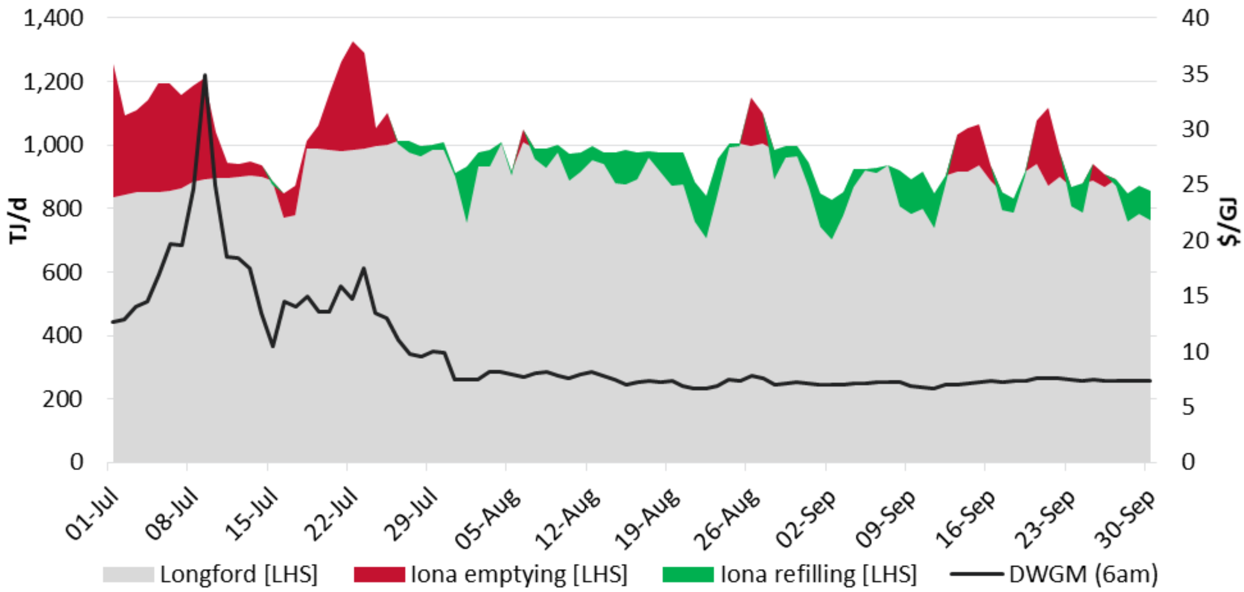
With the plant repaired, Iona was able to refill during August, due to a combination of unusually low system demand resulting from mild weather, lower gas generation demand, and higher Longford production. System demand did not exceed 1,000 TJ from 24 July. As noted above, both August 2019 and 2020 experienced periods of very cold weather, with system demand reaching 1,194 TJ on 9 August 2019 and 1,213 TJ on 4 August 2020.

### 1.2.3 2021 Winter gas price volatility

Gas prices in all regions were at record levels over winter 2021. The Declared Wholesale Gas Market (DWGM) average price over winter was a record $10.75/GJ, compared to $4.72/GJ in winter 2020, a 127% increase. Of note, the 10:00 schedule price reached $58.44/GJ on 9 July, the third highest price since market start and the highest non 22:00 schedule price. The 06:00 schedule price on 9 July of $34.84/GJ was the fourth highest 06:00 schedule price on record.

Prices in July were significantly higher than August and September, due to a partial outage of the Longford Gas Plant from 29 June, reducing supply during the coldest part of winter. This was exacerbated by high demand for LNG and gas generation and record low storage levels at Iona for that stage of winter (**Figure 8**). Following the return of Longford on 18 July and with mild weather in August reducing demand, Iona storage was able to start refilling and market prices fell in all regions and did not exceed $10/GJ during August and September.

**Figure 8 Rapid Iona emptying and reduced Longford supply in July contributes to price spikes**



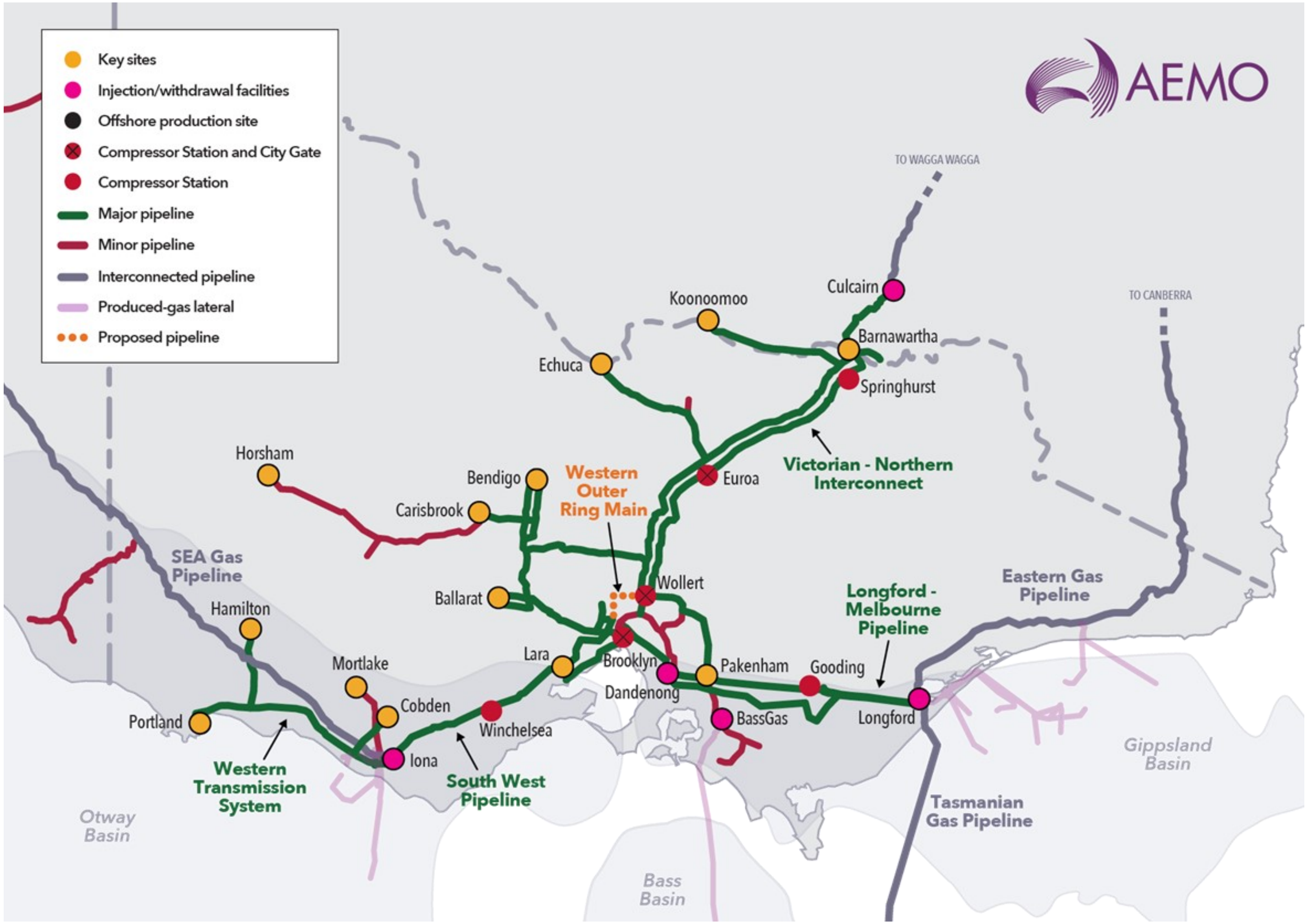

## 1.3 The Victorian Declared Transmission System

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[28] gas production facilities, the Iona UGS facility, and to South Australia via the SEA Gas Pipeline).

**Figure 9** is a high-level map of the Victorian gas transmission network, including the DTS and other gas transmission pipelines.

[28] Minerva Gas Plant was renamed 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 9 The Victorian Declared Transmission System



## 1.4 Gas planning in Victoria

### 1.4.1 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.

### 1.4.2 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 gas-fired generation[29]. Under rule 323(3), AEMO is also required to assess the impact of gas generation demand on 1-in-2 peak system demand days.

[29] Total demand is the sum of system demand and gas generation demand.

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

### 1.4.3 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

- Forecast system demand diverges between the *Progressive Change* and *Step Change* scenarios.
- Under the ***Progressive Change*** scenario:
  - Annual system consumption is forecast to increase by 1.7% in the five-year outlook, from 193 PJ in 2022 to 196 PJ in 2026.
  - The forecast peak day system demands are:
    - 1,147 TJ/d for a 1-in-2 year system demand day in 2022, reducing to 1,144 TJ/d in 2026.
    - 1,255 TJ/d for a 1-in-20 year system day in 2022, reducing to 1,251 TJ/d in 2026.
- Under the ***Step Change*** scenario:
  - Annual system consumption is forecast to decrease by 14.5%, from 192 PJ in 2022 to 164 PJ in 2026.
  - The forecast peak day system demands are:
    - 1,142 TJ/d for a 1-in-2 year system demand day in 2022, reducing to 935 TJ/d in 2026.
    - 1,249 TJ/d for a 1-in-20 year system day in 2022, reducing to 1,022 TJ/d in 2026.
- DTS gas generation consumption is forecast to reduce by 43% over the five-year outlook, from 7.8 PJ in 2022 to 4.4 PJ in 2026.
  - The forecast reduction in annual consumption of gas for generation is driven by continued uptake in grid-scale variable renewable energy (VRE) generation projects and distributed solar photovoltaics (PV) in the NEM, which are expected to reduce the need for gas generation. The projected fall is smaller than the 71.1% reduction forecast in the 2021 VGPR, due to increased NEM demand in the *Step Change* scenario and forecast coal generator unavailability.
  - Despite the forecast fall in annual consumption, peak gas generation during winter is forecast to remain high as gas continues to play a critical role during periods of high electricity demand, particularly when there is low VRE generation or coal generation outages. This may coincide with peak system demand conditions, creating very high total demand conditions.
- Ongoing work from home arrangements are forecast to continue to impact the system demand profile on high demand days in 2022, resulting in greater linepack depletion prior to the evening peak. This increases the likelihood Dandenong LNG will be required to support system pressures.

The gas usage forecasts in this VGPR Update were produced using the *Gas Statement of Opportunities* (GSOO) demand forecasting methodology[30].

[30] AEMO, *Gas Demand Forecasting Methodology Information Paper*, 2021, at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities-methodology-demand-forecasting.pdf?la=en.

The VGPR Update forecasts consider the following scenarios that are presented in the 2022 GSOO[31]:

- The ***Progressive Change* scenario** represents a future that delivers action towards an economy-wide net zero emissions objective by 2050 through technology advancements, and is based on current state and federal government environmental and energy policies. Under this scenario, gas demand is forecast to remain at near-current levels over the VGPR Update's five-year outlook period.
- The ***Step Change* scenario** represents a future with rapid consumer-led transformation of the energy sector. It assumes a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions (including electrification of gas heating load), driven by consumer-led change with a focus on energy efficiency, digitalisation and step increases in global emissions policy above what is already committed. Under this scenario, peak day gas demands are forecast to reduce by approximately 18% over the outlook period.

These two scenarios are used to illustrate the uncertainty in the future demand for gas.

This chapter sets out AEMO's forecasts across the outlook period for annual gas consumption, monthly gas consumption, peak day gas demand, and gas for the generation of electricity in the NEM. While both the *Progressive Change* and *Step Change* scenarios show a decrease in gas usage over the next five years, the future for gas use diverges between the scenarios as early as next year.

## Definitions

**Annual consumption** means includes system consumption (Tariff V and Tariff D customers, compressor and heater fuel gas, and unaccounted for gas [UAFG]), and DTS-connection gas generation consumption.

**Unaccounted for gas (UAFG)** is the difference between the metered amount of gas entering the DTS and the amount of gas delivered to consumers as well as compressor and heater fuel.

**System demand** refers to daily gas usage by residential, commercial, and industrial gas users. It includes DTS compressor and heater fuel gas usage. Gas generation demand is not included in system demand.

**Total demand** refers to the sum of system demand and gas generation demand.

System demand and annual consumption are further classified into Tariff V and Tariff D:

- **Tariff V** – residential and small commercial customers, each normally consuming less than 10 TJ per year (TJ/y) of gas.
- **Tariff D** – large commercial and industrial customers, each normally consuming over 10 TJ/y of gas.

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

System demand is primarily driven by Tariff V gas usage for heating, which depends on several variables. To capture the impact of weather on system demand, AEMO uses a measure known as the **Effective Degree Day (EDD)**, which considers the temperature profile, average wind speed, sunshine hours and season for the gas day. The higher the EDD, the higher the likely gas use.

Peak day demand forecasts are given as probability of exceedance (POE) forecasts, which means the statistical probability the forecast will be met or exceeded. The forecasts are given as:

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

- **1-in-2** peak day forecasts, meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions.
- **1-in-20** peak day forecasts are based on more extreme conditions that could be expected only one year in 20.

## 2.1 Annual consumption

Annual DTS total gas consumption is forecast:

- In the *Progressive Change* scenario, to initially decrease from 201 PJ in 2022 to 194 PJ in 2024, then to increase to 201 PJ in 2026, as shown in **Table 4** and **Figure 10**. The trend is driven by a reduction in Tariff V consumption over the outlook period, and an increase in forecast Tariff D consumption, particularly from 2025.
- In the *Step Change* scenario, to decrease from 200 PJ in 2022 to 168 PJ in 2026 as shown in **Table 5** and **Figure 10**. This is primarily driven by a strong reduction in Tariff V consumption.

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 gas generation consumption.

These scenarios provide an uncertainty range around the consumption forecast in the 2021 VGPR, which projected total consumption decreasing to 188 PJ in 2025.

The impact of the ongoing COVID-19 pandemic is not included as a long-term variable in the annual and monthly consumption forecasts. AEMO will continue to closely monitor the situation.

**Table 4 Total annual gas consumption forecast, *Progressive Change* scenario, 2022-26 (PJ/y)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **Tariff V** | 128 | 128 | 125 | 123 | 124 | -3.2% |
| **Tariff D** | 65.2 | 64.4 | 64.5 | 73.1 | 72.7 | 11.4% |
| **System consumption** | 193 | 192 | 190 | 196 | 196 | 1.7% |
| **DTS gas generation consumption** | 7.77 | 7.09 | 3.96 | 3.53 | 4.43 | -43.0% |
| **Total DTS consumption** | 201 | 199 | 194 | 200 | 201 | 0.0% |
| **Non-DTS system consumption** | 1.45 | 1.40 | 1.40 | 1.30 | 1.16 | -19.5% |
| **Non-DTS gas generation consumption** | 9.66 | 8.65 | 5.70 | 4.99 | 6.02 | -37.7% |
| **Victorian gas generation Consumption** | 17.43 | 15.74 | 9.66 | 8.52 | 10.45 | -40.1% |
| **Total Victorian consumption*** | 212 | 209 | 201 | 206 | 208 | -1.9% |

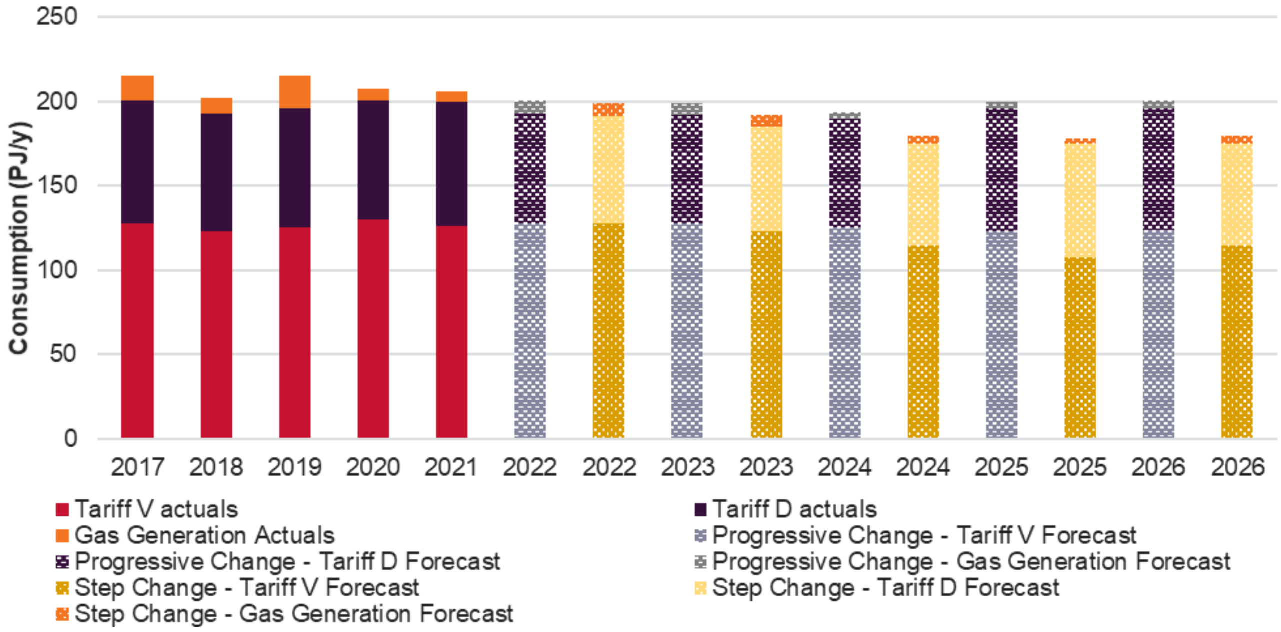
Note: totals and change over outlook percentage may not add up due to rounding.
* Total Victorian consumption includes total DTS consumption, non-DTS Tariff V and Tariff D consumption at Bairnsdale, Lang Lang, and demand off the South Gippsland pipeline, and non-DTS gas generation consumption at Bairnsdale and Mortlake. The Lang Lang production facility supplies demand in Lang Lang and off the South Gippsland pipeline, reducing available supply to the DTS.

Table 5 Total annual gas consumption forecast, *Step Change* scenario, 2022-26 (PJ/y)

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **Tariff V** | 128 | 123 | 114 | 108 | 99 | -22.4% |
| **Tariff D** | 64.2 | 61.8 | 61.1 | 66.9 | 64.8 | 0.9% |
| **System consumption** | 192 | 185 | 175 | 175 | 164 | -14.6% |
| **DTS gas generation consumption** | 7.77 | 7.09 | 3.96 | 3.53 | 4.43 | -43.0% |
| **Total DTS consumption** | 200 | 192 | 179 | 178 | 168 | -15.7% |
| **Non-DTS system consumption** | 1.43 | 1.36 | 1.33 | 1.22 | 1.07 | -25.6% |
| **Non-DTS gas generation consumption** | 9.66 | 8.65 | 5.70 | 4.99 | 6.02 | -37.7% |
| **Victorian gas generation Consumption** | 17.43 | 15.74 | 9.66 | 8.52 | 10.45 | -40.1% |
| **Total Victorian consumption** | 211 | 202 | 186 | 185 | 175 | -16.8% |

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

Figure 10 Historical and forecast total annual gas consumption, *Step Change* and *Progressive Change* scenarios, 2017-26 (PJ/y)




### 2.1.1 Tariff V consumption

The Tariff V consumption (residential and small commercial customers) is different in the two scenarios:

- Under *Progressive Change*, Tariff V consumption is forecast to decrease by 3.2% over the outlook period.
  - This moderate decrease is driven by energy savings under the Victorian Energy Upgrades[32] (VEU) scheme, which reduces gas consumption per connection for both residential and small commercial

[32] The VEU program provides Victorian households and businesses with a range of low and no-cost energy saving options such as lighting and draught sealing as well as subsidies for replacing major appliances like energy efficient hot water systems. See https://www.esc.vic.gov.au/victorian-energy-upgrades-program.

customers. The assumed energy savings from the program are lower than assumed in the 2021 VGPR, based on a review of actual energy efficiency savings.

– This is partially offset by a forecast increase in the number of connections (as shown in **Figure 11**).

- Under the *Step Change* scenario, Tariff V consumption is forecast to decline by 22.4% over the outlook period. This rapid decline is primarily due to increased consumer switching from gas to electric heating. Figure 11 shows the level of gas disconnections required to achieve a reduction of this magnitude by 2026. This level and pace of reduction is likely to require strong government policy, rebates, or incentive schemes.

**Figure 11 Historical and forecast DTS Tariff V connections, 2013-26**

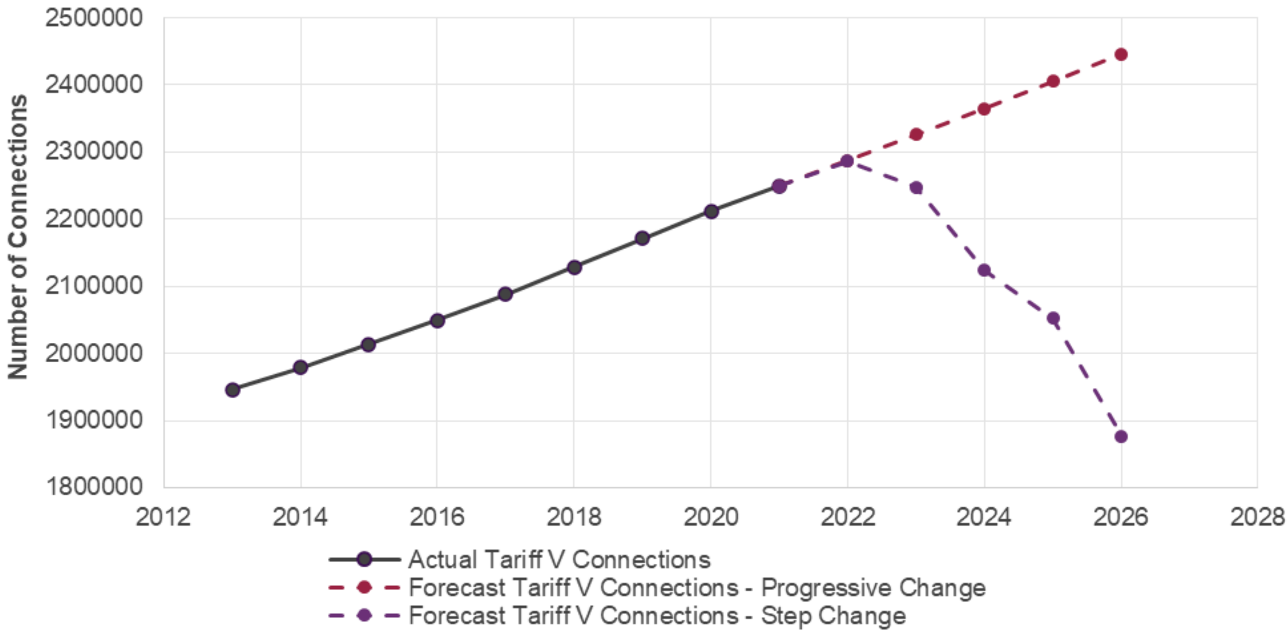



**Table 6** and **Table 7** show the projected Tariff V consumption by SWZ[33] for the *Progressive Change* and *Step Change* scenarios respectively.

Under the *Progressive Change* scenario, the behaviour varies between SWZs:

- In the Melbourne zone, Tariff V consumption is forecast to decrease, as the projected number of new connections is offset by the adoption of the energy efficiency VEU program described above.
- In all other zones, Tariff V consumption is forecast to increase or stay relatively constant, due to the number of new connections in the low-density population growth corridors on the fringe of Melbourne and in regional towns that are expected to continue to install gas appliances.
- In the Step Change scenario, there is a strong forecast reduction in Tariff V consumption across all zones.

[33] The DTS is divided into six SWZs: Northern, Geelong, Melbourne, Western (Western Transmission System, or WTS), Ballarat, and Gippsland. The SWZs are used to report demand forecast, and to assess adequacy by zone.

**Table 6 Annual Tariff V consumption by SWZ, *Progressive Change* scenario, 2022-26 (PJ/y)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **Ballarat** | 9.0 | 9.1 | 9.2 | 9.2 | 9.4 | 4.7% |
| **Geelong** | 11.4 | 11.6 | 11.7 | 11.7 | 12.0 | 4.7% |
| **Gippsland** | 6.1 | 6.3 | 6.4 | 6.5 | 6.7 | 9.7% |
| **Melbourne** | 89.4 | 88.5 | 86.4 | 84.3 | 83.9 | -6.2% |
| **Western** | 1.3 | 1.3 | 1.2 | 1.2 | 1.2 | -3.8% |
| **Northern** | 10.7 | 10.7 | 10.6 | 10.5 | 10.6 | -1.2% |
| **DTS Tariff V system consumption** | 127.9 | 127.6 | 125.4 | 123.4 | 123.8 | -3.2% |
| **Non-DTS Tariff V system consumption** | 0.52 | 0.53 | 0.53 | 0.53 | 0.55 | 5.3% |
| **Total Victorian Tariff V** | 128.4 | 128.1 | 125.9 | 123.9 | 124.3 | -3.2% |

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

**Table 7 Annual Tariff V consumption by SWZ, *Step Change* scenario, 2022-26 (PJ/y)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **Ballarat** | 8.9 | 8.8 | 8.3 | 8.0 | 7.5 | -16.2% |
| **Geelong** | 11.4 | 11.3 | 10.6 | 10.2 | 9.6 | -16.2% |
| **Gippsland** | 6.1 | 6.1 | 5.8 | 5.7 | 5.4 | -11.9% |
| **Melbourne** | 89.2 | 85.7 | 78.7 | 73.8 | 67.1 | -24.8% |
| **Western** | 1.3 | 1.2 | 1.1 | 1.1 | 1.0 | -23.0% |
| **Northern** | 10.7 | 10.4 | 9.7 | 9.2 | 8.4 | -20.8% |
| **DTS Tariff V system consumption** | 127.5 | 123.5 | 114.3 | 107.9 | 98.9 | -22.4% |
| **Non-DTS Tariff V system consumption** | 0.52 | 0.52 | 0.50 | 0.50 | 0.48 | -7.0% |
| **Total Victorian Tariff V** | 128.0 | 124.0 | 114.8 | 108.4 | 99.4 | -22.4% |

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

### 2.1.2 Tariff D consumption

The Tariff D (large commercial and industrial) consumption trend is similar in the *Progressive Change* and *Step Change* scenarios, but consumption is lower in *Step Change* due to the increased electrification of gas use in this scenario (see **Table 8** and **Table 9**).

Under both scenarios, Tariff D consumption is forecast to reduce in 2022 in comparison to actual demand in 2021 – due to reduced consumption at the Mobil Altona refinery[34] and Qenos Altona[35] – and to continue to decline to 2024.

From 2025, there is a substantial forecast increase in Tariff D load in all SWZs except Gippsland and non-DTS areas. This projected increase is driven by a significant uptake in consumption from steam methane reforming (SMR), a technology that converts natural gas into hydrogen to support industry, transport, and small amounts of pipeline blending, as modelled by the CSIRO[36].

[34] See https://www.exxonmobil.com.au/Community-engagement/Local-outreach/Mobil-community-news/2021/Altona-Shut-Down-Teams.

[35] See https://maribyrnonghobsonsbay.starweekly.com.au/news/qenos-mothballing-150-jobs-lost/.

[36] See page 25, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf?la=en.

**Table 8 Annual Tariff D consumption by SWZ, *Progressive Change* scenario, 2022-26 (PJ/y)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| Ballarat | 1.4 | 1.3 | 1.3 | 1.9 | 1.9 | 37.5% |
| Geelong | 9.7 | 9.7 | 9.7 | 13.7 | 13.4 | 37.4% |
| Gippsland | 8.9 | 8.3 | 8.2 | 7.0 | 5.5 | -38.2% |
| Melbourne | 34.2 | 34.0 | 34.1 | 39.0 | 40.3 | 17.9% |
| Western | 2.8 | 2.8 | 2.7 | 3.0 | 3.1 | 12.2% |
| Northern | 8.4 | 8.4 | 8.4 | 8.5 | 8.6 | 2.9% |
| DTS Tariff D system consumption | 65.2 | 64.4 | 64.5 | 73.1 | 72.7 | 11.4% |
| DTS SMR load (included in total) | 0 | 0 | 0 | 8.4 | 9.9 | N/A |
| Non-DTS Tariff D system consumption | 0.93 | 0.87 | 0.87 | 0.76 | 0.62 | -33.4% |
| Total Victorian Tariff D | 66.1 | 65.3 | 65.3 | 73.8 | 73.3 | 10.8% |

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

**Table 9 Annual Tariff D consumption by SWZ, *Step Change* scenario, 2022-26 (PJ/y)**

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| Ballarat | 1.3 | 1.3 | 1.3 | 1.7 | 1.6 | 18.7% |
| Geelong | 9.6 | 9.3 | 9.2 | 12.1 | 11.4 | 18.7% |
| Gippsland | 8.7 | 7.9 | 7.8 | 6.6 | 5.1 | -41.1% |
| Melbourne | 33.7 | 32.7 | 32.3 | 35.7 | 35.9 | 6.7% |
| Western | 2.7 | 2.6 | 2.6 | 2.8 | 2.8 | 2.7% |
| Northern | 8.2 | 8.0 | 8.0 | 8.0 | 8.0 | -2.4% |
| DTS Tariff D system consumption | 64.2 | 61.8 | 61.1 | 66.9 | 64.8 | 0.9% |
| DTS SMR load (included in total) | 0 | 0 | 0 | 6.1 | 6.6 | N/A |
| Non-DTS Tariff D system consumption | 0.92 | 0.84 | 0.83 | 0.72 | 0.58 | -36.1% |
| Total Victorian Tariff D | 65.2 | 62.6 | 62.0 | 67.7 | 65.4 | 0.4% |

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

## 2.2 Monthly consumption in 2022

Forecast monthly consumption in 2022 is similar in both *Step Change* and *Progressive Change* scenarios. While the consumption forecasts for *Step Change* and *Progressive Change* scenarios are similar, data shown in this section is from the *Progressive Change* scenario only, because the quantities are the higher of the two.

