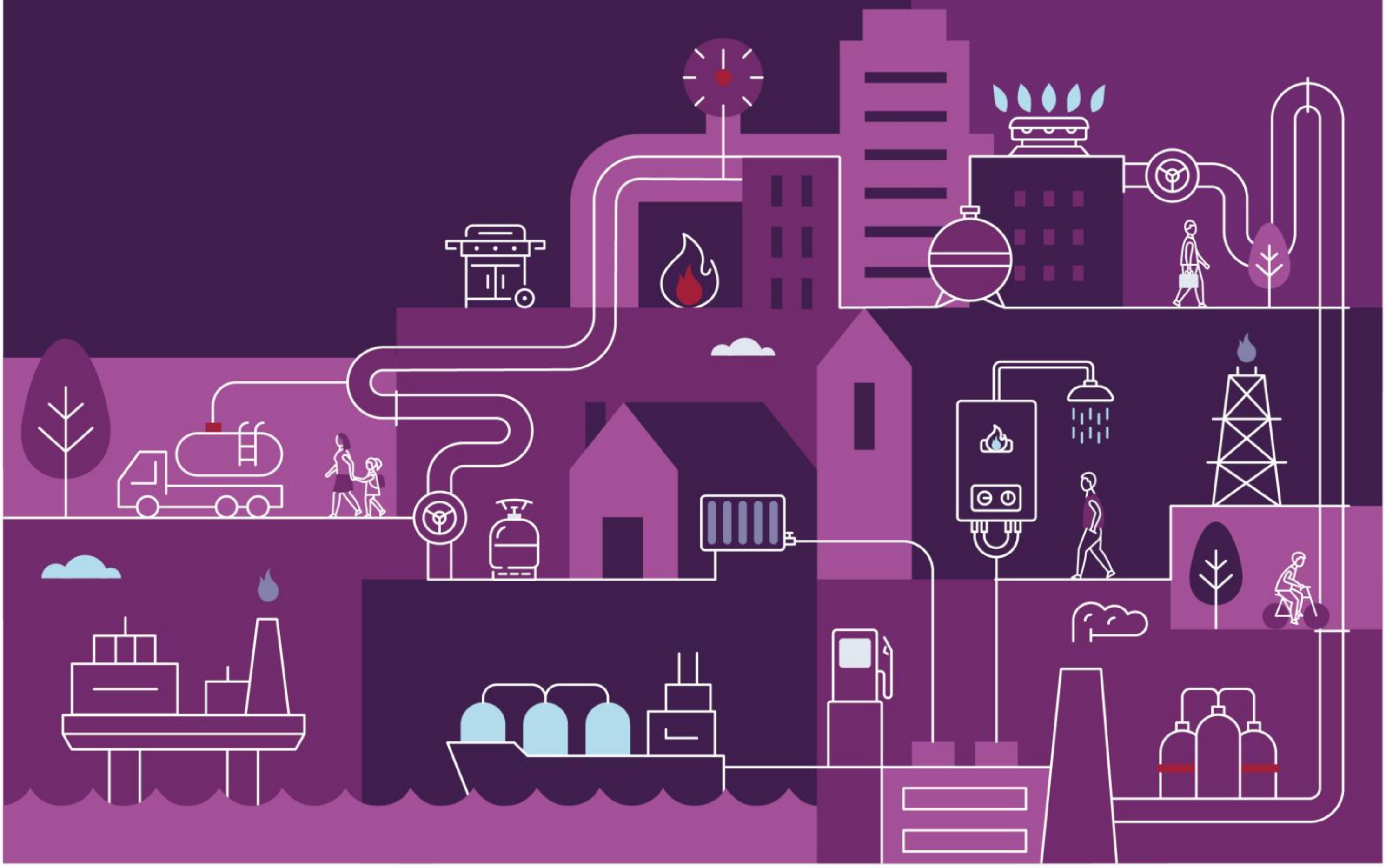
Gas Statement of Opportunities

March 2024

For Australia's East Coast Gas Market



Important notice

Purpose

The purpose of this publication is to provide information to assist registered participants and other persons in making informed decisions about investment in pipeline capacity and other aspects of the natural gas industry.

AEMO publishes this Gas Statement of Opportunities in accordance with section 91DA of the National Gas Law and Part 15D of the National Gas Rules.

This publication is generally based on information available to AEMO as at 31 December 2023, unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (which includes information and forecasts from third parties) should independently verify its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or in respect of a person's use of the information in this publication.

Copyright

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Contents

Executive summary

The 2024 *Gas Statement of Opportunities* (GSOO) forecasts the adequacy of gas supplies in central and eastern Australia[1], based on information from gas industry participants, to meet the changing energy needs of households and businesses from now to 2043. The GSOO's purpose is to provide information to assist registered participants and other persons in making informed decisions about investment in the East Coast Gas Market (ECGM).

During Australia's transition to a net zero emissions future, gas will continue to be used by Australian households, businesses and industry, and support the reliability and security of the electricity sector.

The 2024 GSOO continues to forecast risks of shortfalls on extreme peak demand days from 2025 and the potential for small seasonal supply gaps from 2026, predominantly in southern Australia, ahead of annual supply gaps that will require new sources of supply from 2028. Gas consumption by residential, commercial and industrial consumers is forecast to decline, but production in the south is forecast to decline faster.

While the scale of gas consumption remains uncertain through the energy transition, particularly in relation to gas usage for electricity generation, all scenarios identify the urgent need for new investments to maintain supply adequacy. Gas inadequacy risks over the short, medium, and long term include:

- From 2025, risks of shortfalls on some days in winter are forecast in southern Australia under extreme peak demand conditions, if extreme weather conditions drive very high demand for heating, coincident with high demand for gas-powered electricity generation (GPG). Deep and shallow gas storages are vital to meeting peak demands, while also providing seasonal flexibility, and the ongoing availability of stored gas ahead of winter conditions continues to be important to mitigate adequacy risks.
- Northern producers need to deliver anticipated supplies, and from 2026 investments in currently uncertain supply will be needed to meet domestic requirements and export positions.
- In 2026 and 2027, the potential for small seasonal supply gaps are forecast in each winter in southern Australia under sustained high gas usage conditions.
- From 2028, the forecast annual supply gaps increase in magnitude as southern production declines, meaning a more structural need for anticipated and currently uncertain new supply develops, despite declining residential, commercial and industrial consumption.
- From the mid-2030s, the forecast level of GPG increases as coal generators are forecast to retire through the energy transition, as outlined in the Draft 2024 *Integrated System Plan* (ISP). Further consideration of these forecasts, along with market and policy settings, is warranted.
- Various solutions are being considered by industry that may address these risks. In this GSOO, AEMO has included assessment of several potential future supply, storage and transportation options, to provide additional information on potential investments and their impact on gas adequacy. All options assessed delay annual supply gaps and help mitigate the risk of peak day shortfalls, but to varying degrees. This assessment does not represent a merits or cost-benefit assessment of one option over another and has not considered the viability of each based on current market settings. Based on current forecasts, a combination of solutions will be required in the long term.

[1] This GSOO includes forecasts for all Australian jurisdictions other than Western Australia. The Western Australia *Gas Statement of Opportunities* is at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

Key changes since the 2023 GSOO

Demand

Since publication of the 2023 GSOO, AEMO's consumption forecasts now feature:

- Greater consideration of potential fuel limitations on coal generators and new generation development delay risks consistent with the *Electricity Statement of Opportunities* (ESOO) methodology[A].
- All hydrogen is assumed to be produced via electrolysis rather than from steam methane reforming (SMR).

Supply and transportation capacity

Between 2026 and 2028, southern producers are expecting to supply more gas from existing, committed and anticipated developments compared to the projections provided for the 2023 GSOO.

Key infrastructure projects to increase transportation capacity are under construction or have been completed. These projects were considered committed in the 2023 GSOO and will contribute additional supply:

- Victoria's **Western Outer Ring Main** (WORM) pipeline and second compressor at Winchelsea are now operational, increasing peak supply capacity to Melbourne by 83 terajoules per day (TJ/d).
- **East Coast Grid Expansion Stage 1** is commissioned and operational, increasing north to south transmission capacity by 49 TJ/d. **East Coast Grid Expansion Stage 2** remains on track for completion by winter 2024, increasing north to south transmission capacity by a further 59 TJ/d.
- Lochard Energy has completed an upgrade to the **Iona Underground Storage** (UGS) facility, expanding storage capacity by 0.4 petajoules (PJ) to 24.4 PJ and increasing supply capacity to 570 TJ/d.

Forecasts for gas production from existing developments show a varied supply outlook in the near term:

- **Gippsland** production forecasts for 2024 are higher than in the 2023 GSOO. Peak day production of 877 TJ/d is forecast until mid-2024, reducing to 767 TJ/d coinciding with the forecast retirement of Longford Gas Plant 1 in mid-July. Production from Longford's large legacy fields is forecast to continue to reduce significantly, with the retirement of Gas Plant 3 later this decade.
- Supply from the **Blacktip** field in the Northern Territory has reduced during 2023. Eni Australia, the operator of the field, drilled a new well and completed a well workover during 2023. Supply from the Blacktip field has not returned to historical levels[B].
- Other supply projects have experienced delays in the near term. Examples include:
  - Beach Energy's **Enterprise** and **Thylacine West** developments are delayed to Q3 2024[C] (previously forecast to be online in Q1 2024 and Q3 2023 respectively). Both remain committed projects.
  - Comet Ridge's anticipated Mahalo and Mahalo North developments have been delayed by 1-2 years[D].
  - Senex's Atlas and Roma North expansions have been delayed by approximately one year. Senex announced a pause for these projects in December 2022 but has since resumed expansion plans and entered into new gas supply agreements (GSAs)[E]. These expansions remain anticipated projects.
  - APLNG's Ironbark development has been delayed by 1-2 years[F]. This remains an anticipated project.

Notes:

A. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.
B. See https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb.
C. See Beach Energy 2023 AGM Chairman and CEO Address, 14 November 2023, at https://beachenergy.com.au/asx.
D. See https://cometridge.com.au/wp1/wp-content/uploads/2023/09/2023.09.21-Annual-Report-to-shareholders.pdf.
E. See, for example, Senex Energy, "Senex Energy and AGL sign deal to deliver energy security for Australians", 16 June 2023, at https://senexenergy.com.au/news/senex-energy-and-agl-sign-deal-to-deliver-energy-security-for-australians/.
F. Australian Competition and Consumer Commission (ACCC), Gas Inquiry December 2023, pg. 58, at https://www.accc.gov.au/system/files/Gas%20Inquiry%202017-2030%20-%20December%202023_0.pdf.

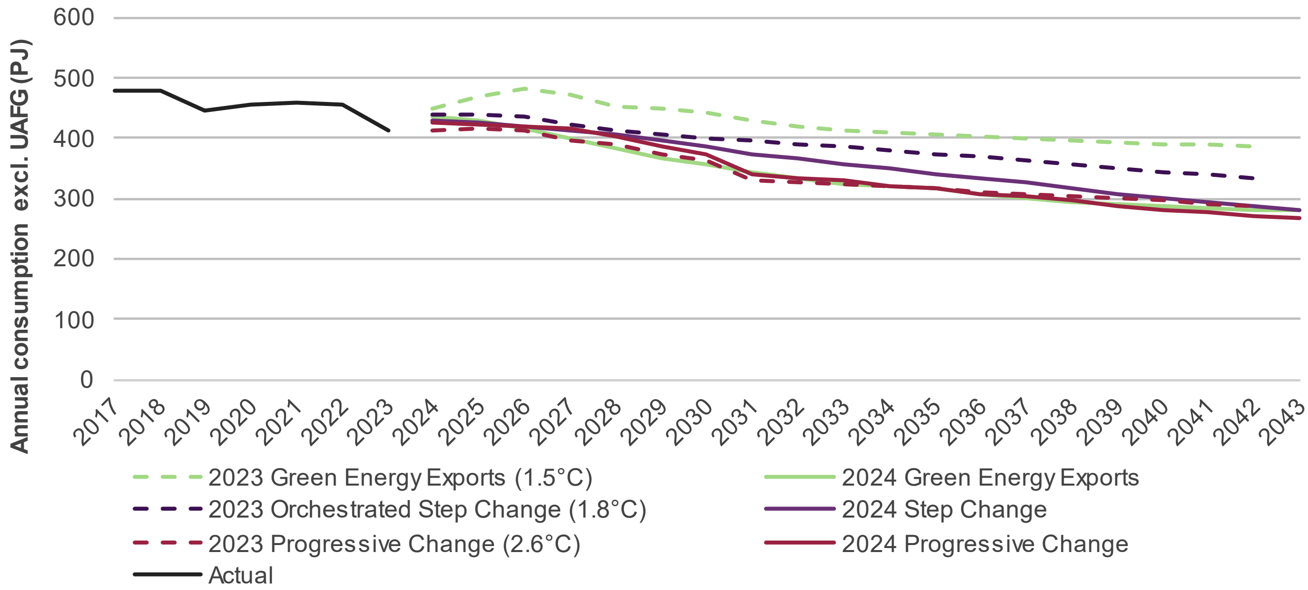
Forecast fuel-switching contributes to a downward trend in gas consumption for commercial, residential and industrial users

Since publication of the 2023 GSOO, gas consumption has noticeably declined across all sectors, with emerging indications of fuel-switching from gas to electricity. The reduction in gas consumption has coincided with noticeably higher retail gas prices compared to recent years and some of the warmest winter temperatures on record[2].

Forecast gas consumption for commercial, residential and industrial users is expected to decline over the outlook period to 2043. Residential and small commercial consumption is forecast to slightly decline in the short term, with more significant fuel-switching to electricity in the medium to longer term as the economy transitions to meet net zero emissions goals. Large commercial and industrial sectors are forecast to remain relatively stable, however some large industrial loads are forecast to decline, particularly in Queensland.

Figure 1 below demonstrates the three 2024 GSOO scenarios AEMO has applied to assess gas adequacy through Australia's energy transition.

Figure 1 Actual and forecast domestic natural gas consumption, excluding GPG, all scenarios and compared to 2023 GSOO forecasts, 2017-43 (petajoules [PJ])



Notes:

- 2023 GSOO forecasts have been amended to align with 2024 GSOO forecasts, where scenarios anticipate consumer demand will be met by natural gas, or a combination of natural gas and renewable gases.
- The Northern Territory is included in actual gas consumption from 2020 onwards.

Similar to the 2023 GSOO, the potential to electrify gas loads in the residential, commercial and certain industrial sectors accounts for much of the downward trend in gas consumption over the outlook period. Electrification and other drivers in the *Step Change* scenario are forecast to reduce natural gas consumption by around 135 petajoules (PJ) to around 280 PJ by 2043.

---

[2] Mean winter temperatures in 2023 were the warmest on record for Queensland, New South Wales and Tasmania, and second warmest for Victoria and South Australia: See http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml for further details.

Recent policy changes contribute to the pace of electrification, reducing gas consumption, including:

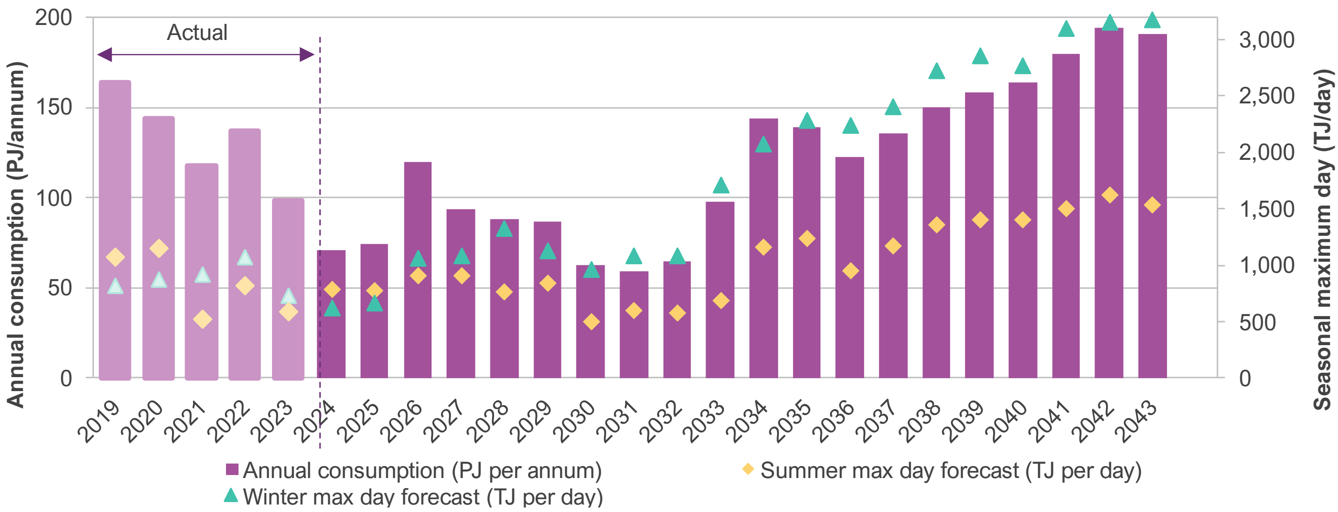
- The Victorian Gas Substitution Roadmap Update[3] bans new residential gas connections for developments requiring a planning permit from 1 January 2024 through an amendment of the Victorian Planning Provisions.
- The Australian Capital Territory Government has introduced legislation to prevent new gas connections in most areas from 8 December 2023.

Annual GPG consumption is forecast to increase from the early 2030s, with significant growth in peak day consumption

Analysis from the Draft 2024 ISP[4] reinforces the important role GPG is forecast to play in the NEM by helping manage extended periods of low variable renewable energy (VRE) generation and providing firming support when other dispatchable sources are unavailable. GPG's role may also extend to providing critical power system services to maintain grid security and stability as the coal generation fleet retires in the NEM.

Figure 2 illustrates recent and forecast[5] volumes of gas consumption for electricity generation in the NEM from the Draft 2024 ISP, as well as forecast GPG in the Northern Territory, highlighting a potential escalation in the need for gas generation in the winter season. Forecast gas consumption for GPG is highly weather-dependent and will be influenced by retirements of coal generators in the NEM and the capacity that replaces them. The next coal retirement (Eraring Power Station, currently announced to retire in August 2025) is forecast to increase the risk of needing higher volumes of gas for electricity production during peak winter periods.

Figure 2 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ per year [PJ/y]) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-43



Note: Northern Territory GPG consumption is included from 2020 onwards in this chart and any other charts related to GPG in this document.

[3] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

[4] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf?la=en.

[5] The GPG forecasts differ marginally to those presented in the Draft 2024 ISP. The GSOO applies assumptions regarding bidding behaviour, operational constraints, longer generator build timelines, and generator availability to predict GPG consumption more accurately. GSOO forecasts exclude Yarwun, include the Northern Territory, and are averaged across different historical weather patterns while being presented by calendar year rather than financial year.

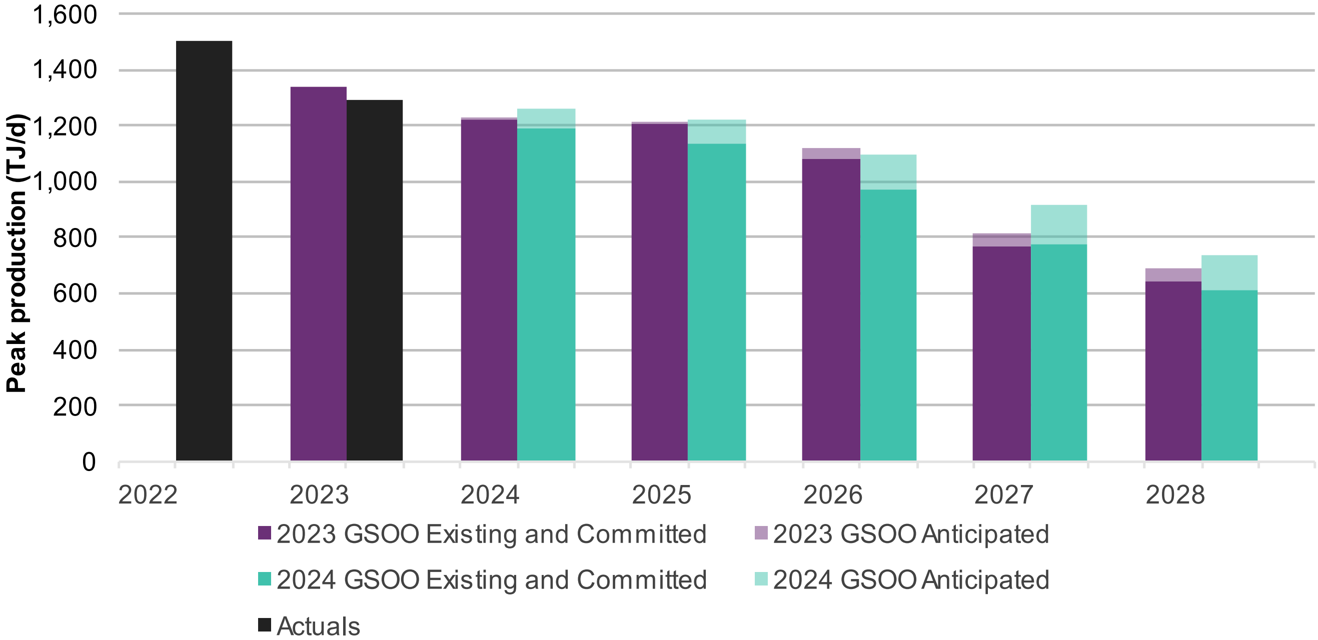
The Draft 2024 ISP analysis in Figure 2 shows that gas generation is forecast to continue providing key support for the NEM over the horizon, while renewable generation develops and particularly after coal generators retire. As production from solar generation naturally reduces during winter, high GPG demand becomes more likely.