Monthly system consumption forecasts for January to December 2022 are shown in **Table 10**:

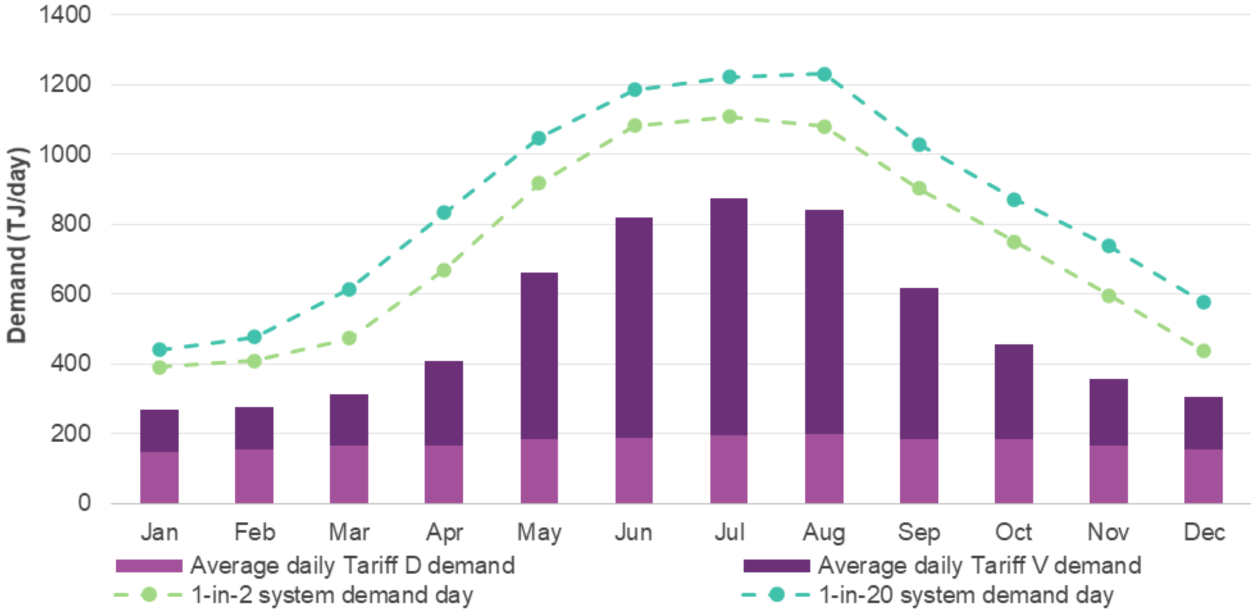
- Maximum monthly system consumption is forecast to be 27.9 PJ per month (PJ/m) during July, with slightly lower amounts during June and August.
- System consumption during summer months is forecast to be less than 10 PJ/m.
- DTS-connected gas generation monthly consumption is forecast to be highest during the winter months due to high coincident NEM demand, reduced VRE output, and planned coal generator maintenance.

**Table 10 Forecast monthly gas consumption for 2022, *Progressive Change* scenario (PJ/m)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System consumption** | 8.29 | 8.55 | 9.75 | 12.65 | 20.51 | 25.33 | 27.09 | 26.06 | 19.14 | 14.08 | 11.07 | 9.43 |
| **Gas generation consumption** | 0.88 | 0.45 | 0.58 | 0.45 | 0.54 | 1.08 | 0.77 | 0.71 | 0.60 | 0.64 | 0.80 | 0.27 |
| **Total consumption** | 9.2 | 9.0 | 10.3 | 13.1 | 21.0 | 26.4 | 27.9 | 26.8 | 19.7 | 14.7 | 11.9 | 9.7 |

**Figure 12** shows that monthly gas consumption is much higher during winter. The forecast average daily July demand of 874 TJ is over three times the average daily January demand of 268 TJ. The significant increase during winter is mainly attributed to Tariff V heating demand. Tariff D demand is forecast to remain relatively constant over the year.

**Figure 12 Forecast average daily 2022 demand compared to 2022 peak day system demand, *Progressive Change* scenario (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 2022 to December 2022.

### 2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 peak day system demand forecasts, summarised in **Table 11** and **Table 12**, show a strong divergence between the forecast scenarios, consistent with the trends in annual consumption.

- In the *Progressive Change* scenario, there is a forecast increase in Tariff D peak day demand (due to SMR load), and a forecast decrease in Tariff V peak day demand from increased energy efficiency measures.

- In the *Step Change* scenario, there are small forecast increases in Tariff D peak day demand due to SMR load more than offsetting the reduction in other Tariff D demand, but a significant reduction in Tariff V load due to electrification of heating load (see Section 2.1.1 for further details).

**Table 11 Annual peak day system demand forecast, *Progressive Change* Scenario, 2022-26 (TJ/d)**

| | | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|---|
| **1-in-2 peak day** | Tariff V | 920 | 916 | 900 | 888 | 887 | -3.5% |
| | Tariff D | 227 | 226 | 227 | 254 | 256 | 12.7% |
| | System demand | **1,147** | **1,142** | **1,128** | **1,142** | **1,144** | **-0.3%** |
| **1-in-20 peak day** | Tariff V | 1,018 | 1,013 | 999 | 980 | 986 | -3.2% |
| | Tariff D | 237 | 235 | 235 | 266 | 265 | 12.0% |
| | System demand | **1,255** | **1,248** | **1,234** | **1,246** | **1,251** | **-0.3%** |

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

**Table 12 Annual peak day system demand forecast, *Step Change* Scenario, 2022-26 (TJ/d)**

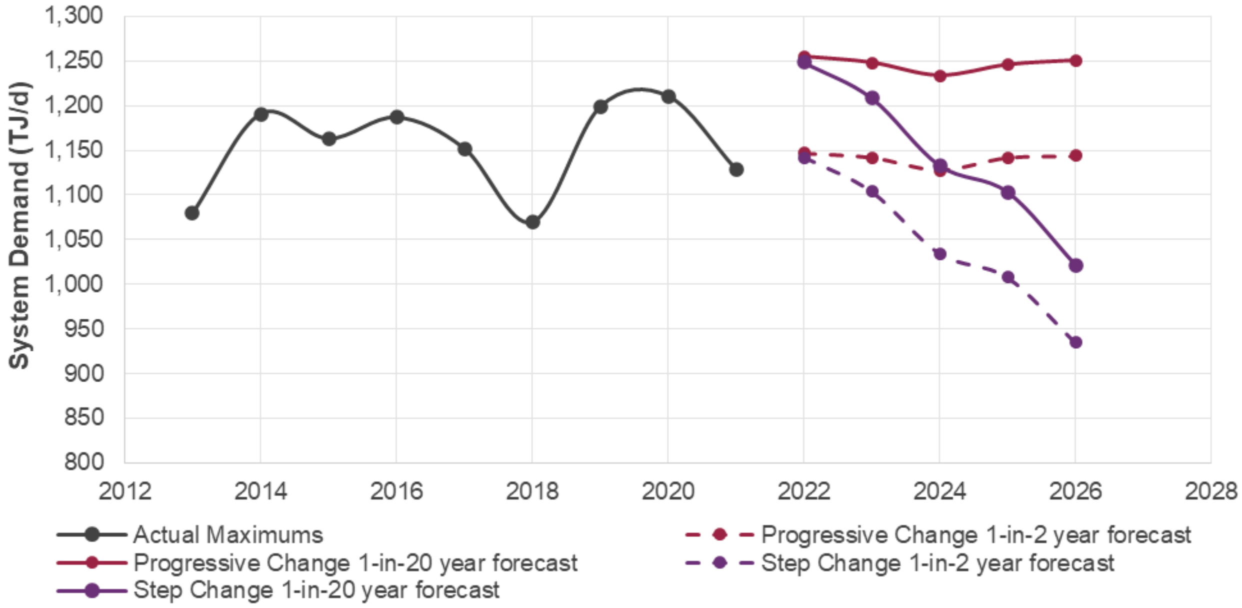
| | | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|---|
| **1-in-2 peak day** | Tariff V | 915 | 888 | 819 | 772 | 707 | -22.8% |
| | Tariff D | 227 | 216 | 215 | 236 | 228 | 0.6% |
| | System demand | **1,142** | **1,104** | **1,035** | **1,008** | **935** | **-18.1%** |
| **1-in-20 peak day** | Tariff V | 1,015 | 983 | 910 | 859 | 785 | -22.7% |
| | Tariff D | 234 | 226 | 223 | 244 | 237 | 1.5% |
| | System demand | **1,249** | **1,209** | **1,133** | **1,103** | **1,022** | **-18.2%** |

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

As shown in **Figure 13**:

- The *Progressive Change* peak day demand forecast aligns with previous historical peak system demand days that vary based on the actual coldest day for the year. Winter 2019 and winter 2020 both experienced several cold days during August, whereas system demand did not exceed 1,000 TJ during August 2021.
- The *Step Change* peak day forecasts represent a significant reduction in peak day demand over historical levels.

Figure 13 Historical peak day maximum system demand and forecast peak day system demand, 2013-26 (TJ/d)




### 2.3.2 Monthly peak day demand for 2022

**Table 13** shows forecast peak day system demand for each month during 2022 for *Progressive Change* (note there is only a small difference between the *Progressive Change* and *Step Change* scenarios in 2022). The peak day system demand is forecast to occur during the three coldest winter months: June, July, and August.

Table 13 Forecast monthly peak day demand for 2022, *Progressive Change* scenario (PJ/m)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1-in-2** | 392 | 409 | 473 | 670 | 917 | 1,082 | 1,108 | 1,080 | 903 | 749 | 596 | 437 |
| **1-in-20** | 440 | 478 | 614 | 832 | 1,047 | 1,186 | 1,221 | 1,231 | 1,028 | 871 | 738 | 575 |

### 2.3.3 Ongoing impact of COVID-19 on the daily demand profile

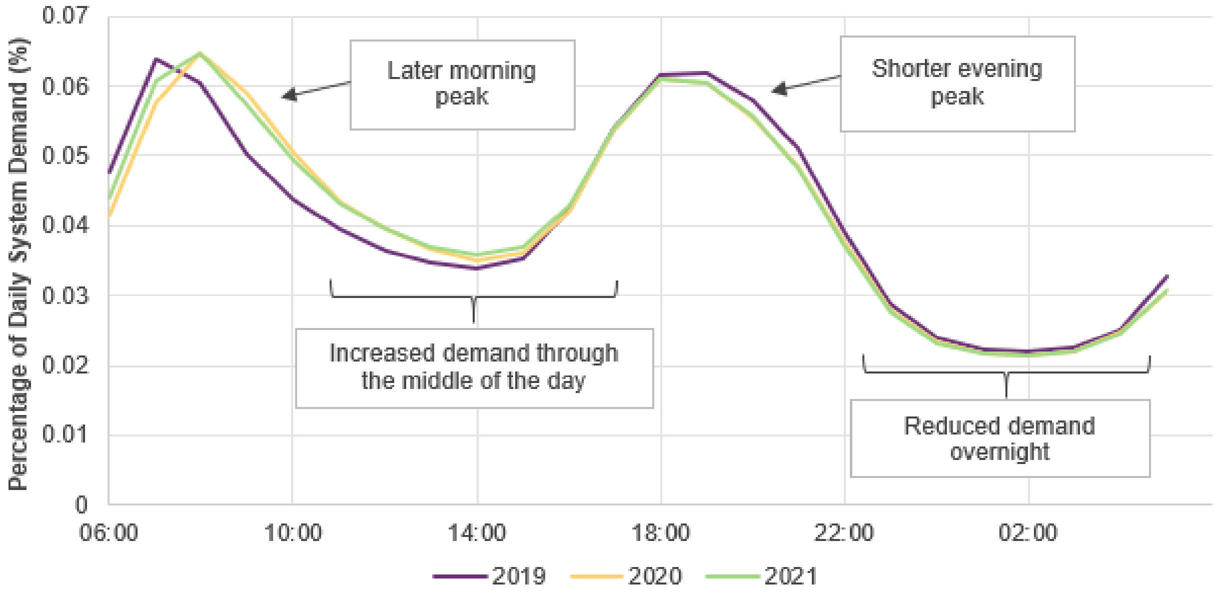
Victorian residents and businesses were subject to various levels of movement restrictions due to the COVID-19 pandemic during winter 2021. This resulted in a continuation of the behaviour observed in winter 2020, including:

- Reduced commercial and industrial activity.
- Reduced social activity including restaurant dining and sporting matches.
- A large proportion of the population working from home.

**Figure 14** shows that the average percentage demand profile[37] on winter weekdays in 2021 was almost identical to that observed in 2020. The figure also highlights the differences between 2021 and 2020 (pandemic profile), and 2019 (typical profile).

[37] Note that the average percentage demand profile is shown to *normalise* for weather effects.

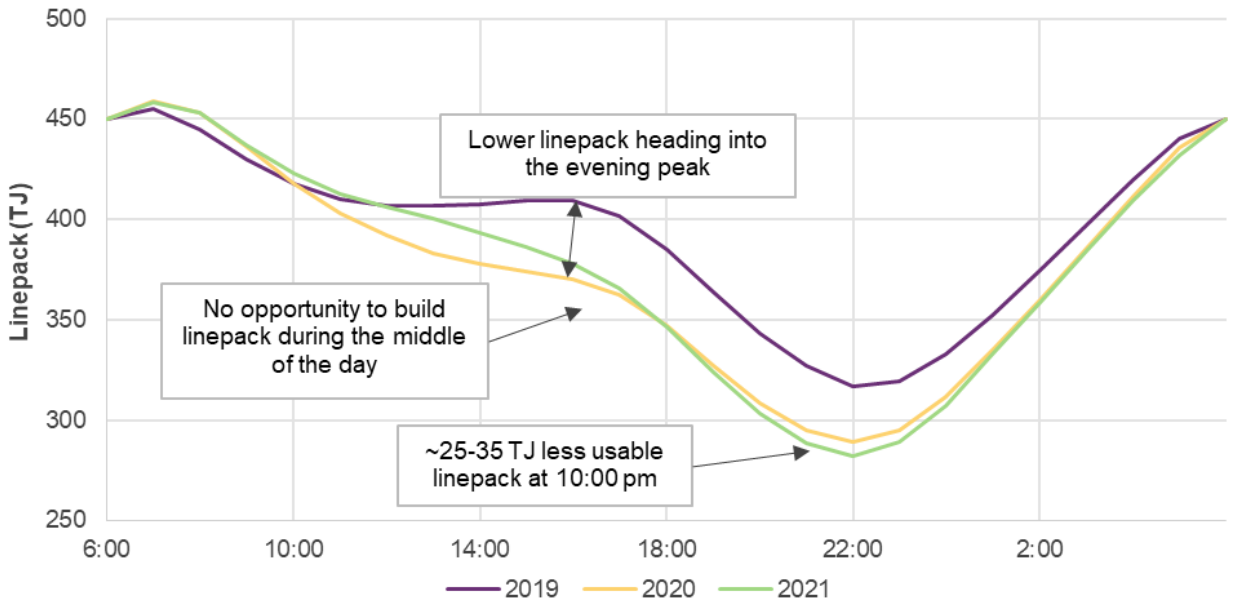
Figure 14 Average percentage of weekday winter system demand profile in 2019, 2020 and 2021




As highlighted in the 2021 VGPR and shown in **Figure 15**, the pandemic profile has the following impacts in comparison to a typical profile:

- A greater proportion of daily system demand occurs before 10:00 pm, which reduces the usable system linepack at 10:00 pm[38].
- There is limited opportunity to build system linepack during the middle of the day. This reduces system resilience leading into the evening peak, increasing the likelihood of Dandenong LNG being required to manage system pressures.

Figure 15 Impact demand profile on system linepack for a perfectly forecast, 1,100 TJ day in 2019, 2020 and 2021




38 This is a critical time operationally, as it corresponds to the time of minimum system linepack, and minimum system pressure.

There were no threats to system security during winter 2021 due to a generally mild winter and improvements to AEMO's demand forecasting processes.

AEMO anticipates 'working from home' arrangements may be maintained throughout the recovery from the COVID-19 pandemic, and that the system demand profile in 2022 may be similar to those observed in 2020 and 2021. AEMO therefore expects that the demand profile on high system demand days will continue to 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[39] to minimise interventions by AEMO.

## 2.4 Gas generation forecasts

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

As highlighted in the 2022 Draft ISP, gas generation will play a crucial role as coal generation retires. It will compliment battery and pumped hydro generation to support periods of peak demand, particularly during periods when output from VRE is limited, as well as provide critical grid security and stability services[40].

The gas generation forecasting methodology assumed generation and transmission assets were developed in line with the optimal development pathway and the *Step Change* scenario detailed in the 2022 *Draft Integrated System Plan*[41] (ISP), and incorporated the most recent assumptions on gas prices, demand forecasts, bidding behaviour, and information on committed generation projects. The *Step Change* scenario best reflects the current state of the electricity market, in terms of the economic recovery following the initial slump due to COVID-19 that was observed in 2020-21, with strong levels of electricity demand, PV penetration, and technology developments forecast.

Gas generation forecasts are produced for a variety of scenarios that account for various combinations of weather patterns and generator outages. Therefore, the potential uses for gas generation are varied and depend on actual weather conditions and generator availability.

This section has reported a range of potential gas generation forecast outcomes, rather than an average across all weather conditions.

DTS gas generation consumption forecasts are subject to a wide range of uncertainties, including:

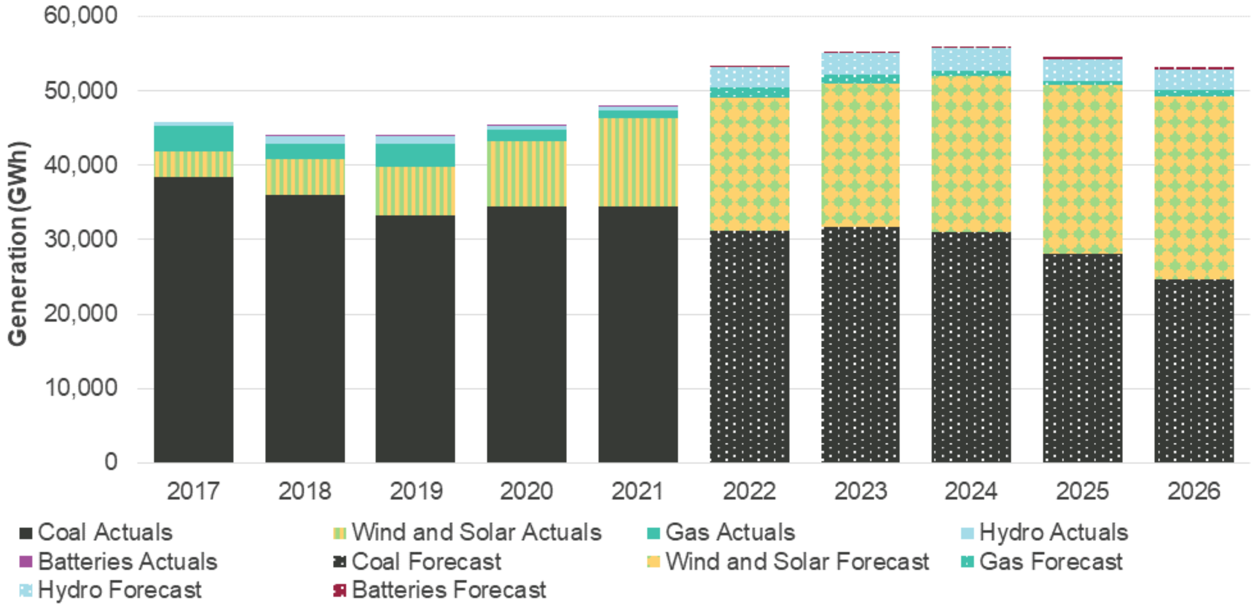
- **Timing of installation of renewable energy projects**, both large-scale and behind-the-meter. A large amount of VRE is forecast to be commissioned in Victoria from 2022, as shown in **Figure 16**. If forecast investments in VRE are delayed or do not proceed, gas generation consumption is likely to be higher than in Table 14 (in Section 2.4.1).

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

[40] AEMO, "Draft 2022 Integrated System Plan", pg. 10, at: https://www.aemc.gov.au/rule-changes/dwgm-distribution-connected-facilities.

[41] See https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en.

**Figure 16 Historical and forecast Victorian electricity generation, *Step Change* scenario, 2017-26 (GWh/year)**




- **Weather variability**. Gas generation 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 generation. Possible impacts of weather variability on gas generation consumption are presented in this section.
- **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. The project of particular interest in the outlook period is Project EnergyConnect, connecting South Australia and New South Wales in 2025. If the completion of this project is delayed, Victorian gas generation consumption is likely to be higher than reported in Table 14.
- **Major transmission outages**. Outages of key electricity transmission assets in the NEM can result in increased levels of gas generation.
- **Uncertainty around early closure of coal-fired generators**. These gas generation forecasts consider the early closure of some coal fired generators as modelled in the *Step Change* scenario. Although this is considered the most likely retirement path in the 2022 Draft ISP, deviations from this could affect gas generation consumption. This is reflected by the recent announcement that Origin Energy's Eraring coal-fired power station will close in 2025[42], seven years ahead of schedule (which has been incorporated in the forecast), and the rejected takeover bid of AGL that sought to retire its coal-fired generators 15 years ahead of schedule[43].
- **Reliability of coal-fired generators**. Unavailability of coal-fired generators can greatly increase gas generation consumption. For example, gas generation consumption increased by approximately 10 PJ

[42] See https://www.abc.net.au/news/2022-02-17/origin-to-shut-eraring-power-station-early/100838474#:~:text=Origin%20Energy%20is%20seeking%20approval,to%20close%20by%20August%202025.

[43] See https://www.abc.net.au/news/2022-02-21/agl-rejects-mike-cannon-brookes-brookfield-bid/100847318.

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. Similarly, very high gas generation was observed in June 2021 due to flooding impacting the Yallourn coal mine[44].

- **Operating behaviour of coal-fired generators**. Seasonal mothballing and shutting down at times of low prices are examples of behaviour that may impact the level of gas generation.
- **Gas prices**. Gas prices varying from projected levels may impact the amount of gas generation offered in the NEM.

### 2.4.1 Annual gas generation consumption forecast

**Figure 17** shows historical annual DTS gas generation consumption from 2017 to 2021, and a range of annual gas generation consumption forecasts from 2022 to 2026. The maximum and minimum forecasts in this figure relate to forecast variability due to weather. The average gas generation forecast for all scenarios is presented in **Table 14**.

Figure 17 Historical and forecast minimum and maximum annual DTS gas generation consumption, 2017-26 (PJ)

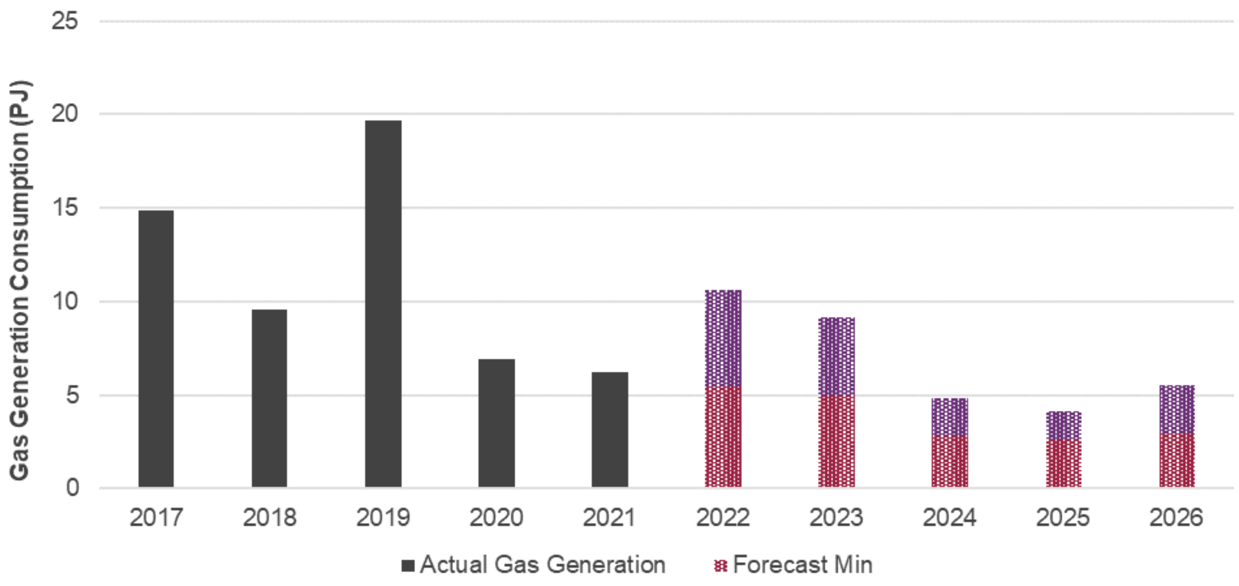



Table 14 Gas generation consumption forecast, 2022-26 (PJ/y)

| | 2022 | 2023 | 2024 | 2025 | 2026 | Change over outlook |
|---|---|---|---|---|---|---|
| **DTS gas generation consumption** | 7.8 | 7.1 | 4.0 | 3.5 | 4.4 | -43.0% |
| **Non-DTS gas generation consumption** | 9.7 | 8.6 | 5.7 | 5.0 | 6.0 | -37.7% |
| **Victorian gas generation Consumption** | 17.4 | 15.7 | 9.7 | 8.5 | 10.4 | -40.1% |

The following important points are shown in both Figure 17 and Table 14:

- DTS gas generation consumption is forecast to reduce by 43% over the outlook period.

[44] See https://www.abc.net.au/news/2021-06-17/victoria-declares-state-energy-emergency/100222092.

- Compared to the 2021 VGPR, this is less than the previous forecast reduction of 71.1%, and gas generation consumption forecasts are now higher – forecast DTS gas generation consumption in the 2021 VGPR was 2.19 PJ in 2022 and 0.92 PJ in 2025. The increase in forecast consumption is driven by increased NEM demand in the *Step Change* scenario and coal generator unavailability.

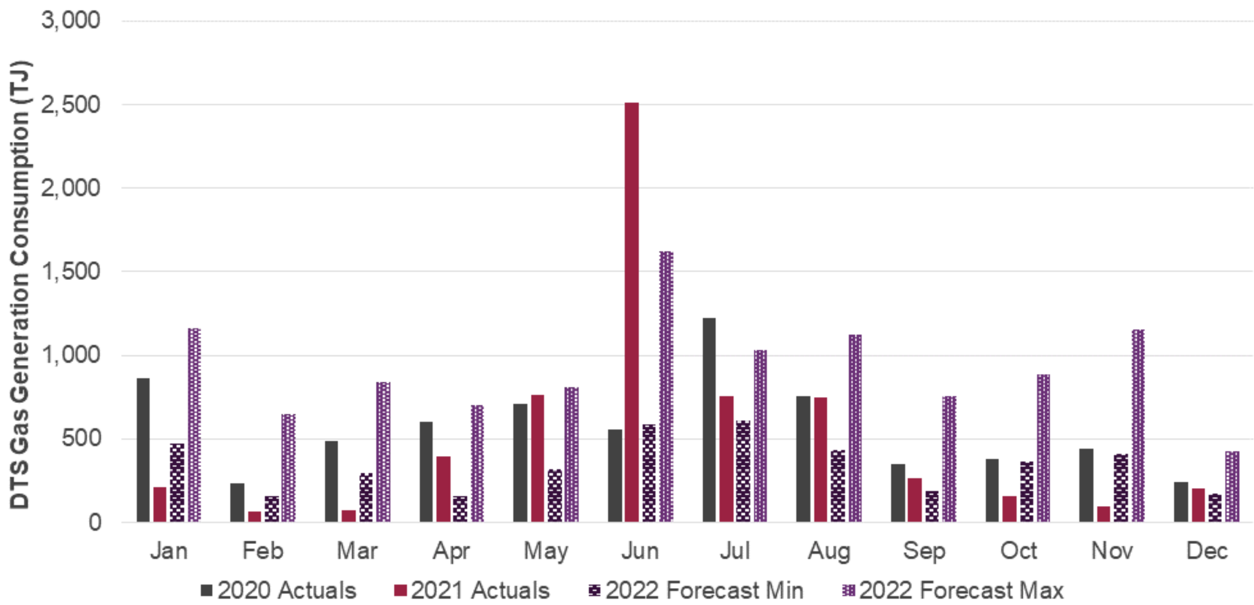
- Weather uncertainty and generator outages create a broad range in forecast annual gas generation consumption, particularly early in the outlook period.
- The reduction in forecast gas generation consumption over the outlook period is driven by increasing solar and wind generation capacity (shown in Figure 16), as well as small amounts of battery storage and distributed energy resources (DER).
- Forecast consumption decreases until 2025, then increases slightly in 2026 due to announced and forecast coal unit closures in the *Step Change* scenario.

### 2.4.2 Monthly gas generation forecast

**Figure 18** shows actual monthly DTS-connected gas generation consumption of gas in 2020 and 2021, and the predicted minimum and maximum monthly forecast consumption for 2022.

Monthly gas generation 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. The forecast shows that monthly gas generation consumption is projected to peak in June, driven by a combination of high NEM demand, coal generator outages, and limited VRE output. For actual consumption, June 2021 experienced very high gas generation consumption due to the extended outage of the Yallourn Power Station.

**Figure 18 Monthly DTS-connected gas generation consumption, actual 2020-21 and forecast 2022 (TJ/m)**




### 2.4.3 Seasonal peak gas generation forecast

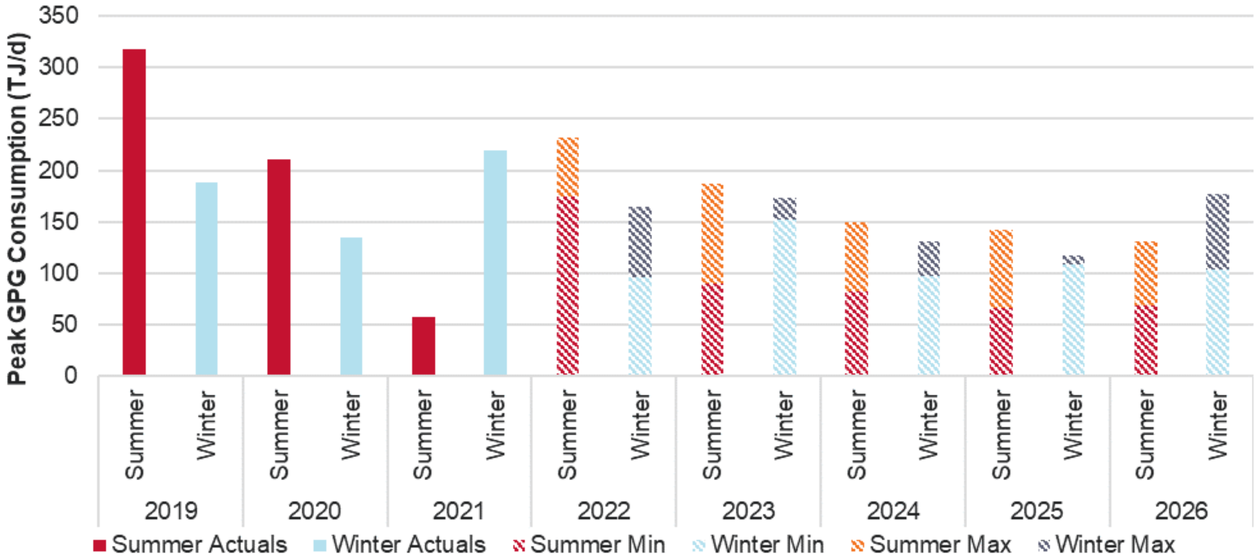
**Figure 19** shows that despite a forecast reduction in annual consumption for gas generation, maximum gas generation demand during the winter peak period is expected to remain high, and in some years during the outlook period it is forecast to exceed the forecast maximum summer gas generation demand.