Southern regions are forecast to be at risk of shortfalls on some days in winter from 2025 under extreme peak demand conditions

Despite slight improvements in maximum daily production capacity from committed and anticipated production since the 2023 GSOO, the risk of shortfalls during extreme peak conditions is forecast from 2025, two years later than that forecast in the 2023 GSOO. The risk of shortfalls on some days then increases in each year across the horizon. Due to some improvements in the granularity of the information that has been provided to AEMO, some peak production capacity has been reclassified from committed to anticipated status during the period to 2028. Southern production is still expected to reduce significantly from 2026 and again in 2028 as legacy fields in southern regions deplete.

Figure 3 shows actual production in 2022 and 2023 and forecast production capacity in each year to 2028.

Figure 3 Actual and forecast maximum daily production capacity from southern gas fields, June 2022-28 (TJ/d)



The projected reduction in daily maximum production is forecast to cause challenging gas adequacy conditions for southern regions and require a greater reliance on storage and gas supplied from northern regions.

Completed projects – upgrades to Iona underground gas storage (UGS)[6], expansion of the South West Pipeline (SWP, including the Western Outer Ring Main, or WORM) in Victoria[7], and the ECGE Stage 1 project[8] – and the

[6] During 2023, Iona UGS increased storage capacity by 0.4 PJ to 24.4 PJ, and supply capacity by 12 TJ/d to 570 TJ/d.

[7] The SWP capacity expansion is now completed and the WORM is due to be completed prior to winter 2024, delivering an additional 83 TJ/d of capacity to Melbourne.

[8] ECGE Stage 1 was completed during 2023 and allows an extra 49 TJ/d of northern gas to supply southern markets.

committed ECGE Stage 2[9] project, add increased capacity but will not completely mitigate the risk of southern supply shortfalls.

The changing seasonal gas supply and demand dynamics in the south, and the important role of storages and gas delivered from northern regions, are emphasised in Figure 4. This shows the ability of committed and anticipated southern production, pipeline capacity and stored gas to meet actual southern gas demand in 2022 and 2023, and its projected ability to meet extreme peak day gas demand in each year until 2028 in the *Step Change* scenario[10].

Horizontal lines in **Figure 4** indicate the maximum capacity forecast to be available to meet daily gas demand, from each of the following sources cumulatively:

- Existing and committed gas production capacity from southern regions only (solid purple line), plus
- Expected gas imported from Queensland through the South West Queensland Pipeline (SWQP)[11] (dashed purple line), plus
- Gas injection capacity from deep storage at Iona UGS (dotted purple line), plus
- Gas injection capacity from shallow liquefied natural gas (LNG) storages at Dandenong and Newcastle (solid red line), plus
- Anticipated gas production capacity from southern regions (dashed red line).

Figure 4 indicates gas shortfall risks are forecast to emerge on some days in winter 2025 under extreme peak day demand conditions. This is a lower risk than forecast in the 2023 GSOO, due to lower forecasts for GPG and residential, commercial and industrial users. From 2026 the southern supply-demand balance continues to tighten, and pipeline infrastructure becomes less able to deliver the volumes of gas required under extreme conditions, increasing the risks to peak day adequacy on the most extreme demand days.

As Gippsland supply continues to decline and production facilities at the Longford Gas Plant are decommissioned, southern regions will be exposed to increased risk if unscheduled interruptions occur due to the reduced supply resilience in the southern region[12].

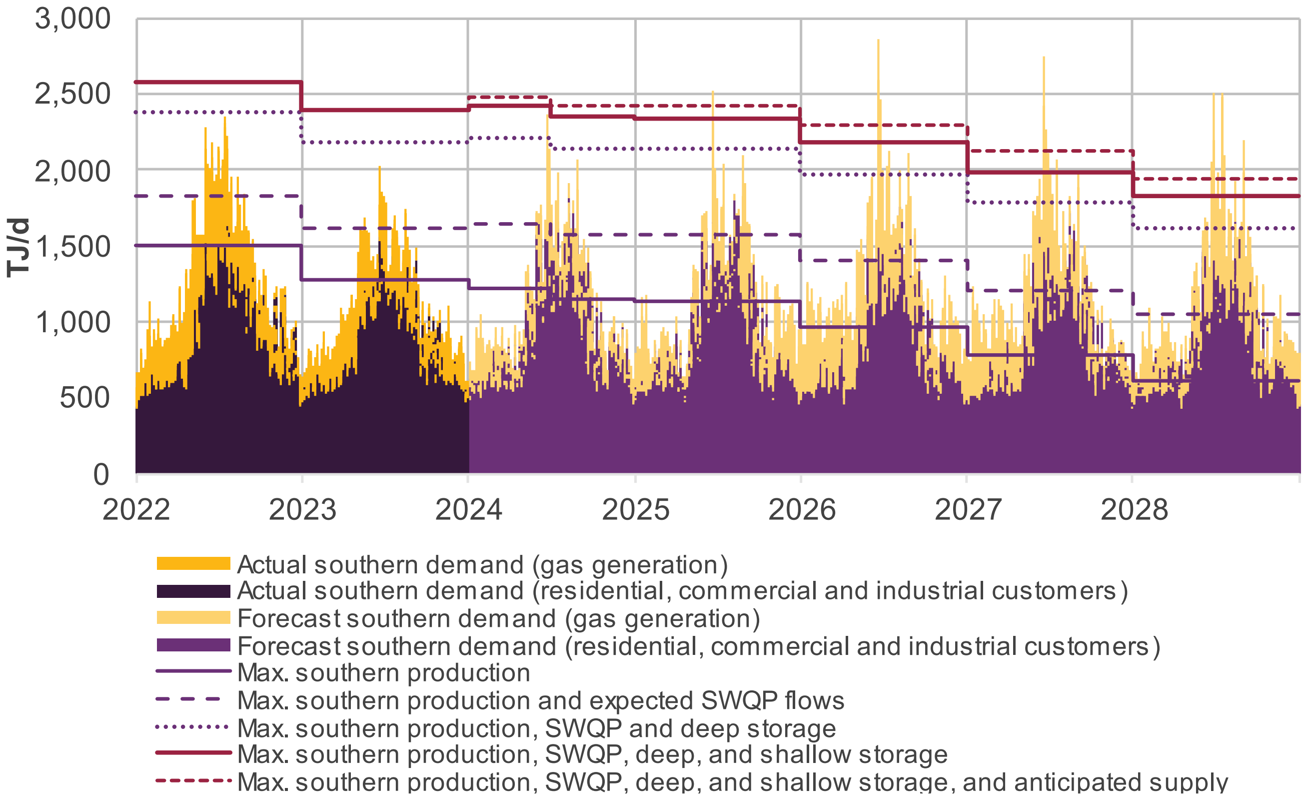
[9] The ECGE Stage 2 project is planned for completion in 2024 and will increase north to south transportation capacity by 59 TJ/d.

[10] Extreme peak day demand is characterised by 1-in-20-year highs in daily demand from residential, commercial and industrial customers and 1-in-10-year high daily gas requirements for GPG.

[11] Ongoing supply issues in the Northern Territory mean that no flow is expected down the Northern Gas Pipeline (NGP) into Queensland. Therefore, the estimate of available SWQP flow accounts for gas flow along the Carpentaria Gas Pipeline (CGP) to Mount Isa.

[12] The retirement of Longford Gas Plant 1 in July 2024 means the two remaining gas plants will be required to achieve peak day capacity of 700 TJ/d. Gas Plant 3 is forecast to retire later this decade.

Figure 4 Actual daily southern gas system adequacy since January 2022, and forecast to 2028 using existing, committed and anticipated projects (TJ/d)



Near-term solutions to address peak day shortfall risks are limited

Consistent with the 2023 GSOO, it is critical that committed and anticipated supply and infrastructure projects are progressed and completed to schedule to minimise shortfall risks:

- Development of anticipated supply is crucial to ensure sufficient supply is available to support southern demand and mitigate the risk of peak day shortfalls. These anticipated supply projects are also necessary to provide supply to meet established domestic and export contracts from 2025.
- The East Coast Grid Expansion Stage 2 project will increase the capacity of the SWQP and Moomba – Sydney Pipeline (MSP) to transport gas to southern demand centres. It is important this expansion is completed on time to maximise supply to southern regions from 2024.
- Ensuring all storages are at full capacity prior to winter is critical to reduce shortfall risks. Throughout winter, appropriate operation to manage southern storage depletion is important. In extreme cases where depletion is taking place at an accelerated rate, northern supply should be sourced to ensure depletion is minimised.
  - The Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[13] requires that AEMO contract any uncontracted capacity at Dandenong LNG until 2025. This will ensure the Dandenong LNG tank is full prior to winter during this period.

[13] AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

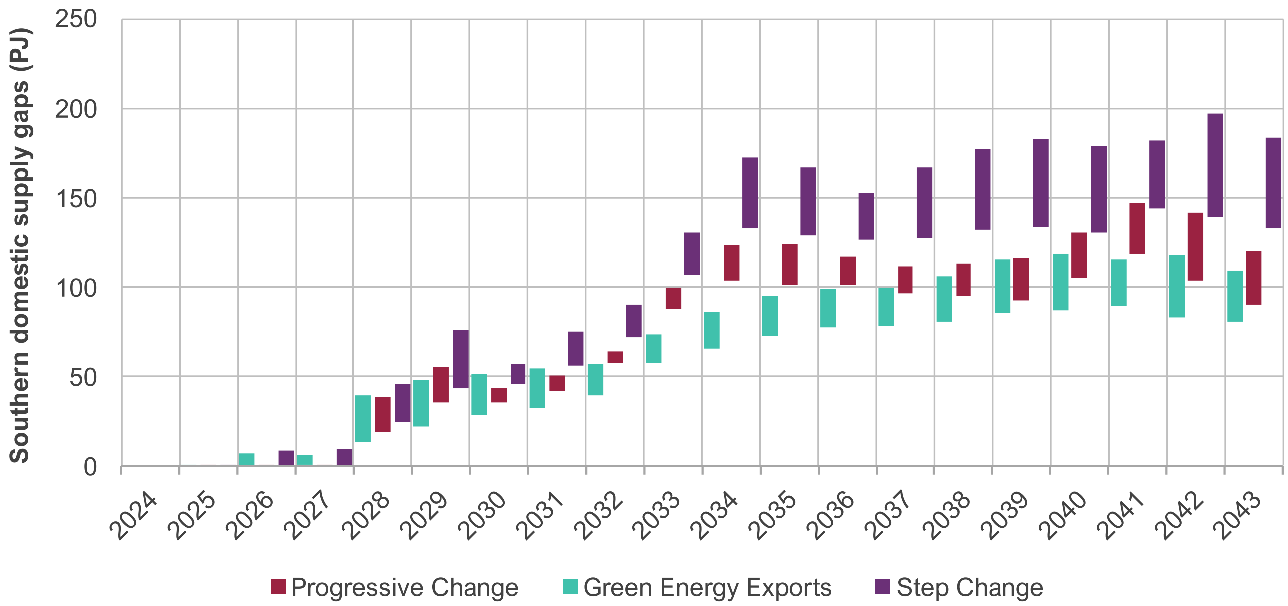
- Given the lead time needed to plan, obtain approval for, and build new greenfield infrastructure, demand flexibility is likely the best solution to address forecast short-term supply shortfall risks. In extreme gas shortfall conditions, secondary fuels may be needed to operate gas generation for short periods so electricity reliability is not compromised.

Annual and seasonal supply gaps are increasingly forecast in southern Australia

From 2026, small seasonal supply gaps are forecast if conditions lead to sustained high gas usage, particularly in winter, even with the development of anticipated supplies as currently planned. This risk is one year earlier than was forecast in the 2023 GSOO. In 2026 and 2027, the potential for annual or peak day shortfalls can likely be managed by industry and if necessary by AEMO, through gas storages and by switching gas powered generators to secondary fuels. From 2028 a solution which brings in more supply is needed.

The emergence of seasonal supply gaps in 2026, shown in **Figure 5**, is mainly driven by forecast increases in GPG demand as set out in the Draft 2024 ISP. Ongoing reduction in southern gas supply provides a more structural supply gap that will require greater supply to resolve than is currently committed or anticipated. These are higher across later years in the horizon than in the 2023 GSOO, primarily due to higher forecast GPG and reclassification of some anticipated supply to uncertain supply. The breadth of forecast shortfalls across the modelled scenarios in this 2024 GSOO diverges from the early 2030s, reflecting uncertainty in the speed of the energy transition affecting consumer demand and gas for electricity generation.

Figure 5 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, all scenarios, 2024-43 (PJ)



Northern producers need to deliver anticipated supplies, and by 2026 more uncertain supply is required to meet export agreements and domestic supply

Northern gas producers provide critical support to keep domestic users adequately supplied[14]. LNG producers control around 70% of total 2P reserves[15] in central and eastern Australia, and volumes of gas exported internationally via Curtis Island in Queensland represent around 70% of annual consumption in the ECGM. Production of gas from Queensland and the daily and seasonal operation of these facilities will have a growing impact on domestic supply adequacy as southern production declines:

- Gas production from LNG producers' existing and committed developments, in addition to domestic third-party supply, will only be sufficient to meet export and domestic supply contracts until the end of 2024.
- The development of northern anticipated supply will only maintain sufficient supply until 2026, and uncertain supply developments will then be required to ensure that northern demand, LNG exports and southern demand can be satisfied.

It remains critical that LNG producers make supply available during winter in all years of the outlook period to support flows to southern regions to mitigate the risk of southern supply shortfalls.

Reliance on alternative and interim gas arrangements may persist in the Northern Territory

The Northern Territory is presently reliant on alternative and interim gas arrangements, including with Darwin LNG exporters[16]. There is currently reduced production from the Blacktip field, and it is not clear when production levels will be fully restored. The Northern Gas Pipeline (NGP) which transports gas eastward to Mount Isa from the Northern Territory is currently not flowing, and the resumption of these flows is not forecast in the gas adequacy assessments presented in Section 4. The NGP is not presently capable of flowing towards the Northern Territory from Queensland. Reversal of the NGP may provide an alternative solution to address forecast supply gaps in Northern Territory.

A combination of solutions is required to address the risk of southern daily shortfalls and forecast annual supply gaps

Given the identified supply gaps, the 2024 GSOO includes a collection of *what if* analyses to explore potential future supply, transportation, and storage projects.

Table 1 shows the options assessed and their capacities, timings, and effects on shortfalls. The options assessed are not exhaustive and are only intended to provide insights into the effectiveness of a broad range of potential options in addressing forecast supply challenges. This assessment does not consider all factors such as cost, regulatory approvals, land use, social license, safety, or operational challenges of each option, and does not amount to a recommendation or representation regarding any investment.

[14] AEMO's physical gas adequacy assessments assume that gas from Queensland LNG producers is made available to the domestic market if required to avert domestic shortfalls. This includes uncontracted gas that could otherwise be exported as spot cargoes to international markets.

[15] 2P, or proved and probable, is widely accepted as the best estimate of reserves.

[16] Detail on this arrangement is at https://www.aemc.gov.au/sites/default/files/2019-08/Information%20sheet.pdf.

Table 1 Future supply, transportation and storage options assessed

Option name	New southern supply	Transportation capacity (if relevant)	Southern annual supply gaps delayed until	Optimal storage required (PJ)[A]	Northern Supply required (PJ/y)[B]
LNG import terminal	NSW (Port Kembla) from 2026	Eastern Gas Pipeline (EGP) reversal Stages 1 and 2	2033	35	Increasing to ~600 PJ/y from mid-2030s
	SA (Outer Harbour) from 2026	Port Campbell to Adelaide (PCA) pipeline reversal, from 2026			
	VIC (Geelong[C]) from 2027	None modelled			
Pipeline expansions and upgrades	None	• ECGE Stages 3a, 3b and 4 • EGP reversal Stages 1 and 2 • Port Campbell to Adelaide pipeline reversal from 2026	2029	50	Increasing to ~670 PJ/y from mid-2030s
Southern Supply and renewable gases	• 2C Southern Supply[D], from 2028 • Renewable Gases	Hunter Gas Pipeline (Narrabri to Newcastle) – by 2028	2033	35	Increasing to ~560 PJ/y from mid-2030s

A. New storage capacity is forecast as being needed to address seasonal adequacy challenges. The figures in this column represent the storage depth required to address seasonal supply gaps before annual supply gaps emerge.
B. Represents the magnitude of northern supply required to service northern (including LNG exports) and southern markets; new pipelines or pipeline expansions may be needed to ensure any new supply is able to connect to existing northern pipelines.
C. This could be either Viva's or Vopak's proposed LNG import terminal project.
D. A contingent (2C) resource is a best estimate of a quantity of gas that is less certain, and potentially less commercially viable, than 2P. This option only includes production profiles from southern 2C resources reported to AEMO via the GSOO surveys. Projects included in this additional southern supply include projects in the Gunnedah, Otway, Gippsland, Bass and Cooper basins.

Figure 6 and **Figure 7** present key findings from this assessment, summarised below:

- AEMO modelling indicates a range of supply and infrastructure options will delay annual supply gaps and help to mitigate the risk of peak day shortfalls, particularly when paired with increased storage capacity.
- A portfolio of solutions is likely to be required to address annual, seasonal and peak day shortfall risks, including:
  - **Upgrades and expansions of existing pipelines** that may delay annual gaps to 2029, but will require additional solutions to increase supply and provide peak day flexibility.
  - **Uncertain 2C southern supply and renewable gas projects** that may delay annual supply gaps to 2033 and help mitigate peak day shortfall risks.
  - **LNG import terminal(s)** which may require associated pipeline infrastructure depending on the terminal may delay supply gaps until 2033 and help mitigate peak day shortfall risks, depending on the availability of LNG cargoes.
  - **Increased storage** to cater for peak seasonal loads is likely to be a good complement to all other developments. Demand response mechanisms may also mitigate peak supply shortfall risks.
- In total, up to 7,000 PJ of new northern supply above committed and anticipated projects is expected to be required during the period to 2043, including to meet forecast LNG exports and domestic demand.
- Investments in infrastructure from the mid-2030s are highly dependent on the volume and rate at which gas is required for GPG.

Figure 6 Forecast southern daily adequacy for each of the future options assessed, excluding optimal storage build, 2024-35 (TJ/d)

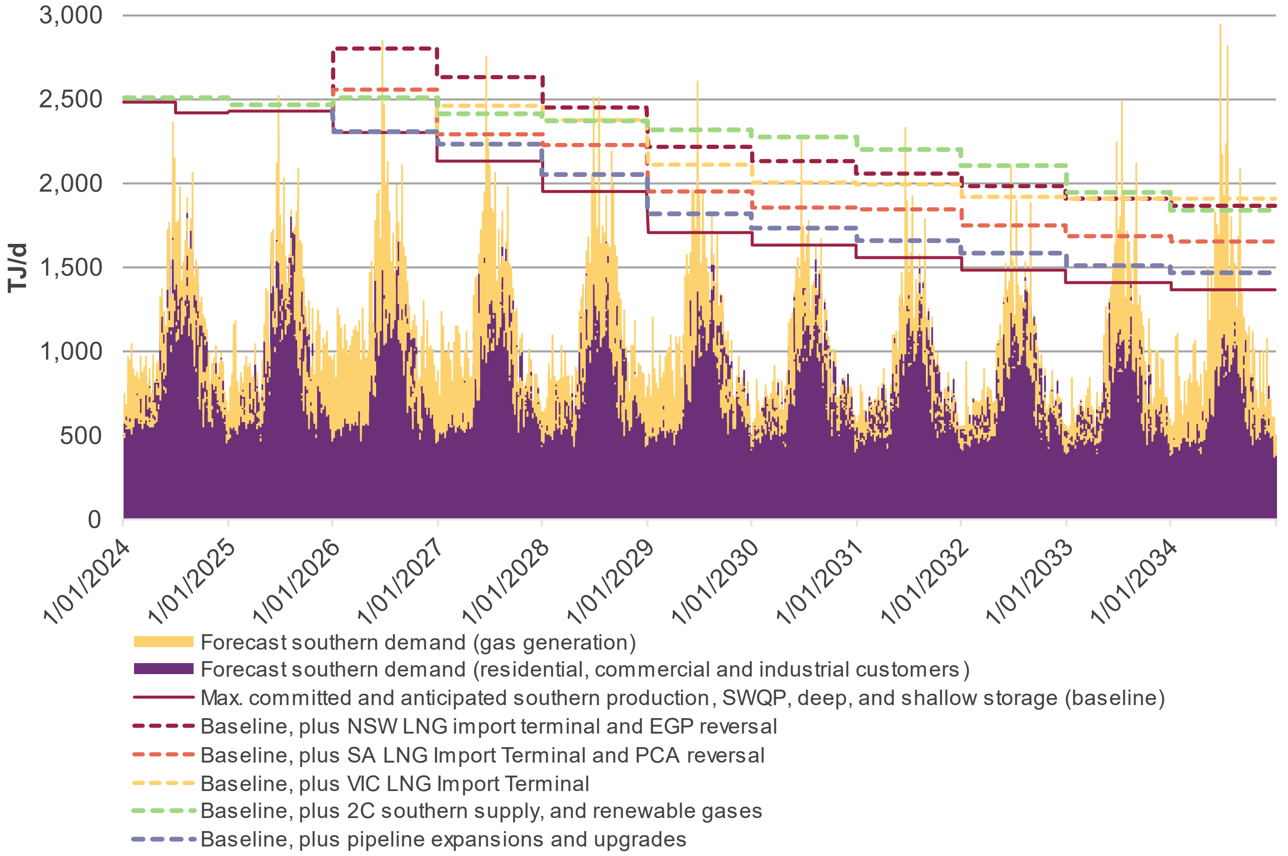
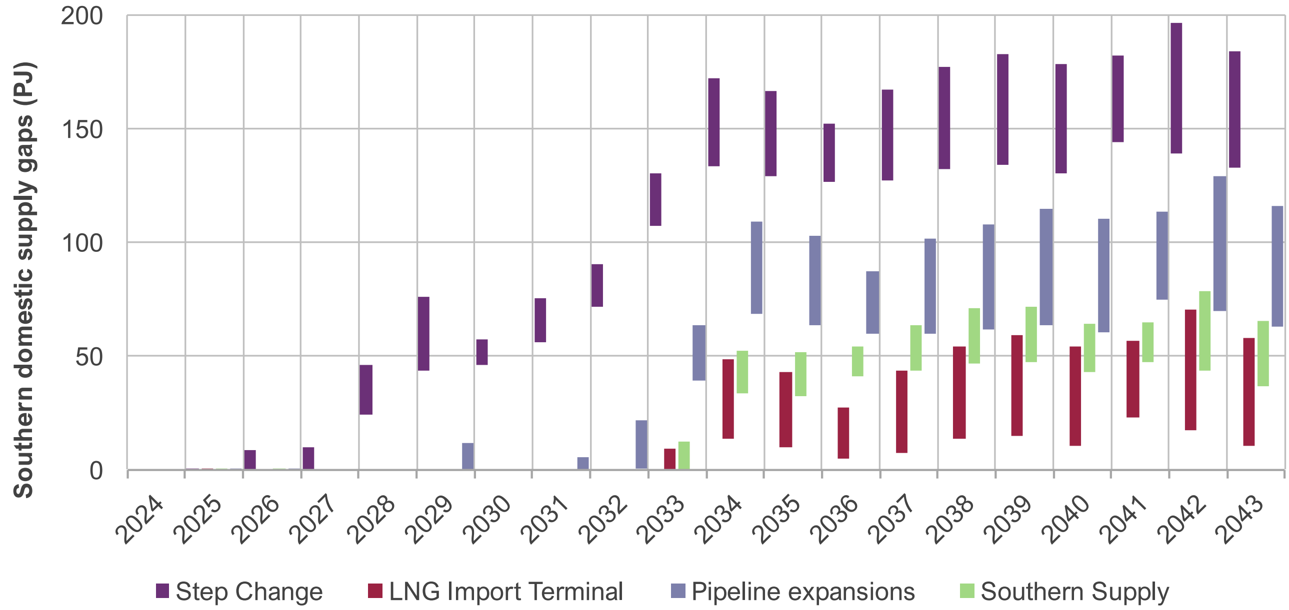


Figure 7 Range of annual shortfalls for each option assessed across various weather conditions when paired with optimal storage build, 2024-43 (PJ)



1 Introduction

The *Gas Statement of Opportunities* (GSOO) assesses the adequacy of gas reserves, resources, and infrastructure to meet domestic and export needs over a 20-year outlook period across central and eastern Australia (that is, all Australian jurisdictions other than Western Australia), referred to in this GSOO as the East Coast Gas Market (ECGM). The GSOO provides a physical assessment of gas adequacy by assessing the capability for existing, committed and anticipated production to meet demand for gas, including gas required for gas-powered generation of electricity (GPG) in the National Electricity Market (NEM) and in the Northern Territory.

The physical assessment[17] provided in the 2024 GSOO provides an analysis of the additional investments in new supply and infrastructure to meet the minimum requirements of the domestic market. Contractual and commercial arrangements may impact gas operations, including gas storages, and whether excess gas production offered to domestic consumers is able to be transported to demand centres.

The GSOO analyses a range of potential futures, focusing on the adequacy of the system to meet changing gas needs from now until 2043. To provide additional insights, modelling and assessment of the impact of future supply, transportation and storage projects currently being considered on gas adequacy is also included. It should be noted that this assessment does not represent a merits or cost-benefit assessment and has not considered the viability of projects based on current market settings.

AEMO's 2024 *Victorian Gas Planning Report Update* (VGPR Update)[18] is a separate, complementary analysis to meet a specific Victorian AEMO obligation, focusing on the gas supply-demand balance in Victoria for the next five years.

1.1 Scenarios

Considering the uncertainties in the speed and extent of gas sector transformation, AEMO uses scenarios and sensitivities to explore the needs of gas consumers and the adequacy of gas infrastructure to meet those needs.

For the 2024 GSOO, AEMO modelled the next 20 years using scenarios from the 2023 *Inputs, Assumptions, Scenarios Report* (IASR)[19] to assess the impacts of changes to specific scenario assumptions. These scenarios are described in detail in the 2023 IASR and remain highly comparable to scenarios used in the 2023 GSOO.

In summary:

- ***Step Change*** – achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. Electrification is a key enabler to transition the economy at a pace aligned with beating the 2°C abatement target of the Paris Agreement. Consumer actions lead to rapid and significant continued investment in orchestrated consumer energy

[17] Note that the GSOO does not consider gas contracts, but identifies the level of physical production capacity in excess of advised liquefied natural gas (LNG) export contractual positions, that can be made available to domestic consumers.

[18] At https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

[19] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

resources (CER) and include electrification of the transportation sector. The 2024 GSOO *Step Change* scenario is comparable to the 2023 GSOO *Orchestrated Step Change (1.8°C)* scenario.

- ***Green Energy Exports*** – reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane.
- ***Progressive Change*** – meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.

Table 2 summarises key parameters for each scenario.

Table 2 Key parameters by scenario

Parameter	*Step Change*	*Green Energy Exports*	*Progressive Change*
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030, net zero by 2050
Global economic growth and policy coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Moderate	Higher (partly driven by green energy)	Lower
Electrification	High	Higher	Lower
Energy efficiency across all energy forms	Moderate	Higher	Lower
IEA 2021 World Energy Outlook scenario	Sustainable Development Scenario (SDS)	Net Zero Emissions (NZE)	Stated Policies Scenario (STEPS)
Most similar 2023 GSOO scenario	*Orchestrated Step Change (1.8°C)*	*Green Energy Exports (1.5°C)*	*Progressive Change (2.6°C)*

Note: AEMO has explored additional sensitivities on the *Step Change* scenario, detailed in Section 2.3.

1.2 Gas Market Code

The Federal Government's Gas Market Code (Code)[20] commenced on 11 July 2023 and, following a transition period, came into full effect on 11 September 2023. The purpose of the Code is to ensure that the domestic wholesale gas market supplies adequate gas at reasonable prices and reasonable terms. The Code includes:

- Price rules which prevent the sale of gas above the reasonable price unless exempted under the exemptions framework, currently set at $12/gigajoule (GJ).
- Good faith rules and procedural requirements for gas market participants negotiating with each other.
- Record keeping, reporting and publication rules.

[20] More information is at https://www.accc.gov.au/business/industry-codes/gas-market-code#:~:text=The%20Gas%20Market%20Code%20is,prices%20and%20on%20reasonable%20terms.

- An exemptions framework, including for small producers (<100 petajoules per year (PJ/y)) who supply that gas domestically[21], and for larger producers who commit to additional future domestic supply and other conditions.

AEMO's GSOO survey data requests were sent[22] on 1 September 2023 and received by 30 September 2023, giving reporting entities the opportunity to consider the effects of the Code in their 2024 GSOO survey responses.

At the time of writing, the Federal Government has granted conditional exemptions under the Code for supply totalling 564 PJ[23]. AEMO acknowledges that gaining a conditional exemption under the Code may help accelerate progress towards project approvals, contracting and delivery. These conditional exemptions include commitments that remain subject to additional approvals, including final investment decisions by producers. As such, this total supply is not committed in the GSOO, although the majority of this supply is already classified as anticipated.

1.3 Gas market reform

A package of rule changes increasing transparency in the ECGM[24] were made on 23 June 2022. These changes are in effect from the 2024 GSOO and require reporting entities to supply more granular data that covers wider timeframes in comparison to previous publications.

On 12 August 2022, Energy Ministers agreed[25] on a set of actions to support a more secure, resilient and flexible ECGM. These actions include Stage 1 measures which came into effect on 4 May 2023 to provide AEMO with tools to monitor, signal and manage gas supply shortfalls.

On 18 December 2023, Energy Ministers agreed to progress Stage 2 measures expected to build on Stage 1 which seek to establish a fit-for-purpose Reliability and Supply Adequacy Framework. This framework may include a reliability standard that has closer alignment with that of the NEM, and greater monitoring, communication, and supply adequacy management tools[26].

1.4 Supplementary information

Supporting material including previous GSOO reports, supply input data files, methodology reports, and figures and data is available on AEMO's website[27], and is listed in **Table 3**.

[21] More information is at https://www.dcceew.gov.au/energy/markets/gas-markets/conditional-exemptions-mandatory-gas-code-conduct.

[22] Surveys were sent to gas producers, explorers, gas plant operators, storage facility operators, pipeline operators, large users, retailers, liquefied natural gas (LNG) exporters, LNG import facility operators and distributors. Surveys were also sent to renewable gas project proponents for voluntary submissions.

[23] See https://www.dcceew.gov.au/energy/markets/gas-markets/conditional-exemptions-gas-market-code.

[24] See https://www.aemc.gov.au/sites/default/files/2022-08/20220630_Gas%20Market%20Transparency%20Rule.pdf.

[25] See https://www.energy.gov.au/sites/default/files/2022-08/Energy%20Ministers%20Meeting%20Communique%20-%2012%20August%202022.docx.

[26] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/consultation-stage-2-reliability-and-supply-adequacy-framework-east-coast-gas-market.

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

Key materials include:

- AEMO's **demand forecasting portal**[28] – interactive access to detailed forecasts of annual gas consumption and maximum gas demand, for each region and scenario included in this GSOO.
- **Supply input data files**[29] – information (including capacity) about pipelines, production facilities, storage facilities, field developments, and any new projects or known upgrades considered in this GSOO analysis. The files also provide an update of reserves and resources, and cost estimates used for GSOO modelling[30].
- **2024 *Victorian Gas Planning Report Update* (VGPR Update)**[31] – focused assessment of the gas supply-demand balance to 2028 in Victoria's Declared Transmission System (DTS), complementing the GSOO.

Table 3 Other relevant reference materials

Information source	Website address and link
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb
2023 *Inputs, Assumptions, Scenarios Report* (IASR), and Excel Workbook	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
BIS Oxford Economics, 2022 Macroeconomic projections report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf
CSIRO and ClimateWorks, 2022 Multi-sector energy modelling	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf
Strategy.Policy.Research, Energy Efficiency Forecasts 2023 – Final Report	https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf
ACIL Allen: 2023 Natural gas price forecast report	https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf
ACIL Allen: 2023 Natural gas price forecast workbook	https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecast.xlsx

Figure 8 provides a map of the basins, pipelines, and load centres across the ECGM in this 2024 GSOO.

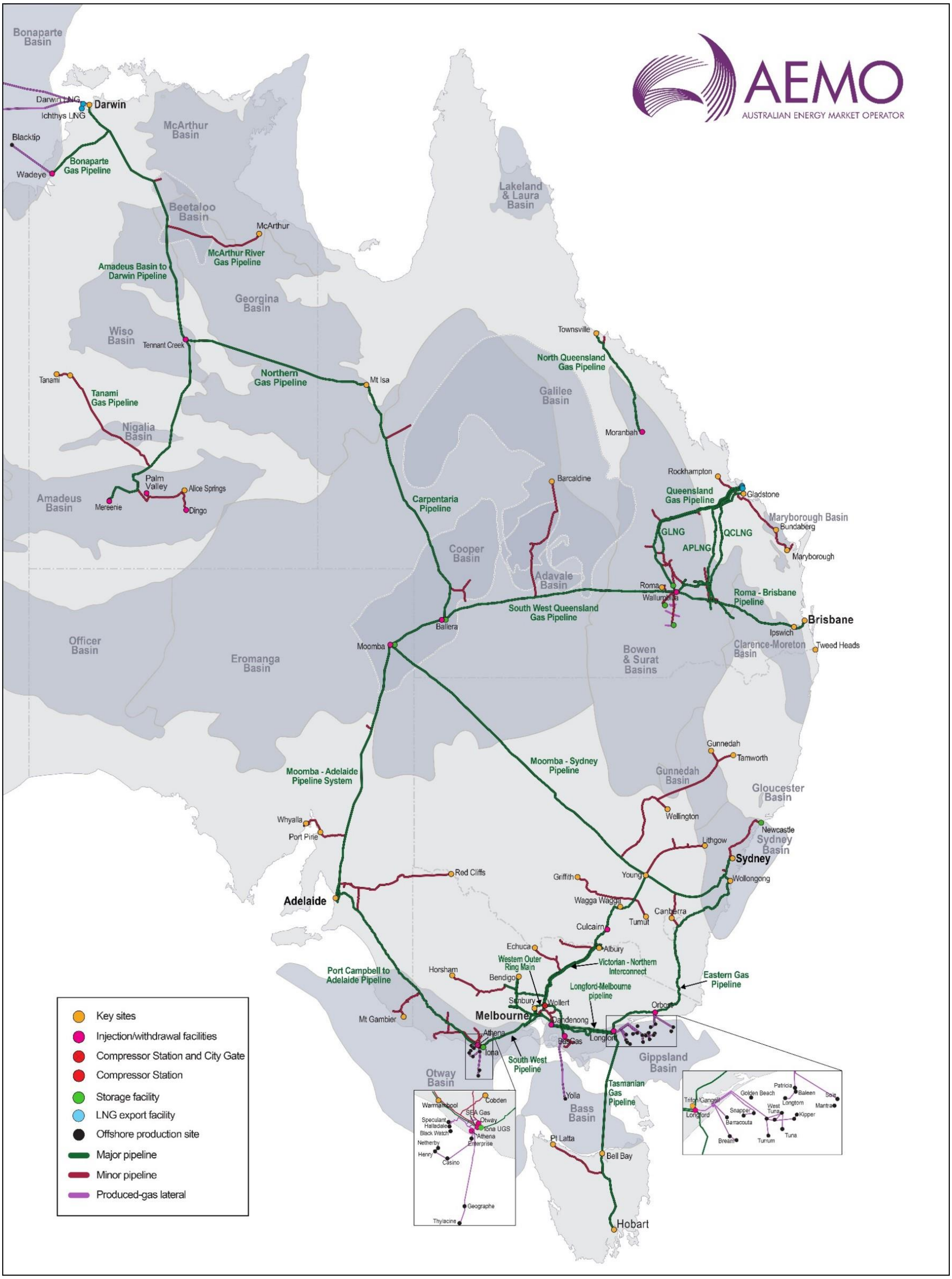
[28] At https://forecasting.aemo.com.au/.

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

[30] The published file showing reserves and resources is based on AEMO's survey of gas producers and information from Rystad Energy, supplemented by 2023 GSOO data if required.

[31] At https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

Figure 8 Map of basins, major pipelines, and load centres



2 Gas consumption and demand forecasts

This section outlines forecasts of annual gas consumption and maximum daily gas demand across the various customer sectors of gas. The forecasts presented are for the *Step Change* scenario, unless otherwise specified. The forecasts are available on the AEMO Forecasting data portal[32].

Key insights

- **The annual, seasonal, and peak daily needs of gas consumers are evolving** as Australia commits to and develops new infrastructure to meet a net zero emissions future. The pace at which the transition will occur remains uncertain, although in the first five years of the outlook, the spread between scenario forecasts is less than in the 2023 GSOO.
- **Annual residential and small commercial gas consumption is forecast to decline** in the short term in line with recently observed trends, and in the long term due to the potential to fuel-switch to electric alternatives across the residential, commercial and, to a lesser extent, industrial sectors. These trends are also expected to drive reductions in peak day gas demand forecasts for residential and small commercial consumers.
- **Large commercial and industrial consumption is forecast to remain relatively stable** before reducing from the 2030s due to a combination of electrification and reduced demand from large industrial loads (LILs).
- **Gas for generation of electricity is forecast to increase** in the long term, due to electricity demand growth, coal retirements, and to firm renewable energy generation in the NEM. Peak demand for GPG is forecast to experience significant growth, particularly in winter when renewable generation is naturally lower.

2.1 Total gas consumption forecasts

Figure 9 shows the 20-year total consumption forecast under the *Step Change* scenario broken down by consumer type for all regions in eastern and central Australia. The drivers and trends for each sector are discussed in Sections 2.2.1 to 2.2.3.

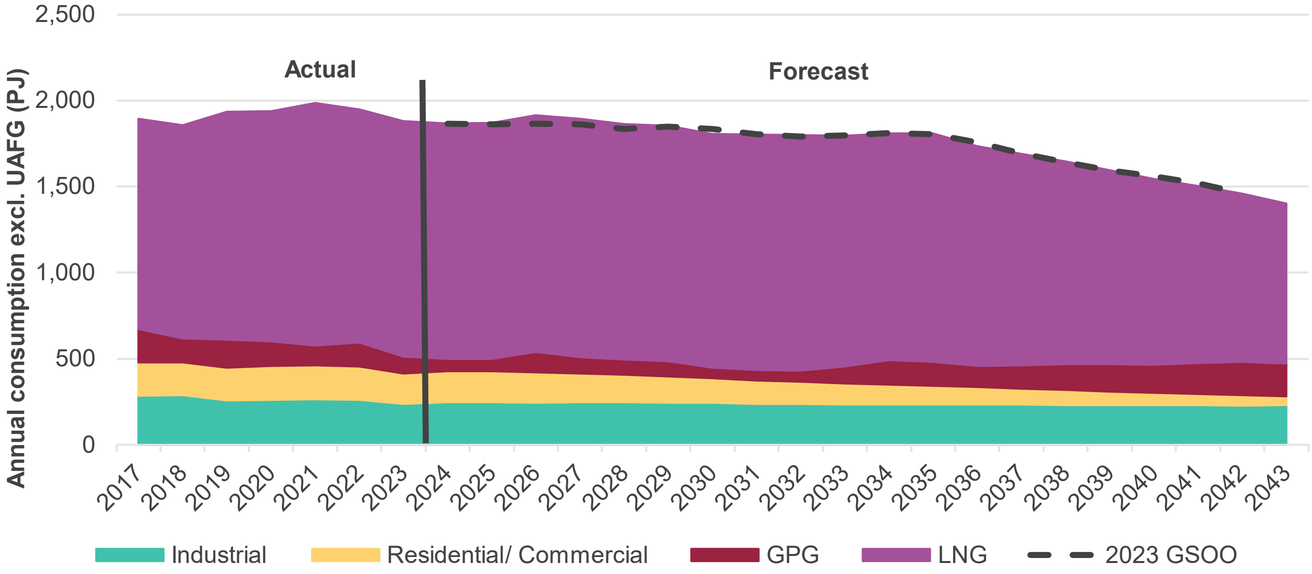
The total 2024 GSOO forecast follows a gradually declining trajectory, similar to the 2023 GSOO. A comparative increase in GPG forecasts[33] in the 2024 GSOO, particularly from the 2030s, is offsetting lower forecasts for industrial, residential, and commercial customers.