This trend is driven by increasing penetration of VRE and a reduction in available dispatchable capacity in the NEM, leading to an increased requirement for gas generation on cold, still days during winter. The 2022 GSOO reports that gas generation demand is forecast to become increasingly 'peaky' beyond this VGPR Update's outlook period, and in some scenarios, a month's worth of gas generation consumption may be used in a few days.

It is important to note that the seasonal peak gas generation shown in Figure 19 has the potential to coincide with a peak system demand day.

Significant gas generation consumption during the winter period may create operational challenges and has the potential to lead to a threat to system security if gas generation demand is not forecast accurately from the beginning of the gas day, or it is higher than available gas supply.

**Figure 19 Historical and forecast seasonal maximum and minimum DTS gas generation demand in summer and winter, 2019-26 (TJ/d)**



# 3 Gas supply adequacy forecast

## Key findings

- The Port Kembla Energy Terminal (PKET) project was considered a committed project in the 2021 VGPR and GSOO with supply available from winter 2023. There are **two key changes to how this project is viewed for the 2022 VGPR Update**:
  - PKET supply is currently considered anticipated, based on advice from project proponent Australian Industrial Energy (AIE) that there are currently insufficient contracted volumes at PKET to justify the relocation, leasing, and operating expenses of the FSRU.
  - Supply from PKET would be available for winter 2024. AIE's construction schedule has been delayed, partly in response to a lack of customer demand for 2023 with planned completion in Q4 2023. Jemena continue to progress works on the Port Kembla lateral, which is required for PKET supply.
- **Available Victorian production is projected to decline by 33% in the next five years**, from 360 PJ in 2022 to 243 PJ in 2026. This is higher than what was reported in the 2021 VGPR, due to a combination of increased forecast production from already producing fields and newly committed projects.
  - From 2023, Victorian gas production is forecast to flatten. Both the monthly winter peaking production capacity and the associated peak day supply capacity will significantly decrease, which increases the imbalance between winter production and demand.
  - Victoria is becoming increasingly reliant on the Iona UGS facility to supply seasonal demand. Net imports from New South Wales (effectively from Queensland) are forecast to be required during winter from 2023 to supply seasonal demand under both scenarios.
  - The seasonal supply demand balance is tight in winter 2026 under the *Progressive Change* scenario. Prolonged unplanned outages of gas production facilities, or of coal-fired generators (which would increase gas generation), could result in a risk to seasonal supply demand as early as winter 2023.
- The **peak day supply demand balance remains finely balanced** over the outlook period, with a slight improvement since the 2021 VGPR.
  - Victorian peak day supply capacity available to the DTS is expected to decline by 28%, from 1,552 TJ/d in 2022 to 1,121 TJ/d in 2026.
  - Under the *Progressive Change* scenario:
    - Projected peak day supply is sufficient to meet 1-in-20 forecast demand from 2022-24. A negligible shortfall is forecast for winter 2025 which could be supplied from non-firm sources, and a 130 TJ shortfall is forecast in winter 2026 under 1-in-20 peak demand conditions without additional supply.
    - The supply demand balance in 2023 on a 1-in-20 peak day is tight, with available supply of 1,287 TJ/d, and demand of 1,248 TJ/d. There are no anticipated supply options to improve the supply outlook by winter 2023. Duplication of the Winchelsea compressor, if it was able to be completed prior to winter 2023, would increase SWP capacity by a further 52 TJ/d to 528 TJ/d.

  - Development of anticipated supply projects from 2024 is important to provide supply for coincident gas generation, and to increase resilience to transmission or production outages which coincide with peak demand conditions.
- Under the *Step Change* scenario:
  - Peak day supply is sufficient to meet 1-in-20 forecast demand throughout the outlook period. For a 1-in-20 peak day in winter 2026, 50 TJ of New South Wales supply or Dandenong LNG is required to meet demand.
  - The supply demand balance in 2023 on a 1-in-20 peak day improves slightly in comparison to the *Progressive Change* scenario, with demand of 1,209 TJ and available supply of 1,287 TJ/d.

## Background

AEMO assesses supply adequacy based on its demand forecasts (see Chapter 2) and the forecast available Victorian supply from data provided to AEMO by producers, storage providers, pipeline operators, and market participants. This assessment includes commentary on supply from outside of Victoria through the Culcairn interconnection, as modelled in the 2022 GSOO.

During consultation for the 2022 ISP, stakeholders identified *Step Change* as the scenario they considered to be the most likely pathway for Australia's energy sector. In the absence of significant additional policy commencing, there is also a material risk that in the near term gas use will not reduce in line with the *Step Change* scenario from 2023-26.

The VGPR is primarily a security of supply assessment document, reporting on the forecast supply demand balance and identifying potential risks to that balance. Considering the supply challenges as early as next winter, AEMO has therefore assessed supply adequacy using the both the *Step Change* and *Progressive Change* scenarios in forecasts of consumption and peak demand for the outlook period.

As government policy and electrification of gas heating load progresses, AEMO will refine these scenarios and update its supply adequacy assessments in future reports.

AEMO assesses adequacy over three time periods in the VGPR:

- **Annual demand** – an annual supply shortfall indicates that annual production is projected to be insufficient to meet forecast annual demand, and is likely to be realised throughout the winter period, including on peak demand days. Supply from storages and pipeline constraints are not considered.
- **Seasonal (monthly) winter demand** (1 May to 30 September inclusive) – a seasonal supply demand imbalance indicates that a combination of production, Iona UGS, and interconnected pipeline flows is projected to be insufficient to meet forecast demand. Supply from Iona UGS (deep storage) and pipeline constraints are considered. A seasonal supply shortfall will likely be realised on multiple days throughout winter, including on peak demand days.
- **Peak day demand** (1-in-2 and 1-in-20) – a peak day shortfall indicates that supply is projected to be insufficient to meet forecast peak day demand on peak days only. Supply from Iona UGS (deep storage) and Dandenong LNG (shallow storage) and pipeline constraints are considered.

## Gas supply classification

**Table 15** defines gas supply classifications used in this 2022 VGPR Update, with notes on the differences to these classifications in the 2022 GSOO and the Petroleum Resources Management System (PRMS)[45].

**Table 15 Gas supply classification definitions**

| VGPR | 2022 VGPR Update 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 5. | 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. They are considered less likely to proceed than the anticipated supply projects during the outlook period, due to:<br>• 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<br>• Insufficient gathering pipeline or appropriate gas processing capacity being available; or<br>• The project requiring new infrastructure that currently does not have approved planning permits or environmental approvals. | Contingent Resources: Development Pending, Development on Hold, Development Unclarified | Uncertain supply |
| **Exploration projects** | These projects are associated with undiscovered gas resources that are usually mapped using seismic data. These have not been physically proven with exploration wells, so commercial quantities of hydrocarbons may not actually be present. Neighbouring wells and seismic data are used to estimate the 'gas in place', with the reported prospective resource volumes usually representing the estimated recoverable volume of hydrocarbons. These are not included in any of the supply forecasts but are discussed in the GSOO. | Prospective resources: Prospect/Leads/Plays | |

# 3.1 Updates to supply information impacting the supply demand balance

This section highlights updates to supply information, including key projects, that materially changes the supply demand balance, in comparison to what was presented in the 2021 VGPR. Further detail on these and other projects is in chapters 5 and 6.

[45] 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

### 3.1.1 Port Kembla Energy Terminal

The PKET was considered a committed project in the 2021 VGPR and GSOO, with supply available before winter 2023. The classification was based on the substantial commitments that project proponent AIE had made to progress it. There are two key changes regarding treatment of this project in the 2022 GSOO and VGPR Update:

- **PKET supply is currently considered anticipated**. AIE announced on 30 November 2021 that it had signed a long-term charter party agreement with the owner of the FSRU[46], which is a prerequisite for the vessel to be moored at Port Kembla. However, AIE has informed AEMO that there are insufficient contracted volumes at PKET to justify the relocation, leasing, and operating expenses of the FSRU. PKET cannot be considered as a committed project until AEMO is advised that there is sufficient contracted volumes.
  - AIE has indicated that customer contracting decisions are being impacted by increased LNG prices and near-term uncertainty caused by:
    - Rising global demand for gas due to the economic recovery from the COVID-19 pandemic.
    - Winter peaks in Europe combined with dwindling reserves.
    - The Ukraine-Russia conflict driving European countries to source gas from sources other than Russia[47]. This is increasing global demand for FSRUs.
  - Any extended period of uncertainty may delay customer contracting and therefore the timing of anticipated supply from PKET.
- **Supply from PKET would be available for winter 2024**. AIE remains committed to the construction of the wharf and associated pipeline infrastructure. AEMO has been advised that the project works will now not be completed until Q4 2023.

  Jemena continues to progress works on the Port Kembla lateral, which is required for PKET supply. Jemena is also progressing the EGP reverse flow project to enable gas to flow from PKET to VicHub. Planned completion will be in line with PKET project's receiving and gasification unit.

Further detail on PKET can be found in Section 5.4.

### 3.1.2 Moomba to Sydney Pipeline capacity

On 5 May 2021, APA announced a $270 million 25% expansion of the Moomba to Sydney Pipeline (MSP) and the South West Queensland Pipeline (SWQP) that will be completed in multiple stages[48]. A further possible third stage was also announced.

APA has committed to Stage 1 of the MSP and SWQP expansion. This will increase the nominal capacity of the SWQP by 49TJ/d from 404 TJ/d to 453 TJ/d and the MSP by 30 TJ/d from 446 TJ/d to 475 TJ/d, prior to winter 2023. This expansion will support increased injections from the Young Compressor Station on the MSP, into the DTS via Culcairn.

Stage 2 of the MSP expansion is currently considered as a potential project for the purposes of VGPR modelling as it is yet to reach FID. Further details on this expansion can be found in Section 5.5.

[46] See https://ausindenergy.com/2021/11/30/aie-and-hoegh-lng-sign-deal-to-secure-nsw-and-victorias-energy-future-co-develop-new-generation-clean-energy-transport-potential/.

[47] See https://www.cnbc.com/2022/02/24/russia-ukraine-crisis-could-see-gas-supply-ramifications-for-the-world.html/.

[48] See https://www.apa.com.au/about-apa/our-projects/east-coast-grid-expansion/.

### 3.1.3 Golden Beach

Golden Beach was reported as an anticipated project in the 2021 VGPR, with production commencing prior to winter 2023. Project delays mean that production from Golden Beach will not commence until 2024. Golden Beach remains an anticipated project. Further detail regarding the Golden Beach Project may be found in Section 5.2.

### 3.1.4 Kipper field development

The Kipper development is progressing, with committed additional supply from the Kipper compression project expected in 2024[49]. This development will assist in minimising the reduction in Gippsland capacity between 2023 and 2024 that was reported in the 2021 VGPR. Further detail may be found in sections 5.1 and 5.2.

## 3.2 Annual supply demand balance

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

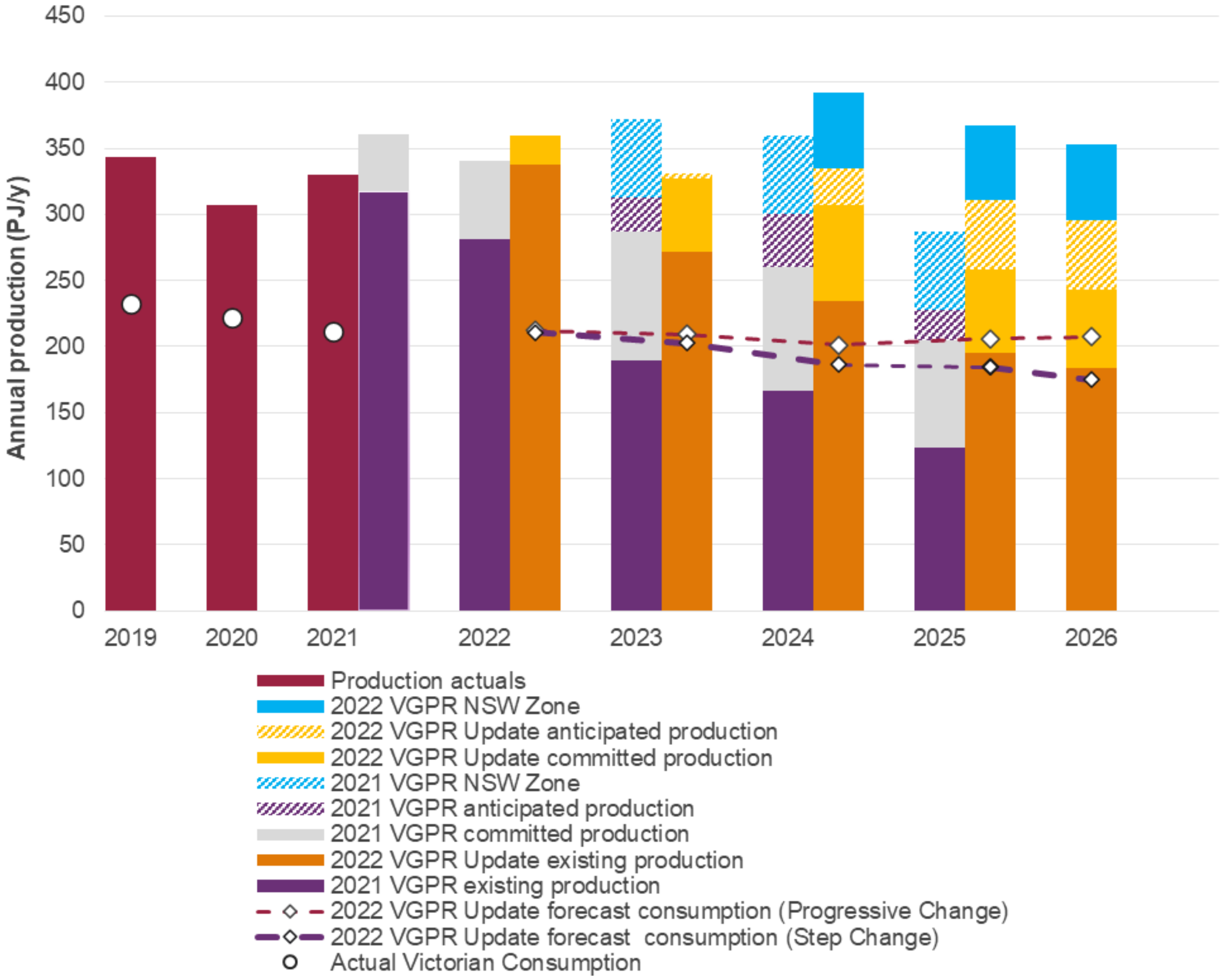
The section does not consider DTS storage facilities, because these facilities provide seasonal balancing for peak demand periods and are not expected to provide annual supplies.

### 3.2.1 Annual production forecasts

**Figure 20** shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2021 VGPR.

[49] ExxonMobil, "Esso Australia to Expand Gas Development in the Gippsland Basin", 17 March 2022, at https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2022/Esso-Australia-to-Expand-Gas-Development-in-the-Gippsland-Basin.

**Figure 20 Historical and forecast annual supply, *Step Change* and *Progressive Change* and compared to 2021 VGPR, 2019-26**




## Gippsland zone[50]

Total available supply from Gippsland fields is forecast to decline 36% from 312 PJ in 2022 to 200 PJ in 2026. This increase from the 2021 VGPR forecast (from 292 PJ in 2022 to 153 PJ in 2025) is driven by an increase in production from already producing Longford fields and committed Kipper field supply from early 2024.

The largest reduction in available Gippsland production is forecast to occur prior to winter 2023, which is in line with the forecast provided in the 2021 VGPR. This is driven by a decline in production from large legacy Gippsland Basin Joint Venture (GBJV) fields, which are forecast to cease production prior to winter 2023. There is some uncertainty in the remaining volumes in these large legacy gas fields:

- As reported in the 2021 VGPR, GBJV's large legacy fields are predominantly aquifer-driven. Aquifer-driven reservoirs are characterised by rapid and less predictable production declines at the end of their field life. The age and size of these fields, combined with varying production quantities, also creates uncertainty.

[50] Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP, and TGP.

- Esso is continuing to monitor the performance of its production fields and will keep AEMO informed of developments impacting production performance.

Anticipated production projects that may increase supply in the Gippsland zone include:

- Golden Beach from winter 2024.
- Yolla and Trefoil developments from 2025 (Lang Lang Gas Plant).
- Further development of the Kipper field.

Further details on these projects can be found in Chapter 5.

### Port Campbell zone[51]

Forecast total available production (existing and committed) from the Port Campbell zone is similar to that reported in the 2021 VGPR. Production is forecast to increase from 33 PJ (actual) in 2021 to 48 PJ in 2022 and 69 PJ in 2023, then to decrease to 42 PJ in 2026.

The Enterprise field is an anticipated supply project that may further increase Port Campbell production. Further details can be found in Chapter 5. Any increase in production from this field may be limited by the processing capacity of the Otway Gas Plant.

Peak day supply from production facilities at Port Campbell, along with supply from the Iona UGS facility, is expected to be constrained by the capacity of the SWP, even with the commissioning of the WORM.

### New South Wales zone

This zone was introduced in the 2021 VGPR to include net supply from New South Wales into Victoria. This was required because forecast depletion of Victorian production may require net imports into Victoria to satisfy forecast demand, particularly on peak demand days.

The New South Wales zone encompasses the following flows into Victoria:

- Flows into the DTS via Culcairn and the MSP. Gas originates from Moomba or Queensland.
- Flows into the DTS via VicHub with southbound flow on the EGP (after the EGP reversal project, see Section 3.1.1). Gas originates from PKET or the Orbost Gas Plant.

The combined delivery capacity from New South Wales into Victoria, if PKET is available and the EGP has reverse flow capability, is 380 TJ/d[52]. Anticipated supply of 11.4 PJ per month over winter from 2024 has been assumed for planning purposes.

## 3.2.2 Annual supply adequacy

**Table 16** shows the annual supply adequacy forecast over the outlook period.

[51] Port Campbell includes the Otway and Athena gas plants. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

[52] This is less than the capacity reported in the 2021 VGPR of 395 TJ/d, due to a reduction in capacity of the Culcairn interconnection point. Refer to Section 7.3 for more details.

**Table 16 Victorian annual available and anticipated supply balance, 2022-26 (PJ/y)**

| Supply source | | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|
| Gippsland[A] | Available supply | **312** | **258** | **243** | **212** | **200** |
| | Anticipated supply | 0 | 0 | 21 | 38 | 39 |
| Port Campbell (Geelong)[B] | Available supply | **48** | **69** | **64** | **47** | **42** |
| | Anticipated supply | 0 | 4 | 7 | 14 | 14 |
| NSW[C] | Available supply | 0 | 0 | 0 | 0 | 0 |
| | Anticipated supply | 0 | 0 | 57 | 57 | 57 |
| Total VIC available supply | | 360 | 327 | 307 | 258 | 243 |
| Total VIC and NSW available supply | | 360 | 327 | 307 | 258 | 243 |
| Total VIC and NSW anticipated supply | | 0 | 4 | 85 | 109 | 110 |
| Progressive Change scenario | Total Victorian consumption | 212 | 209 | 201 | 206 | 208 |
| | Surplus quantity with VIC and NSW available supply | **148** | **118** | **106** | **52** | **35** |
| Step Change scenario | Total Victorian consumption | 211 | 202 | 186 | 184 | 175 |
| | Surplus quantity with VIC and NSW available supply | **149** | **125** | **121** | **74** | **68** |

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Project, Sole Gas project, and Lang Lang production facilities. Combined Longford production is gas available to the DTS, EGP, and TGP. Supply from the Lang Lang production facility is also used to supply some small loads in Lang Lang and off the South Gippsland pipeline.
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 PKET via the EGP through VicHub

The annual supply adequacy assessment indicates that:

- The forecast available supply exceeds forecast consumption for each year of the outlook period under both *Step Change* and *Progressive Change* scenarios. This is consistent with the 2021 VGPR.
- Victoria's annual production surplus is expected to decline over the outlook period, from:
  - 148 PJ in 2022 to 35 PJ in 2026 under the *Progressive Change* scenario; and
  - 149 PJ in 2022 to 68 PJ in 2026 under the *Step Change* scenario.
- This annual supply adequacy assessment for Victoria is subject to a number of limitations because it assumes there is sufficient production capacity throughout the year to meet demand.
  - During the summer months, Victorian monthly gas consumption and daily demands are generally lower than Victorian production. Production that is in excess of Victorian consumption is used to supply New South Wales, South Australia and Tasmania, and to refill the Iona UGS reservoirs.
  - Monthly consumption and daily demands during winter are substantially higher than Victorian production. Supply from the Iona UGS facility is used to support the increased Victorian gas use. Supply from Victoria to other states during winter reduces, and these states are increasingly being supplied with gas from Queensland.
  - To date, Victoria has remained a net exporter of gas, including during winter. Imports from New South Wales via Culcairn are less than the gas supplied to New South Wales via the EGP. The forecast large

reduction in Victorian production prior to winter 2023 is expected to result in Victoria becoming a net gas importer during winter. It is possible that winter consumption may exceed available production and storage capacity. Monthly (seasonal) adequacy is discussed in Section 3.3.2.

## 3.3 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. Commentary on DTS storage facilities and interstate supply from DTS-connected gas pipelines is included, because they are essential for balancing supply and demand during the winter period.

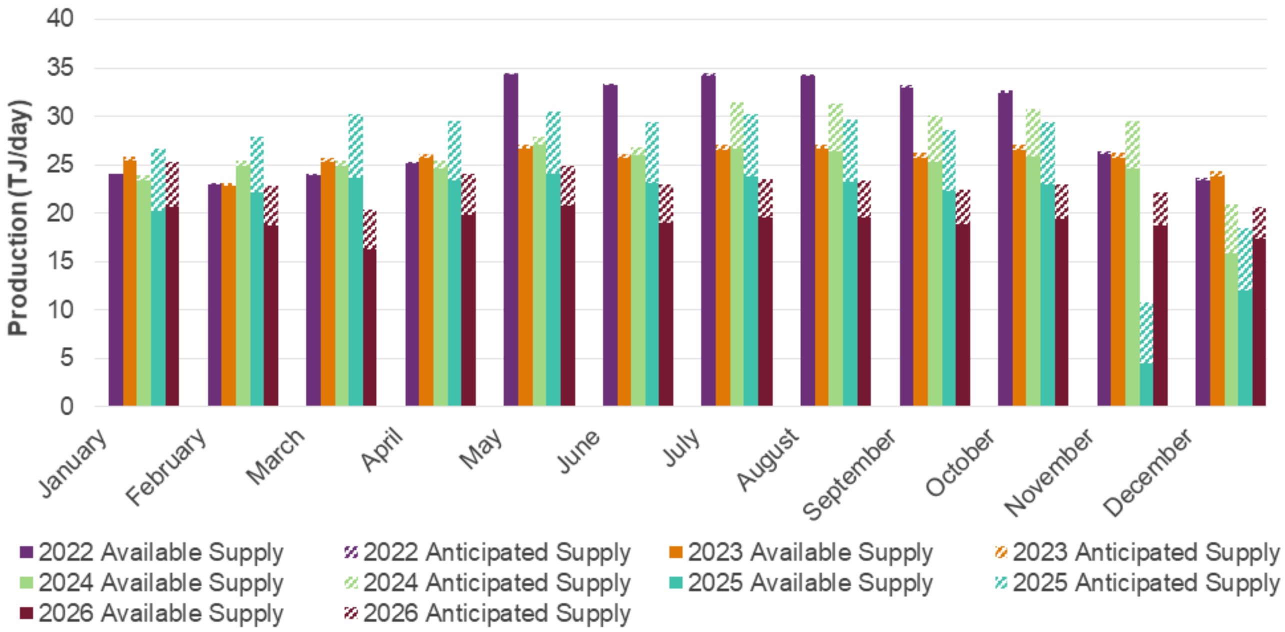
### 3.3.1 Monthly production forecasts

**Figure 21** shows forecast monthly production for the outlook period. The figure shows that:

- Forecast monthly gas production is expected to decline over the outlook period.
- Available winter monthly Victorian production is forecast to be less than monthly winter consumption (28-30 PJ/m) from 2023.

Monthly production forecasts are slightly higher than those presented in the 2021 VGPR for the same reasons as discussed in Section 3.2.1.

**Figure 21 Monthly production forecast, 2022-26 (PJ)**

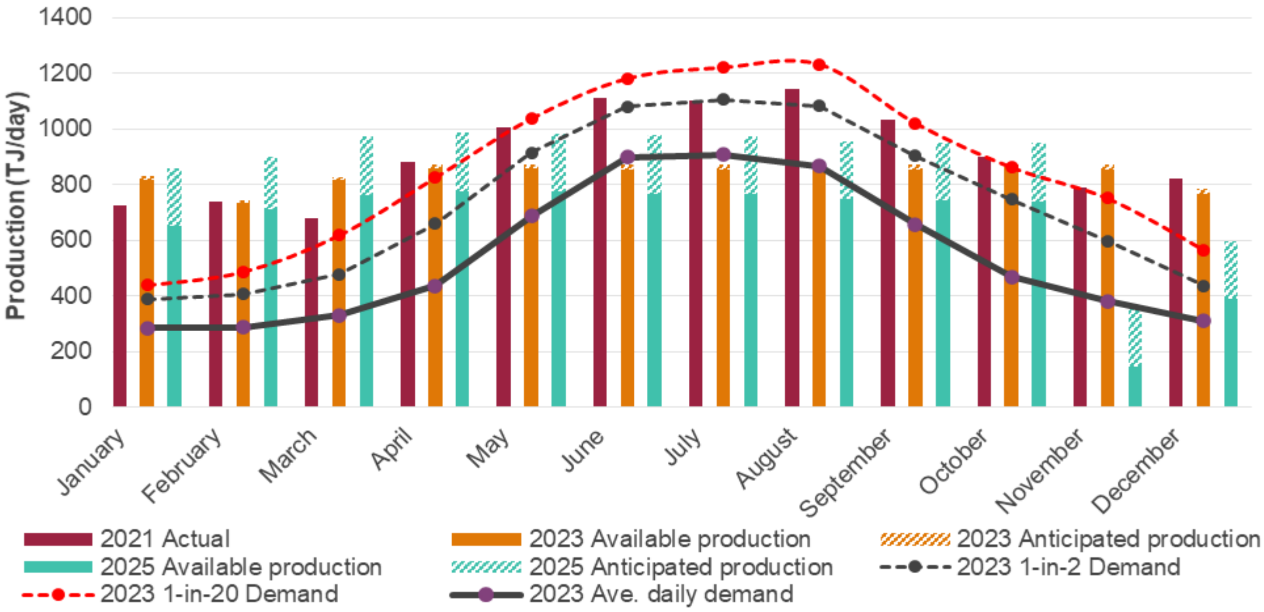



### 3.3.2 Monthly supply adequacy

As reported in the 2021 VGPR, 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 22 shows forecast production in 2023 and 2025, compared to 2021 actuals and the *Progressive Change* demand forecast for 2023. Demands under the *Step Change* scenario in 2023 are forecast to be approximately 3% lower.

**Figure 22 Average monthly production, and average and peak day system demands 2021-25 (TJ/d)**




The graph shows that 2021 average monthly winter production was more than Victoria's average monthly system demand.

The forecast reduction in Longford production capacity from 2023 will also result in a flatter supply profile. During the winter months, the average consumption exceeds average production from 2023, which means that:

- Supply from Victoria to other jurisdictions will be limited over the winter period.
- Victoria will need to rely on gas held in Iona UGS and potentially gas imports from Queensland via New South Wales to meet seasonal demand.

Modelling results from the 2022 GSOO have been used to estimate the quantities of gas that need to be made available from Queensland over the winter period to support winter consumption in the southern states[53] . The GSOO modelling considered demand across the entire east coast, and pipeline flows between jurisdictions.

**Table 17** and **Figure 23** present the minimum required flows from Queensland to the southern states to satisfy seasonal demand. The modelling used the following data and assumptions:

- The minimum required flows correspond to utilisation of 18.5 PJ of Iona UGS inventory during the winter period. This is approximately equal to the Iona UGS utilisation during winter 2021, which provides a buffer to cover unplanned outages or increases in demand while also maintaining Iona UGS at full supply capacity.

[53] The southern states are New South Wales and the Australian Capital Territory, Victoria, South Australia, and Tasmania.

- The range of Queensland supply requirements corresponds to possible demand conditions for both *Progressive Change* and *Step Change* scenarios. The average of the ranges in Table 17 is plotted in Figure 23.
- All production facilities and transmission assets are available at forecast capacities.
- The volume required is made available by Queensland producers.

The results show that:

- The amount of gas that needs to be supplied from Queensland is projected to increase over the outlook period under both scenarios, in line with the forecast Victorian production decline.
- The minimum required flows from 2022-25 under the *Progressive Change* scenario, and the flows across the entire outlook period under the *Step Change* scenario, are within historically observed flows between 2019 and 2021.
- The minimum required flows in 2026 under the *Progressive Change* scenario requires a very high utilisation of the MSP (near 90%). While this is possible, it indicates a tight seasonal supply demand balance because there would be little additional pipeline capacity available to support increased demand or unplanned outages.

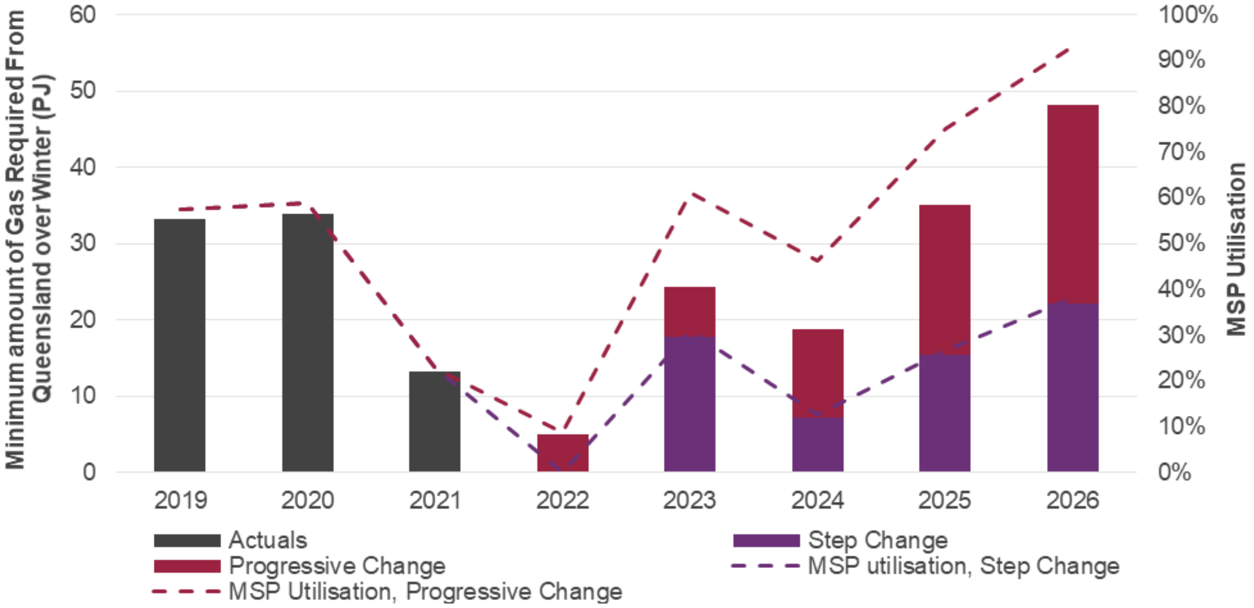
If the quantity of gas supplied from Queensland is less than the amounts presented in Table 17 and Figure 23, it is possible that Iona UGS storage will be depleted prior to the end of that winter.

The minimum volume required in 2022 is less than the actual supply from Queensland in 2021, due to a forecast increase in Port Campbell production and a forecast reduction in gas generation in the southern states. Unplanned events – including coal-fired generator and gas production facility outages (like those experienced in winter 2021, refer to Section 1.2.1) – will increase the minimum volume required to be supplied from Queensland. Section 4.2 discusses additional risks to the peak day supply demand balance.

**Table 17 Minimum required flows from Queensland to southern states to satisfy forecast seasonal demand, 2022-26**

| Year | Minimum required supply from Queensland to southern states (PJ) | |
|---|---|---|
| | *Progressive Change* | *Step Change* |
| **2022** | 0-5 | 0-5 |
| **2023** | 13-35 | 7-29 |
| **2024** | 11-27 | 0-14 |
| **2025** | 26-43 | 7-24 |
| **2026** | 41-53 | 13-31 |

**Figure 23 Historical and forecast Queensland gas supply to the southern states (PJ), 2019-26**




### Reliance on Iona UGS

The results of the seasonal adequacy assessment presented above assume that Iona UGS is at full capacity at the start of May. If Iona inventory is drawn down before this, or it has not been able to refill to its capacity, the amount of gas required from Queensland to prevent a supply shortfall increases.

Refilling the Iona UGS storage reservoirs relies on production being higher than consumption during the summer and shoulder periods. Historically, this is also when producer maintenance occurs. This reduces gas availability to refill storage and can result in storage depletion during summer if there is high gas generation utilisation.

Decreases in monthly production will reduce available gas supply for refilling storage. This may result in the need for increased gas supply to the southern states outside of winter, particularly during production facility maintenance, to ensure that Iona UGS is refilled before each winter.

If Iona UGS is depleted prior to the end of winter, significant supply capacity is lost. This is likely to result in gas shortfalls on moderate demand days during winter. This risk is explored further in sections 4.2 and 4.3. There was significant Iona UGS inventory depletion and concern about remaining supplies during winter 2021 (refer to Section 1.2.2).

## 3.4 Peak day supply demand balance

This section outlines the forecast Victorian peak day gas supply adequacy over the outlook period.

### 3.4.1 Forecast Victorian supply capacity

The forecast maximum daily Victorian supply capacity by SWZ, including capacity from the Iona and Dandenong storage facilities, is shown in **Table 18**. DTS capacity constraints and gas flows between the DTS and other jurisdictions are discussed in Section 3.4.2.

Based on advice from gas producers and storage providers, the available Victorian peak day supply capacity is forecast to decline by 28% over the outlook period:

- Gippsland peak day production capacity (including the Orbost Gas Plant) is forecast to reduce from 1,018 TJ/d in 2022 to 558 TJ/d in 2026. Demand on the EGP and in Tasmania that can only be supplied from Victoria reduces Gippsland supply into the DTS to 972 TJ/d in 2022 and 496 TJ/d in 2026. Gippsland production capacity during winter 2021 was 1,072 TJ/d.
  - This forecast is higher than the quantities reported in the 2021 VGPR, due to a smaller production capacity decline from already producing fields, and an increase in supply from newly committed projects.
  - As reported in the 2021 VGPR, Esso has advised that the depletion of its large legacy gas fields is driving the reduction in its forecast peak day capacity over the outlook period, particularly prior to winter 2023.
  - The Golden Beach anticipated supply development is forecast to commence production prior to winter 2024 with a capacity of 125 TJ/d. This gas field is expected to produce for approximately two years[54] prior to its development as gas storage reservoir with a 250 TJ/d supply capacity. This is classified as an anticipated supply development for winter 2026.
- Port Campbell facility operators (producers and storage) have advised that the maximum available daily supply capacity will increase from 719 TJ/d in 2022 to 803 TJ/d in 2023, then decrease to 725 TJ/d in 2026, unless additional anticipated projects are developed.
  - This forecast is higher than the quantities reported in the 2021 VGPR, which were 703 TJ/d in 2022, 726 TJ/d in 2023, and 677 TJ/d in 2025. This increase is primarily due to a committed expansion of Iona UGS from 530 TJ/d to 570 TJ/d (see Section 5.1) from 2023.
  - Anticipated development of the Enterprise gas field, and potential additional production field development and a further expansion of Iona UGS, would increase Port Campbell supply.

**Table 18 Peak day maximum daily quantity (MDQ) capacity by SWZ, 2022-26 (TJ/d)**

| SWZ | Supply source | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|
| **Gippsland**[A] | Available | 1,018 | 724 | 715 | 676 | 558 |
| | Anticipated | - | - | 125 | 169 | 358 |
| | **Total available plus anticipated** | **1,018** | **724** | **840** | **846** | **915** |
| **Port Campbell (Geelong)**[B] | Available | 719 | 803 | 778 | 732 | 725 |
| | Anticipated | 7 | 15 | 31 | 39 | 23 |
| | **Total available plus anticipated** | **726** | **818** | **809** | **772** | **748** |
| **Melbourne** | Available | 87 | 87 | 87 | 87 | 87 |
| **Total Victorian supply** | Total VIC available | 1,825 | 1,614 | 1,581 | 1,496 | 1,369 |
| | Total VIC anticipated | 7 | 15 | 156 | 209 | 381 |
| | **Total VIC available plus anticipated** | **1,831** | **1,630** | **1,736** | **1,704** | **1,750** |

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford GBJV, Longford Kipper Project, Lang Lang and Orbost production facilities. The combined Gippsland number is gas available to the DTS, EGP, and TGP. All of this capacity cannot be supplied into the DTS due to EGP and TGP demand.
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. All of this capacity cannot be supplied into the DTS due to SWP capacity constraints.

54 See https://gbenergy.com.au/production.

### 3.4.2 Peak day supply adequacy

AEMO's peak day supply adequacy assessment uses 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. This assessment includes expected supply to the DTS from other jurisdictions, as well as pipeline constraints.

The forecasts shown in **Figure 24** and **Table 19** used the following data and assumptions:

- Forecast annual 1-in-2 and 1-in-20 peak day system demands, discussed in Chapter 2.3.
- 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.
- Available Gippsland supply does not include the portion of Longford and Orbost gas plant supply that is needed to supply demand along the EGP including in south-east New South Wales that cannot be supplied from any other source, as well as Tasmanian demand.
- 'Anticipated DTS expected supply' considers anticipated production projects.
- 'Available NSW Supply' is the expected level of peak day supply made available to the DTS via Culcairn. This has been developed using a supply demand balance that includes supply via the MSP, forecast New South Wales and Canberra demand, and the expected EGP supply from Victoria, as well as GSOO modelling outcomes. The analysis assumes that there is no net flow between Victoria and New South Wales (that is, supply via Culcairn into Victoria equals the supply to New South Wales via the EGP).
- 'Expected Anticipated Supply' from the New South Wales supply zone increases available plus anticipated supply to 380 TJ/d on peak days from winter 2024 following the anticipated commissioning of PKET. This includes the supply from MSP via Culcairn, and from the PKET via VicHub injection point.
- Demand from gas generation was not considered. Total demand on a 1-in-2 system demand day combined with moderate gas generation demand is equivalent to a 1-in-20 system demand day. Events in the NEM (including coal generator outages and low wind and solar generation) could result in high gas generation demand.

Figure 24 and Table 19 highlight the following key points:

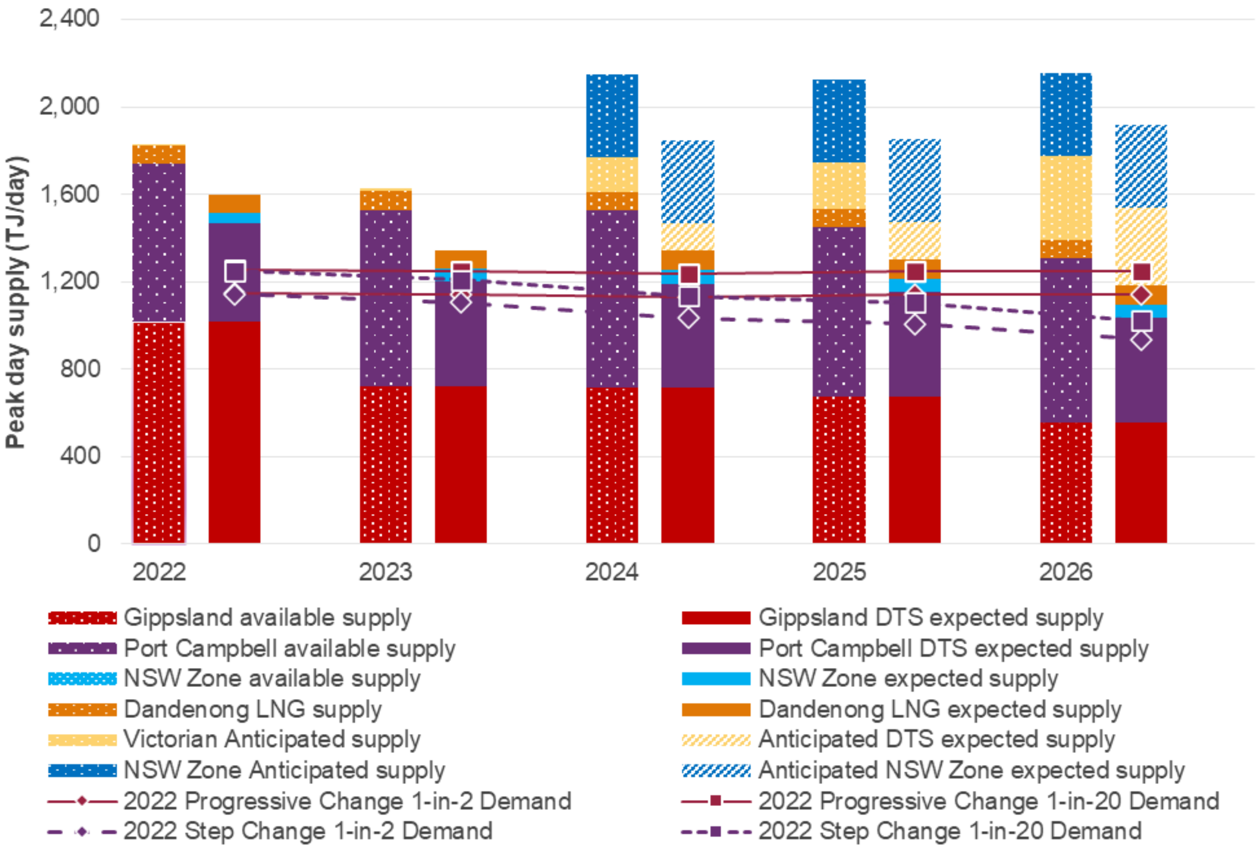
- Although there is sufficient peak day supply for winter 2023, the supply demand balance is tight for both the *Progressive Change* and *Step Change* scenarios. Dandenong LNG injections are required to satisfy a 1-in-2 year system demand with moderate generation or a 1-in-20 year system demand. There is likely to be insufficient capacity to support high levels of gas generation on a peak day. The system is unlikely to be able to support the record total demand of 1,308 TJ on 9 August 2019 and may not support the 1,243 TJ of total demand on 4 August 2020 without the curtailment of gas generation.
- No anticipated supply or DTS augmentations projects are expected to be able to be implemented prior to winter 2023 to improve the supply outlook, except for duplication of the Winchelsea compressor (discussed earlier in the document).
- The supply demand balance for winter 2024 and 2025 is also finely balanced (a negligible shortfall is indicated for 2025 that could be supplied from non-firm sources including Dandenong LNG[55], other supply facilities and pipeline linepack) under the *Progressive Change* scenario, with Dandenong LNG required to

[55] Firm Dandenong LNG is up to 5.5 TJ/h, and non-firm LNG is up to 9.9 TJ/h.

support peak day demand. The forecast reductions in Gippsland production capacity are offset by forecast reductions in peak day demand. The supply demand balance tightness is reduced under the *Step Change* scenario with Dandenong LNG less likely to be required on peak days.

- The development of anticipated supply projects is important to provide additional supply to support coincident gas generation, and to increase resilience to production, storage or transmission outages coinciding with peak demand conditions.
- Development of anticipated supply is required to avert shortfalls on peak system demand days in 2026 under the *Progressive Change* scenario. Under the *Step Change* scenario, there is no forecast shortfall.
- The Port Campbell peak day maximum daily quantity (MDQ) is expected to continue to be constrained by the SWP transportation capacity limit. This includes the assumption that the supply capacity increases to 476 TJ/d in winter 2023 following the expected commissioning of the WORM (see Section 6.1).

**Figure 24 Forecast peak day supply and Declared Transmission System supply adequacy, 2022-26 (TJ/d)**



### Table 19 Peak day supply adequacy (TJ/d), 2022-26

| SWZ | Supply source | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|
| **Gippsland**[A] | **Available** | 972 | 666 | 654 | 615 | 496 |
| | **Anticipated** | - | - | 125 | 169 | 358 |
| | **Total available plus anticipated** | **972** | **666** | **779** | **784** | **853** |
| **Port Campbell (Geelong)**[B] | Available | 447 | 476 | 476 | 476 | 476 |
| | Anticipated | - | - | - | - | - |
| | **Total available plus anticipated**[C] | **447** | **476** | **476** | **476** | **476** |
| **Melbourne** | Available | 87 | 87 | 87 | 87 | 87 |
| **NSW**[D] | Available | 47 | 59 | 62 | 62 | 62 |
| | Anticipated | - | - | 318 | 318 | 318 |
| **DTS total Victorian supply** | **Total VIC and NSW available** | **1,552** | **1,287** | **1,278** | **1,239** | **1,121** |
| | Total VIC and NSW anticipated | - | - | 443 | 488 | 676 |
| | Total VIC available plus anticipated | 1,506 | 1,229 | 1,342 | 1,347 | 1,416 |
| | Total VIC and NSW available plus anticipated | 1,552 | 1,287 | 1,722 | 1,727 | 1,796 |
| **Progressive Change Scenario** | 1-in-2 system demand | 1,147 | 1,142 | 1,128 | 1,142 | 1,144 |
| | 1-in-20 system demand | 1,255 | 1,248 | 1,234 | 1,246 | 1,251 |
| | **1-in-2 day Surplus quantity with VIC and NSW available Supply** | **405** | **145** | **151** | **97** | **- 23** |
| | **1-in-20 day Surplus quantity with VIC and NSW available Supply** | **297** | **39** | **45** | **- 6** | **- 130** |
| **Step Change Scenario** | 1-in-2 system demand | 1,142 | 1,104 | 1,035 | 1,008 | 935 |
| | 1-in-20 system demand | 1,249 | 1,209 | 1,133 | 1,103 | 1,022 |
| | **1-in-2 day Surplus quantity with VIC and NSW available Supply** | **410** | **184** | **244** | **232** | **186** |
| | **1-in-20 day Surplus quantity with VIC and NSW available Supply** | **304** | **79** | **145** | **136** | **99** |

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. Orbost is not considered in the aggregated Gippsland peak day production as it is used to supply demand on the EGP that cannot be supplied from another source. Supply from the Lang Lang production facility is also used to supply some small loads in Lang Lang and off the South Gippsland pipeline.
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. Port Campbell supply (Table 18) is limited by the capacity of the SWP.
D. NSW includes Culcairn injections via VNI, Sole Gas project via VicHub, and Port Kembla LNG receiving terminal via VicHub.

# 4 Managing risks to supply adequacy

Chapter 3 reported a fine balance between peak day supply demand balances and seasonal supply adequacy over the outlook period, particularly under the *Progressive Change* scenario. This chapter focuses on the supply consequences and highlights the risks that may lead to shortfalls. If actual demand follows the *Step Change* scenario, the impact of these risks is reduced.

## Key findings

- **System resilience risks** include:
  - Declining Longford Gas Plant production capacity, reduced redundancy that increases the probability of unplanned outages, and full plant outages to support maintenance, which were not previously required. This increases the likelihood of threat to system security events from winter 2022 – a risk which grows from winter 2023.
  - Ongoing low contracted volumes by market participants at the Dandenong LNG facility that are insufficient to respond to both operational and emergency scenarios. Low Dandenong LNG contracted capacity is unlikely to be sufficient to cover expected operational requirements during winter 2022 and 2023. This increases the likelihood of curtailment being required on very high demand days when there is unforecast gas generation or unplanned gas facility and transmission equipment outages. **AEMO has identified low Dandenong LNG contracted capacity as a threat to system security and is seeking a market response.**
- **Risks to peak day supply** include delayed construction of the WORM, gas facility trips, gas generation, or under-forecast demand.
  - In 2023, mitigation options are limited:
    - The SWP capacity could be increased through the addition of a second compressor at the Winchelsea Compressor Station (discussed in Section 6.4).
    - Operational options including injection profiling and injection of operational response LNG exist to reduce the likelihood of a threat to system security.
    - Existing electricity demand reduction mechanisms could be utilised to reduce demand for gas generation to improve the supply demand balance during peak demand conditions.
  - From 2024, it is important that additional supply and/or DTS augmentation options are developed to mitigate against risks to peak day supply.
- The **seasonal supply balance** could be adversely impacted from winter 2023 by extended outages of coal-fired generators, a reduction in gas supply from Queensland to the southern states, or a prolonged outage at a gas production or storage facility. Potential mitigation strategies include prudent management of critical storage inventories, development of anticipated supply projects to increase system resilience, and the Australian Domestic Gas Security Mechanism (ADGSM).

## 4.1 System supply and resilience risks

System resilience is defined as the ability of a system to limit the extent, severity, and duration of system degradation following an abnormal event[56]. The "system" could be the DTS, or a complex production system such as the Longford Gas Plant, including its offshore facilities.

### 4.1.1 Longford production resilience

#### Gas Plant 1 inlet section retirement

At the end of 2021, Esso retired the inlet section of Longford Gas Plant 1 (one of three Longford processing trains) to:

- Align Longford's operating footprint with system capacity
- Manage risks associated with Gas Plant 1 inlets equipment, and
- Increase focus on Gas Plants 2 and 3 inlets systems.

Esso has advised that the capacity of Gas Plants 2 and 3 inlets is sufficient to accommodate Longford gas capacity.

While an Esso review of Gas Plant 2 and 3 inlet systems showed high historical uptime performance, if one of the two remaining inlet sections was unavailable (for example, due to unplanned downtime), the Longford Gas Plant capacity would reduce to 500-650 TJ/d, depending on the gas system conditions at the time.

An outage on a peak demand day is likely to result in a threat to system security, which is likely to require operational response LNG to manage and may result in curtailment in the event of very high gas demands. AEMO is continuing to work with Esso on this issue.

#### Ethane constraint

The Longford production system produces an ethane by-product stream that is used by a downstream customer. Periods of reduced customer ethane offtake may constrain Longford production during winter 2022. AEMO is working collaboratively with Esso to minimise the impact on Longford operations and gas supply into the DTS.

AEMO understands that this ethane constraint is unlikely to impact Longford production from winter 2023 due to the forecast reduction in Longford capacity.

#### Large legacy gas field depletion

As identified in the 2021 VPGR, 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 from early 2023. Esso is continuing to review field performance to refine the expected production capacity for winter 2023.

Currently, the impact of supply disruptions that occur within the production system can often be reduced 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 Longford supply

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

into the DTS. This shortfall would need to be covered by another supply facility to avoid curtailment of gas demand.

### Full plant outages for maintenance

Esso has also advised AEMO that as part of the Longford production decline and reduced redundancy, full plant outages are being planned to enable the completion of major onshore and offshore maintenance activities. Historically, the impact of planned maintenance activities was mitigated by only shutting down parts of the production system, which enabled some production to continue.

Based on Esso's preliminary long-term maintenance plans, a full day outage of the Longford Gas Plant is expected to be required as early as the fourth quarter of 2023. A longer one-month shutdown has been proposed for late 2025. Infrequent planned full plant outages are also expected to occur beyond the five-year VGPR planning horizon. Esso will coordinate the timing of any required outages with AEMO through normal maintenance planning processes.

The anticipated development of the PKET supply and the Golden Beach facility from winter 2024 would also assist with managing Longford outages.

## 4.1.2 Dandenong LNG

The Dandenong LNG facility has historically been used to provide an operational response to alleviate threats to system security and for emergency response to manage emergency events including extensive customer curtailment. The facility is used as a flexible supply source to quickly respond to incidents including supply disruptions, equipment outages or failures, unforecast increases in demand, and high gas generation demand.

AEMO reported a reduction in contracted Dandenong LNG services in the 2021 VGPR[57], and issued a Notice of a Threat to System Security[58] due to there being insufficient inventory to respond to operational and emergency scenarios. AEMO's modelling indicated that 140 TJ of Dandenong LNG was required for emergency reserve, and an additional 110 TJ was required to minimise the likelihood of curtailment during threats to system security. Following publication of this threat notice, market participants contracted some additional capacity, although this remained below the quantity specified by AEMO.

During winter 2021 while AEMO considered options for increasing Dandenong LNG inventory, the LNG stock level remained above the level specified in the Notice of a Threat to System Security. After a thorough assessment of the available options, AEMO contracted 60 TJ of capacity at the Dandenong LNG facility in January 2022 on the basis that the threat would be ongoing and impact into winter 2022 due to the expected contracted capacity remaining relatively low. AEMO notified the market on 8 March 2022 that this threat to system security had ended, and published an Intervention Report[59].

AEMO's modelling indicates that for winter 2022, 140 TJ of Dandenong LNG is required for an emergency reserve, and 128 TJ is required to minimise the level of curtailment during threats to system security to a 1-in-20 year or 5% POE. This increased operational quantity is due to the reduction in Gippsland supply capacity and the Longford Gas Plant resilience issues discussed in Section 4.1.1.

[57] See page 50, AEMO 2021 VGPR, at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2021/2021-victorian-gas-planning-report.pdf?la=en.

[58] See https://aemo.com.au/-/media/files/gas/dwgm/2021/threat-to-system-security-notice-dwgm-dandenong-lng-contracted-capacity.pdf?la=en.

[59] See https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-er-21-004-winter-2021.pdf?la=en.

A further forecast Gippsland capacity reduction increases the LNG requirement to 266 TJ in winter 2023 (310 TJ if the WORM is delayed) to respond to threats to system security increases. The emergency reserve is likely to reduce slightly in winter 2023, primarily due to the planned commissioning of the WORM that provides increased supply capacity and DTS linepack.

If there is insufficient capacity for operational response, there is an increased risk of curtailment, particularly of gas generation. AEMO intends to respond to ensure there is sufficient capacity to provide an emergency reserve if market participants do not contract capacity.

AEMO will continue to consult with stakeholders, including via the Gas Wholesale Consultative Forum (GWCF), on the development of a more detailed framework for the ongoing procurement and management of Dandenong LNG services.

### 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[60]. 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 from 2022 (including currently contracted AEMO volumes) to manage operational and emergency responses during periods of high unforecast demand or a supply disruption, which increases the risk of AEMO curtailing supply to customers.

This risk has increased compared to the 2021 VGPR, due to the increased possibility of reduced Longford Gas Plant capacity due to the retirement of the Gas Plant 1 inlet section. The risk increases further in 2023 in line with the projected reduction in available supply, which presents a material risk of gas generation curtailment on peak demand days.

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.

## 4.2 Risks to peak day supply demand balance

**Table 20** summarises the key risks to the peak day supply demand balance, including an estimate of the probability and the impact of these risks. While this list is not exhaustive, it serves to highlight several potential risks to peak day supply. Key risks in Table 20 and their impact on reducing supply capacity are shown in **Figure 25**:

- From 2023, even risks with a small impact to supply capacity, such as WORM delay, reduce supply to very near, or below, 1-in-20 demand levels under both the *Progressive Change* and *Step Change* scenarios.
- Without development of anticipated supply projects, these same risks reduce supply capacity below 1-in-2 levels from 2025 under the *Progressive Change* scenario.
- Production facility trips pose a risk to peak day supply under all demand scenarios across the outlook period.

[60] NGR 341

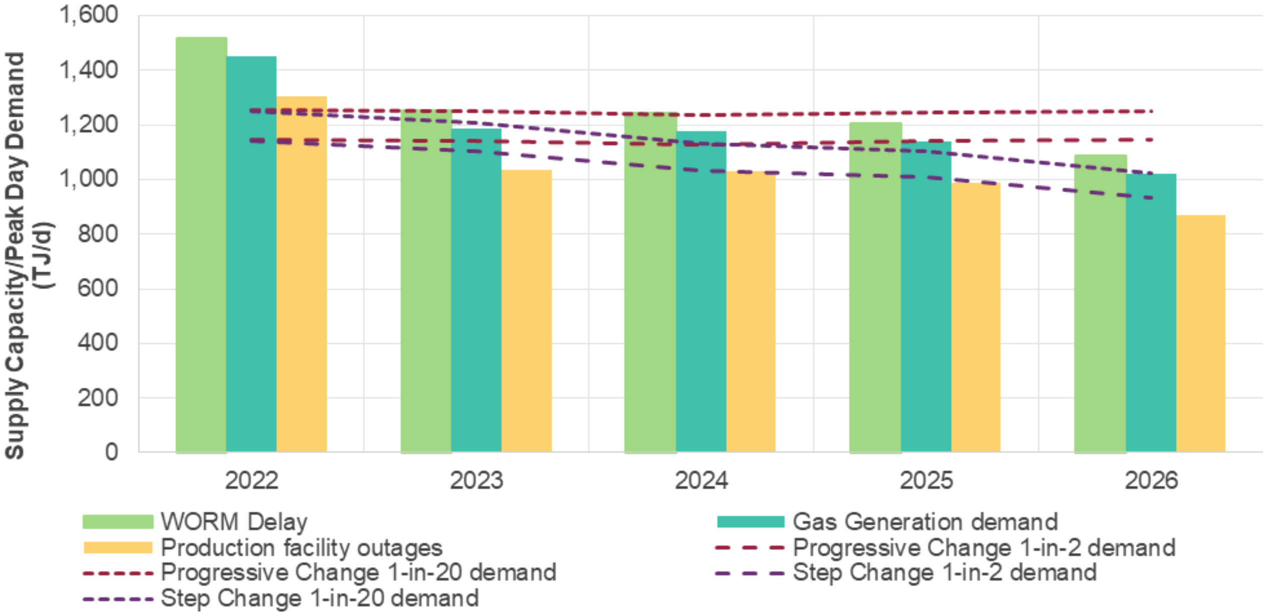
Although it is unlikely, the supply capacity is reduced further if multiple risks occur simultaneously.

### Table 20 Risks to peak day supply demand balance

| Risk | Description | Probability* | Impact |
|---|---|---|---|
| **WORM delay** | As discussed in Section 6.1, the construction timeframe for delivery prior to winter 2023 is tight. | Possible | Reduced SWP supply by 29 TJ/d on a 1-in-20 day and reduced DTS linepack. |
| **Production lower than forecast** | Accurately forecasting the production capacity and remaining reserves as gas fields approach depletion, can be challenging. Deviations can, and occasionally do, occur. | Possible | Reduced supply capacity to meet demand, potentially also impacting the refilling of storage. |
| **Gas generation** | Gas generation demand may increase total demand above available supply – 2017, 2019 and 2021 saw high gas generation coincide with peak day demand conditions. | Likely | Gas generation consumption may increase peak day demand by over 100 TJ/d. |
| | Gas generation consumption at the Uranquinty Power Station in New South Wales can significantly reduce gas supply into Victoria via Culcairn | Possible | Injections into Victoria via Culcairn may reduce to a low rate, that may result in Dandenong LNG being scheduled. |
| **Production facility outages** | Production facilities are aging, and as discussed in Section 4.1.1, the Longford Gas Plant has retired the inlet section to Gas Plant 1. Unplanned facility outages may occur more frequently.<br>Production facility outages have contributed to three threat to system security events in the past three years. | Possible | Unplanned outages can threaten peak day supply even if they are short-term. Depending on the scale of the outage, supply could be reduced by up to 400 TJ/d. |
| **Transmission facility outages** | The Winchelsea CS on the SWP has no spare unit. An outage of this compressor reduces the SWP transportation capacity into Melbourne. | Unlikely | SWP capacity reduced by approx. 80 TJ/d on a peak day. |
| | The Young – Wagga compressor on the MSP increases the pressure on the Young – Culcairn pipeline to support injections into Victoria via Culcairn. An outage at this compressor significantly reduces deliverability through Culcairn. | Unlikely | Limits imports into the DTS via Culcairn to 0-20 TJ/d. |
| **Unavailability of Dandenong LNG capacity** | As discussion in Section 4.1.2, retailer contracted volumes at the Dandenong LNG facility are insufficient to respond to operational and emergency response scenarios. If retailers do not increase their contracted position, it is possible that LNG inventory will be depleted resulting in insufficient capacity available on a peak day. | Possible | Reduces available peak day supply capacity by at least 87 TJ/d. |
| **Demand under-forecast** | As the supply demand balance is finely balanced over the outlook period, injections must be maximised from the beginning of the day to supply required gas quantities. Accurate demand forecasts are needed to achieve this, and under-forecasting demand may reduce the amount of supply available on peak demand days.<br>Peak demand days are difficult to forecast and are typically under-forecast. | Likely | 50-100 TJ/d. |
| **Unavailability of Iona UGS injection capacity** | As highlighted in Section 1.2, a confluence of events during winter 2021 caused a rapid depletion of Iona inventory. The depletion of storage reservoirs significantly reduces Iona UGS supply capacity. | Unlikely | Up to 272 TJ/d. |

* Probabilities are estimated based on available data and operational experience, and align with the risk framework outlined in AS2885, the standard for gas and liquid petroleum pipelines.