Despite the declining liquefied natural gas (LNG) outlook (also forecast in the 2023 GSOO), LNG exports remain the largest consuming sector in the forecast, contributing approximately two-thirds of total gas consumption by 2043.

[32] At https://forecasting.aemo.com.au/. First select either **Gas/ Annual consumption** or **Gas/ Maximum Demand**, then select 'GSOO 2024' from the Publication drop-down.

[33] The GPG forecasts in this 2024 GSOO are based on coal generator closures as forecast in the Draft 2024 ISP, which in some cases are earlier than announced.

Figure 9 Actual and forecast total annual gas consumption, all sectors, *Step Change* scenario, 2017-43 (PJ)

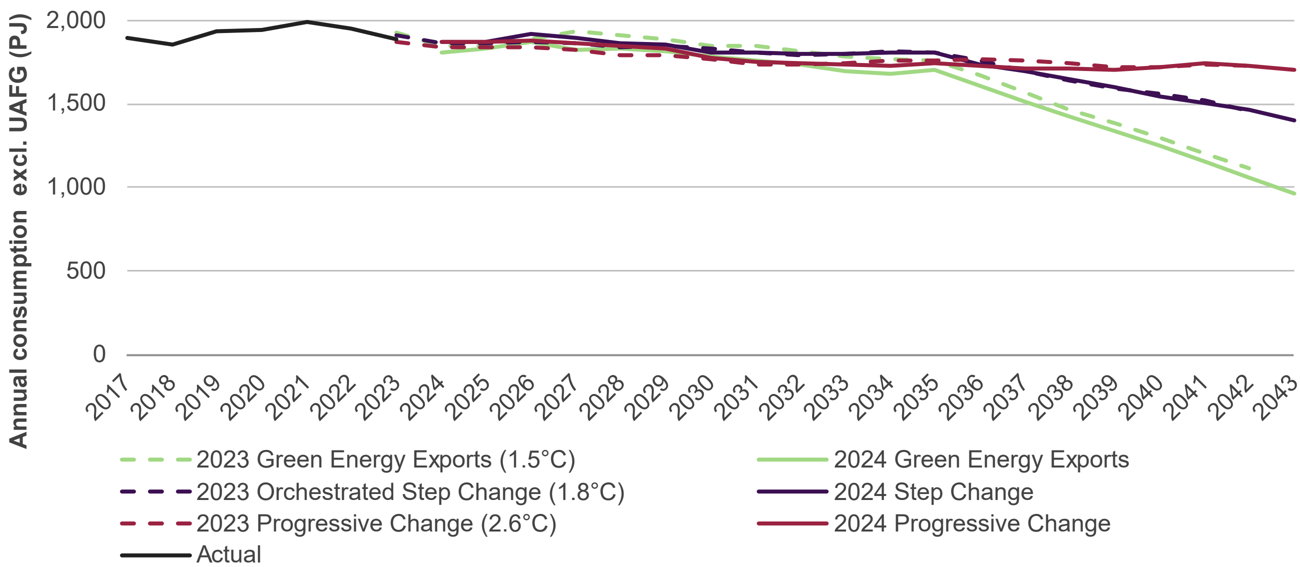


Notes:

- Forecasts assume demand is met by natural gas, and renewable gases if they are developed.
- Northern Territory domestic gas consumption is included from 2020 onwards. Northern Territory LNG forecasts are excluded.

Figure 10 compares total gas consumption forecasts for the 2023 and 2024 GSOOs.

Figure 10 Actual and forecast total annual gas consumption, all sectors, all scenarios, and compared to 2023 GSOO, 2017-43 (PJ)



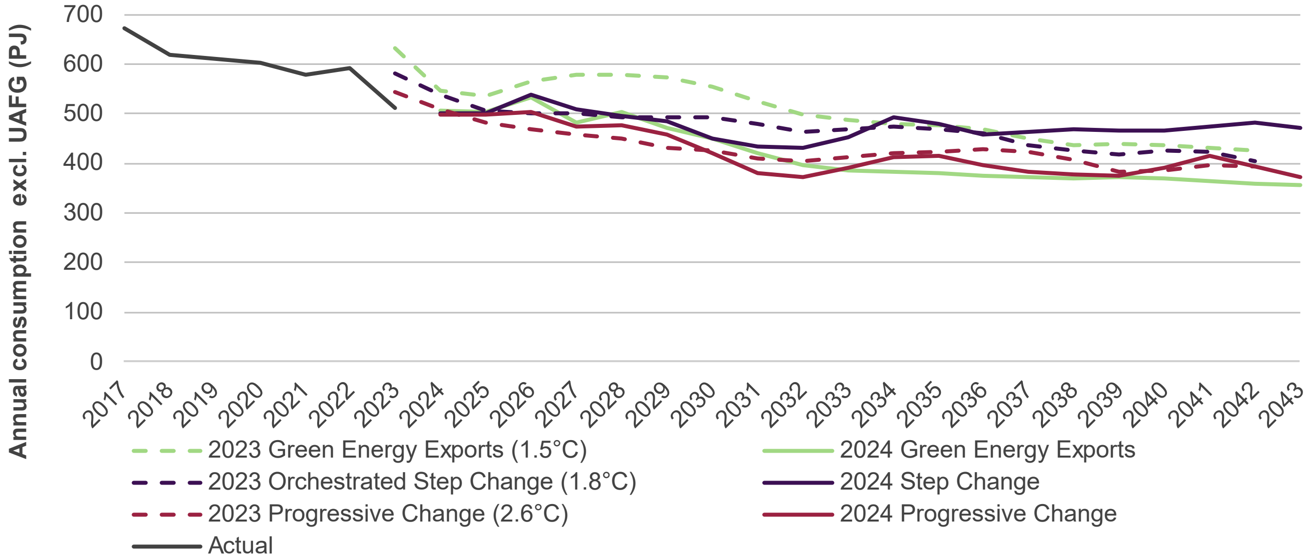
Notes:

- Forecasts assume demand is met by natural gas, and renewable gases if they are developed.
- Northern Territory domestic gas consumption is included from 2020 onwards. Northern Territory LNG forecasts are excluded.

Figure 11 focuses on annual domestic consumption forecasts and excludes LNG exports. The key drivers for the consumption trends in these forecasts include the following observations for the *Step Change* scenario:

- The forecast for residential consumption has been revised down relative to the 2023 GSOO due to recent sharp reductions in per household consumption observed in 2023. This may be attributed to price impacts from significant increases in retailer bills, emerging indications of fuel-switching to electricity, and some of the warmest winter temperatures on record[34].
- Residential and small commercial consumption is forecast to slightly decline in the short term, with more significant fuel-switching to electricity in the medium to longer term as the economy transitions to meet net zero emissions goals. Electrification and other drivers are forecast to reduce residential and small commercial natural gas consumption by around 125 PJ, down to 50 PJ in 2043.
- Large commercial and industrial consumption is forecast to remain relatively stable before reducing from the 2030s due to a combination of electrification and reduced demand from LILs, particularly in Queensland.
- GPG consumption is forecast to continue its downward trend in the short term before remaining relatively stable until the early 2030s. As increased renewable generation and battery connections develop in the NEM, historical usage patterns for GPG are expected to change. The 2024 GSOO forecasts the potential for a long-term increase in GPG consumption compared to the 2023 GSOO, due to an increasing need for firming support as coal generators continue to retire and electrical demand increases through electrification, particularly during winter seasons when solar output is lower.

Figure 11 Actual and forecast domestic gas consumption, all scenarios, and compared to 2023 GSOO scenarios, 2017-43 (PJ)



Notes:

- Forecasts assume demand is met by natural gas, and renewable gases if they are developed.
- Northern Territory domestic gas consumption is included from 2020 onwards. Northern Territory LNG forecasts are excluded.

Major drivers of the gas consumption forecasts are provided in the following sub-sections.

[34] Mean winter temperatures in 2023 were the warmest on record for Queensland, New South Wales and Tasmania, and second warmest for Victoria and South Australia; see http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml for further details.

Electrification

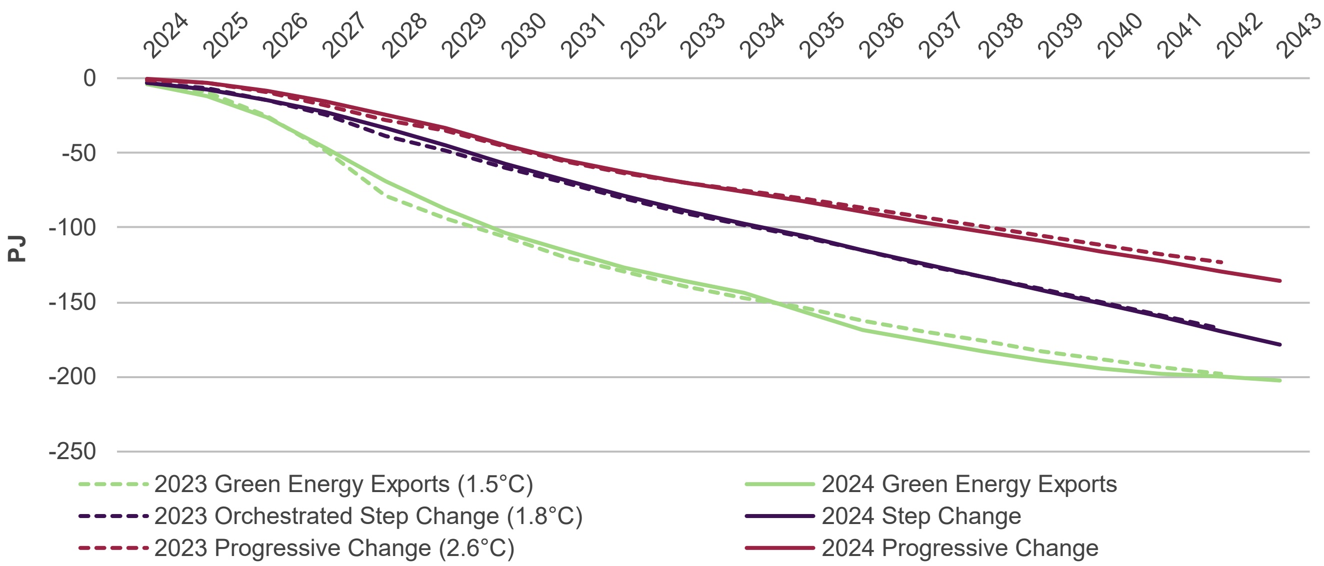
The pace of investments to electrify remains a key uncertainty in AEMO forecasts, however the recent introduction of policies to limit future gas connections in Victoria and the Australian Capital Territory is forecast to increase the rate of electrification in the residential and commercial sectors.

Figure 12 shows electrification projections across all scenarios; these are broadly comparable to the 2023 GSOO.

Most electrification of natural gas demand is projected to occur in the residential and commercial sectors, driven by switching gas heaters in homes to electric heat pumps. Victoria's current gas use is predominantly for space heating, which increases consumption particularly in winter.

In the industrial sector, electrification is expected to be more limited than in residential and/or commercial applications, due to the difficulty and/or high cost of technologies to electrify high heat processes (temperatures exceeding 400°C). Apart from retrofitting site equipment, the increased power requirements could also call for electricity network upgrades. Additionally, a significant share of natural gas usage in industry is for chemical feedstock, for which electricity is not a substitute.

Figure 12 Forecast reduction in gas consumption from electrification by scenario, 2024-43 (PJ)



Economic and population outlook

In 2022, AEMO engaged Oxford Economics Australia[35] to develop long-term economic and population forecasts for each Australian state and territory as a key input to AEMO's demand forecasts[36].

The Australian economy slowed throughout 2023 after a strong rebound from the COVID-19 pandemic. Economic growth is expected to begin to pick up towards the end of 2024 and into 2025 as inflation moderates and pressure

[35] The former BIS Oxford Economics.

[36] BIS Oxford Economics, 2022 Macroeconomic Projections Report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf.

on household budgets eases. In terms of the sectoral breakdown, the utilities[37] sector is expected to grow gradually in the near term as energy prices trend downward and industrial activity continues to normalise after the pandemic. Mining and manufacturing have both benefitted from stimulatory fiscal policy[38] and the initial rebound in economic activity, both domestically and overseas. Strong economic growth for the mining sector is expected, particularly in the medium term before 2030, driven by industrial commodities and new resources during the transition to a net zero emission economy. Beyond this, growth for emissions -intensive sectors is expected to lag behind other sectors, particularly the services sectors. Growth in manufacturing is expected to gradually slow as economic activity continues to normalise from COVID conditions.

Overall population growth forecasts remain relatively unchanged compared to the 2023 GSOO. Australia's population had strong growth in 2022-23, spurred on by a strong migration intake. The fast rebound in net overseas migration has helped replace the loss of population growth during the pandemic and been a major contributor to recent economic growth. While New South Wales is currently capturing the largest share of overseas migrants, the state is expected to experience a net outflow of interstate migrants over the long run. Queensland is expected to continue capturing a large share of interstate migration, particularly from New South Wales, reflecting a strengthening labour market and post-pandemic shift towards more affordable lifestyle locations. Overall, these economic and population forecasts have a direct impact on the forecast number of connections to the gas system.

Figure 13 shows the potential for households and commercial businesses to fuel-switch to electricity under all scenarios, represented by an 'effective' gas connections forecast that relates historical levels of consumption per connection to the forecast electrification outlook in Figure 12. In all forecasts, AEMO anticipates that the gas use per connection will continue to decline, as appliances that have traditionally used gas improve their efficiency, or are replaced with alternatives. As such, this 'effective' connections forecast may not be representative of the forecast number of physical connections, but represents the equivalent number of connections if all connections maintained historical usage levels.

This alternative representation of electrification may be broken down further to account for new residential dwellings and commercial businesses that may never connect to gas, existing gas connections that partially fuel-switch to electricity, and existing gas connections that entirely fuel-switch to electricity (that is, disconnections). Future gas connections under *Step Change* would therefore likely fall between the 'effective' gas connections forecast in Figure 13 and a forecast that assumes gas connections grow in line with economic and population projections (shown as *Step Change – No Electrification* for comparison).

Policy incentives to limit future gas connections are now in place in Victoria and the Australian Capital Territory. These policies are expected to increase the rate of electrification of residential and/or commercial customers. For example, the Australian Capital Territory Government has introduced legislation to prevent new gas network connections in most areas from 8 December 2023[39]. The Victorian Gas Substitution Roadmap Update[40] bans new

[37] 'Utilities' refers to the Electricity, Gas, Water and Waste Services industry.

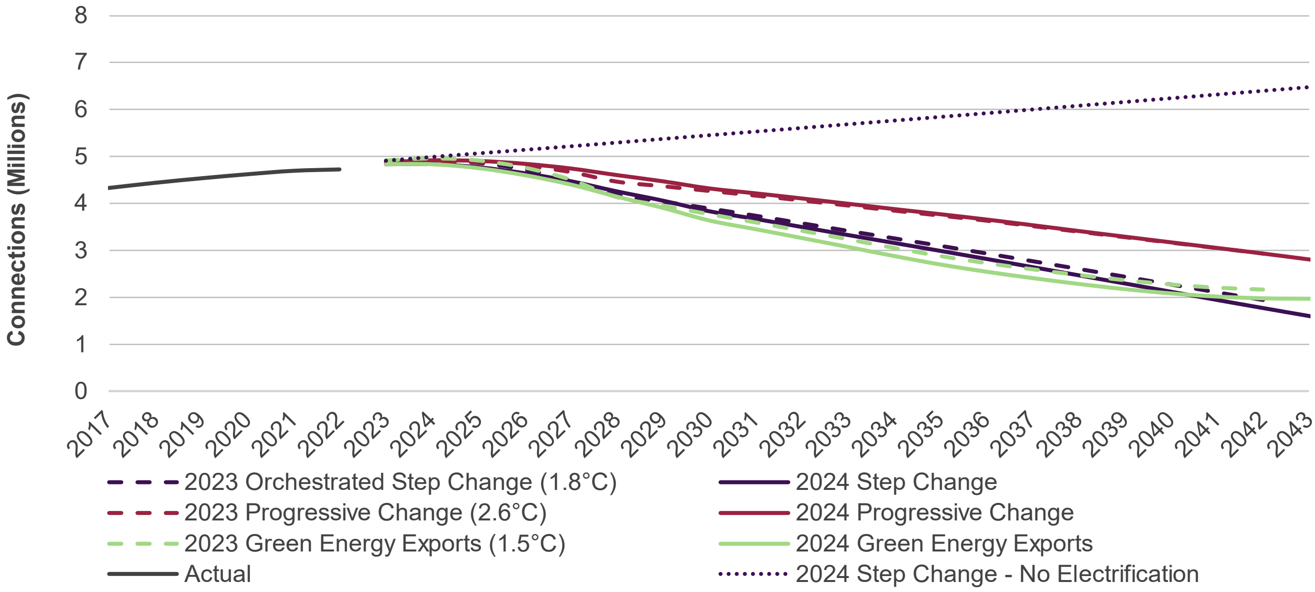
[38] For example, businesses increased their demand for machinery and equipment and other capital goods in response to the government's tax incentives. Growth projections in the construction sector as supported by the HomeBuilder scheme also increased demand for materials.

[39] See https://www.climatechoices.act.gov.au/policy-programs/preventing-new-gas-network-connections#:~:text=Compliance%20and%20enforcement-,Overview,and%20electrify%20Canberra%20by%202045.

[40] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

residential gas connections for developments requiring a planning permit from 1 January 2024 through amendment of the Victorian Planning Provisions.

Figure 13 Actual and effective forecast residential and commercial business connections, all scenarios and compared to the 2023 GSOO, 2017-43



Note: 'Effective connections' presented here reflects a number of connections that is equivalent to if household consumption was maintained at historical levels.

AEMO recognises that the pace of disconnections through full electrification is highly uncertain, and that there will likely be varying degrees of partial electrification, as well as households that remain connected to gas networks but increase their uptake of electric appliances.