**Figure 25 Maximum supportable peak day demand with examples of supply impacts, 2022-26 (TJ/d)**




## 4.2.1 Impact of peak day supply demand imbalance

If peak day demand exceeds available supply, subject to operational and market responses, AEMO will implement DTS curtailment in line with the Gas Load Curtailment, Gas Rationing, and Gas Recovery Guidelines[61]. This is likely to include the curtailment of gas generation. Curtailed generators would need to hold sufficient stocks of alternate fuels to continue generating.

Simultaneous curtailment across multiple jurisdictions is a trigger for convening the National Gas Emergency Response Advisory Committee (NGERAC).

## 4.2.2 Potential mitigation strategies

There are several strategies that may be implemented to mitigate against potential supply shortfalls. These fall into the categories of operational, supply and augmentations, and demand management.

### Operational strategies

The following operational strategies are available to potentially mitigate peak day shortfalls.

- Injection profiling – AEMO may profile injections from gas facilities to increase supply during the first portion of the gas day when demand is also higher. This protects against the risk of under-forecasting demand, and increases the amount of linepack in the DTS at critical times, reducing the likelihood of needing operational LNG.
- Non-firm Dandenong LNG – the Dandenong LNG facility can supply gas into the DTS at non-firm rate of up to 9.9 TJ/h for up to 16 hours, noting that this significantly increases the risk of inventory depletion.

[61] See https://www.aemo.com.au/Gas/Emergency-management/-/media/6C6D137D3B554DC2ADD3BB2DFD251B85.ashx.

### Supply and augmentations strategies

Development of production projects and system augmentations can assist by providing increased supply:

- Development of anticipated and potential supply projects – refer to sections 5.2 and 5.3.
- System augmentations – refer to Chapter 6.

### Demand management strategies

Demand response mechanisms incentivise customers to reduce demand when there is a supply demand imbalance, as an alternative to increasing supply. The STTM Contingency Gas Mechanism and the Reliability and Emergency Reserve Trader (RERT) mechanism in the NEM are mechanisms that can initiate a demand response (they can also initiate increased supply). A new Wholesale Demand Response mechanism has also recently been implemented in the NEM, as a low-cost mechanism allowing large electricity consumers to sell demand reduction into the wholesale market to allow more flexibility and compete with peaking generation to help in the management of peak demand.

There is no current formal demand response process for the DTS (aside from curtailment), and it has been several years since curtailment has been implemented. A gas demand reduction mechanism would be subject to several issues and challenges to be effective, including:

- The willingness or ability of industrial and large commercial (Tariff D) customers to participate in a demand reduction scheme is currently unknown.
- Accurate day-ahead forecasting is required to determine the shortfall quantity and arrange for sufficient demand reduction. Peak gas demand days are inherently very difficult to forecast, with many occurring unexpectedly due to lower than forecast temperatures. Inaccurate forecasting of a high demand may also result in an unnecessary demand response.
- If a shortfall scenario is not forecast on the day before, the number of customers that would need to be curtailed increases to provide the same benefit. For example, if a shortfall scenario was identified at 14:00, due to an inaccurate weather forecast, curtailment of Tariff D load alone would no longer be effective, resulting in possible supply disruptions for residential and small commercial (Tariff V) customers.
- While curtailment of Tariff D and Tariff V customers is tested during emergency exercises, large-scale curtailment of Victorian gas customers has not been necessary since the 1998 Longford incident. There is a large uncertainty surrounding the level of expected response during curtailment. Verification of actual customer response is also difficult, as very few customers have real-time gas metering that can be monitored remotely (compared to the widespread use of electricity smart meters, including for residential customers).

It is possible that existing mechanisms in the NEM could be leveraged to reduce demand for gas during peak demand periods:

- Existing NEM maintenance planning procedures identify periods of reduced generation reserves and a higher likelihood of gas generation being required.
- Electricity demand reduction mechanisms could reduce electricity demand at times of high gas demand, and consequently reduce gas generation demand.

While these mechanisms may improve the supply demand balance, they may not completely mitigate a gas supply shortfall.

## 4.3 Risks to seasonal supply demand balance

**Table 21** summarises the key risks to the seasonal supply demand balance. This list is not exhaustive. It is difficult to quantitatively predict the impact of each of these risks on the seasonal supply adequacy, or comment on what combination of risks may result in a supply demand imbalance. It is possible that any one of these risks could result in a supply demand imbalance if its impact was severe.

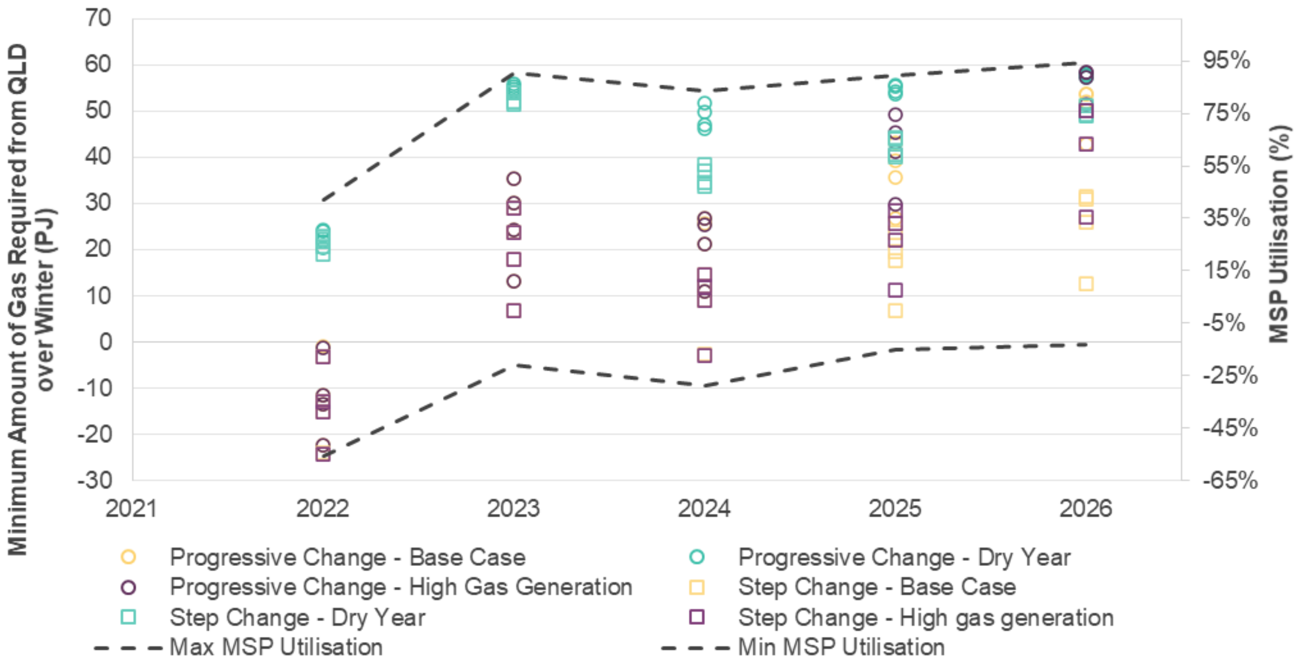
Table 21 Risks to seasonal supply demand balance.

| Risk | Description | Probability | Impact |
|---|---|---|---|
| **Prolonged outage of coal-fired generator** | Prolonged outages at coal-fired generators can lead to increased gas generation. Extended coal generation outages occurred during 2019 and 2021. | Possible | Increased gas generation over the winter period, leading to increased gas supply requirement that may not be available. |
| **Reduction in gas made available from Queensland to the southern states** | The Queensland LNG producers have made gas available to the domestic market during previous winters. Figure 23 shows the historical volumes of gas supplied from Queensland. Volumes may be reduced due to reduced Queensland production, transmission pipeline capacity reduction or a high alternate demand. | Unlikely | Less imports from Queensland into New South Wales and Victoria, resulting in a storage depletion risk and possible shortfalls. |
| **Prolonged outage of gas production or storage facility** | A prolonged outage of a production or storage facility can greatly decrease seasonal gas supply. As described in Section 1.2.1, there was a three-week partial outage at Longford during winter 2021. | Possible | Increased production required from other sources, higher gas flows from Queensland, and/or utilisation of storage. |
| **Significantly colder weather than expected** | Cold weather will increase seasonal system demand above forecast levels, particularly a period of sustained cold weather (for example, winter 2015 was the coldest for 26 years that included nine consecutive days with a system demand above 1,000 TJ/d). | Possible | Increased production, gas made available from Queensland LNG producers, and/or utilisation of storage required. |

The risks presented in Table 21 increase the probability of storage depletion and a seasonal demand imbalance.

**Figure 26** shows the effect of sensitivities modelled in the 2022 GSOO in increasing the amount of gas that must be supplied from Queensland to the southern states, testing the impacts of a dry year (reduced hydro generation and increased gas generation), and high gas generation (due to increased coal generation outages). This modelling shows that in extreme cases, the amount of required Queensland supply to the southern states is projected to reach near-unsustainable levels from as early as 2023.

**Figure 26 Range of possible minimum volumes of gas from Queensland over winter to satisfy seasonal demand, 2022-26 (PJ)**




### 4.3.1 Impact of seasonal supply demand imbalance

A seasonal supply demand imbalance manifests as a depletion of storages, resulting in a large reduction in supply capacity. If storage depletion occurred:

- Curtailment and rationing of customers would be required frequently and, from 2023, on days with demand potentially as low as 850 TJ/d.
- Curtailment of gas generation would be required, which may lead to electricity supply issues in the NEM.
- Curtailment across multiple jurisdictions (trigger for NGERAC) is likely during period of high gas demand.
- High gas prices are likely (as observed at times during 2021). This would increase pressure on market participants and gas users with insufficient contracted gas supply

### 4.3.2 Potential mitigation strategies

In comparison to addressing risks to peak day supply demand, potential mitigation strategies for seasonal supply demand issues are limited:

- Prudent management of critical storages, including Iona UGS. As described in Section 1.2.2, Iona UGS storage fell quickly to a low level before the end of July during winter 2021.
- Increasing supply and system resilience development of anticipated supply or potential sources, as summarised in sections 5.2 and 5.3, would mitigate against the risks presented in Table 21.
- Australian Domestic Gas Security Mechanism (ADGSM). The ADGSM enables controls to be placed on Queensland LNG producers to limit the amount of LNG they can export overseas. The ADGSM will have limited benefit if the pipelines from Queensland to the southern states are already operating at full capacity.

# 5 Future supply sources

## Key findings

- **Several committed, anticipated and potential projects may contribute to additional DTS supply during the outlook period**. These include:
  - Committed, anticipated and potential production projects in the Gippsland and Otway Basins.
  - Pipeline expansion projects from other jurisdictions which increase supply into Victoria.
  - LNG import terminal projects in Victoria and in other jurisdictions. The most mature of these projects is not expected to be available for gas supply until at least 2024.
- As Australia transitions to a lower emissions future, it will be critical to strike a balance between investment and government policies to prevent gas shortfalls by providing **more flexible sources of gas supply and reduce stranded asset risk** in the long term.
- The **transition to biogas and hydrogen** may play an important role in the decarbonisation of Australia's energy sector, with these distributed supplies not yet expected to be able to produce sufficient gas to replace the current declining Victorian production.
  - Investments in hydrogen-ready pipelines or assets, which require low amounts of capital, and utilising existing pipelines are expected to be faster and cheaper than the development of new pipelines.

Committed, anticipated and potential supply projects that AEMO has been informed of are listed in the following sections.

## 5.1 Committed supply projects

Committed supply considers developments or projects which have successfully passed FID, and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational. Committed supply is included in 'available supply' for the purposes of supply adequacy assessment in Chapter 3.

### Kipper field development

As discussed in Section 3.1.4, the Kipper development is progressing, with committed additional supply from the Kipper compression project expected in 2024[62]. Production from newer fields with higher quantities of carbon dioxide and other impurities likely needs to be processed at Longford's Gas Conditioning Plant, which is expected to remain near capacity for the outlook period.

This project is expected to maintain Kipper field production at close to its current rates, but is not expected to replace the production capacity of GBJV's large legacy gas fields. This development will assist in minimising the reduction in Gippsland capacity between 2023 and 2024 that was reported in the 2021 VGPR.

[62] ExxonMobil, "Esso Australia to Expand Gas Development in the Gippsland Basin", 17 March 2022, at https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2022/Esso-Australia-to-Expand-Gas-Development-in-the-Gippsland-Basin.

### Geographe, and Thylacine North and West development

Beach Energy has committed to development of the Geographe, and Thylacine North and West fields, including drilling six new production wells[63]. This development is largely responsible for the increase in available Port Campbell production reported in Chapter 3.

### Athena Gas Plant and Casino, Henry and Netherby Optimisation

First gas from the Casino, Henry and Netherby fields was introduced into the Athena Gas Plant on 10 December 2021. Gas from these fields was previously processed at the Iona UGS facility.

Gas production rates have increased to approximately 28 TJ/d in March 2022. Cooper Energy is progressing work to optimise well deliverability and further increase processing rates[64].

### Iona 570 TJ/d Expansion

Lochard Energy's expansion of the Iona UGS supply capacity from 530 TJ/d to 570 TJ/d prior to winter 2023 has reached the construction phase, and is considered committed[65]. This will also increase the Iona UGS capacity from 23.5 PJ to 24.5 PJ. This was reported as an anticipated project in the 2021 VGPR.

## 5.2 Anticipated supply projects

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).

### Kipper field further development and Turrum optimisation

In addition to the committed Kipper development, there is ongoing evaluation and preparation for future Kipper Phase 1B drilling. As part of the Kipper field development announcement referenced above, GBJV is also advancing funding decisions to optimise production from the Turrum field.

Both projects are not expected to increase future Longford winter capacity to the levels provided by current GBJV legacy field production.

### Bass Basin development (Yolla and Trefoil)

Beach Energy, the operator of the Lang Lang Gas Plant (BassGas), and associated fields, is progressing developments in the Yolla and Trefoil fields to increase the production of BassGas. Beach Energy is:

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[63] Beach Energy, "Otway Offshore Project, 2020-2023 Program", June 2021, at https://www.beachenergy.com.au/wp-content/uploads/2021/06/GD21-0111_OtwayOffshoreProject_Detailed.pdf.

[64] Cooper Energy, "Quarterly Report – Q2 FY22, 27 January 2022, at https://www.cooperenergy.com.au/Upload/2022.01.27---Amended-Quarterly-Report---Q2-FY22.pdf.

[65] Lochard Energy, "Lochard Energy submission to AER on APA's Victorian Transmission System gas access arrangement proposal 2023-27", 18 February 2022, at https://www.aer.gov.au/system/files/Lochard Energy - AER APA AA Submission - 18 February 2022.pdf.

- Planning a new infield well in the Yolla field, with drilling planned to commence in Q1 2023 once regulatory approvals are granted[66].
- Progressing its Trefoil development of two subsea wells, which will connect to the existing Yolla platform. This would support the extension of the Yolla field. FID is expected in 2023, with the additional supply coming online in 2025[67].

### Golden Beach

The Golden Beach Gas Project involves the development of the Golden Beach gas field in the Gippsland Basin, with a forecast supply of 43 PJ over two years from 2024 (delayed 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 2026 (delayed from 2025) to initially provide approximately 12.5 PJ of storage which can be withdrawn at rates up to 250 TJ/d[68].

On 6 April 2021, the Victorian Minister for Planning completed assessment of the project under the *Environmental Effects Act 1978*, which concluded that the residual impacts of the project are not significant and would be acceptable[69].The Golden Beach Gas Project has also been highlighted as a priority action in the 2021 National Gas Infrastructure Plan (NGIP) to increase gas storage capabilities in the east coast grid[70].

On 21 March 2022, the Federal Government announced a $32 million commercial loan with GB Energy to accelerate development of the Golden Beach gas production and storage project[71].

### Enterprise field development

Following successful drilling of the Enterprise-1 well in November 2020, Beach Energy is targeting FID on the Enterprise pipeline project, which connects the well site to the Otway Gas Plant, in the second half of financial year 2022[72]. Development of the Enterprise field is expected to help return the Otway Gas Plant to its nameplate capacity of 205 TJ/d.

## 5.3 Potential supply projects

Potential projects are uncommitted gas supply projects that have not yet reached FID. These projects are not considered to be sufficiently developed to be included in AEMO's supply adequacy assessment as anticipated projects. Brief qualitative updates on Victorian potential projects are included below.

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[66] Beach Energy, "Yolla Infield Well – Environmental Plan", 21 February 2022, at https://www.beachenergy.com.au/wp-content/uploads/Yolla-Infield-Well-Project-update-21-February-2022.pdf

[67] Beach Energy, "Quarterly report for the period ended 30 September 2021", 20 October 2021, at https://www.beachenergy.com.au/wp-content/uploads/BPT_Quarterly_report_for_the_period_ended_30_September_2021.pdf.

[68] GB Energy, "Annual Report 2020", 18 November 2020, at https://static1.squarespace.com/static/5bfbcef850a54f868ec3031a/t/5fbdab396457125654f61002/1606265669237/GB+Energy+Holdings+Limited+-++Annual+Report+2020+-+Final.pdf.

[69] State Government of Victoria Department of Environment, Land, Water and Planning, "Golden Beach Gas Project - Minister's Assessment under Environment Effects Act 1978", April 2021, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0025/518353/Golden-Beach-Gas-Project-Ministers-Assessment.pdf.

[70] Australian Government Department of Industry, Science, Energy and Resources, 2021 National Gas Infrastructure Plan, 26 November 2021, at https://www.energy.gov.au/sites/default/files/2021%20National%20Gas%20Infrastructure%20Plan.pdf.

[71] The Hon Angus Taylor MP, "Unlocking critical local gas production and storage", 21 March 2022, at https://www.minister.industry.gov.au/ministers/taylor/media-releases/unlocking-critical-local-gas-production-and-storage.

[72] Beach Energy, "FY22 Half Year Results", 14 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02486113-6A1076860?access_token=83ff96335c2d45a094df02a206a39ff4.

## Annie field

Cooper Energy is developing Annie-2 alongside Henry-3 as part of the Otway Phase 3 Development Project. Gas produced from the Annie field would be processed at the Athena Gas Plant[73]. The project is preparing to enter detailed front end engineering design (FEED)[74].

## Artisan field

Beach Energy announced its Artisan 1 discovery on 22 March 2021[75]. The well has been cased and suspended as a potential future production source, with scope to tie into an offshore pipeline and gas processing at the Otway Gas Plant[76].

## Iona UGS Expansion

Lochard Energy is currently in the pre-FEED stages of the Heytesbury Underground Storage (HUGS) project. This development aims to increase the storage capacity of the Iona UGS facility to 30 PJ and supply capacity to 670 TJ/d. This development would also increase the injection capacity into the storage reservoirs from 260 TJ/d to 340 TJ/d[77]. The SWP would need to be expanded to utilise this increased supply capacity, as discussed in Section 6.4.

## Longtom field

The Longtom field is wholly owned by Seven Group Holdings, which is seeking to resume production from the field[78]. As outlined in the Australian Competition and Consumer Commission's (ACCC's) Gas Inquiry 2017-2025 Interim Report – January 2022, this project faces numerous risks that threaten its timeframe for first gas in 2023[79]. AEMO considers it unlikely that gas supply will be available by 2023. Gas from the Longtom field was previously processed at the Orbost Gas Plant.

## Wombat field

The Wombat field is wholly owned by Lakes Blue Energy. The ban on Victorian exploration under the *Petroleum Legislation Amendment Act 2020* was lifted from 1 July 2021, which allowed Lakes Blue Energy to resume exploration of the Wombat field. Work is underway to secure approvals for drilling of Wombat-5[80] which has an estimated capacity of 10 TJ/d[81].

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[73] Cooper Energy, "Developing gas for southern Australia", 10 March 2021, at https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/FINAL-Euroz-Hartleys-Institutional-Conference.pdf.

[74] Cooper Energy, Quarterly Report Q2 FY22, 27 January 2022, at https://www.cooperenergy.com.au/Upload/2022.01.27---Amended-Quarterly-Report---Q2-FY22.pdf.

[75] Beach Energy, "Artisan 1 Gas Discovery", 22 March 2021, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1288336/BPT_Artisan_1_Gas_Discovery.pdf.

[76] Offshore Technology, "Beach Energy makes gas discovery at Artisan 1 well offshore Australia", 22 March 2021, at https://www.offshore-technology.com/news/beach-energy-gas-artisan-1-well/.

[77]Lochard Energy, Lochard Energy submission to AER on APA's Victorian Transmission System gas access arrangement proposal 2023-27, 18 February 2022, at https://www.aer.gov.au/system/files/Lochard Energy - AER APA AA Submission - 18 February 2022.pdf.

[78] Seven Group Holdings, 2021 Annual Report, 25 August 2021, at https://www.sevengroup.com.au/assets/7349302f61/2021-Annual-Report.pdf.

[79] ACCC, Gas Inquiry 2017-2024 interim report – January 2022, pg. 59, January 2022, at https://www.accc.gov.au/system/files/Gas%20Inquiry%202017-2025%20Interim%20Report%20-%20January%202022_FA.pdf.

[80] Lakes Blue Energy, "ASX Announcement – Victorian Work Programs Approved", 1 March 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02493840-3A588804?access_token=83ff96335c2d45a094df02a206a39ff4.

[81] Lakes Blue Energy, "Gippsland", 12 October 2021, at https://lakesoil.net.au/2021/10/12/gippsland/.

Gas processing and compression facilities would need to be constructed to treat and transport any gas produced. The ACCC's Gas Inquiry 2017-2025 Interim Report – January 2022 highlights risks to project delivery, including exploration and appraisal, financing, and regulatory approvals. In line with these risks, AEMO considers that the proposed date for first gas of 2023 is unlikely to be met.

## 5.4 LNG receiving terminal projects

### 5.4.1 Victorian LNG receiving terminal projects

#### Crib Point receiving terminal

Since the publication of the 2021 VGPR, AGL's proposed Crib Point LNG receiving terminal project has ceased development. On 29 March 2021, the Victorian Planning Minister rejected the Crib Point terminal and the associated pipeline to Pakenham due to it being assessed as having "unacceptable effects on the environment in Western Port, which is listed as a Ramsar wetland of international significance"[82].

#### Viva LNG receiving terminal

The proposed Viva LNG receiving terminal, located adjacent to its Geelong refinery, would connect to the SWP at Lara. The terminal is forecast to supply 140 PJ/y, have a capacity of 500-600 TJ/d[83], and be operational and available to the market from 2024[84,85].

The project is currently undergoing public consultation of its Environmental Effects Statement (EES)[86]. Viva Energy has signed a Memorandum of Understanding (MoU) with Woodside for capacity rights at Viva's LNG terminal, as well as signing a Heads of Agreement with Hoegh LNG to charter a FSRU for the LNG receiving terminal. A FSRU is an LNG storage ship that has an onboard regassification plant capable of vaporising the stored LNG for supply into a gas pipeline. Viva Energy is expected to reach FID for this project by Q3 2022[87].

The impacts of injections from the Viva LNG receiving terminal on SWP capacity are discussed in Section 6.3.

[82] State Government of Victoria Department of Environment, Land, Water and Planning, "Crib Point Gas Import Jetty and Crib Point – Pakenham Gas Pipeline Project - Minister's Assessment under *Environment Effects Act 1978*", March 2021, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0023/517280/Ministers-Assessment-March-2021.pdf.

[83] Viva Energy Australia, "Viva Energy Gas Terminal Project EES Referral", March 2020, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0039/495876/Viva-Energy-Gas-Terminal-Project-EES-Referral.pdf.

[84] Adnan Bajic, Offshore Energy, "Viva Energy brings in partners for Geelong LNG facility", 7 December 2020, at https://www.offshore-energy.biz/viva-energy-brings-in-partners-for-geelong-lng-facility/.

[85] Angela Macdonald-Smith, Australian Financial Review, 24 August 2021, "Viva pursues Geelong hub after profit rebound" at https://www.afr.com/companies/energy/viva-pursues-geelong-hub-after-profit-rebound-20210823-p58l9h.

[86] State Government of Victoria Department of Environment, Land, Water and Planning, "Viva Energy Gas Terminal Project", 28 February 2022, at https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/viva-energy-gas-terminal-project.

[87] Viva Energy Australia, "MoU agreed with Woodside to progress LNG regasification agreement, Viva Energy signs Heads of Agreement for FSRU", 9 December 2021, at https://www.vivaenergy.com.au/media/news/2021/mou-agreed-with-woodside-to-progress-lng-regasification-agreement-viva-energy-signs-heads-of-agreement-for-fsru.

### Vopak LNG receiving terminal

Vopak has announced[88] 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. This project would also impact SWP capacity, which is discussed in Section 6.3.

## 5.4.2 Receiving terminal projects in other jurisdictions

### Port Kembla Energy Terminal

The PKET project involves the construction of an LNG receiving terminal at Port Kembla, and connecting facilities to the EGP at Kembla Grange (see **Figure 27**). The import terminal has planning permission for 130 PJ/y of LNG supply. Jemena is constructing the Port Kembla lateral pipeline, and progressing works on the EGP that will allow it to flow south from New South Wales into Victoria. Similar to the other LNG receiving projects, the PKET will use a FSRU.

As indicated in Section 3.1.1, the PKET is currently considered an anticipated project. Gas supply would be available in winter 2024.

**Figure 27 Schematic of the location of the PKET receiving terminal, and tie into existing facilities**

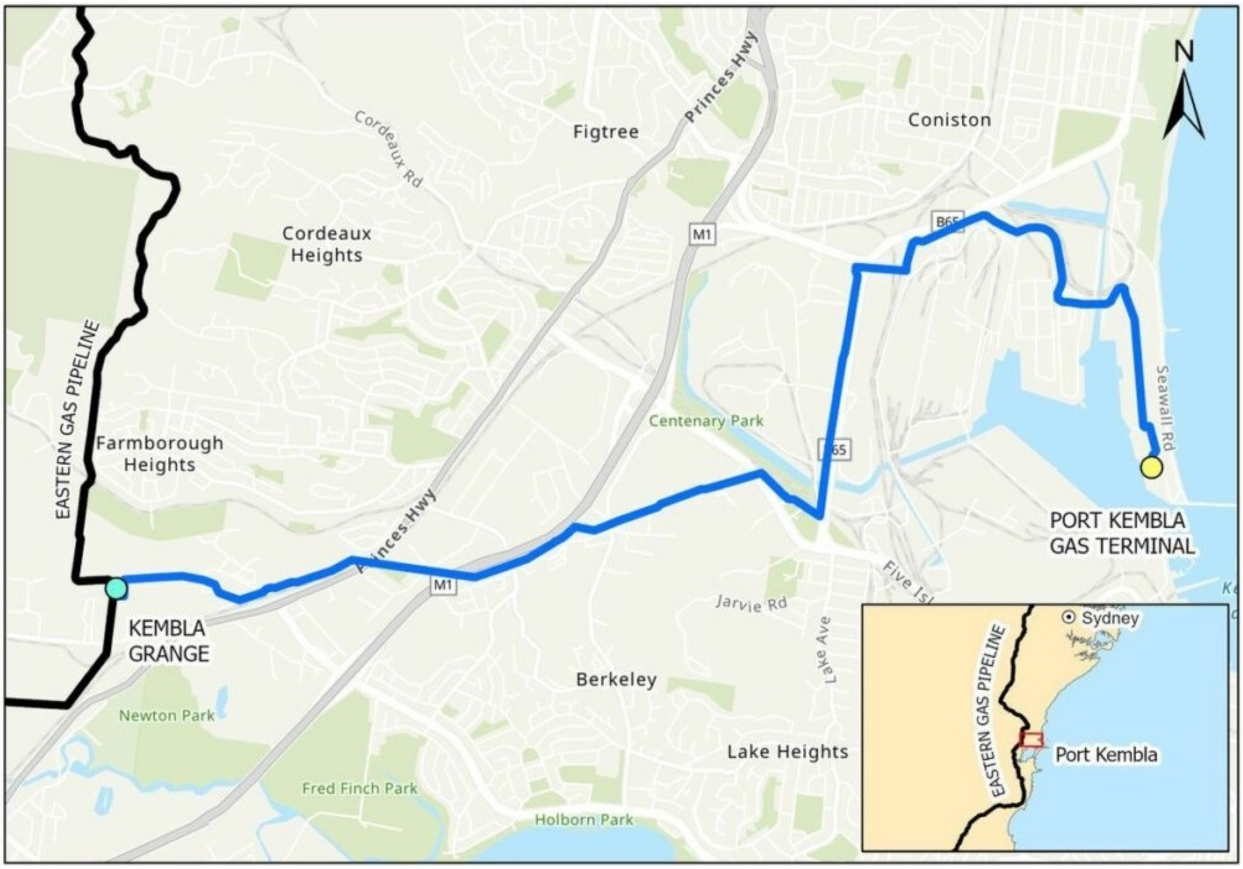


Image source: Adnan Bajic, Offshore Energy, "Jemena, AIE firm up Port Kembla LNG pipeline connection", 18 March 2021, at https://www.offshore-energy.biz/jemena-aie-firm-up-port-kembla-lng-pipeline-connection/.

[88]Elouise Fowler, Australian Financial Review, "Vopak vies for coveted LNG import terminal license", 15 March 2021, at https://www.afr.com/companies/energy/vopak-vies-for-coveted-lng-import-terminal-licence-20210315-p57avc.

### Venice receiving terminal

Venice Energy has a proposal to develop an LNG receiving terminal at Outer Harbor, near Adelaide in South Australia. Venice Energy was granted development approval on 23 December 2021 by the South Australian Government[89]. It is targeting an initial public offering and FID for the LNG terminal project in 2022, with LNG imports commencing during the fourth quarter of 2023[90].