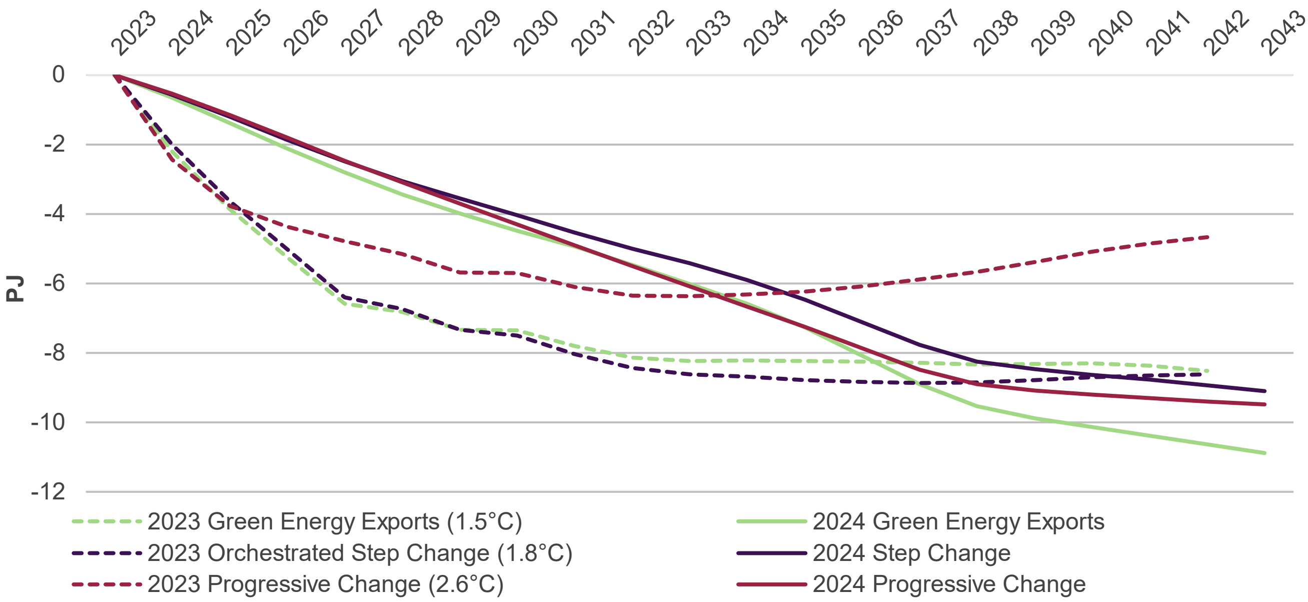
Energy efficiency

Working with Strategy.Policy.Research (SPR), AEMO developed energy efficiency savings forecasts based on existing, planned, and prospective policies, including:

- The National Construction Code 2022 (NCC 2022), including whole of home (WOH) provisions, which allow households to offset their energy consumption with efficient appliances, as well as distributed photovoltaic (PV) systems and batteries.
- State schemes – New South Wales Energy Savings Scheme (ESS), Victorian Energy Upgrades (VEU), and South Australia's Retailer Energy Productivity Scheme (REPS).
- Disclosure measures – Commercial Building Disclosure (CBD), and National Australian Built Environment Rating System (NABERS).
- Prospective policies – minimum energy performance standards for rental homes (MEPS), and universal mandatory disclosure of energy ratings for existing homes (UMD) in all scenarios, with more ambitious uptake rates in *Green Energy Exports* and delayed introduction in *Progressive Change*, compared to *Step Change*.

Figure 14 shows gas energy efficiency savings forecasts across the scenarios. Compared to the 2023 GSOO, forecast savings are lower in the near and medium term, largely due to lower estimates for the VEU Program. NCC is the largest component of gas savings, growing to around 7 PJ by 2043 in the *Step Change* scenario. This is driven by improved thermal construction for homes and buildings, as well as the forecast growth in dwellings. In addition, the WOH provisions introduced in NCC 2022 are forecast to drive the uptake of electric heat pumps, replacing gas water heaters and contributing to gas savings. Other modelled policies add about 3 PJ of savings by 2043.

Figure 14 Forecast reduction in gas consumption from energy efficiency savings, by scenario and compared to the 2023 GSOO, 2023-43 (PJ)



Wholesale and retail gas prices

AEMO engaged ACIL Allen to prepare wholesale gas price forecasts for the 2024 GSOO[41]. These updated price forecasts were undertaken to consider the impact of the Gas Market Code on wholesale prices. They consider fundamental inputs such as forecast gas production costs from existing and upcoming fields, reserves, infrastructure and pipelines, in addition to international gas prices, oil prices and measures of the domestic economy.

These forecasts are also based on assumptions about the influence of international prices on gas prices across the ECGM through LNG netback pricing, and the local level of competition. The prices forecast are lower than in the 2023 GSOO, reflecting the impact of the Code in the near term, and use adjusted assumptions on LNG netback prices[42] and supply and demand forecasts in the long term. More information on the wholesale gas price forecasts can be found in Section 3.6.1 of the 2023 IASR[43].

AEMO uses wholesale price forecasts to derive retail price forecasts and therefore the price paid by consumers. As with most commodities, price levels will influence consumption levels. The impact of retail prices on gas consumption is minimal in AEMO's forecasts, given gas is an essential service with low substitutability in the short

[41] ACIL Allen, *Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO*, at https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf.

[42] See https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

[43] See https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

term. It is therefore modelled as being relatively inelastic to price. This low elasticity, coupled with low variations in wholesale price forecasts, results in year-on-year impacts of forecast prices of less than 1 PJ/y to 2043.

As recognised earlier, the 2023 observed gas consumption across the ECGM was significantly lower than recent years, and lower than the 2023 GSOO forecast. AEMO considers this variance resulted from a record mild winter, lower gas requirements for GPG, early signs of increased electrification, and consumer demand responses to the high aggregate cost of living.

AEMO is undertaking ongoing efforts to identify the explicit cost impacts to adjust its price elasticity assumptions, so this 2024 GSOO forecasts a continued low relative elasticity to price. AEMO will continue to monitor gas consumption patterns and interrogate gas and electricity consumption data to attempt to confirm price and/or electrification trends that differ to those observed historically.

Hydrogen and biomethane potential

In the 2023 GSOO, AEMO identified an emerging potential for natural gas demand to be reduced if hydrogen and biomethane producers commenced supplying the ECGM. This potential was identified as a means to lower gas emissions and increase the gas sector's contribution to Australia's net zero objectives. The forecast was underpinned by multi-sector modelling conducted for the 2023 IASR.

No material renewable gas facilities (>0.5 PJ/y) – biomethane or hydrogen – have been committed since the 2023 GSOO identified the opportunity. Voluntary data submissions made for this GSOO by renewable gas project proponents identified potential biomethane supplies that are broadly consistent with the scale forecast in the 2023 GSOO.

There have been policy developments supporting renewable gas projects since the 2023 GSOO. State governments have committed to policies to support electrolyser development in Whyalla (South Australia) and Kogan Creek (Queensland), and New South Wales has introduced a renewable hydrogen target (8 PJ a year) under its New South Wales Renewable Fuel Scheme.

Biomethane blended into transmission or distribution gas pipelines has the potential to offset natural gas consumption and lower emissions. Depending on the location and connection for hydrogen facilities, hydrogen production may also provide a means to decarbonise gas consumption, via direct supply for industrial facilities, or blended into appropriate distribution pipelines.

Hydrogen production in this forecast is now assumed to be provided by electrolysis, rather than a combination of electrolysis and steam methane reforming (SMR), due to stakeholder feedback received on the Draft 2023 IASR. The hydrogen forecast for this 2024 GSOO considers only domestic hydrogen that is used by facilities that are connected to the ECGM, consuming a hydrogen/gas blend supplied by distribution pipelines, directly-supplied industrial consumers, and hydrogen for GPG. Hydrogen used by remote facilities, not connected to the ECGM, is excluded.

2.2 Consumption forecasts by sector

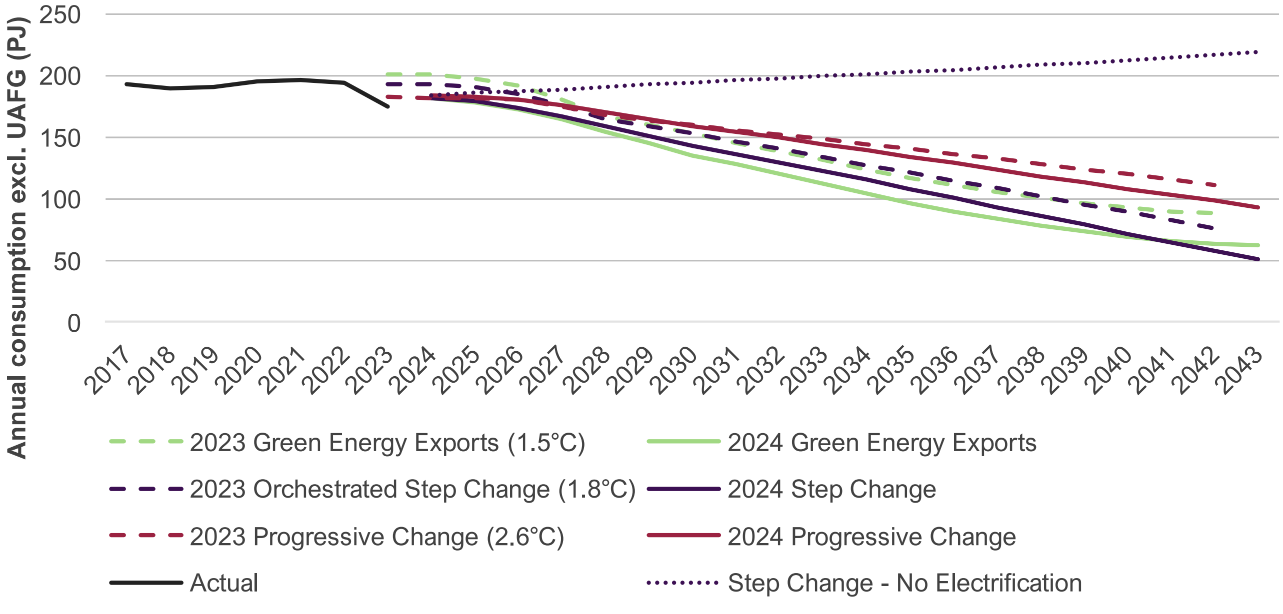
2.2.1 Residential and commercial consumption

Residential and commercial consumers are defined in the GSOO as those that use relatively small gas volumes of less than 10 terajoules (TJ) per annum and have a basic gas meter. AEMO forecasts residential and commercial gas consumption on a per connection basis, with adjustments made for fuel-switching to electricity, energy efficiency savings, climate change impact, and behavioural response to retail price. The growth trajectory is driven by the gas connections forecast. Recent introduction of policies in Victoria and the Australian Capital Territory to limit gas connections are expected to reduce gas consumption.

The electrification forecasts presented in Figure 12 above also anticipate material fuel-switching from residential and commercial customers, and therefore, to avoid double-counting risks, the effect of the policy changes on gas connections is accounted for in the electrification forecasts.

Figure 15 shows forecast residential and commercial consumption for all scenarios. The starting point of the forecasts is generally lower compared to the 2023 GSOO, driven by a noticeable decline in recent consumption. This decline has coincided with higher retail gas prices compared to recent years, some of the warmest winter temperatures on record[44], and emerging indications of fuel-switching to electricity.

Figure 15 Actual and forecast residential and commercial annual consumption, all scenarios and compared to 2023 GSOO, 2017-43 (PJ)



Notes:

- The Northern Territory is included in actual gas consumption from 2020 onwards.
- More information on the *Step Change – No Electrification* sensitivity is in Section 2.3.

[44] Mean winter temperatures in 2023 were the warmest on record for Queensland, New South Wales and Tasmania, and second warmest for Victoria and South Australia; see http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml for further details.

In the *Step Change* scenario:

- Forecast residential and commercial gas consumption in 2043 is estimated to be around 50 PJ, down by around 125 PJ from 2023.
- Compared to the 2023 GSOO, the forecast is around 20 PJ lower by the end of the outlook period, informed by the recently observed rapid reduction in consumption.
- Electrification remains the most significant driver of forecast declining consumption, with an anticipated demand reduction of around 50 PJ in 2030 increasing to about 170 PJ at the end of the outlook period. New dwellings in all jurisdictions are increasingly likely to be built without a gas connection or to use gas for applications other than heating (cooking and/or hot water).
- Improving energy efficiency is forecast to contribute to a modest reduction in consumption of about 10 PJ at the end of the outlook period.

In other scenarios and in the *Step Change – No Electrification* sensitivity:

- *Progressive Change* forecasts relatively stable gas consumption from residential and commercial consumers in the short term before entering a more gradual decline than *Step Change*, with forecast gas consumption falling to around 95 PJ in 2043. This scenario has reduced electrification and a delay in uptake, because investment in energy efficient appliances is considered more cost-effective to reduce exposure to gas bills than the investment required to switch to electric alternatives. Electrification impacts are lower than *Step Change*, with approximately 35 PJ in 2030 and 120 PJ in 2043, while energy efficiency impacts are forecast to exceed that of *Step Change* across the outlook period.
- *Green Energy Exports* forecasts the most rapid decline of the three scenarios through the 2030s until stabilising at around 70 PJ in the 2040s. For this scenario to achieve the strong decarbonisation component of the scenario's settings, it assumes the highest rate of fuel-switching to electricity.
- Without electrification, forecast gas consumption under the *Step Change – No Electrification* sensitivity would reach around 220 PJ by 2043. This sensitivity, however, presents an unlikely future, where current policies and consumer actions do not lead to higher rates of electrification. It is provided to compare forecast outcomes where no electrification occurs with core scenarios where fuel-switching to electricity is assumed to occur.

2.2.2 Industrial consumption

AEMO forecasts industrial sector consumption for the following customer category definitions for the GSOO:

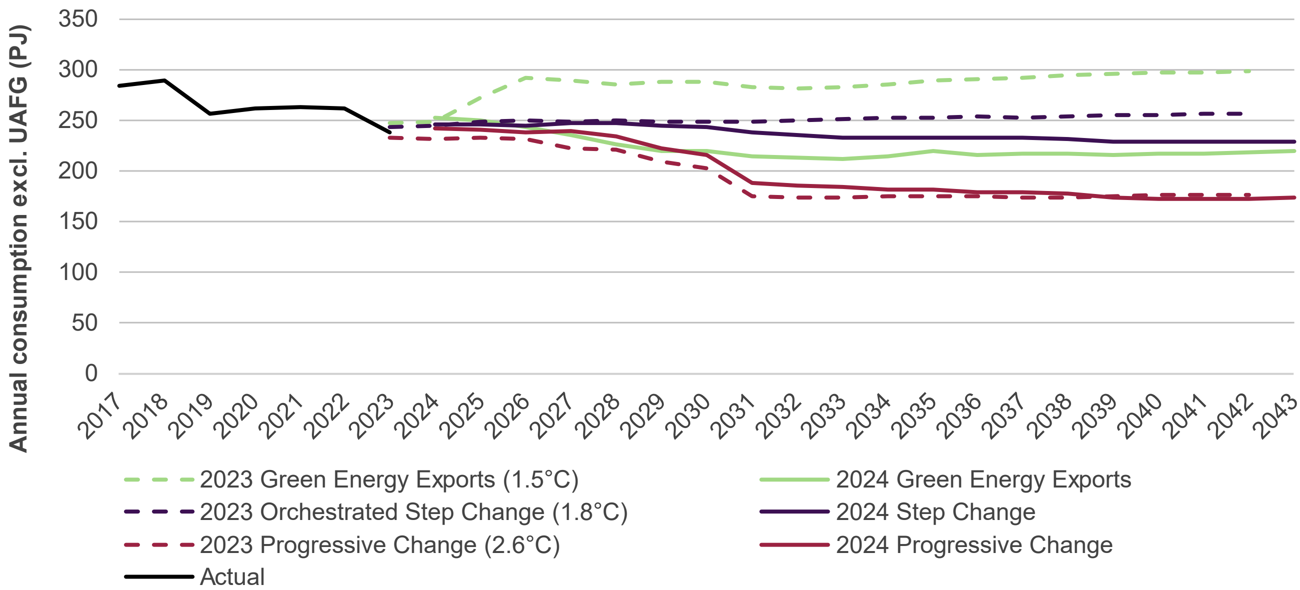
- LILs – customers in this category consume an amount of gas greater than or equal to 500 TJ per annum, accounting for over 65% of total industrial sector consumption.
  - Each LIL is forecast individually, informed by future consumption predictions provided via survey and interviews with the operators of the facility.

- This category comprises large customers such as fertiliser producers, mineral processing, primary metal, paper and chemical producers, oil refineries, large food processors, and mining. Any on-site electricity generation that consumes gas is also included[45].
- The 2023 GSOO included SMR load in the LIL category. Following feedback from consultation on the 2023 IASR, and early government policy indications that green or renewable hydrogen is likely to be the preferred technology that has government support[46], AEMO considered that production of hydrogen using gas that is increasingly scarce relative to electrical alternatives is unlikely to materialise. While this does not preclude industry from developing this technology, SMR load is not considered in the 2024 GSOO[47].

- Small to medium industrial loads (SMILs) – customers in this category consume between 10 TJ and 499 TJ per annum at each individual site. SMIL forecasts are developed in aggregate, instead of at the individual site level.

Figure 16 shows forecasts for all industrial customer categories for all scenarios and sensitivities compared to the 2023 GSOO.

Figure 16 Actual and forecast industrial consumption, all scenarios and compared to 2023 GSOO, 2017-43



Note: The Northern Territory is included in actual gas consumption from 2020 onwards.

In the *Step Change* scenario:

- Annual consumption is forecast to marginally increase to around 245 PJ in 2024 due to reported fuel-switching from coal to gas in some industries, before a general decline to 230 PJ by 2043.
- Compared to the 2023 GSOO, the forecast is around 30 PJ lower by the end of the outlook period. Removal of SMR load accounts for around 15 PJ of this difference, with a further 15 PJ reduction from downgraded LIL and SMIL forecasts combined.

[45] On-site gas generation reflects embedded generation that is "behind the meter", servicing the customer's own load rather than the NEM at large. These facilities are included in the LIL forecast category, rather than the gas generation category.

[46] See https://www.dcceew.gov.au/energy/hydrogen/hydrogen-headstart-program.

[47] See Section 3.4.6 in the 2023 IASR Consultation Summary Report, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-consultation-summary-report.pdf.

- The electrification forecast offsets natural gas consumption by around 10 PJ in 2043, which is comparable with the impact reported in the 2023 GSOO.

In other scenarios and sensitivities:

- The *Green Energy Exports* scenario forecasts a temporary increase in consumption in the short term due to higher economic outcomes inherent in the scenario and some fuel-switching from coal to gas in the LIL sector. From 2026 onwards, increasing availability of electrification technology for LILs reduces the demand for gas.
- The *Progressive Change* scenario projects steady consumption until the late 2020s, followed by a significant decline, which is driven by industrial closure risks.

2.2.3 LNG export

AEMO derives export consumption forecasts from surveys provided by the Queensland LNG producers which include contracted LNG exports, firm domestic supply contracts, and expected spot LNG export sales. These forecasts exclude expected LNG exports from the Northern Territory.

LNG producers' contract positions will sometimes require access to third-party gas (or the use of other suppliers in each producer's global gas portfolio) to deliver to the relevant international customer.

LNG exported from Queensland's Curtis Island in 2023 was 1,371 PJ, a 13 PJ increase from 2022, and slightly higher than survey responses indicated in the 2023 GSOO.

Figure 17 shows recent and forecast LNG exports for different scenarios and compared to the 2023 GSOO.

LNG exporters have forecast a level of LNG exports in 2024 of between 1,297 PJ (quantity under long-term contracts) and 1,369 PJ (quantity under long-term contracts and expected spot sales). The higher end of this range is 43 PJ higher than advised for the 2023 GSOO and 2 PJ lower than actual LNG exports in 2023.

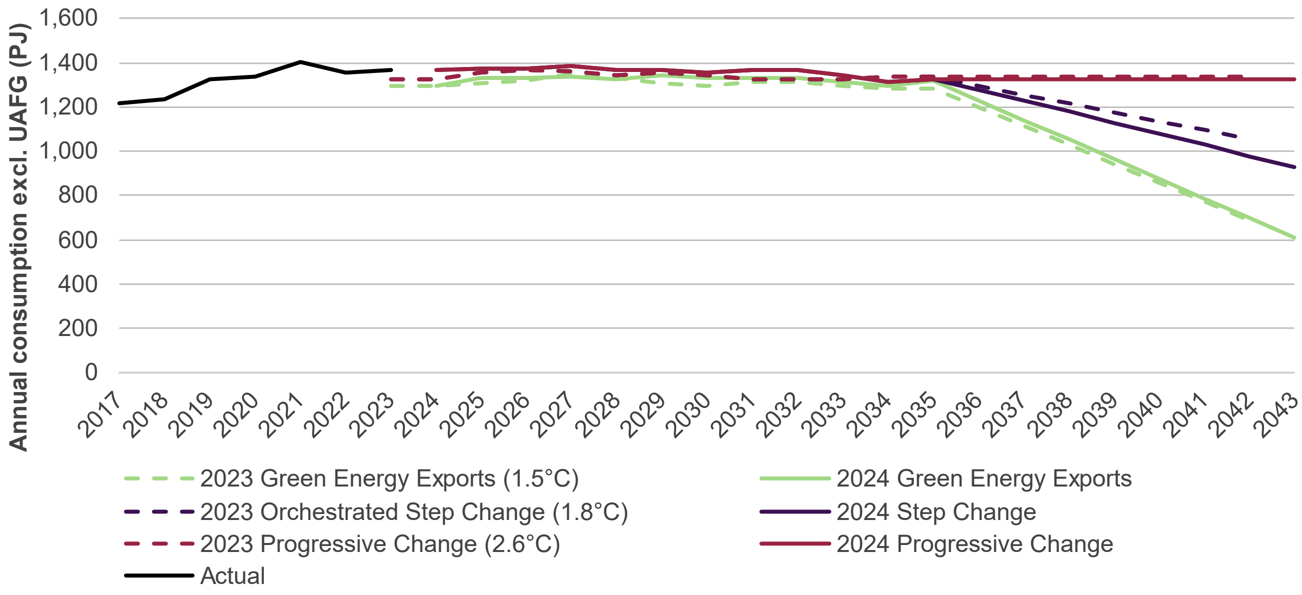
The LNG producers advised a forecast outlook to 2035, beyond which AEMO has assumed a scenario dispersion in line with trends observed in International Energy Agency (IEA) forecasts[48]. Small differences to forecasts after 2035 reflect updates in the 2023 IEA World Energy Outlook (WEO) forecasts used for this 2024 GSOO, relative to the 2022 IEA WEO previously used for the 2023 GSOO.

The following applications of the 2023 IEA WEO to forecasts after 2035 are consistent with the 2023 GSOO:

- In the *Progressive Change* scenario, lower global economic growth and reduced steps towards global decarbonisation mean LNG exports have been forecast to be flat across the horizon, with greater continued use of current energy forms.
- The *Step Change* and *Green Energy Exports* scenarios apply increasing levels of decarbonisation action globally to lower energy sector emissions, so reducing levels of LNG export are forecast as many countries seek alternative energy forms with lower emissions footprints.
- The significant spread in forecast LNG export by 2043 reflects the strong uncertainty regarding the scale of export demand across these scenarios.

[48] The 2023 IASR aligns AEMO scenarios with IEA scenarios. AEMO has therefore aligned IEA forecasts of LNG export from Australia from the 2023 World Energy Outlook (see https://www.iea.org/reports/world-energy-outlook-2023) with AEMO forecasts where possible.

Figure 17 Actual and forecast liquefied natural gas consumption, by scenario and compared to the 2023 GSOO, 2017-43 (PJ)



2.3 Sensitivities in annual consumption to domestic uncertainties

In addition to the scenario forecasts provided in previous sections, AEMO has included three additional sensitivities, described below, to explore additional influences on the gas consumption forecasts:

- ***Step Change – Net***.
  - In the 2023 GSOO, supply of renewable gases (hydrogen and biomethane) was assumed to develop based on the outputs of multi-sector modelling that forecast the gas sector's contribution to emission reduction in the energy transition. Those renewable gas volumes were removed from the total gas consumption forecast to obtain a forecast of net natural gas consumption, effectively lowering the need for natural gas supply.
  - The opportunity for development of hydrogen and biomethane remains, although there is less support to use hydrogen for heating this year[49]. AEMO and industry recognise that demand for hydrogen or biomethane in hard-to-electrify and high-temperature applications are still expected to develop.
  - The 2024 GSOO *Step Change* scenario consumption forecast is presented with no assumed renewable gas supply, offsetting the demand for natural gas. Since the 2023 GSOO, no firm, material supply of biomethane has been committed to, and only a small number of electrolyser-based hydrogen projects have been committed to (see Section 5.1). All consumer demand will need to be supplied by natural gas, or a combination of natural gas and renewable gases if they are developed.
  - In contrast, the *Step Change – Net* sensitivity is provided to describe a future where supply of renewable gases is developed as assumed in the 2023 IASR. This follows the convention used in the 2023 GSOO, with

[49]See research study at https://www.cell.com/joule/fulltext/S2542-4351%2822%2900416-0.

renewable gas volumes removed from total consumption to give a ‘net’ natural gas consumption forecast[50]. This provides a forecast for natural gas supply needs, if renewable gas developments that are currently uncertain do occur.

- ***Step Change – No Electrification***.
  - This sensitivity demonstrates the potential growth in gas consumption in line with economic and population forecasts, without investment or policy incentives to switch to electricity use. This sensitivity presents an unlikely future where electrification of gas demand does not occur. This sensitivity is not consistent with Australia’s net zero commitments. It is, however, provided to compare with the potential outcomes forecast under the core scenarios, where fuel switching to electricity is assumed to occur.
- ***Step Change – DRI***.
  - The steel industry is considering direct reduced iron (DRI) as the pathway to reduce its emissions. DRI is an alternative reduction method that aims to replace coal usage in blast furnaces. Natural gas as well as hydrogen can be used in DRI technology. Through GSOO surveys, steelmakers have indicated that natural gas may be used in the DRI process until hydrogen becomes available and economically viable if a shift away from coal is selected to reduce the emissions footprint of steel production[51]. To provide an upper estimate of DRI impacts, the sensitivity retains gas use for the full horizon, and does not consider a shift to hydrogen.
  - Assuming that the amount of raw iron produced stays at historical levels, the industrial gas usage would peak in the early 2030s at about 320 PJ per annum (or an additional 80 PJ per annum above *Step Change*), before slightly decreasing, leading to the difference between the *Step Change* scenario and the sensitivity, as shown in the figure below.

[50] For a schematic showing the relationship between ‘gross’ and ‘net’ forecasts, see 2024 GSOO demand methodology, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[51] For more information, see https://www.primetals.com/fileadmin/user_upload/landing_pages/2021/Green_Steel/Publications/downloads/AISTech_2021_MIDREX_H2_Final.pdf.

Figure 18 shows forecast domestic gas consumption for each of the sensitivities.

Figure 18 Actual and forecast domestic gas consumption, *Step Change* scenario and sensitivities, 2017 – 43 (PJ)

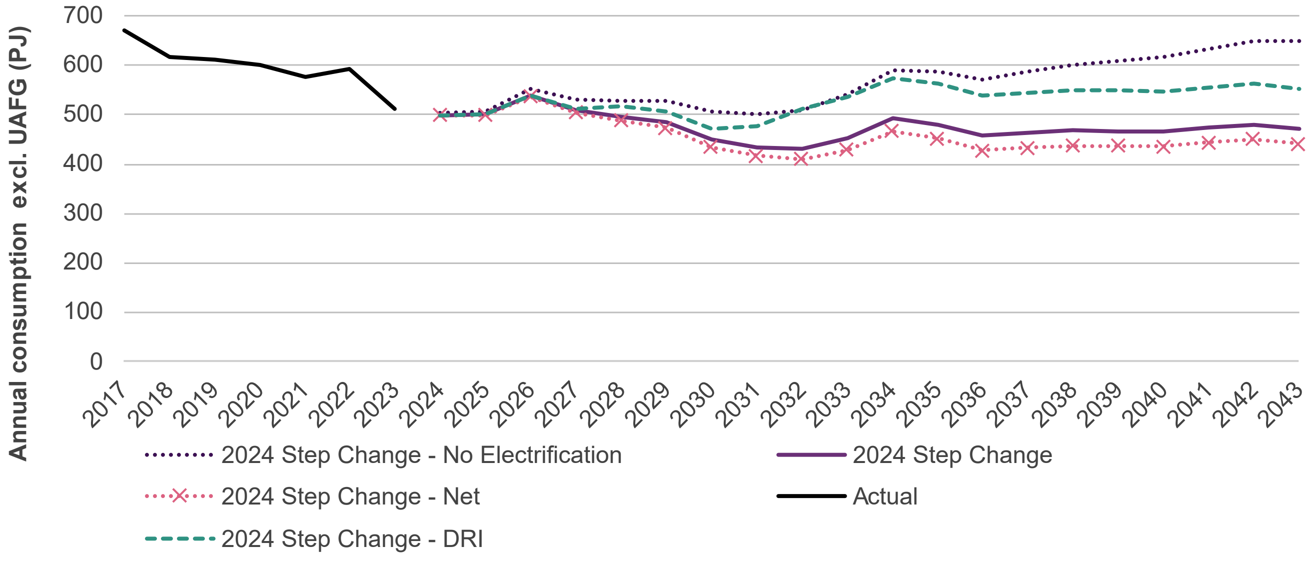
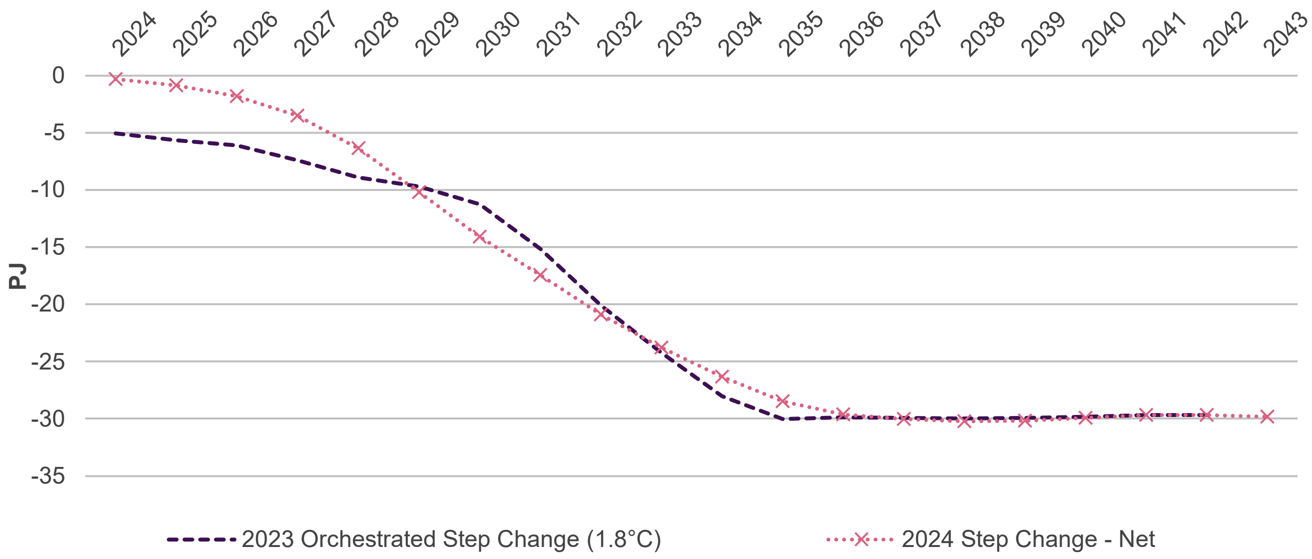


Figure 19 below shows the isolated potential impact to natural gas consumption under the *Step Change – Net* sensitivity, demonstrating the relative similarity in this sensitivity to the contribution assumed in the 2023 GSOO *Orchestrated Step Change (1.8°C)* scenario.

Figure 19 Forecast reduction in natural gas consumption from the *Step Change* scenario, if uncertain hydrogen and biomethane supply is developed, 2024-43 (PJ)



Notes:

- This chart only considers hydrogen consumption due to fuel-switching from natural gas. Total hydrogen consumption is higher when considering fuel-switching from other sources, such as coal and oil.
- Graph excludes reductions from gas generation.

2.4 Maximum daily gas demand forecasts

The maximum daily gas demand forecasts are split into three main components:

- Gas demand from residential, commercial and industrial customers.
- Gas for LNG export.
- GPG.

The following section discusses the seasonality of peak demand, followed by the maximum daily demand forecast for the first two components listed above, with GPG covered in Section 2.5.

2.4.1 Seasonal variance and extreme peaks

Daily demand for residential, commercial and industrial consumers is strongly seasonal, with the maximum demand occurring in winter driven by the demand for space heating, particularly in the south. Customers in the northern states (Queensland and the Northern Territory) and industrial consumers in general show less seasonality in demand due to lower heating requirements.

To date, the highest southern daily gas demands from residential, commercial and industrial consumers observed each year typically only occur on a relatively small number of days, when conditions compound to lead to very high utilisation of residential and commercial heating appliances. It is possible for these events to occur in conjunction with conditions in the electricity sector leading to high requirements for GPG.

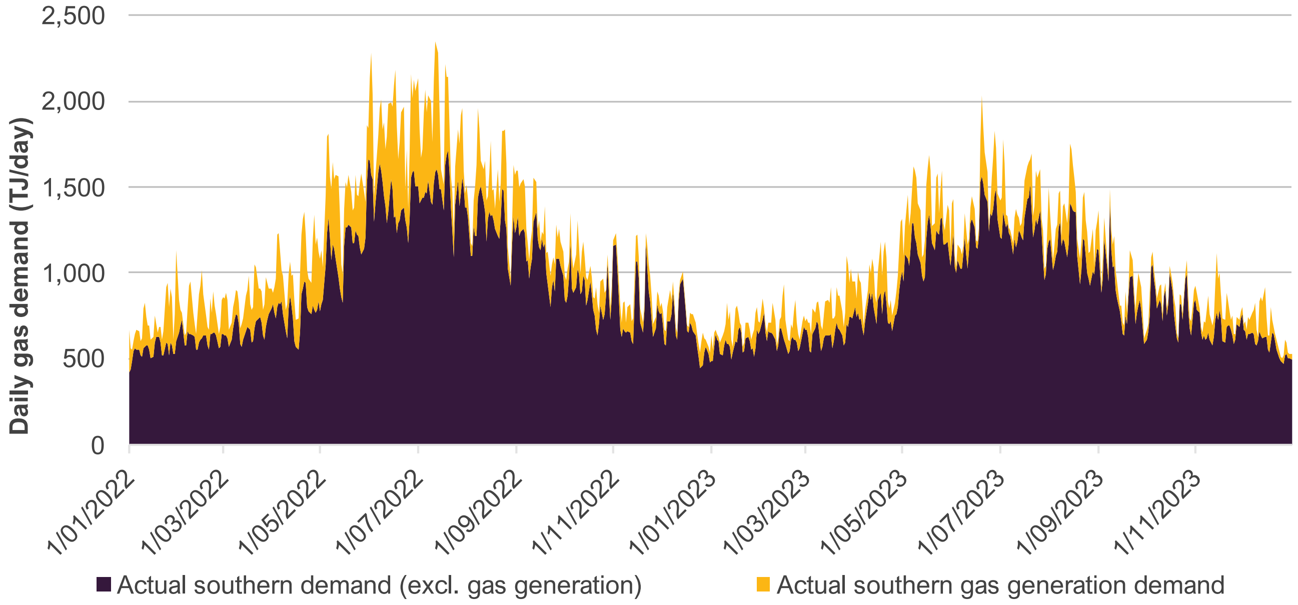
Figure 20 below demonstrates the historical volatility and the strong seasonality of daily peak demand in the southern regions of New South Wales (including the Australian Capital Territory), South Australia, Tasmania and Victoria in 2022 and 2023.

Daily demand by residential, commercial and industrial consumers is shown as the dark purple area in the chart. While industrial loads and some household and commercial loads (such as cooking and hot water) operate consistently across the year, significant additional gas is used for heating in households and businesses in the winter months, leading to winter peaks in southern regions that may be two to three times higher than in summer.

Gas volumes required for GPG (yellow in chart) depend on the requirements of electricity consumers and the availability of other electricity generating technologies. High GPG may coincide with high gas demand by residential, commercial and industrial consumers, as cold weather in winter that drives higher gas demand typically also leads to higher electricity demand, and winter typically has lower utilisation of renewable resources (with shorter days reducing PV output, for example). As outlined in Section 2.1, the impact of electrification will contribute to the magnitude of winter peaks for GPG potentially growing at a significantly faster pace than summer peaks (depending on investments in other electricity technologies such as battery and hydro storages), and consequently, GPG is likely to become increasingly at risk of winter peaking.

Gas used for LNG exports may also be seasonal but is not captured in the southern region's profile because the export is from Queensland. LNG demand has its typical seasonal peak in summer when key Asian markets experience their northern hemisphere winter.

Figure 20 Actual domestic daily gas demand in southern regions from January 2022 to December 2023, showing seasonality and peakiness (TJ)



2.4.2 Forecasts and trends in maximum daily gas demand excluding GPG

Table 4 and **Table 5** show recent actual observed daily maximum demand for each region, as well as the seasonal forecasts of daily gas demand for all sectors excluding GPG in the *Step Change* scenario, across the summer and winter seasons. These forecasts include unaccounted for gas (UAFG) that is lost while being transported through the gas network.

Maximum daily demand is forecast with a probability of exceedance (POE), meaning the statistical likelihood identified through forecast models as to whether the forecast will be met or exceeded. A 1-in-20 forecast is expected to be exceeded, on average, only once in 20 years, while a 1-in-2 forecast is expected, on average, to be exceeded every second year.

2023 was generally a mild year across most regions, which had the effect of reducing demand for gas. Hence, there is typically a noticeable increase between 2023 and the first year of the forecast period (2024). This is because the forecasts presented in the tables below assume a return to average (1-in-2) or more extreme (1-in-20) weather conditions, both of which will be more conducive to higher gas demand than was experienced in 2023. Regional forecasts for all scenarios and sensitivities (as described in Section 2.3) are available on AEMO's National Electricity and Gas Forecasting portal[52].

[52] At https://forecasting.aemo.com.au/. Note the peak day forecast estimates are at time of the combined peak for residential, commercial and industrial usage. The peak day gas used for electricity generation presented represents the gas generation at the time of the combined residential, commercial and industrial peak. Gas for GPG may be higher than the presented value at other times when looking only at that demand sector.

Table 4 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding gas generation, including UAFG (terajoules per day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2021	469		4,155		345		149		23		1,134		16	
2022	483		4,087		346		134		23		1,093		17	
2023	436		4,229		316		133		21		982		18	
Step Change														
2024	482	510	4,027	4,038	321	332	147	156	24	25	1,098	1,179	19	21
2025	481	508	4,031	4,041	319	329	146	154	23	24	1,084	1,164	19	21
2030	429	454	3,979	3,989	306	315	133	140	23	25	897	965	20	21
2035	379	400	3,865	3,874	269	278	120	127	23	25	725	778	18	19
2040	331	349	3,191	3,199	268	277	108	114	15	16	546	583	1	1

Table 5 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding gas generation, including UAFG (TJ a day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2021	286		4,546		342		97		20		517		18	
2022	283		4,534		339		97		21		585		17	
2023	268		4,669		328		87		19		420		17	
Step Change														
2024	314	341	4,405	4,415	315	325	101	108	22	24	424	504	19	21
2025	316	343	4,410	4,419	313	322	100	107	21	23	421	501	19	21
2030	294	317	4,354	4,363	300	310	95	102	22	23	366	431	20	21
2035	271	292	4,232	4,241	265	273	90	96	22	24	322	370	18	19
2040	250	268	3,490	3,498	264	273	86	91	13	14	277	314	1	1

Outlook for *Step Change*

Forecast regional trends in winter maximum daily gas demands (excluding both gas for LNG export and GPG) are:

- **New South Wales** is projected to experience a short-term increase in maximum demand driven by an expansion in LIL. Despite the forecast growth in industrial loads, gas demand is then forecast to follow a steady decline to the end of the forecast horizon. This trajectory is similar to the 2023 GSOO and is consistent with the declining trends affecting residential, commercial and industrial annual consumption.
- **Queensland** is projected in the short term to maintain a reasonably steady maximum daily demand, consistent with the 2023 GSOO. Post-2027, however, maximum daily demand is now forecast to decline, driven by industrial customer electrification throughout the late 2020s and 2030s, before stabilising again by 2040.

- **South Australia** experienced mild winters in 2022 and 2023, hence the actual demand in those years is not comparable to the first year of the forecast period. The 2024 GSOO forecasts a decline in demand over the forecast horizon that is consistent with the 2023 GSOO.
- **Tasmania** is projected to maintain a reasonably stable level of gas demand until 2040, when the survey responses from LILs reveals an expected large reduction in demand from one customer. Also notable is a large reduction in the forecast demand of an LIL relative to what was reported in the 2023 GSOO LIL survey process. Based on the updated response from this LIL customer, maximum daily demand in the 2024 GSOO has been revised downwards compared to the 2023 GSOO.
- **Victoria** is projected to decrease its maximum daily demand to the end of the forecast horizon. The trend is generally similar to the 2023 GSOO forecast. The forecast decline in demand in Victoria is greater than other regions, because of the projected impacts of the Victorian Gas Substitution Roadmap Update on connections and electrification. As reported above in Table 4, Victoria experienced historically low gas demand in 2023[53], driven partly by mild weather, so the first year of the forecast is more consistent with 2022 actual demand.
- **Northern Territory** demand is expected to increase slightly to the mid-2030s, before a sharp decline associated with the closures of LILs results in gas demand declining by more than 90%.