Injections at the Venice LNG terminal would offset supply from Moomba via the Moomba to Adelaide Pipeline System (MAPS) and from Port Campbell via the SEA Gas Pipeline. The SEA Gas Pipeline is currently unidirectional and can only transport gas from Port Campbell to Adelaide. Venice Energy will conduct a feasibility study to make the SEA Gas Pipeline bi-directional to allow gas to be transported to Victoria.

Supply into the DTS from the SEA Gas Pipeline (at Port Campbell) would be limited by the capacity of the SWP.

### Newcastle GasDock LNG terminal

Newcastle GasDock is an LNG receiving terminal being developed by EPIK (Energy Projects & Infrastructure Korea), which will be located at the Port of Newcastle in New South Wales. The project is currently looking to include a 3.5 PJ FSRU, as well as investing in onshore infrastructure at the Port of Newcastle to allow the unit to connect to the east coast natural gas network[91]. The project is expected to be capable of delivering up to two million tonnes of LNG per year (~250 TJ/d)[92]. The Newcastle GasDock terminal was declared Critical State Significant Infrastructure by the New South Wales Government on 14 August 2019[93].

Supply from the Newcastle GasDock would have limited supply benefits for the DTS. By supplying Newcastle and some Sydney demand, it may enable some increased supply from the MSP to flow into Victoria via Culcairn.

## 5.5 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 476 TJ/d upon completion of the WORM expansion, which is expected to be available from mid-2023. Section 6.4 discusses future potential SWP expansion options.

### Eastern Gas Pipeline bi-directional flows

The EGP is a unidirectional pipeline that transports gas from Longford to Sydney. In 2021 AIE and Jemena signed a Project Development Agreement[94] to connect the PKET with the EGP at Kembla Grange, with a capacity to

[89] Venice Energy, “LNG import terminal granted development approval”, 23 December 2021, at https://veniceenergy.com/wp-content/uploads/2021/12/LNG-import-terminal-approved-FINAL-Dec21-WEB.pdf.

[90] Angela Macdonald-Smith, Australian Financial Review, “Aspiring LNG importer heads for IPO”, 6 January 2022, at https://www.afr.com/companies/energy/aspiring-sa-lng-importer-heads-for-ipo-20220106-p59map.

[91] Port of Newcastle, “NSW Government supports a boost for proposed Newcastle gas import terminal”, 14 August 2019, at https://www.portofnewcastle.com.au/news/nsw-government-support-a-boost-for-proposed-newcastle-gas-import-terminal/.

[92] James Markham-Hill (EPIK), Energy Magazine, “The Newcastle Gasdock Project: The solution for NSW’s growing energy demands”, 3 December 2019, at https://www.energymagazine.com.au/the-newcastle-gasdock-project-the-solution-for-nsws-growing-energy-demands/.

[93] EPIK, “EPIK’s Newcastle GasDock LNG Import Terminal Declared Critical State Significant Infrastructure by NSW Government”, 14 August 2019, at https://www.epiklng.com/uploads/1/2/0/9/120994094/20190814_epik_pr_cssi_for-release.pdf.

[94] Energy News Bulletin, “Jemena and AIE ink deal for Port Kembla pipeline”, 18 March 2021, at https://www.energynewsbulletin.net/pipelines/news/1406740/jemena-and-aie-ink-deal-for-port-kembla-pipeline.

deliver up to 522 TJ/d. Jemena plans to modify the EGP to enable bidirectional flow with the capacity to initially inject 200 TJ/d of southern flow from PKET into Victoria, and up to 440 TJ/d from PKET towards Sydney, either via the Horsley Park connection into Sydney, or the Wilton connection into the MSP. The earliest practical completion of these works is in readiness for winter 2024. Potential future expansion includes the installation of a compressor at Kembla Grange, which would increase southbound capacity on the EGP to 323 TJ/d, and northbound to 550 TJ/d.

## APA East Coast Grid Expansion project

As summarised in Section 3.1.2, on 5 May 2021 APA announced a 25% expansion of the MSP and the SWQP in multiple stages.

**Figure 28 APA compressor locations for proposed East Coast Grid expansion**

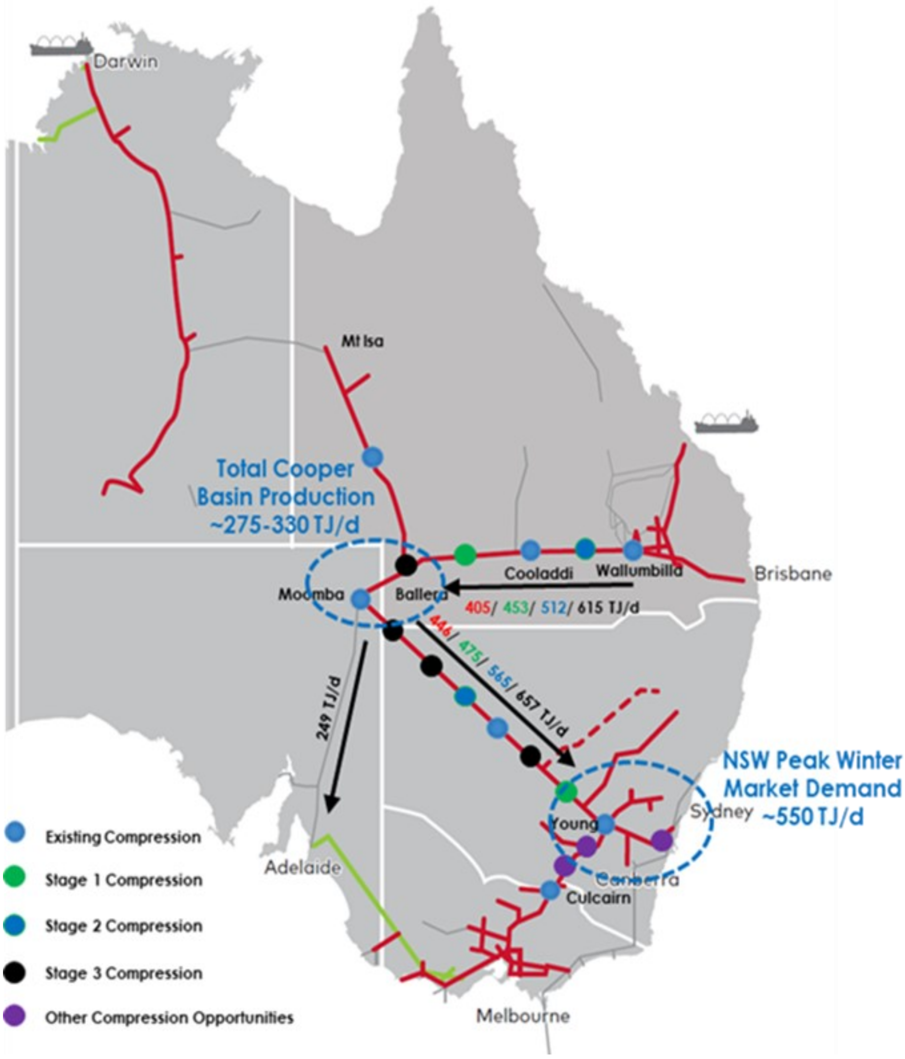


Image supplied by APA Group.

APA has committed to a Stage 1 expansion of the SWQP and MSP will increase capacity prior to winter 2023. This will consist of an additional compressor between Moomba and Young, and an additional compressor on the SWQP. This will increase the nominal capacity of the SWQP by 49 TJ/d from 404 TJ/d to 453 TJ/d and the MSP by 29 TJ/d from 446 TJ/d to 475 TJ/d.

Additional proposed expansion stages include:

- Stage 2 – a 59 TJ/d increase in capacity from Queensland to the southern markets with an additional compressor station constructed on both the SWQP and MSP. This will increase the nominal capacity of the SWQP by 59 TJ/d from 453 TJ/d to 512 TJ/d and the MSP by 90 TJ/d from 475 TJ/d to 565 TJ/d. Subject to foundation contracts, this stage is expected to be commissioned in Q1 2024.
- Stage 3 – a further 92 TJ/d expansion to southern transportation capacity with increases to the SWQP and MSP. Currently in initial design phases and subject to customer demand and project approval.

## Distributed renewable gas 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 by Australian Gas Infrastructure Group (AGIG). The project would construct an electrolyser to produce hydrogen and blend with natural gas into the Albury-Wodonga gas distribution network[95]. This project has received $32.1m in funding from the Australian Renewable Energy Agency (ARENA)[96] to support FID in Q2 2022 with production set to commence from Q4 2023.

Additional small-scale biogas projects have also been proposed across the state to supply dairies, hospitals, and other large gas consumers. These projects would reduce natural gas consumption of these facilities by substituting biogas to meet heating or on-site electricity generation requirements[97,98].

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. Chapter 2 of the 2022 GSOO discusses the expected reduction in natural gas consumption due to hydrogen uptake across a range of possible futures. The reduction in consumption of natural gas due to biogas replacement is expected to be small.

The role of renewable gas supply in future gas systems is considered in the Australian Energy Market Commission's (AEMC's) "DWGM distribution connected facilities"[99] rule change, and "Review into extending the regulatory frameworks to hydrogen and renewable gases"[100].

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[95] Australian Gas Infrastructure Group, "Hydrogen Park Murray Valley", at https://www.agig.com.au/hydrogen-park-murray-valley.

[96] Australian Gas Infrastructure Group, "HyP Murray Valley New Hydrogen Blending Project", 5 May 2021, at https://www.agig.com.au/media-release---new-hydrogen-blending-project.

[97] Victorian Bioenergy Network, "Bioenergy projects", at https://vicbioenergy.com.au/projects.

[98] Mt Alexander Bioenergy, "MAB Story", at https://www.bioenergy.net.au/our-story/.

[99] AEMC, "DWGM distribution connected facilities", at https://www.aemc.gov.au/rule-changes/dwgm-distribution-connected-facilities.

[100] AEMC, "Review into extending the regulatory frameworks to hydrogen and renewable gases", at https://www.aemc.gov.au/market-reviews-advice/review-extending-regulatory-frameworks-hydrogen-and-renewable-gases.

# 6 Declared Transmission System adequacy

## Key findings

- The EES process for the Western Outer Ring Main (WORM) pipeline, which increases the capacity of the SWP, has been completed and the Minister for Planning's assessment concluded that the project can proceed. The WORM is expected to be available for winter 2023. APA has requested additional funding to complete the WORM in its submission to the AER for its 2023-2027 Access Arrangement (VTS AA 2023-2027).
- A full day outage of the Longford Gas Plant is being planned for the fourth quarter of 2023 and a longer one month shutdown is being planned for late 2025. These will be the first full planned outages of the Longford Gas Plant. AEMO will need to operate the DTS in an unprecedented manner during these outages and has identified issues that may arise during such operations. The WORM will be an essential component of this operation.
- AEMO is investigating the impact of two proposed Victorian LNG receiving terminals projects that intend to connect to the SWP to increase supply into the DTS.
- APA's VTS AA 2023-2027 submission also includes a proposal to expand the SWP supply capacity to 570 TJ/d in line with the committed expansion of the Iona UGS facility to 570 TJ/d. This includes the development of new compressor stations at Stonehaven in 2024 and at Pirron Yallock in 2025.
- The installation of a second Winchelsea compressor is also being considered and may be a faster, lower cost alternative to new compressor stations that would increase SWP capacity to 528 TJ/d. It may be possible to complete this expansion prior to winter 2023.

## 6.1 Western Outer Ring Main (WORM) system augmentation

The WORM is a planned  DTS pipeline that will connect the SWP/Brooklyn – Lara Pipeline (BLP) at Plumpton to the Victorian Northern Interconnect (VNI) and the Pakenham to Wollert pipeline (also known as the Outer (Eastern) Ring Main) at Wollert (see **Figure 29**).

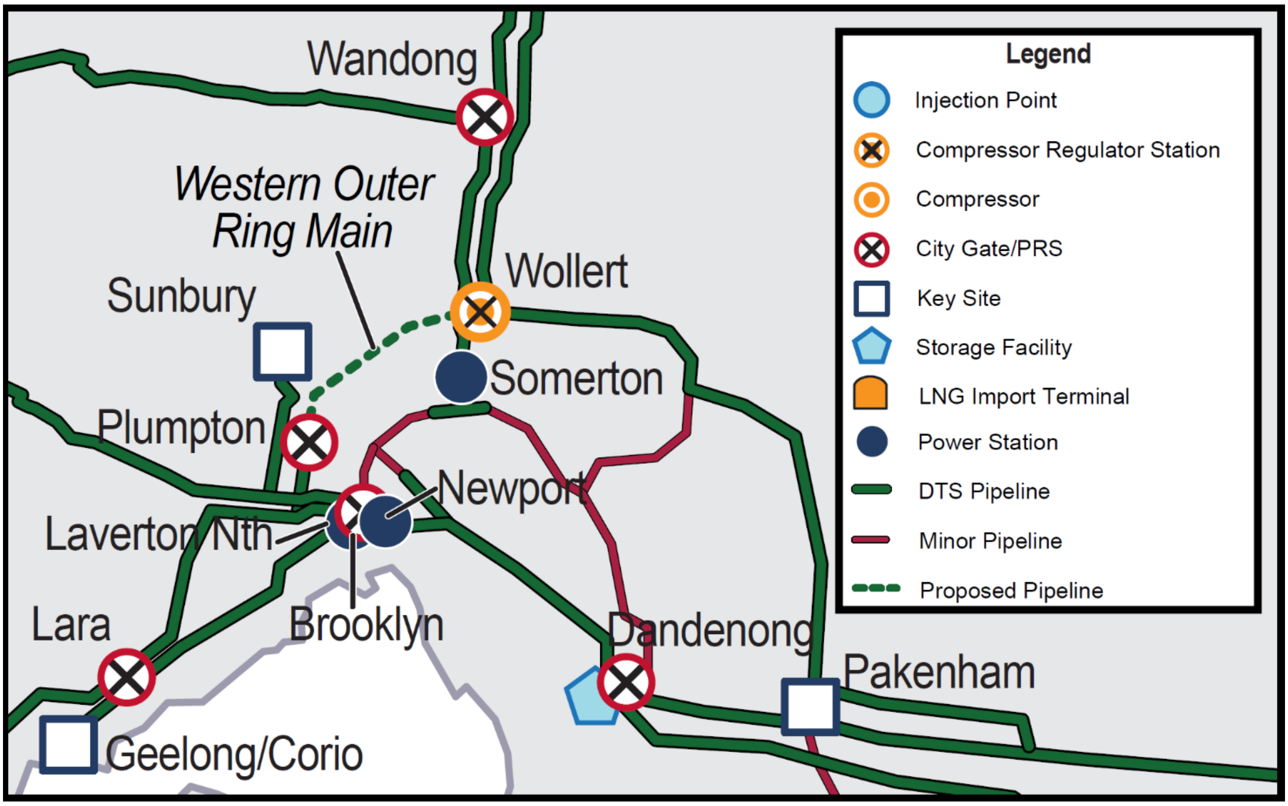
The project will also include the installation of additional compression at Wollert and a new pressure reduction station (PRS) which will enable flow from the WORM into the Pakenham to Wollert pipeline, and in turn enable gas to flow from Port Campbell (which includes supply from Iona UGS) into the Longford Melbourne Pipeline (LMP).

Benefits for the DTS once the WORM is completed include:

- Increased DTS supply capacity, reliability and security.
- Increased Iona UGS refill capability by increasing the SWP capacity towards Port Campbell.
- More supply reliability and flexibility by reducing dependence on Longford close proximity point (CPP) injections, which enables the DTS to support Longford Gas Plant outages during low demand periods.
- Improved operability of the DTS by increasing available system linepack and adding the ability to transfer linepack between pipelines that are currently disconnected.

- More efficient compression options by reducing dependency on Brooklyn Compressor Station (CS).
- Capacity for future growth in Melbourne's west and north, to facilitate new offtakes into distribution systems.
- Increased DTS linepack, which increases supportability of gas generation while the WORM also provides new potential gas generation development site options.

**Figure 29 The Western Outer Ring Main system augmentation**




In addition to the benefits above, the following SWP-related projects assume that the WORM is complete to utilise the additional SWP transportation capacity to Melbourne:

- Expansion of the SWP through the addition of one or two compressors to provide additional pipeline capacity to support the Iona UGS expansion to 570 TJ/d (Section 6.4).
- Viva and Vopak's proposed LNG receiving terminal projects that would connect to the SWP (Section 6.3).
- A further expansion of the SWP that may be triggered by an Iona UGS expansion to 670 TJ/d (Section 6.4).

The WORM is effectively a SWP expansion project. Without the WORM, an LNG receiving terminal is also unlikely to materially increase the SWP injection capacity and would back off more Port Campbell injection capacity than with the WORM available.

### WORM Project Status

On 26 January 2022 the Victorian Minister for Planning's assessment of the WORM EES concluded that the project can proceed[101].

The AER approved initial capital expenditure for the WORM as part of APA's Victorian Transmission System Access Arrangement (VTS AA) 2018-2022[102]. APA has since requested further funding as part of its VTS AA proposal for 2023-2027[103]. The additional costs are mostly associated with the EES process, including additional horizontal directional drilling, approvals costs, additional land costs and increased materials cost due to higher steel prices. The AER's draft decision is expected in May 2022 with the final decision in November 2022[104].

APA is targeting a pre-winter 2023 completion date for the WORM project. This is a tight construction timeline and any delays, such as poor weather, could see the WORM commissioned after winter 2023. See Chapter 3 for detailed discussion of supply adequacy.

## 6.2 Longford full plant outages

As discussed in Section 4.1.1, Esso, the operator of the Longford Gas Plant, has advised AEMO that full Longford Gas Plant outages are being planned to enable significant maintenance activities to be carried out both onshore and offshore. Historically, the impacted of planned Longford maintenance activities were mitigated, because only parts of the Longford production system were taken out of service.

Based on Esso's preliminary long-term maintenance plans, a full day Longford Gas Plant outage is expected as early as the fourth quarter of 2023 and a longer shutdown of one month is currently expected in late 2025. Additional infrequent planned full plant outages are also expected to occur beyond the five-year VGPR Update outlook period.

Without production at the Longford Gas Plant, injections at the Longford CPP will be limited to what can be injected from the EGP and TGP via VicHub and TasHub respectively. If either Golden Beach or PKET is not commissioned, supply will be limited to Orbost Gas Plant production, noting that Orbost will also be required to support EGP and TGP demand that would normally be supplemented by supplied from the Longford Gas Plant. TGP and EGP linepack would also provide some assistance during a short outage.

The DTS has always relied on the Longford Gas Plant to supply most of the gas used in Victoria, and the system has been designed and built to transport gas from Longford to Melbourne and through to the rest of the DTS. The LMP has never flowed east from Dandenong to Longford.

To support a full Longford Gas Plant outage, and therefore low injections at Longford CPP, AEMO will need to operate the DTS in an unprecedented manner. The DTS will need to be altered to enable increased supply from

[101] State Government of Victoria Department of Environment, Land, Water and Planning, "Minister's Assessment Environmental Effects Act 1978", January 2022, at https://www.planning.vic.gov.au/__data/assets/pdf_file/0018/557100/WORM-Ministers-Assessment-Signed.pdf.

[102] Australian Energy Regulator, "FINAL DECISION APA VTS Australia Gas access arrangement 2018 to 2022 Attachment 6 – Capital expenditure", November 2017, at https://www.aer.gov.au/system/files/AER%20-%20Attachment%206%20-%20Capital%20expenditure%20-%20November%202017_0.pdf.

[103] APA, "A look at plans for Victorian Transmission System", 1 December 2021, at https://www.aer.gov.au/system/files/APA%20VTS%20-%20Access%20Arrangement%202023-27%20-%20A%20Look%20at%20plans%20for%20VTS%20-%20Proposal%20Overview%20-%20December%202021.pdf.

[104] Australian Energy Regulator, "APA Victorian Transmission System – Access Arrangement 2023-27 – Initiation", 3 February 2022, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2023%E2%80%9327/initiation.

Port Campbell (that will be enabled through the construction of the WORM, as well as other changes to enable easterly flow along the LMP and to manage lower pressures at the Longford end of the pipeline).

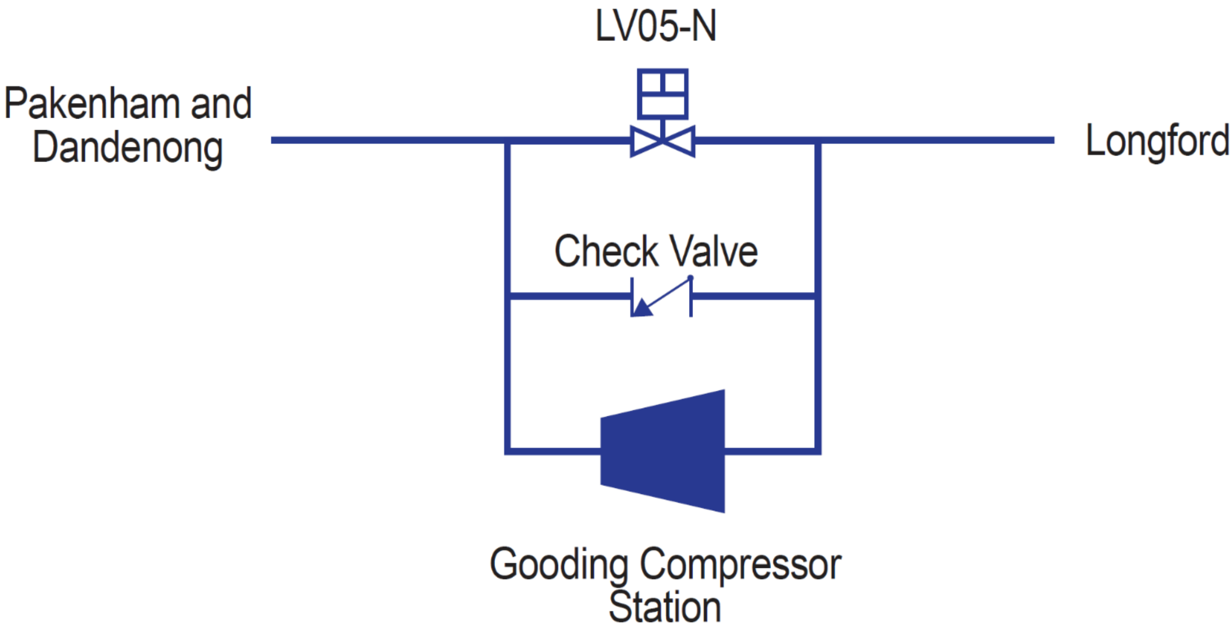
Potential DTS adequacy due to low Longford CPP injections during full Longford Gas Plant outages is discussed in the following sections.

### 6.2.1 Gooding bypass valve

The Gooding Compressor Station provides mid-line compression on the LMP. The facility consists of four high flow compressors that move linepack and increase gas flow from Longford towards Dandenong. The station has a single direction bypass that enables free flow from Longford towards Dandenong when the compressors are not operating. There is a check valve in this bypass that prevents reverse flow from Dandenong to Longford (see **Figure 30**).

The final flow path at Gooding is via line valve LV05N that bypasses the entire compressor station and is normally closed. LV05N is a locally operated valve which requires APA site attendance to open.

**Figure 30 Gooding compressor station valve arrangement**




In the event of insufficient injections at Longford CPP, LV05N will need to be opened to allow easterly flow at Gooding. The valve will need to be closed again to enable Gooding compression. To remove the requirement for APA site attendance every time easterly flow is required, modification to this valve or elsewhere in the station should be undertaken to enable remote operation by AEMO and APA.

### 6.2.2 Sale City Gate minimum pressure

Sale City Gate (CG) is the closest offtake to Longford and has a relatively high minimum operating pressure of 4,800 kilopascals (kPa). AEMO modelling has indicated that Sale CG will be the first offtake to breach its minimum supply pressure when operating the DTS with low Longford CPP injections.

In addition to planned Longford Gas Plant outages, the current high resilience of the Longford production system is expected to degrade due to the forecast capacity depletion, as discussed in Section 4.1.1. Sale CG is among the most vulnerable locations to short-term Longford Gas Plant production interruptions due to the proximity of Sale CG to Longford. The need to maintain the Sale minimum delivery pressure was noted in AEMO's threat to system security notices issued on 10 and 21 June 2021 that occurred due to Longford production disruptions. Details of these events have been documented in DWGM Intervention Reports[105,106].

The AER approved initial capital expenditure for an upgrade of the distribution system downstream of Sale CG as part of Australian Gas Networks (AGN) Victoria and Albury Access Arrangement 2018-2022[107]. This upgrade will allow the minimum operating pressure of Sale CG to be lowered from 4,800 kPa to 4,500 kPa while maintaining supply to Sale and Maffra. The lower Sale CG pressure will also reduce the pressure required in the LMP and therefore reduce the minimum supply required at Longford CPP. AEMO and AGN have agreed to an operational arrangement that enabled AGN to postpone the capital expenditure for the upgrade (to accept a lower pressure). This has also been enabled through lower Sale CG demand than forecast, which has reduced the risk of pressure breaches.

AGN has advised AEMO that it will be resubmitting the business case for the upgrade of Sale CG in the next Access Arrangement period, 2023-2028, based on the threat to system security notices issued on 10 and 21 June 2021. AEMO's preference is for this upgrade to be completed as soon as possible.

### 6.2.3 Western Outer Ring Main

The planned WORM pipeline provides a supply path from the SWP to the LMP via a new PRS at Wollert, which enables flow from the WORM into the Pakenham to Wollert pipeline. Without this new flow path, the flow out of the SWP is limited by the capacity of Brooklyn Corio Pipeline (BCP) CG. BCP CG supplies the Melbourne demand centre and can offset flow out of the LMP at Dandenong CG, but does not provide a path to flow from the SWP into the LMP (which operates at a higher pressure to the Melbourne inner ring main network). Only the WORM can provide this flow path.

Full planned outages of the Longford Gas Plant will occur during periods of low demand. Modelling indicates that the WORM increases the SWP supply capacity by 236 TJ/d, from 208 TJ/d to 444 TJ/d, on a 300 TJ system demand day. System demand, normal levels of gas generation, and some VNI exports can be supported without Longford CPP injections in this model.

The WORM is also discussed in Chapter 4.

### 6.2.4 Western DTS expansions

The potential for most of Victoria's gas supply to come from the western side of the system would require a fundamental shift in the way the DTS has been configured and operated. An LNG receiving terminal connecting to the SWP or increased Port Campbell supply through further Iona UGS expansions, coupled with the potential for periods of high gas generation demand, makes the DTS upgrades discussed in this section even more pertinent.

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[105] AEMO, "Declared Wholesale Gas Market – Intervention Report, 10 June 2021", at https://aemo.com.au/en/energy-systems/gas/declared-wholesale-gas-market-dwgm/dwgm-events-and-reports.

[106] AEMO, "Declared Wholesale Gas Market – Intervention Report, 21 June 2021", at https://aemo.com.au/en/energy-systems/gas/declared-wholesale-gas-market-dwgm/dwgm-events-and-reports.

[107] Australian Energy Regulator, "DRAFT DECISION Australian Gas Networks Victoria and Albury gas access arrangement 2018 to 2022 Attachment 2 – Capital base", July 2017, at https://www.aer.gov.au/system/files/AER%20-%20Draft%20decision%20-%20AGN%20Victoria%20and%20Albury%20gas%20access%20arrangement%202018-22%20-%20Attachment%202%20-%20Capital%20base.pdf.

## 6.3 Victorian LNG receiving terminals

As discussed in Section 5.4.1, there are two proposed Victorian LNG receiving terminals that could increase supply to the DTS. Viva is proposing an LNG receiving terminal at Geelong, and Vopak an LNG receiving terminal at Avalon. Both projects are proposing to connect to the SWP at a similar location, so for the purposes of DTS adequacy the impact of connecting either project would be the same.

AEMO modelling completed for the 2021 VGPR indicated that an LNG receiving terminal connecting to the SWP would increase the SWP injection capacity significantly, if the WORM is completed without any additional upgrades to the DTS. If LNG injections are maximised, modelling indicates that Iona CPP supply would be backed out and will not be able to inject at the current SWP injection capacity due to the higher supply pressure of the LNG receiving terminal that is located closer to Melbourne.

DTS upgrades that would be needed to mitigate the impacts of the LNG injections on the Iona CPP injection MDQ include looping of the SWP/BLP or mid-line compression between Lara and Wollert.

The modelling also indicated that Iona CPP withdrawal capacity would increase with the connection of an LNG receiving terminal at Avalon or Geelong, especially on higher demand days.

Additionally, an increase to the BCP CG and BLP CG flow capacity would further increase the SWP injection capacity with an LNG receiving facility. APA has included this Brooklyn upgrade as a Rule 80 application in its VTS AA 2023-2027[108].

## 6.4 South West Pipeline Expansion

Current Port Campbell supply capacity already exceeds the SWP injection capacity, and committed and anticipated projects at Iona UGS and the Otway Gas Plant are expected to provide additional Port Campbell supply capacity. Expansion of the SWP would therefore increase available peak day supply for Victoria and mitigate the risk of shortfalls. It would also diversify available supply options and improve system resilience, particularly when the forecast reduction in Longford Gas Plant capacity and production system resilience is considered.

AEMO has been working with APA to assess potential SWP expansion options to access the pipeline constrained Port Campbell production and storage capacity.

### Single compressor option

AEMO modelling indicates that if only a single additional unit is added on the SWP, the most advantageous site to increase SWP supply capacity would be an additional compressor at Winchelsea. Preliminary modelling indicates that a second Taurus unit at Winchelsea with the WORM completed would increase the SWP supply capacity by 52 TJ/d to 528 TJ/d. This augmentation would also require the existing unit at Winchelsea to be re-wheeled to enable the required flow profile through the compressor station.

Other benefits of this option include increased redundancy at Winchelsea, which is currently a single unit site, and likely lower project costs due to the brownfield nature of the site compared to new greenfield compressor station

[108] APA, "APA VTS Application under Rule 80 of the National Gas Rules", 1 December 2021, at https://www.aer.gov.au/system/files/APA%20VTS%20-%20Access%20Arrangement%202023-27%20-%20Application%20under%20Rule%2080%20of%20the%20NGR%20-%20December%202021.pdf.

locations along the pipeline. A second Winchelsea compressor could also be developed faster than a compressor at a greenfield site, and may be possible to complete prior to winter 2023.