Maximum daily gas demand used for LNG export is forecast to remain relatively flat until 2035, then to decline steadily, consistent with drivers reducing annual LNG export consumption (see Section 2.2.3).

2.5 Gas consumption for electricity generation

GPG currently plays an important role in meeting electricity demand for consumers in the NEM and in the Northern Territory, generally operating in a 'mid merit' capacity and as a back-up supply for when baseload coal, or significant amounts of variable renewable energy (VRE) are unavailable. GPG also remains a critical source of capacity to meet peak electricity demand.

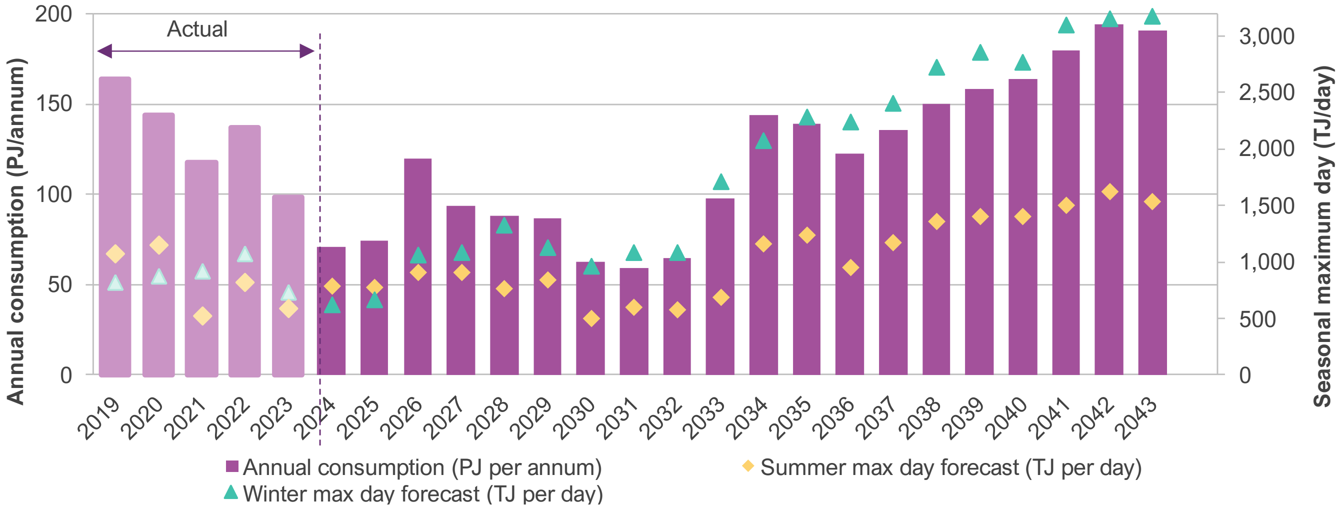
GPG forecasts for the 2024 GSOO are based on the Draft 2024 *Integrated System Plan* (ISP) optimal development path (ODP). To maintain system security and reliability in the NEM, particularly late in the GSOO horizon, a significant role for gas powered generation is forecast to cater for periods of low VRE output. While the Draft 2024 ISP forecasts a significant back-up role for gas there are many considerations – including the costs of alternative fuels/technologies, and cost of fuel delivery – to be assessed before this role for gas powered generation becomes firm. These GPG forecasts, particularly late in the GSOO horizon, are therefore uncertain.

2.5.1 The role of gas generation is expected to change

Figure 21 shows recent volumes of GPG consumption, and volumes forecast based on the *Step Change* scenario. The figure demonstrates a declining forecast utilisation of GPG across the year in the near term, as new renewable electricity generation is commissioned, but a growing need for firm energy production in later years as coal generators retire, and electrification and broader growth increases electricity consumption. Figure 21 also highlights a distinct change in forecast consumption seasonality, with an escalating need for GPG in winter.

[53] Prior to 2023, the lowest daily peak in the previous 10 years was 1,074 TJ in 2018.

Figure 21 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ per year [PJ/y]) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-43



Note: From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.

This figure shows[54] that during the period to 2032:

- GPG is forecast to continue its downward trend into 2024, then to remain relatively stable between 60 PJ/y and 100 PJ/y.
- The planned retirement of Eraring Power Station and growth in electricity demand both contribute to a higher forecast for GPG during 2026.
- Overall, peak demand for GPG is forecast to shift to winter but will remain at around 1,000 terajoules per day (TJ/d). This can be attributed to development of large-scale batteries and deep storages in the NEM.

In the long term beyond 2032:

- GPG consumption is forecast to increase to 120-200 PJ/y to support electricity demand growth and high renewable penetration as coal generation retires.
- Peak demand is forecast to experience significant growth, particularly in winter when renewable generation is naturally lower. Consistent with AEMO's Draft 2024 ISP, this alternative electricity generation source is forecast to be provided by GPG, although alternatives such as hydrogen, diesel and electricity storage (pumped hydro and batteries) could provide a greater share of this firming capacity. AEMO anticipates undertaking further analysis on this in future.

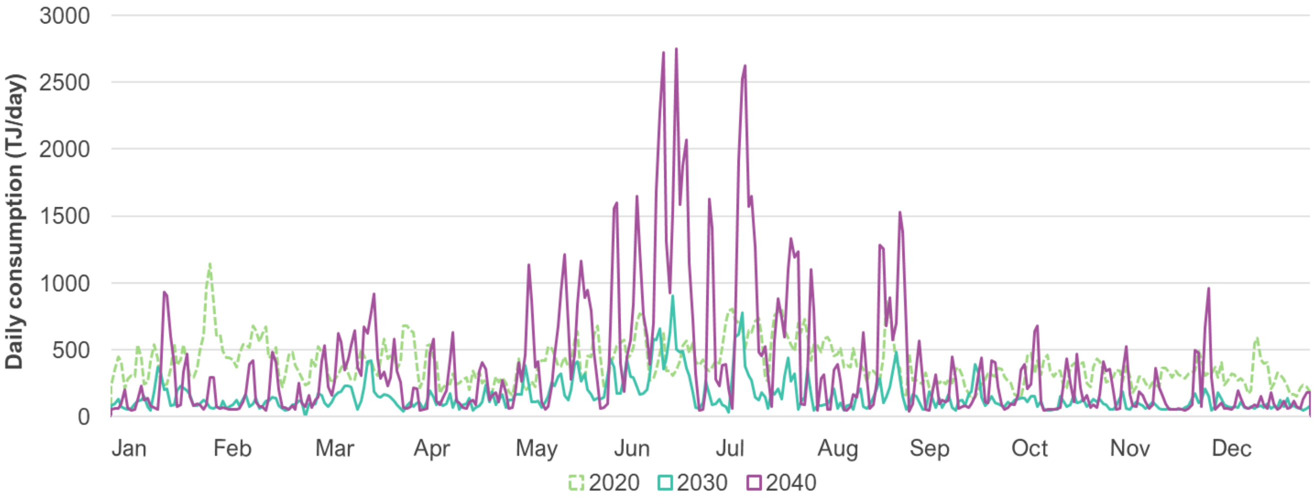
Forecast demand from gas generators will drive large peaks in daily consumption

Figure 22 highlights the forecast increased seasonality of gas consumption for electricity generation, and presents the actual daily consumption profile in 2020, and forecast profiles for 2030 and 2040. It shows that:

[54] The gas generation forecasts differ marginally to those presented in the Draft 2024 ISP report. The least-cost dispatch assumptions applied in core ISP modelling are replaced with assumptions regarding generator bidding, operational constraints, new generating capacity build timelines, and availability of other generators to predict GPG consumption more accurately. Forecasts exclude Yarwun and are averaged across different historical weather patterns. The forecasts in the GSOO are also primarily presented on a calendar year rather than a financial year basis. Greater similarity exists to the Draft 2024 ISP's Appendix 4 that likewise applies similar assumptions when forecasting system operability. Northern Territory actual consumption from 2020 and forecast consumption is also included.

- In 2020, GPG consumption was broadly consistent through the year with summer daily peaks during February.
- By 2030, the utilisation of gas for electricity generation is forecast to decline in summer. While peak electricity demands are still forecast, high growth in renewable generation and electricity storages are forecast to provide sufficient energy generation and firming capacity to reduce gas generation needs, particularly while coal generation remains available. GPG demand is forecast to begin to be utilised more during winter, when more seasonal electricity production tightness is anticipated.
- By 2040, the forecast consumption profile shows higher peaks, particularly during the winter months. In more extreme conditions, GPG demand is forecast to exceed 1,000 TJ/d for around 30 days and may increase to over 2,500 TJ/d (approximately 2.5 times the historical values) depending on the prevailing conditions affecting electricity demand and supply across the NEM generation fleet. This figure presents 1-in-10-year peak electricity demand profiles representative of more extreme conditions. Lower consumption levels across the year may occur during more normal conditions with similar exposure to winter risks.

Figure 22 Actual and forecast NEM and Northern Territory daily gas consumption for electricity generation in 2020, 2030, and 2040, *Step Change* scenario, reference year 2019 (TJ/d)



2.5.2 Gas generation forecasts are highly variable

GPG forecasts are variable and depend on various factors in the NEM which are challenging to predict. Increases and decreases in gas generation may result from unscheduled maintenance, power station and transmission network outages, fuel unavailability, and weather variability affecting electricity supply and demand. In the longer term, the degree of investment in renewable electricity generation, transmission developments, storage developments (from consumer and utility-scale investments of various depths), and other alternatives such as hydrogen turbines, will all influence the overall need for gas to contribute to the firming requirements for the NEM. More information on the development pathway for the NEM is available in the Draft 2024 ISP[55].

[55] See https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

Impact of unforeseen events

GPG consumption has exhibited a declining trend since 2019, but several spikes in consumption have occurred as a result of unexpected events during the past five years. These include:

- In 2019, prolonged high temperatures and bushfires affected New South Wales and Victoria with outages at Victorian coal generators, and fuel supply shortages affected coal generators in New South Wales.
- In 2020, the collapse of transmission towers affected the Heywood interconnector (connecting South Australia and Victoria), and extended outages for coal-fired power stations in Queensland.
- In 2021, flooding at the Yallourn coal mine affected coal generation in Victoria, and an unexpected explosion at the Callide power station in Queensland (the impacted unit remains offline until July 2024).
- In 2022, the war in Ukraine increased international prices for both gas and coal. This coincided with flooding events affecting coal production and an extended period of low renewable output.

Given that major unexpected events have occurred in the NEM in five of the last six years, AEMO has allowed for the potential for unexpected events in this 2024 GSOO forecast by applying reductions in coal fuel availability (included for the 2022 and 2023 GSOO forecasts), some limitations to coal capacity factors and the potential for generation developments to be delayed during construction and commissioning[56]. These assumptions act as a proxy for major unplanned events affecting other generators and represent a reasonable assumption of their impact on GPG.

Scenarios and sensitivities analysis for NEM market impacts to gas consumption

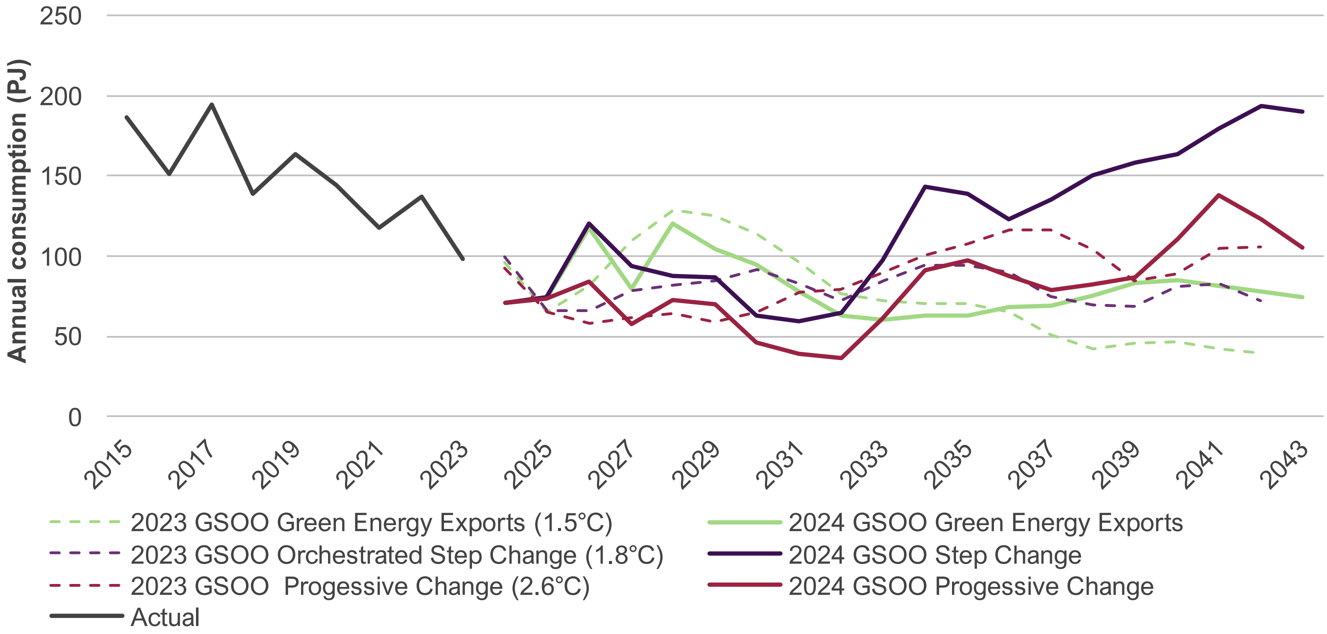
Forecast annual GPG consumption varies across scenarios. **Figure 23** shows actual and forecast annual GPG usage across different scenarios in both the 2023 and 2024 GSOOs.

Compared to the *Step Change* scenario:

- The ***Green Energy Exports*** scenario is forecast to have similar GPG consumption until 2027, when higher electricity load growth increases the use of gas generators until greater renewable generation, transmission and electricity storage projects can be commissioned.
- The ***Progressive Change*** scenario exhibits a similar trend in GPG consumption. Due to flatter electricity load growth and slower coal closures, forecast GPG consumption is lower than in the *Step Change* scenario.

[56] The delays to projects under construction and anticipated are consistent with the approach applied in the ESOO methodology, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf.

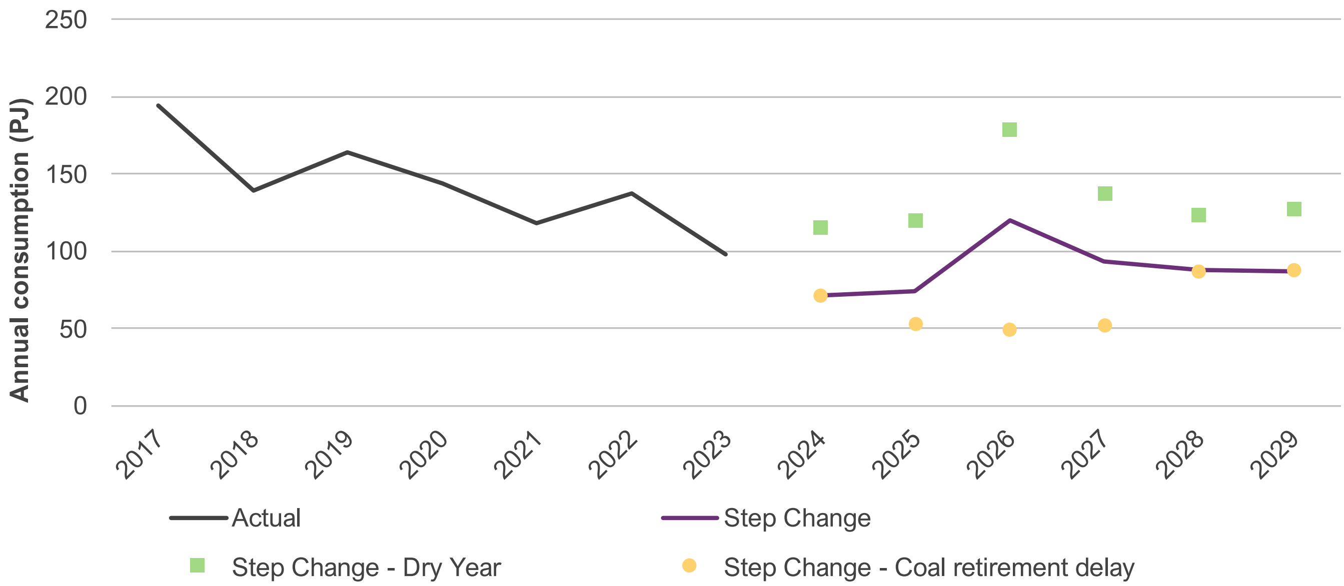
Figure 23 Actual and forecast NEM and Northern Territory gas generation consumption, by scenario, 2015-43 (PJ)



Note: From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.

The 2024 GSOO also examines two sensitivities that explore plausible future events affecting gas consumption for electricity during the next five years, to 2029. These sensitivities are presented in **Figure 24.**

Figure 24 Actual and forecast NEM and Northern Territory gas generation consumption, sensitivities to *Step Change* scenario, 2017-29 (PJ)



Note: From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.

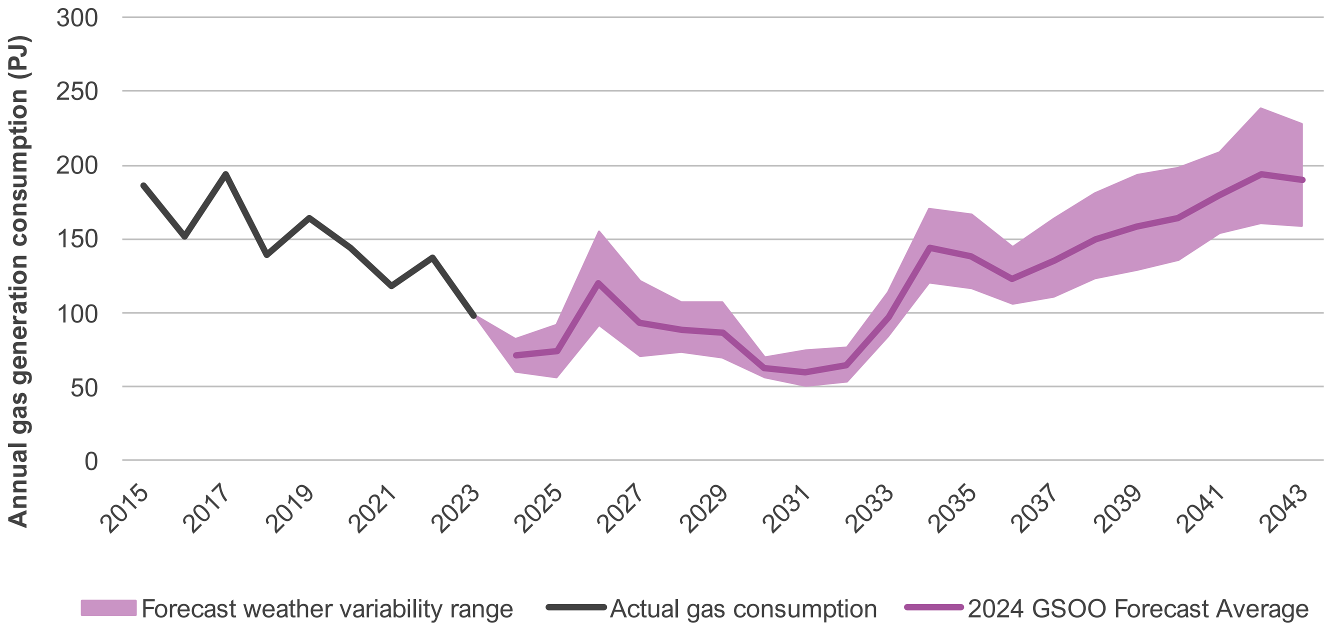
In comparison to the *Step Change* scenario:

- ***Step Change – Dry Year*** – estimates the impact of prolonged droughts on rainfall inflows to large hydro generation. In this sensitivity, rainfall amounts are reduced to the level of the 'millennium drought' of 2006-07 (inflow yield is approximately 45% less than average years). Consequently, annual GPG is forecast to be approximately 60% higher, depending on VRE penetration.
- ***Step Change – Coal retirement delay*** – assesses the impact of the retirement of the Eraring Power Station being delayed two years, as indicative of a coal retirement delay (Eraring has been selected given it is the next announced closure timing). In this sensitivity, GPG consumption would be 30-60% lower.