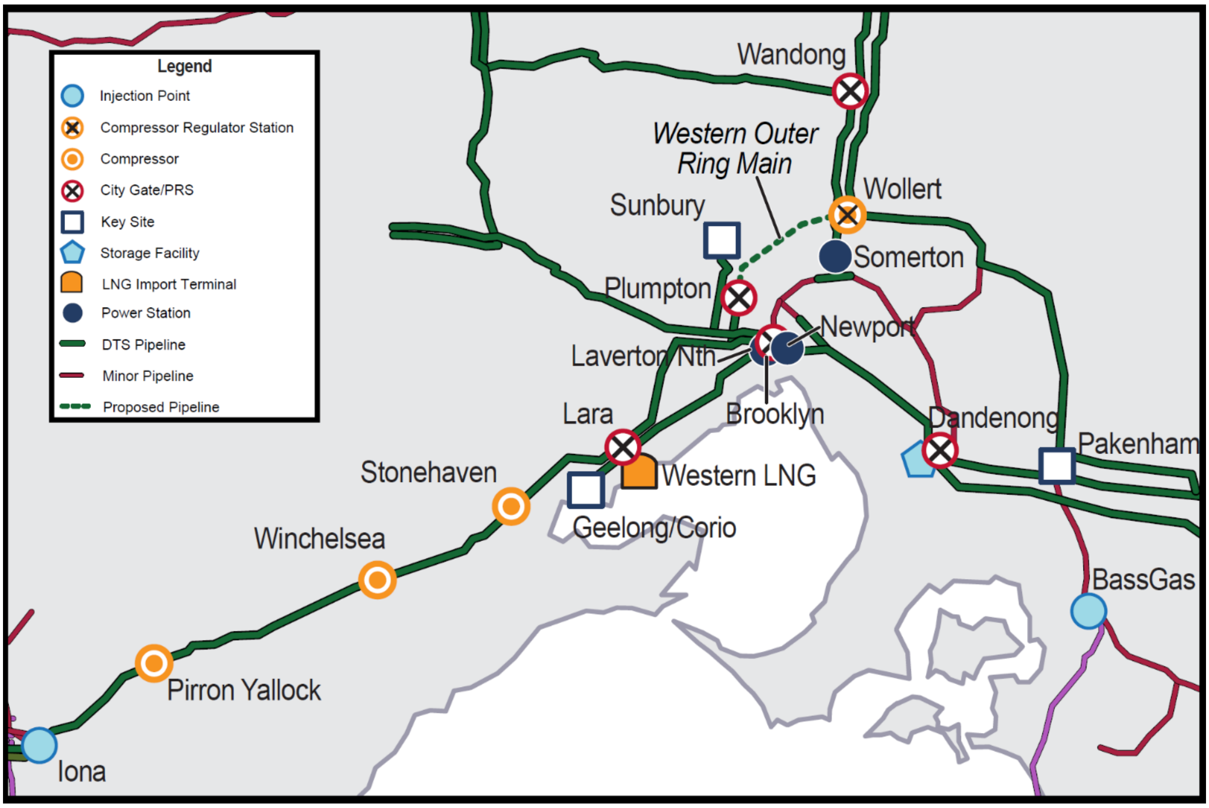
To access further SWP injection capacity after the installation of a second unit, staged pipeline looping could be completed between Port Campbell and Lara when additional capacity is required. The looped pipeline could also be constructed using hydrogen-compatible steel, which may enable future use in hydrogen service to support future green hydrogen development at locations that include GeelongPort[109] and the Iona UGS facility[110].

## Multiple compressor option

APA has requested funding to increase the SWP supply capacity to 570 TJ/d as part of its VTS AA 2023-2027[111], to match Lochard Energy's expansion of the Iona UGS facility to 570 TJ/d (see Section 5.1).

To achieve this capacity increase, APA has proposed the installation of two new compressor stations, one at Pirron Yallock and another at Stonehaven (see **Figure 31**), as well as additional upgrade work at Brooklyn and Winchelsea. APA's proposal is for the Stonehaven compressor, which would be at an undeveloped site owned by APA, to be available in 2024, while a site for the Pirron Yallock compressor would need to be acquired and it would not be available until at least 2025.

**Figure 31 Location of new compressors at Stonehaven and Pirron Yallock**




[109] GeelongPort has announced plans to expand its current operations to establish the Geelong Hydrogen Hub. See https://research.csiro.au/hyresource/geelong-hydrogen-hub/.

[110] Lochard Energy has advised AEMO that it is on a pathway to develop capability for the production and storage of hydrogen at the Iona UGS facility, and has partnered with research authorities on this matter. See https://research.csiro.au/hydrogenfsp/our-research/projects/our-research-in-underground-hydrogen-storage-in-australia/ for more information.

[111] APA, "South West Pipeline Expansion – Iona 570 TJ/d injection", 1 December 2021, at https://www.aer.gov.au/system/files/APA%20VTS%20-%20Access%20Arrangement%202023-27%20-%20Business%20Case%20601%20-%20SWP%20Expansion%20570%20TJ%20-%20December%202021.pdf.

## APA Rule 80 submission

APA has also included an additional SWP expansion proposal as a Rule 80 application in its VTS AA 2023-2027 proposal[112]. This submission assumes the multiple compressor option with units at Stonehaven and Pirron Yallock has been completed. If the Iona UGS supply capacity is expanded again to 670 TJ/d as discussed in Section 5.3, APA has proposed to match this increased supply capacity with additional pipeline looping, an increase to the BCP CG and BLP CG flow capacity, and the installation of an additional compressor unit at Winchelsea.

An alternative, consistent with the single additional compressor option at Winchelsea, is to add more (hydrogen-compatible) looping to the SWP instead of the new Stonehaven and Pirron Yallock compressors. APA has previously preferred adding compression instead of looping to increase pipeline capacity. The energy transition (and the possible stranded asset risk), increased compressor fuel gas costs, the increased linepack provided by looping, and the forecast development of a hydrogen export industry warrant a reassessment of this approach.

[112] APA, "APA VTS Application under Rule 80 of the National Gas Rules", 1 December 2021, at https://www.aer.gov.au/system/files/APA%20VTS%20-%20Access%20Arrangement%202023-27%20-%20Application%20under%20Rule%2080%20of%20the%20NGR%20-%20December%202021.pdf.

# 7 Declared Transmission System pipeline capacities

## Key findings

- The DWGM improvement to the authorised maximum daily quantity (AMDQ) regime Rule changes requires changes to the methodology for determining the LMP capacity and publication of additional capacities that are enabled by the committed WORM project.
- Material changes in the operation of the SWP required updated capacity modelling.

This section outlines the DTS pipeline capacities as at publication of this VGPR Update.

**Table 22 Summary of DTS pipeline capacities**

| Pipeline | | Maximum capacity (TJ/d) | Comment |
|---|---|---|---|
| **Longford to Melbourne** | To Melbourne | 1,169 | Previously reported as 1,030 TJ/d |
| | To Longford | 0 | |
| **South West Pipeline** | To Melbourne | 447 | Includes 17 TJ/d of Western Transmission System (WTS) demand |
| | To Port Campbell | 140 | Unchanged from 2021 VGPR. |
| **Victorian Northern Interconnect** | To Melbourne | 226 | Unchanged from 2021 VGPR. |
| | To New South Wales via Culcairn | 223 | Unchanged from 2021 VGPR. |

## 7.1 DWGM improvement to AMDQ regime

On 12 March 2020, the AEMC published the final rule change that replaces the DWGM AMDQ regime with an entry and exit capacity certificate regime[113]. The new regime allocates system injection point and system withdrawal points to capacity certificate zones that AEMO has determined.

AEMO consulted on these capacity certificate zones and published the final determination on 8 March 2022[114]. The pipeline capacity of each zone is equivalent to previously published VGPR pipeline capacities shown in **Table 22**.

Refer to Appendix A2 for more information on the system capability modelling.

[113] AEMC, "DWGM improvement to AMDQ regime", 12 March 2020, at https://www.aemc.gov.au/rule-changes/dwgm-improvement-amdq-regime.

[114] AEMO, "Final Determination", 8 March 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/gas_consultations/2022/dwgm-enhancement-cc-zone-register/final-determination.pdf?la=en.

**Table 23 DWGM capacity certificate zones and equivalent VGPR pipeline capacity**

| Capacity certificate zone | System points | VGPR pipeline capacity |
|---|---|---|
| **Northern entry zone** | Culcairn injection point | VNI to Melbourne |
| **Northern exit zone** | Culcairn withdrawal point | VNI to New South Wales via Culcairn |
| **South west entry zone** | Iona injection point<br>SEA Gas injection point<br>Otway injection point<br>Mortlake injection point | SWP to Melbourne (including WTS demand) |
| **South west exit zone** | Iona withdrawal point<br>SEA Gas withdrawal point<br>Otway withdrawal point | SWP to Port Campbell |
| **Gippsland entry zone** | Longford injection point<br>VicHub injection point<br>TasHub injection point<br>BassGas injection point | LMP to Melbourne |
| **Gippsland exit zone** | VicHub withdrawal point<br>TasHub withdrawal point | LMP to Longford |
| **Melbourne entry zone** | Dandenong LNG injection point | N/A |

### 7.1.1 Longford to Melbourne Pipeline to Melbourne

The LMP transports gas from the Longford to Dandenong CG, the main supply point for the Melbourne inner ring main, as well as from Pakenham to Wollert. Gas is injected into the LMP at the Longford CPP, consisting of supply from the Longford Gas Plant, VicHub and TasHub, and the BassGas connection point at Pakenham.

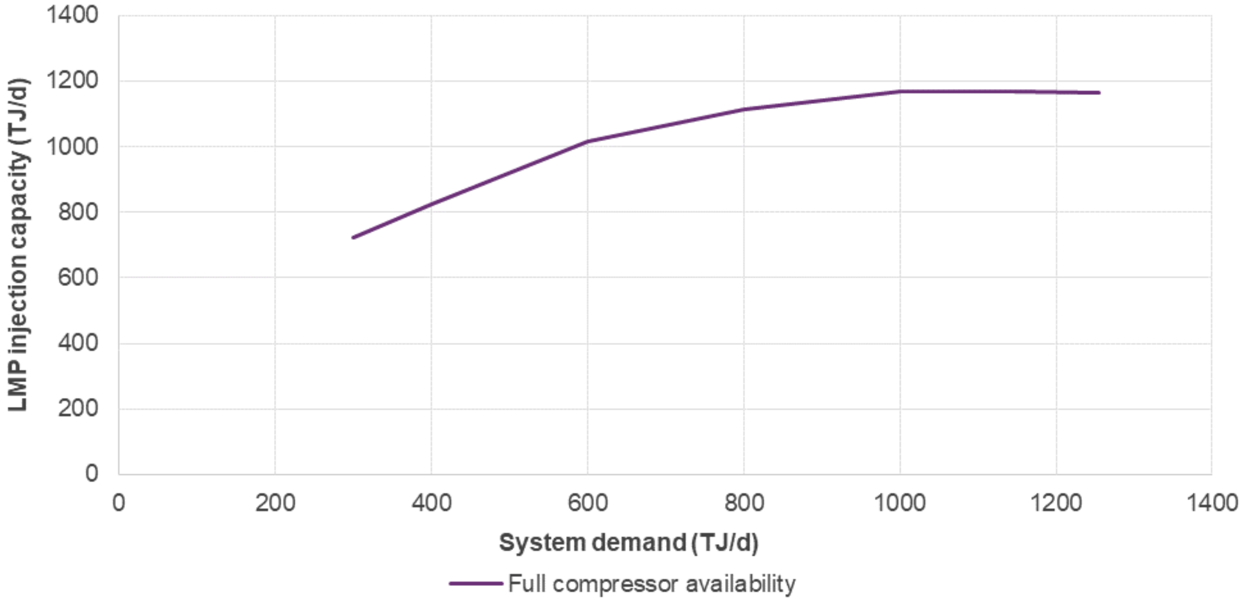
It is a requirement for the new entry and exit certificate regime to retire the static 1,030 TJ/d LMP injection capacity that has been reported in previous VGPRs. The previous 1,030 TJ/d capacity was based on 970 TJ/d of supply at the Longford CPP and 60 TJ/d from BassGas, as defined by the previous DWGM AMDQ regime.

The Gippsland entry zone pipeline capacity is to be modelled using the same methodology as other DTS pipelines. **Figure 32** shows the LMP injection capacity to Melbourne.

At lower demands the LMP injection capacity is mass balance constrained, because the LMP supplies all system demand and gas generation, as well as withdrawals on the other pipelines (SWP and VNI). At higher demands, above 600 TJ/d, the capacity becomes constrained by the capability of DTS compression to move gas from the LMP to other parts of the system.

At even higher demands, above 800 TJ/d, the capacity also becomes constrained by the requirement to maintain pressure at the inlet to Dandenong CG during the evening peak. The LMP swings from minimum pressure at Dandenong during the evening peak and then to maximum pressure at Longford during the early morning high linepack period. This transient nature of DTS demand, pipeline pressures and linepack changes is considered when determining DTS pipeline capacities.

**Figure 32 LMP injection capacity to Melbourne (TJ/d)**




### 7.1.2 Longford to Melbourne Pipeline to Longford

The capacity certificate zones also include the Gippsland exit zone, which consists of withdrawals at VicHub and TasHub. Modelling indicates that withdrawals at the Longford CPP are not currently possible, therefore the pipeline capacity for the LMP towards Longford is 0 TJ/d. This may change in future due to new sources of supply, altered demand profiles and updated modelling assumptions.

### 7.1.3 Impact of Dandenong LNG injections on the LMP injection capacity

As published in the Impact and Implementation Report (IIR) for the Capacity Certificate Zone Register[115], injections at Longford CPP can be backed off by injections at Dandenong LNG. The back-off effect between Longford CPP and Dandenong LNG only occurs when Dandenong LNG is injecting large quantities into the Melbourne inner ring main overnight when demand is low. The likelihood of Dandenong LNG injecting at nameplate quantities at night is very low, therefore the risk of any material back-off effect between the Longford CPP and Dandenong LNG is negligible.

For more information, refer to the IIR for the Capacity Certificate Zone Register.

### 7.1.4 Melbourne entry zone

The Melbourne entry zone consists of the Dandenong LNG injection point. Dandenong LNG injects directly into the inner ring main. Dandenong is the largest supply source for metropolitan Melbourne demand, so large injection quantities are supportable. The pipeline capacity of this injection point is not easily defined due to the transmission system interconnections in this area and the complexity of the different possible operating configurations.

[115] AEMO, "Impact and Implementation Report - Capacity Certificate Zone Register", 12 January 2022, at https://aemo.com.au/-/media/ authorised maximum daily quantity (AMDQ) files/stakeholder_consultation/consultations/gas_consultations/2022/dwgm-enhancement-cc-zone-register/iir---dwgm-enhancement---cc-register-zone-consultation.pdf?la=en.

For the purposes of the DWGM entry certificate auctions, AEMO has declared the pipeline capacity for the Melbourne entry zone equal to the nameplate capacity of the Dandenong LNG facility. This simplified approach is allowed as the quantity of capacity certificates to be auctioned is the lower of the maximum pipeline capacity or the maximum facility capacity. AEMO acknowledges that this is not reflective of the true pipeline injection capacity for the Melbourne entry zone, which would be much higher. This assumption will be reviewed if another system point connects to the Melbourne zone.

## 7.2 South West Pipeline

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

The SWP is typically used to:

- Transport gas from the Port Campbell production facilities and Iona UGS (Iona CPP[116]) towards Melbourne.
- Support withdrawals at the Iona CPP for Iona UGS reservoir refilling, and supply to the Mortlake Power Station and to South Australia via the SEA Gas Pipeline, during periods of lower gas demand summer and during the shoulder seasons.

In 2021 Lochard Energy undertook work at Iona UGS to enable to maximum injection pressure at the facility to be increased from 9,500 kPa to 9,700 kPa. This change, along with some other model corrections, contributed to a material change to the SWP capacities in comparison to those published in the 2021 VGPR. All other modelling assumptions, including those used for the WORM, remaining unchanged from the 2021 VGPR.

The updated capacity modelling for the SWP is outlined below.

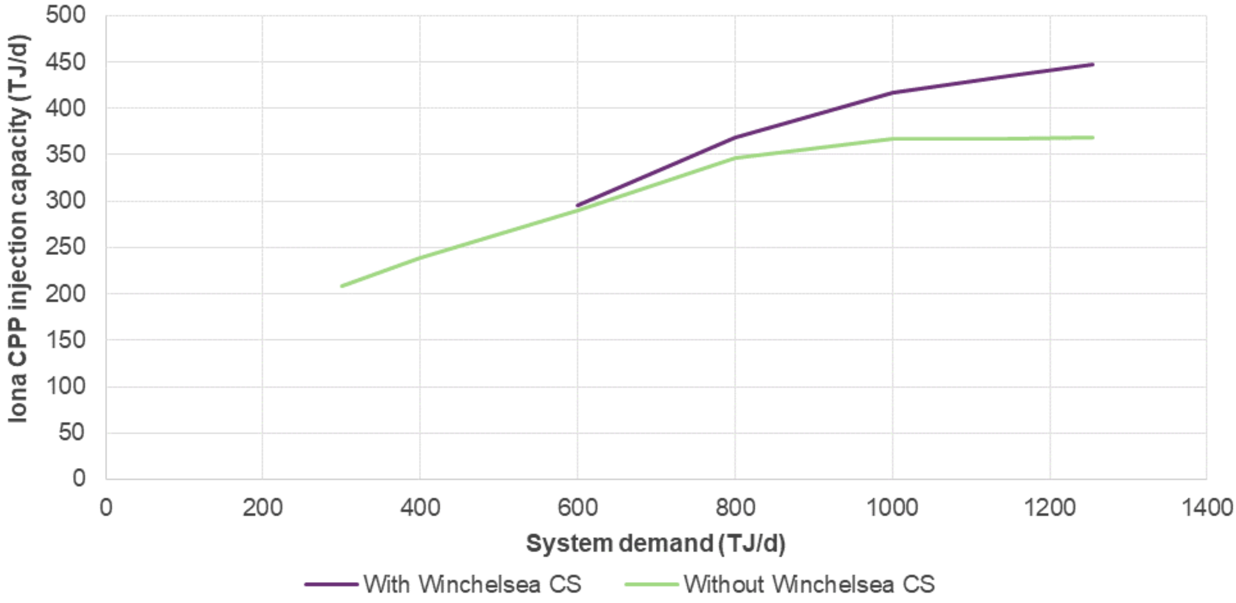
### 7.2.1 South West Pipeline to Melbourne

The SWP injection capacity (including Western Transmission System [WTS] demand), shown in **Figure 33**, is dependent on system demand so it is maximised on peak demand days. The Winchelsea CS is typically operated to increase the transportation capacity and shift the linepack closer to Melbourne on system demand days of 800 TJ and above.

Because of the changes to the assumptions, the SWP injection capacity has increased from 445 TJ/d in 2021 to 447 TJ/d in 2022 on a 1-in-20 system demand day.

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

Figure 33 SWP injection capacity (including WTS demand) to Melbourne (TJ/d)




### 7.2.2 South West Pipeline to Port Campbell

The SWP transportation capacity to support pipeline withdrawals at Iona CPP and WTS demand is unchanged from the 2021 VGPR.

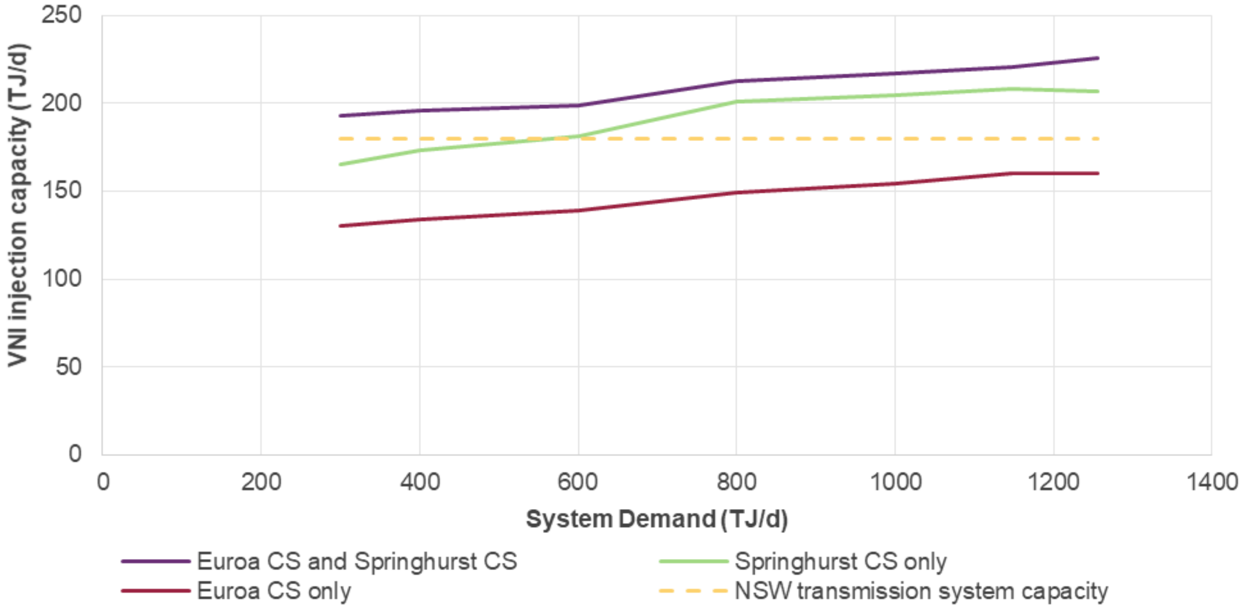
## 7.3 Victorian Northern Interconnect import capacity

APA, the operator of the New South Wales transmission system north of Culcairn, has advised AEMO that Culcairn can supply a maximum of 180 TJ/d into the DTS. This is a reduction from 195 TJ/d reported in the 2021 VGPR. The Culcairn facility has the capacity to accommodate a maximum of 180 TJ/d under all conditions and up to 195 TJ/d only under certain conditions, if the pressure drop across the facility is low enough.

Given 195 TJ/d is not available at all times, APA has advised that the New South Wales transmission system capacity should be reduced to 180 TJ/d to reflect the capacity available at all times at Culcairn. The New South Wales transmission system capacity is less than the capacity of the VNI (part of the DTS) between Culcairn and Wollert if both Euroa CS and Springhurst CS are available, which is shown in **Figure 34**.

The New South Wales transmission system capacity is also dependent upon the operation of the Uranquinty Power Station and other demand on the pipeline between Young and Culcairn, and flows on the MSP.

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




## 7.4 DTS pipeline capacities with the WORM

Under the new capacity certificate rules, AEMO must complete the first system capability modelling by 31 March 2022 to provide information for the first transitional capacity certificate auctions that will be held later in 2022[117]. The system capability modelling is required to include committed projects. Therefore, AEMO has completed modelling that takes into account the impact of the WORM on all DTS pipelines, not just the impact of the WORM on SWP capacities, as previously published.

The SWP capacities with the WORM published in the 2021 VPGR were impacted by the changes in the SWP modelling information discussed in Section 7.2.

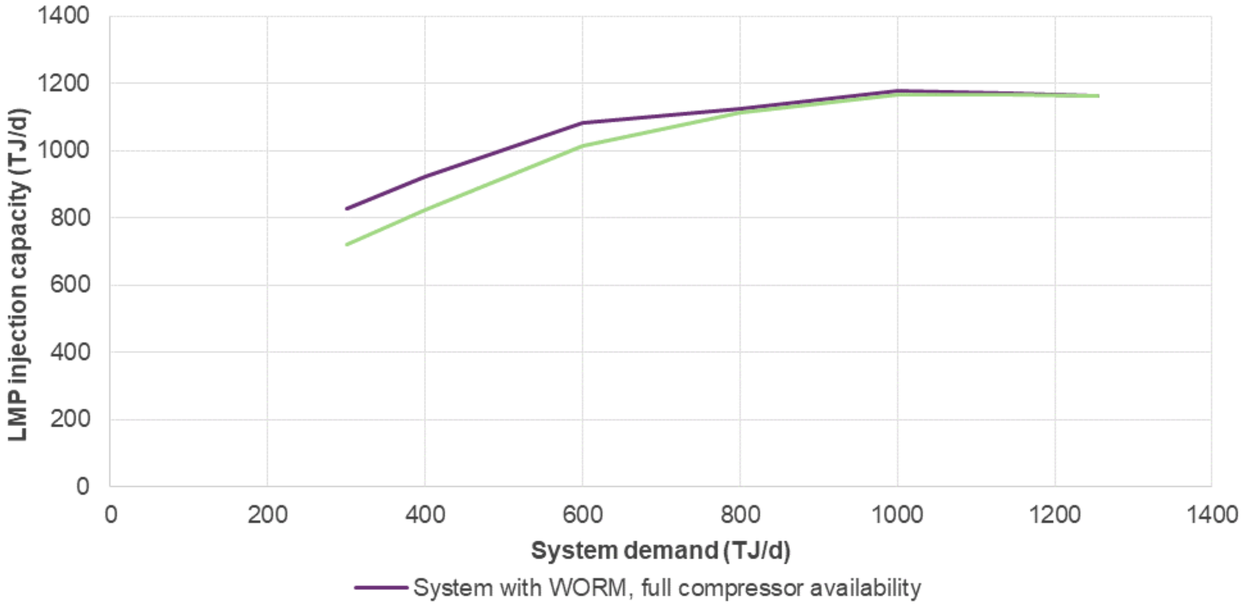
### 7.4.1 Longford to Melbourne capacity with the WORM

The VGPR modelling shows that at system demands below 600 TJ/d, the WORM increases the SWP and VNI withdrawal capacities. This also increases the LMP capacity, as shown in **Figure 35**.

As was the case without the WORM, for system demands above 800 TJ/d, the LMP capacity becomes constrained by the requirement to maintain pressure at the inlet to Dandenong CG during the evening peak. At these system demands the WORM does not increase the LMP capacity.

[117] AEMC, "National Gas Amendment (DWGM Improvement to AMDQ regime) Rule 2020 No. 1", 12 March 2020, at https://www.aemc.gov.au/sites/default/files/documents/grc0051_improvement_to_amdq_regime_final_rule_12_march_2020_final.pdf.

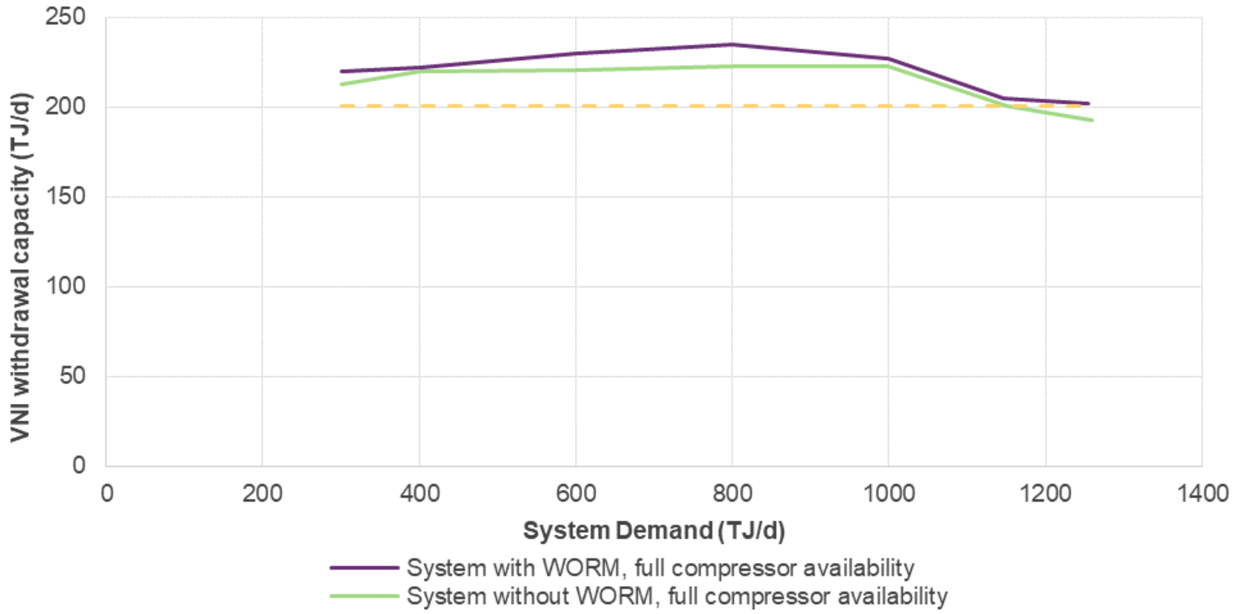
**Figure 35 LMP injection capacity to Melbourne with the WORM (TJ/d)**




## 7.4.2 Victorian Northern Interconnect export capacity with the WORM

The WORM project (as discussed in Section 6.1) includes the installation of an additional (third) compressor unit at the Wollert B Compressor Station, which provides additional compression capacity north towards Culcairn. **Figure 35** shows the VNI capacity with and without the WORM.

**Figure 36 Victorian Northern Interconnect export capacity (TJ/d)**




The increase in capacity for system demands between 300 TJ/d and 400 TJ/d is relatively small, as two Wollert compressors are sufficient to maintain the Wollert outlet pressure close to the maximum discharge pressure. The additional compression provides an increase in capacity for the 600 TJ/d to 1,000 TJ/d system demand models. However, for system demands above 1,000 TJ/d, the capacity is constrained by the requirement to maintain pressure at the inlet to Dandenong CG during the evening peak, meaning only two Wollert units can be running.

This means that the WORM has the most impact to the VNI export capacity for system demands between 400 TJ/d and 1,000 TJ/d.

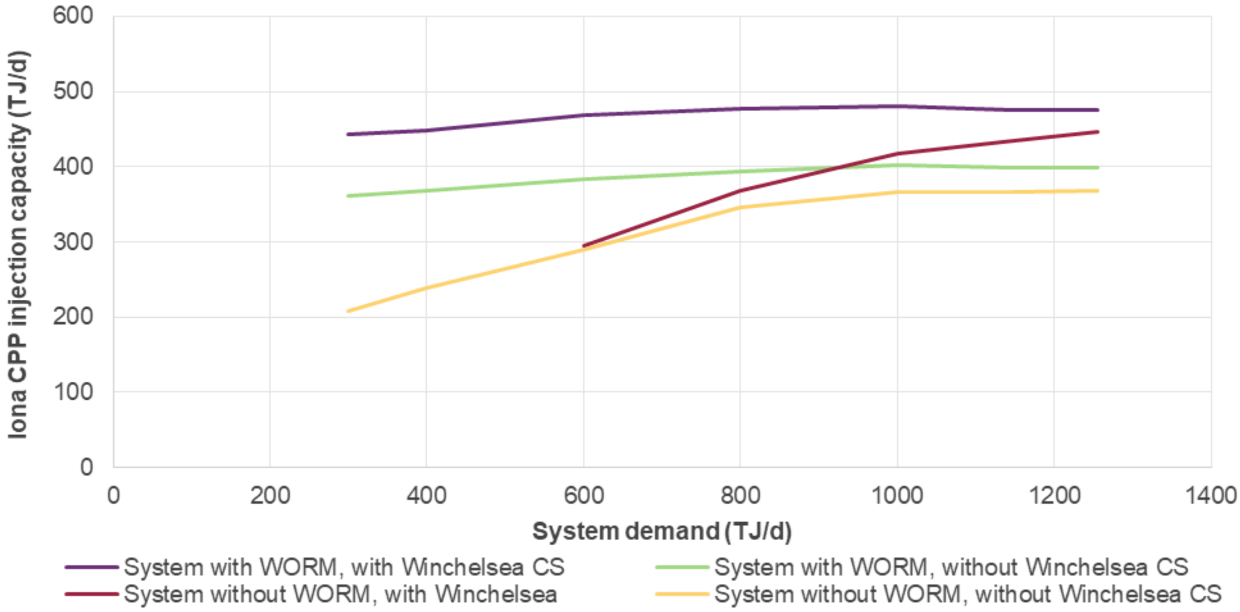
### 7.4.3 Victorian Northern Interconnect import capacity with the WORM

Modelling indicates that the VNI import capacity is not impacted significantly by the completion of the WORM project.

### 7.4.4 South West Pipeline to Melbourne with the WORM

The material changes to the SWP capacity model discussed above have increased the indicative SWP injection capacity (including WTS demand) with the WORM. The updated capacity results are shown in **Figure 37**. The 1-in-20 system demand capacity has increased from 468 TJ/d in 2021 to 476 TJ/d in 2022.

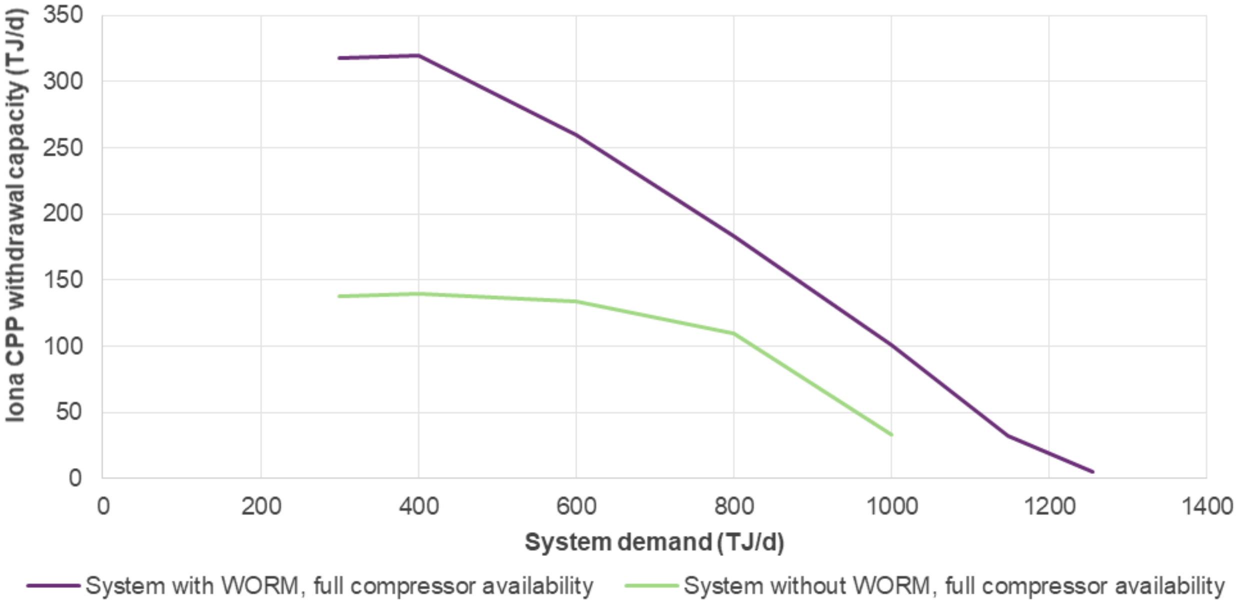
**Figure 37 SWP injection capacity (including WTS demand) to Melbourne with the WORM (TJ/d)**




### 7.4.5 South West Pipeline to Port Campbell with the WORM

The changes in the SWP model have also increased the SWP capacity to support pipeline withdrawals at the Iona CPP and WTS demand. The updated capacity results are shown in **Figure 38**. The 400 TJ/d system demand capacity has increased from 298 TJ/d in the 2021 VGPR to 320 TJ/d in this 2022 VGPR Update.

**Figure 38 SWP withdrawal capacity to Port Campbell with the WORM (TJ/d)**



# A1. Victorian gas planning approach

## A1.1 Planning assumptions

AEMO applied the same planning assumptions as those used in the 2021 VGPR wherever possible to maintain consistency and comparability of results between the 2022 VGPR Update and the 2021 VGPR. This appendix only contains the changes as required for the capacity modelling discussed in Chapter 7. Refer to Appendix A6 in the 2021 VGPR for the full list of planning assumptions.

### A1.1.1 Impact of operational factors modelling assumptions

**Table 24** lists the changed assumptions relating to operation of the DTS and constraints specified in various agreements. Refer to Table 44 in Appendix A6 in the 2021 VGPR for the complete table.

**Table 24 Impact of operational factor modelling assumptions**

| Location | Operational assumptions | Notes |
|---|---|---|
| **Iona** | Maximum pressure is 9,700 kPa. | As per operating agreement. |
| | Minimum pressure is 4,500 kPa. | |

### A1.1.2 Capacity modelling assumptions

Modelling assumptions are listed in **Table 25** for SWP capacity, **Table 26** for Northern capacity and **Table 27** for LMP capacity. Under different operating conditions on the day, the capacity result may differ.

**Table 25 SWP capacity modelling assumptions both with and without the WORM**

| SWP capacity assumptions | Notes |
|---|---|
| **Injections** | For SWP to Melbourne:<br>• Maximum injection from Iona and the remainder will be supplied from Longford CPP and/or BassGas for all cases.<br>For WORM:<br>• No limit on Longford CPP injection capacity. |
| **Gas generation demand** | Without the WORM:<br>• No gas generation demand for all cases at Laverton North and Newport.<br>With the WORM:<br>• Gas generation 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** | The SWP injection capacities were modelled with and without Winchelsea CS. The SWP withdrawal capacity in the 2022 VGPR update was only modelled with full compressor availability. |
| **Linepack** | Beginning of day (BoD) and end of day (EoD) linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed. |

| SWP capacity assumptions | | Notes |
|---|---|---|
| **Critical pressure points** | **Iona** | Maximum pressure is 9,700 kPa. Pressure not allowed to increase over the modelling period.<br>Minimum pressure is 4,500 kPa. |
| | **DCG** | Minimum pressure is 3,200 kPa. |
| | **Wollert CG** | System demand ≤ 1,150 TJ is set to 2,550 kPa.<br>System demand ≥ 1,150 TJ is set to 2,650 kPa. |
| | **Ballarat CG** | Minimum pressure is 2,100 kPa. |

### Table 26 Northern capacity modelling assumptions both with and without the WORM

| Northern capacity assumptions | | Notes |
|---|---|---|
| **Injections** | | Maximum injection from Longford CPP does not exceed 970 TJ/d. The rest will be supplied from Iona CPP and/or BassGas for all cases. |
| **Gas generation demand** | | Gas generation 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 in the 2022 VGPR update was only modelled with full compressor availability. |
| **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. For exports below 150 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports.<br>Modelled maximum 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.<br>System demand ≥ 1,150 TJ is set to 2,650 kPa. |
| | **Wandong CG** | Minimum pressure is 3,500 kPa. |

### Table 27 LMP capacity modelling assumptions both with and without the WORM

| LMP capacity assumptions | | Notes |
|---|---|---|
| **Injections** | | No limit to Longford CPP injection capacity. BassGas injections at plant nameplate capacity (67 TJ/d). VNI and SWP withdrawals were maximised up to capacity. In the event maximum withdrawals were not possible, the withdrawals were reduced in a pro-rata fashion between the two points. |
| **Gas generation demand** | | Gas generation demand for all cases varied as agreed between AEMO and the DTS Service Provider. |
| **Dandenong LNG** | | No LNG injections were required. |
| **Compressors** | | Capacity in the 2022 VGPR update was only modelled with full compressor availability. |
| **Linepack** | | BoD and EoD linepack are equal for system demand and Gippsland zone. For capacity modelling, mining of linepack not allowed. |
| **Critical pressure points** | **Longford** | Maximum pressure is 6,750 kPa. Pressure not allowed to increase over the modelling period.<br>Minimum pressure is 4,500 kPa. |
| | **DCG** | Minimum pressure is 3,200 kPa. |
| | **Wollert CG** | System demand ≤ 1,150 TJ is set to 2,550 kPa.<br>System demand ≥ 1,150 TJ is set to 2,650 kPa. |
| | **Iona** | Minimum pressure is 4,500 kPa. |
| | **Culcairn** | Modelled minimum pressure is 8,600 kPa for free flow. For exports below 150 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports.<br>Modelled maximum pressure is 6,500 kPa for Northern import capacity modelling cases. |

# A2. System capability modelling

On 12 March 2020, the AEMC made a final rule determination that amends the NGR to replace the current AMDQ regime in the Victorian DWGM with a new entry and exit capacity certificates regime.

System capability modelling must measure the capacity of the DTS that is available for allocation of capacity certificates in forthcoming capacity auctions by testing for the maximum capacity that is:

- Deliverable across all system injection points and system withdrawal points; and
- Feasible when tested against the planning criteria used by AEMO (1-in-20).

This appendix summaries the system capability modelling of the DTS that will be used to inform the amount of capacity certificates available.

## A2.1 Monthly peak day demand for 2023-25

**Table 28** shows forecast peak day system demand for each month from 2023 to 2025 for *Step Change*. The forecast peak day system demand will be used to inform the amount of capacity certificates for any month and capacity certificate type[118].

**Table 28 Forecast monthly 1-in-20 peak day demand from 2023 to 2025, *Step Change* scenario (TJ/d)**

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2023** | 424 | 456 | 600 | 800 | 1001 | 1139 | 1175 | 1184 | 984 | 834 | 705 | 551 |
| **2024** | 404 | 433 | 560 | 752 | 942 | 1066 | 1101 | 1109 | 925 | 786 | 666 | 526 |
| **2025** | 409 | 442 | 551 | 741 | 918 | 1041 | 1068 | 1082 | 909 | 767 | 661 | 516 |

## A2.2 Capacity certificates zone

The new regime allocates system injection point and system withdrawal points to capacity certificate zones that AEMO has determined. AEMO consulted on the capacity certificate zones and published the final determination on 8 March 2022[119]. **Table 29** shows the capacity certificates zone and the system points allocated to the capacity certificates zone.

**Table 29 Capacity certificate zones and equivalent VGPR pipeline capacity**

| Capacity certificate zone | System points | VGPR pipeline capacity |
|---|---|---|
| **Northern entry zone** | Culcairn injection point | Victorian Northern Interconnect to Melbourne (Figure 42) |
| **Northern exit zone** | Culcairn withdrawal point | Victorian Northern Interconnect to New South Wales via Culcairn (Figure 43) |
| **South west entry zone** | Iona injection point<br>SEA Gas injection point<br>Otway injection point<br>Mortlake injection point | South West Pipeline to Melbourne (including WTS demand) (Figure 40) |

[118] Capacity certificate type means each combination of exit capacity certificate or entry capacity certificate and capacity certificates zone.

[119] AEMO, "Final Determination", 8 March 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/gas_consultations/2022/dwgm-enhancement-cc-zone-register/final-determination.pdf?la=en.

| Capacity certificate zone | System points | VGPR pipeline capacity |
|---|---|---|
| **South west exit zone** | Iona withdrawal point<br>SEA Gas withdrawal point<br>Otway withdrawal point | South West Pipeline to Port Campbell (Figure 41) |
| **Gippsland entry zone** | Longford injection point<br>VicHub injection point<br>TasHub injection point<br>BassGas injection point | Longford Melbourne Pipeline to Melbourne (Figure 39) |
| **Gippsland exit zone** | VicHub withdrawal point<br>TasHub withdrawal point | Longford Melbourne Pipeline to Longford (Table 30) |
| **Melbourne entry zone** | Dandenong LNG injection point | Table 31 |

## A2.3 DTS pipeline and system points capacity charts

The capacity modelling assumptions used for the system capability modelling are the same as the assumptions used in the 2021 VGPR and 2022 VGPR Update. For the 2022 VGPR Update, refer to Appendix A1, and for the 2021 VGPR, refer to Appendix A6.

Unless otherwise stated, the system point capacities are obtained from the Nameplate Rating reports published on the Gas Bulletin Board. System point capacities refers to the aggregated capacities for either system injection points or system withdrawal points (as the case may be) in a capacity certificates zone.

### A2.3.1 Longford to Melbourne Pipeline

Figure 39 LMP injection capacity to Melbourne (TJ/d)

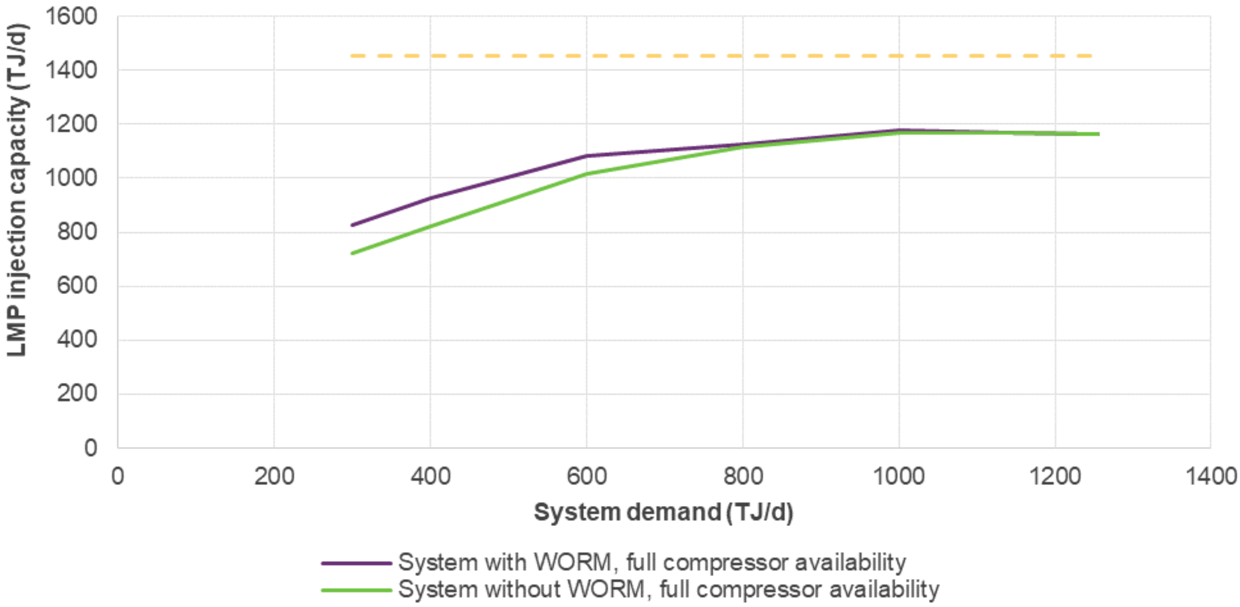


**Table 30 Longford Melbourne Pipeline to Longford capacity**

| Pipeline | System capability modelling (TJ/d) | System points capacity (TJ/d) | Notes |
|---|---|---|---|
| **Longford to Melbourne Pipeline (LMP) to Longford** | 0 | 270 | See Chapter 7 for more information |

### A2.3.2 Melbourne entry zone

For the purposes of the DWGM entry certificate auctions, AEMO has declared the pipeline capacity for the Melbourne entry zone equal to the nameplate capacity of the Dandenong LNG facility.

**Table 31 Melbourne entry zone capacity**

| Capacity certificate zone | System capability modelling (TJ/d) | System points capacity (TJ/d) | Notes |
|---|---|---|---|
| **Melbourne entry zone** | 237 | 237 | See Chapter 7 for more information |

### A2.3.3 South West Pipeline

**Figure 40 SWP injection capacity (including WTS demand) to Melbourne (TJ/d)**

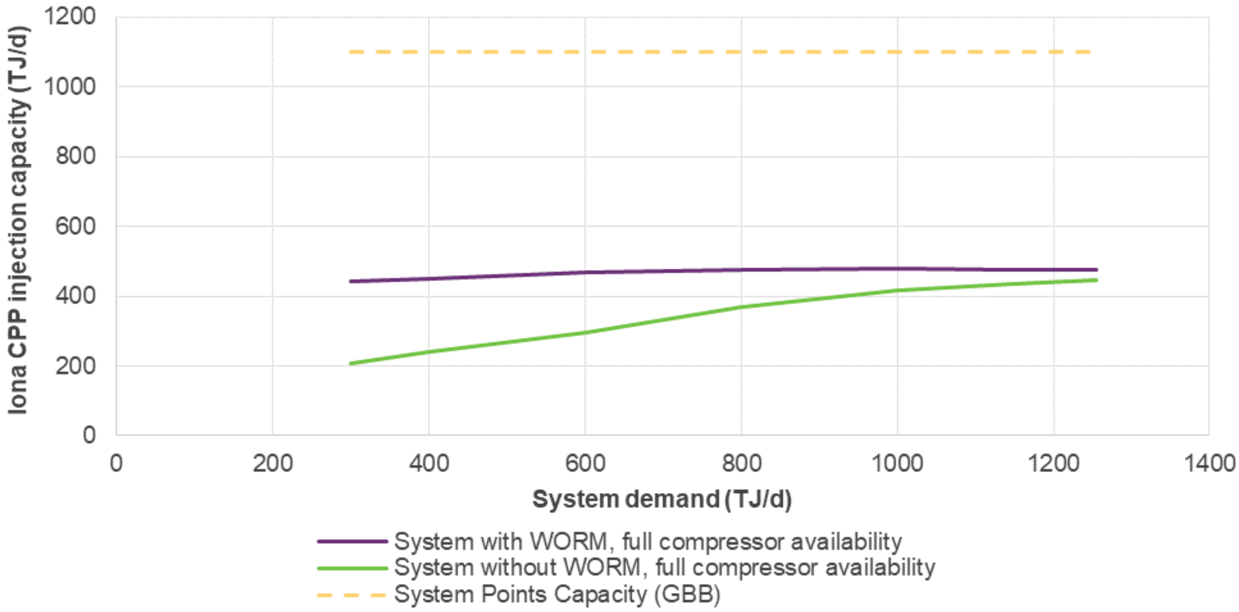
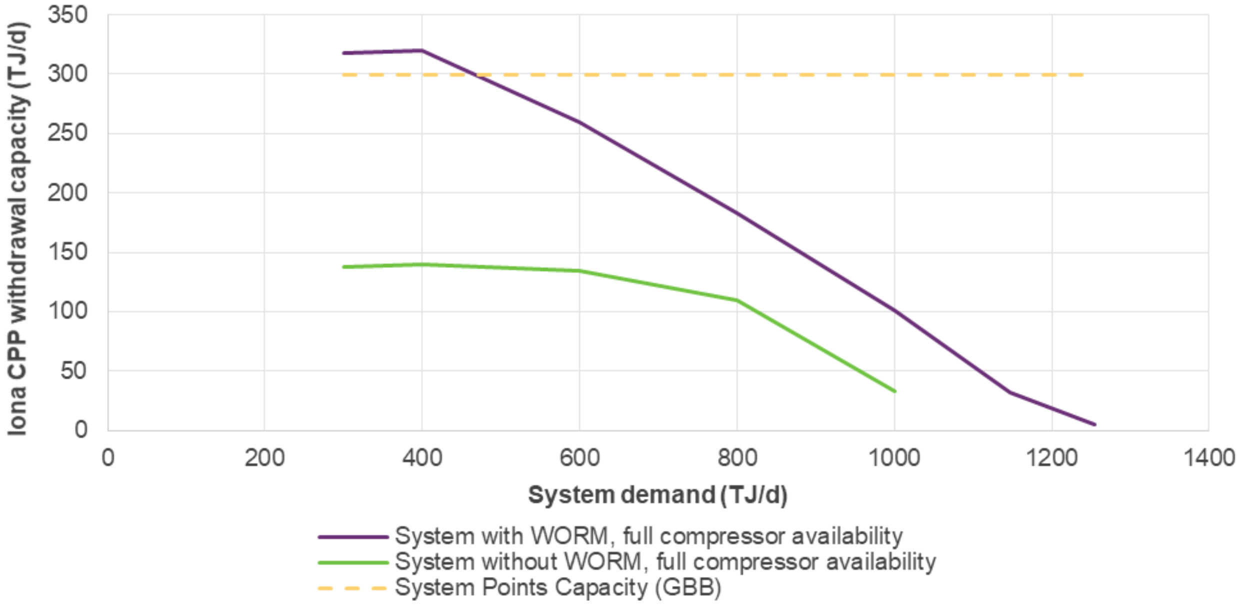


**Figure 41 SWP withdrawal capacity to Port Campbell (TJ/d)**




## A2.3.4 Victorian Northern Interconnect

**Figure 42 Victorian Northern Interconnect import capacity (TJ/d)**

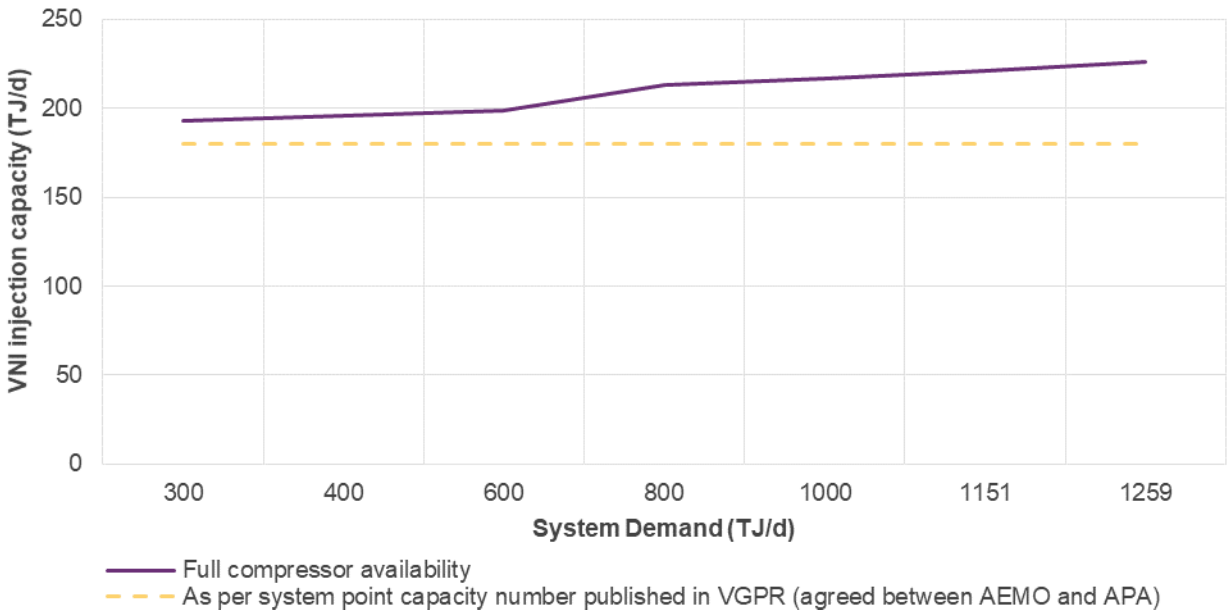
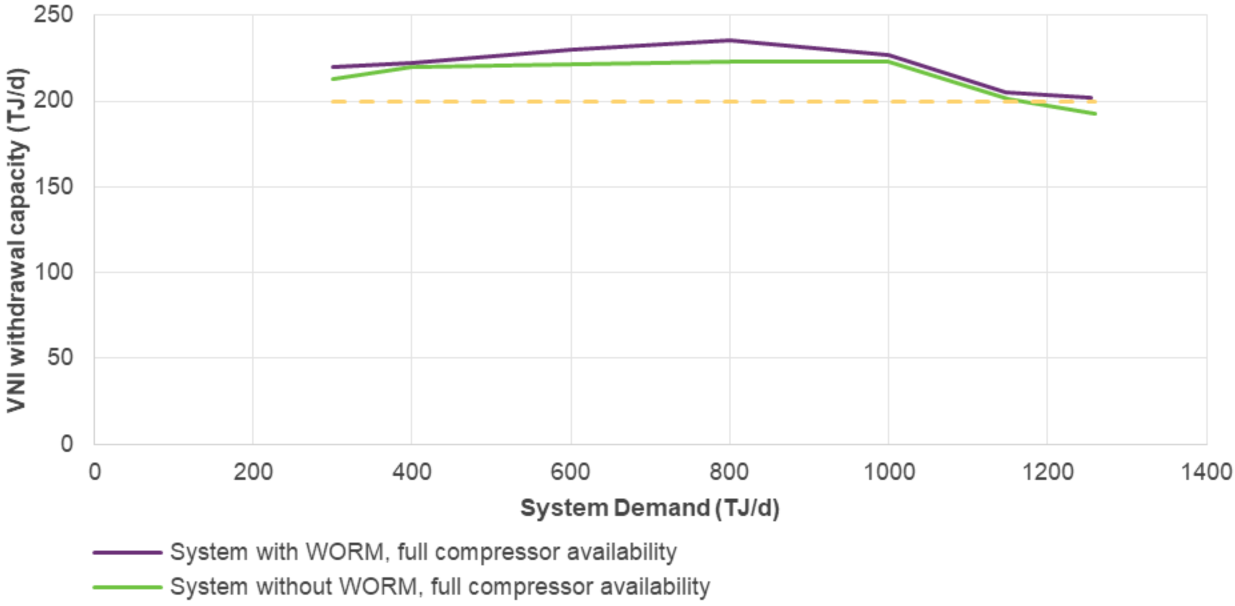


**Figure 43 Victorian Northern Interconnect export capacity (TJ/d)**



# Measures, abbreviations and glossary

## Units of measure

| Term | Definition |
|---|---|
| **Bcf** | billion cubic feet |
| **EDD** | effective degree days |
| **GJ/d** | gigajoules per day |
| **kPa** | kilopascals |
| **mmboe** | million barrels of oil equivalent |
| **MJ/m³** | 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

| Term | Definition |
|---|---|
| **ACCC** | Australian Competition and Consumer Commission |
| **AEMO** | Australian Energy Market Operator |
| **AER** | Australian Energy Regulator |
| **AEST** | Australian Eastern Standard Time |
| **AIE** | Australian Industrial Energy |
| **AMDQ** | authorised maximum daily quantity |
| **BCP** | Brooklyn–Corio Pipeline |
| **BLP** | Brooklyn–Lara Pipeline |
| **BoD** | beginning of day |
| **CG** | City Gate |
| **CPP** | close proximity point |
| **CS** | Compressor Station |
| **DTS** | Declared Transmission System |
| **DWGM** | Declared Wholesale Gas Market |
| **EES** | Environmental Effects Statement |
| **EGP** | Eastern Gas Pipeline |
| **EoD** | end of day |
| **ESV** | Energy Save Victoria |

| Term | Definition |
|---|---|
| **FID** | Final Investment Decision |
| **FSRU** | floating storage and regassification unit |
| **GBJV** | Gippsland Basin Joint Venture |
| **GSOO** | Gas Statement of Opportunities |
| **ISP** | Integrated System Plan |
| **KUJV** | Kipper Unit Joint Venture |
| **LEU** | large energy users |
| **LNG** | liquefied natural gas |
| **MAOP** | maximum allowable operating pressure |
| **MDQ** | maximum daily quantity/ies |
| **MinOP** | minimum allowable operating pressure |
| **MSP** | Moomba Sydney Pipeline |
| **NEM** | National Electricity Market |
| **NGL** | National Gas Law |
| **NGR** | National Gas Rules |
| **PKET** | Port Kembla Energy Terminal |
| **POE** | Probability of exceedance |
| **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 |
| **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

This document uses many terms that have meanings defined in the National Gas Rules (NGR). The NGR meanings are adopted unless otherwise specified.

| 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. |

| Term | Definition |
|---|---|
| **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. |
| **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** | 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 EDD is used to model the daily relationship between weather and gas demand. |
| **facility operator** | Operator of a gas production facility, storage facility, or pipeline. |
| **firm capacity** | Guaranteed or contracted capacity to supply gas. |
| **gas generation** | Where electricity is generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]). |
| **Gas Statement of Opportunities** | Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia 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 LNG storage facility is 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. |
| **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). |

| Term | Definition |
|---|---|
| **peak day profile** | The hourly profile of injection or demand occurring on a peak day. |
| **peak flow rate** | The highest hourly flow rate of gas or 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** | Short duration peaks in gas demand. |
| **peak shaving** | Meeting a demand peak using injections of vaporised LNG. |
| **petajoule** | An International System of Units (SI) unit. One 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 LNG storage facility and Iona Underground Gas Storage (UGS). |
| **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:<br>• Load distribution across the system.<br>• Hourly load profiles throughout the day at each delivery point.<br>• Heating values and the specific gravity of injected gas at each injection point.<br>• Initial linepack and final linepack and its distribution throughout the system.<br>• Ground and ambient air temperatures.<br>• Minimum and maximum operating pressure limits at critical points throughout the system.<br>• Compressor station power and efficiency. |
| **system coincident peak day** | The day of highest system demand (gas). See also system demand. |
| **system constraint** | See Declared Transmission System constraint. |
| **system demand** | Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas generation 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 DTS connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point. |
| **system withdrawal zone** | Part of the gas DTS that contains one or more system withdrawal 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** | An International System of Units (SI) unit. One TJ equals 1 x $10^{12}$ joules. |
| **unaccounted for gas** | 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. |

| Term | Definition |
|---|---|
| **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 DTS at Longford, facilitating gas trading at the Longford hub. |
| **Western Transmission System** | The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the gas market and the gas DTS. |
| **Winter peak demand period** | In this report is defined as 1 May to 30 September of a given calendar year. |