Weather variability

AEMO's GPG forecast examines a range of different weather patterns[57], using a spread of historical weather conditions. **Figure 25** presents the range of projected annual GPG consumption outcomes resulting from weather-driven variation in electricity demand profile, wind and solar availability, and rainfall inflows to hydro reservoirs.

Figure 25 Actual gas generation consumption and forecast variation in consumption due to weather conditions, *Step Change* scenario, 2015-43 (PJ)



Note: From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.

As penetration of renewable energy sources is expected to increase substantially in the NEM, GPG is forecast to be more weather-dependent and volatile in future years as it will be increasingly influenced by renewable energy availability, depending on the development of electrical alternatives.

[57] AEMO simulated five weather patterns for the 2024 GSOO.

3 Gas supply and infrastructure forecasts

This section provides an overview of the reserves, resources and production forecasts for supplies connected to the ECGM, and contracted supply. It also gives an overview of existing and proposed pipelines, storages, and LNG import terminals.

Key insights

- **Overall, the sum of reserves in existing, committed and anticipated supply categories has increased slightly since the 2023 GSOO.** Conversely, there has been a reduction in the total reported resources available from uncertain and prospective supply projects.
- **In comparison to the forecasts provided for the 2023 GSOO, forecasts for annual southern production capacity from existing, committed and anticipated fields is marginally lower for 2024 and 2025** though forecast peak day production is slightly higher.
- Southern production forecasts decline significantly from 363 PJ in 2023 to 236 PJ in 2028, similar to 2023 GSOO forecasts.
- **Northern annual production forecasts are marginally lower until the early 2030s compared with the 2023 GSOO** due to ongoing production issues in the Northern Territory, and reclassification of some supply volumes by the LNG producers.
- The majority of forecast supply is contracted in 2024, but the gap widens progressively between forecast domestic demand and contracted gas supply across the horizon.
- Key projects have been completed since the 2023 GSOO to improve supply to southern demand centres and further committed projects have started construction.

3.1 Changes since the 2023 GSOO

Key infrastructure projects to increase transportation capacity have been completed since the 2023 GSOO

These projects were previously considered committed[58] in the 2023 GSOO and will improve the delivery of gas supply to southern demand centres:

- Victoria's **WORM** pipeline and second compressor at Winchelsea are commissioned and operational, increasing peak supply capacity to Melbourne by 83 TJ/d.

[58] Existing and committed' means gas fields and production facilities that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway. 'Anticipated' means developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made. 'Uncertain' projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

- **East Coast Grid Expansion (ECGE) Stage 1** is commissioned and operational, increasing north to south transmission capacity by 49 TJ/d. ECGE Stage 2 remains on track for completion by winter 2024, increasing transmission capacity by a further 59 TJ/d.
- Lochard Energy has completed an upgrade to the **Iona Underground Storage (UGS) facility**, expanding capacity by 0.4 PJ to 24.4 PJ and increasing injection capacity by 12 TJ/d to 570 TJ/d.

Gas production forecasts from existing developments show a varied outlook in the near term

- **Gippsland production (including Orbost) forecasts for 2024 are higher than in the 2023 GSOO.** Peak day production of 877 TJ/d is forecast until mid-2024, 107 TJ/d higher than forecast in the 2023 GSOO, reducing to 767 TJ/d coinciding with the retirement of Gas Plant 1 in mid-July. Production from legacy fields is still forecast to reduce significantly, and the retirement of Gas Plant 3 will occur later this decade.
- **Forecast supply from the Blacktip field in the Northern Territory has significantly reduced.** Eni Australia, the operator of the Blacktip field, was reported to have drilled a new well and overhauled an existing well during 2023. Although this restored some supply from the Blacktip field, it has not returned to historical levels[59].

Committed and anticipated gas supply projects have experienced delays

- Beach Energy's Enterprise and Thylacine West developments are delayed to Q3 2024[60] (previously forecast to be online in Q1 2024 and Q3 2023 respectively). Both remain committed projects in the 2024 GSOO.
- Comet Ridge's anticipated Mahalo and Mahalo North developments have been delayed by 1-2 years[61].
- Senex's Atlas and Roma North expansions have been delayed by approximately one year. Senex announced a pause for these projects in December 2022 but has since resumed expansion plans and entered into new gas supply agreements (GSAs)[62]. These expansions remain anticipated projects.
- APLNG's Ironbark development has been delayed by 1-2 years[63], but remains an anticipated project in the 2024 GSOO.

3.2 Reserves, resources and supply

Gas supply is dependent on continued investment to identify, prove, and then commercialise gas reserves and resources. Production forecasts for the 2024 GSOO rely on survey responses provided by producers forecasting the available quantities of gas, plans for extraction, and the capability and capacity of gas processing plants.

[59] See https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb and https://www.abc.net.au/news/rural/2023-06-09/blacktip-gas-supply-issues-continue-nt-electricity/102450530.

[60] See Beach Energy 2023 AGM Chairman and CEO Address, 14 November 2023, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1487496/BPT_2023_AGM_addresses_and_presentation.pdf and https://www.offshore-energy.biz/australian-player-sets-wheels-into-motion-for-more-subsea-ops-to-bring-two-gas-wells-online/.

[61] See https://cometridge.com.au/wp1/wp-content/uploads/2023/09/2023.09.21-Annual-Report-to-shareholders.pdf.

[62] See, for example, Senex Energy, "Senex Energy and AGL sign deal to deliver energy security for Australians", 16 June 2023, at https://senexenergy.com.au/news/senex-energy-and-agl-sign-deal-to-deliver-energy-security-for-australians/.

[63] Australian Competition and Consumer Commission (ACCC), Gas Inquiry December 2023, pg. 58, at https://www.accc.gov.au/system/files/Gas%20Inquiry%202017-2030%20-%20December%202023_0.pdf.

Forecasts for gas production provided by market participants are exposed to technical and commercial uncertainties.

Supply forecasts reflect the best advice and updated data provided to AEMO. The surveys for the 2024 GSOO were conducted for most gas producers in September 2023, but surveys have been updated for any material changes since then. Project proponents provide consideration of project development lead time in their survey response.

In this GSOO, the following definitions apply[64]:

- **Existing and committed** – gas fields and production facilities that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway.
- **Anticipated** – developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
- **Uncertain** – these projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

3.2.1 Reserves and resources

Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with recoverability:

- A **proven and probable (2P) reserve** is a quantity of gas expected to be commercially recovered from a known accumulation. The estimate reflects statistically that there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves. 2P reserves are generally associated with existing, committed and anticipated production projects.
- A **contingent (2C) resource** is a best estimate of a quantity of gas that is less certain, and potentially less commercially viable. 2C resources are generally associated with uncertain production projects.
- A **prospective resource** is an estimated volume associated with an undiscovered accumulation of gas. These resources are highly speculative and have not yet been proven by drilling.

The reserves and resources estimates for the 2024 GSOO[65] include all major fields connected to the ECGM, excluding fields in the Northern Territory developed specifically for LNG export. Over time, the estimated supply available from gas reserves and resources changes as they are developed, deplete, or are reassessed.

Figure 26 shows that, compared to the data published for the 2023 GSOO, the total projected 2P volumes have increased by 981 PJ, but the best estimates for all reserves and resources have fallen.

Significant volumes have been upgraded from 2C resources to 2P reserves in northern regions, demonstrating producers' ongoing commitment to exploration, appraisal and development of new gas supply. This is despite some reported delays to uncertain projects.

[64] AEMO began using these classifications in the 2020 GSOO, after stakeholder consultation. The classifications are aligned with the Society of Petroleum Engineers Petroleum Resource Management System (PRMS) project maturity sub-classes.

[65] Like the 2023 GSOO, the natural gas reserve and resource estimates in the 2024 GSOO used information from gas producers, supported by estimates from research from a wide variety of sources, particularly for the more uncertain gas resources.

Figure 26 Reserves and resources reported in the 2023 GSOO and 2024 GSOO

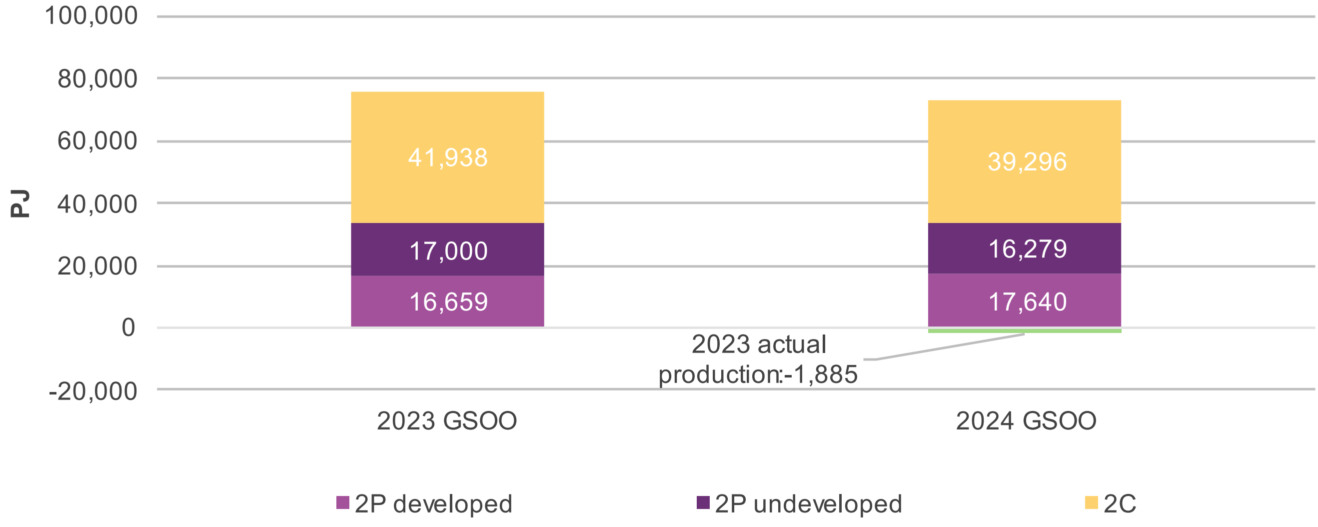
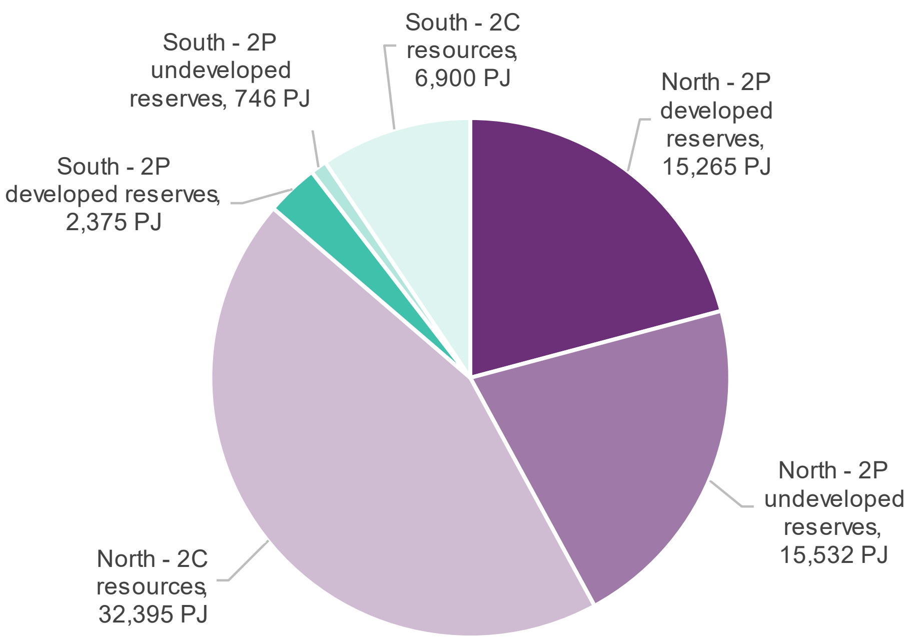


Figure 27 shows a large majority of the 2P reserves and 2C resources are concentrated in the north. Northern LNG producers control around 70% of the 2P developed and undeveloped reserves in the ECGM.

Figure 27 Split of reserves and resources across northern and southern regions for the 2024 GSOO (PJ)



3.2.2 Available annual production

Following extraction, gas needs to be processed to meet standard gas quality specifications for transport in transmission pipelines and onward distribution to consumers. The rate at which gas can be produced is determined by a variety of factors, including:

- Capacity of the production plant, including maintenance and potential downtimes.

- Capacity of the additional processing plant (to manage specific impurities in the raw gas stream from the gas field, such as mercury or CO_2).
- Pressure in the gas well, which determines the rate of flow, particularly for conventional gas.
- The drilling program to access gas pockets, particularly for coal seam gas (CSG).
- The quality of the gas, particularly in terms of the need for additional processing.

Table 6 shows the annual production forecast from existing, committed and anticipated fields from 2024 to 2028, as advised to AEMO by gas producers. These quantities represent maximum annual production capability. The quantity of actual production depends on demand from domestic consumers and international exports.

Table 6 Forecast of available annual production as advised by gas producers, 2024-28 (PJ)

	Commitment criteria	2024	2025	2026	2027	2028
North (NT[A] and QLD)	Existing and committed	1,543	1,449	1,309	1,207	1,088
	Anticipated	57	130	253	407	464
	Total	**1,600**	**1,579**	**1,563**	**1,614**	**1,553**
	Difference from 2023 GSOO	*-23*	*-37*	*-70*	*-25*	*-53*
South (VIC, NSW, SA[B])	Existing and committed	358	347	315	258	192
	Anticipated	23	31	42	46	43
	Total	**381**	**378**	**357**	**304**	**236**
	Difference from 2023 GSOO	*-10*	*-8*	*5*	*34*	*8*
Total gas production in the ECGM		**1,981**	**1,957**	**1,920**	**1,918**	**1,788**
Total difference from 2023 GSOO		*-32*	*-45*	*-65*	*10*	*-45*

A. Northern Territory supply excludes gas production from LNG export facilities in Darwin.
B. The Queensland component of the Cooper Eromanga basin appears in the South Australia category

The table shows that:

- Gas production volumes from existing, committed and anticipated sources are generally lower than volumes projected for the 2023 GSOO. This production figure is in close alignment with that published by the Australian Competition and Consumer Commission (ACCC) in its December 2023 Gas Inquiry 2017-2030 Interim Report[66].
- Southern[67] gas production is forecast to decrease by almost 40% over the next five years, driven by rapidly depleting legacy gas fields in the Gippsland region. The rate of production decline is consistent with prior reporting, but some southern supply committed in the 2023 GSOO has been downgraded to anticipated or has been deferred to later years.
- In the north, gas production projections from existing, committed and anticipated sources are lower than the 2023 GSOO and are relatively stable to 2028.

[66] ACCC. Gas inquiry December 2023 interim report, at https://www.accc.gov.au/about-us/publications/serial-publications/gas-inquiry-2017-30-reports/gas-inquiry-december-2023-interim-report.

[67] Southern regions refer to fields and plants located downstream of the South West Queensland Pipeline (SWQP) and includes gas supply from the Cooper Eromanga basin.

- In the south, compared to the 2023 GSOO, downgrading of some supply by producers based on more accurate information has resulted in lower volumes of existing, committed and anticipated production from 2024-26, despite increased committed supply from other domestic gas projects. 2026 to 2028 shows a small increase in the annual amount of existing, committed and anticipated supply.

Capacity upgrades to some existing processing facilities will be required to process the annual volumes of gas expected from anticipated production projects, including the additional gas supply expected from the Atlas and Range developments.

The long-term production outlook represented by existing, committed and anticipated volumes for southern gas fields is in steep decline. **Figure 28** shows southern annual production from committed fields is forecast to fall well below quantities produced during recent years. Forecast supply volumes from anticipated projects has increased for the 2024 GSOO but are still in decline. Substantial supply remains uncertain and is in the early stages of development. These uncertain projects reflect advice received from producers, but some are subject to extensive feasibility studies before they can be classified as firm supply.

Figure 28 Actual and forecast annual production from southern gas fields, 2021-43 (PJ)

3.2.3 Annual contracted supply

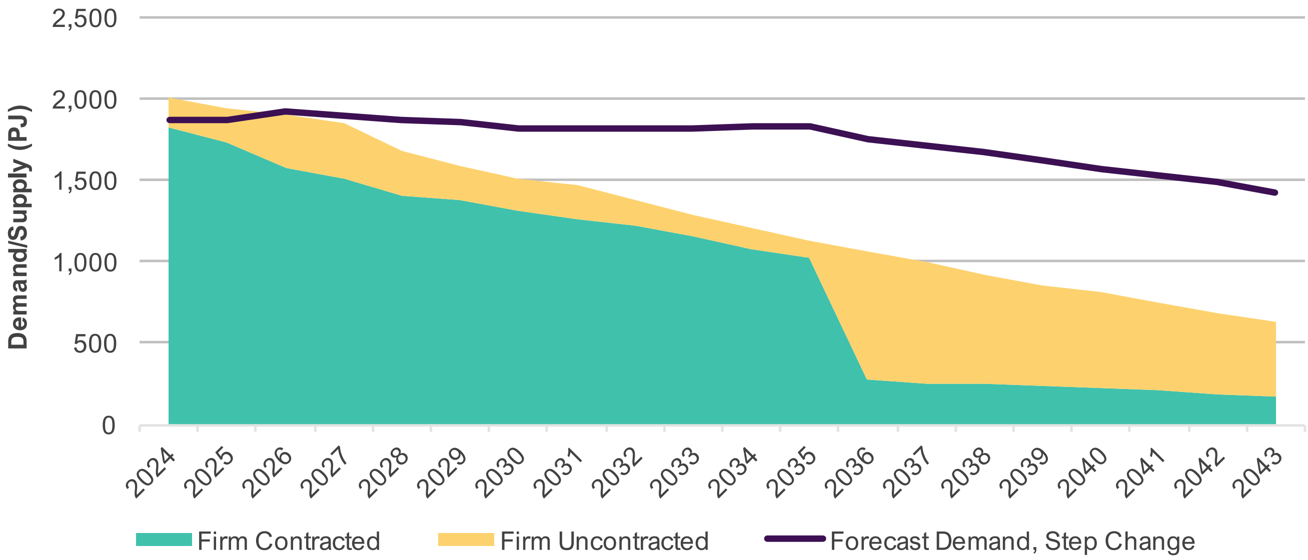
In this section, AEMO presents analysis on the level of annual contracted gas supply, supported by data provided to AEMO pursuant to recent Gas Market Reforms. These contracts are not used for the physical gas adequacy assessment presented in Section 4.

A contract for firm supply of gas between a user and a producer (firm contracted supply) means supply must be made available according to the terms of the contract. Firm contracted supply from each producer is not necessarily equal to their production forecast, so the analysis in this section alone does not provide a definitive overall assessment of domestic supply adequacy.

When supply is firm, but no contract exists for the corresponding production (firm uncontracted supply), supply is assumed to be available – either sold on domestic spot markets or supply hubs or sold to LNG exporters and sold overseas. Gas sold on domestic spot markets or supply hubs will tend to attract a higher price at times of high demand or constrained supply.

Figure 29 shows most supply is subject to firm contracts in 2024, with further uncontracted supply available to meet forecast demand. However, after 2024, there is a growing gap between contracted supply and forecast consumption. Producers generally need firm contracts or GSAs with customers to lower investment risks and bring new gas supply to market. Without firm contracted customers, supply uncertainty remains which presents a significant challenge to de-risking new upstream supply projects. Retailers on the demand-side face similar challenges signing long-term GSAs with producers when trends towards electrification are uncertain and some volumes of gas may not be required in the future by their customers.

Figure 29 Firm contracted and firm uncontracted contract quantities for all producers (including LNG producers) in comparison to forecast demand, *Step Change* scenario (PJ)



Notes:

- There are currently no known contracts or other firm arrangements for supply from LNG imports.
- This chart does not provide a direct comparison with the equivalent chart from the 2023 GSOO which incorporated domestic gas contracts only. This figure provides a more complete understanding of contracts.

The ACCC has noted[68] that contracts are expected to be renewed for shorter periods and for lower volumes. The Gas Code of Conduct (see Section 1.2) includes a provision for parties to negotiate in good faith and follow procedural requirements which may result in more firm contracted supply being brought forward for domestic customers in the long term.

[68] ACCC. Gas inquiry December 2023 interim report, at https://www.accc.gov.au/about-us/publications/serial-publications/gas-inquiry-2017-30-reports/gas-inquiry-december-2023-interim-report.

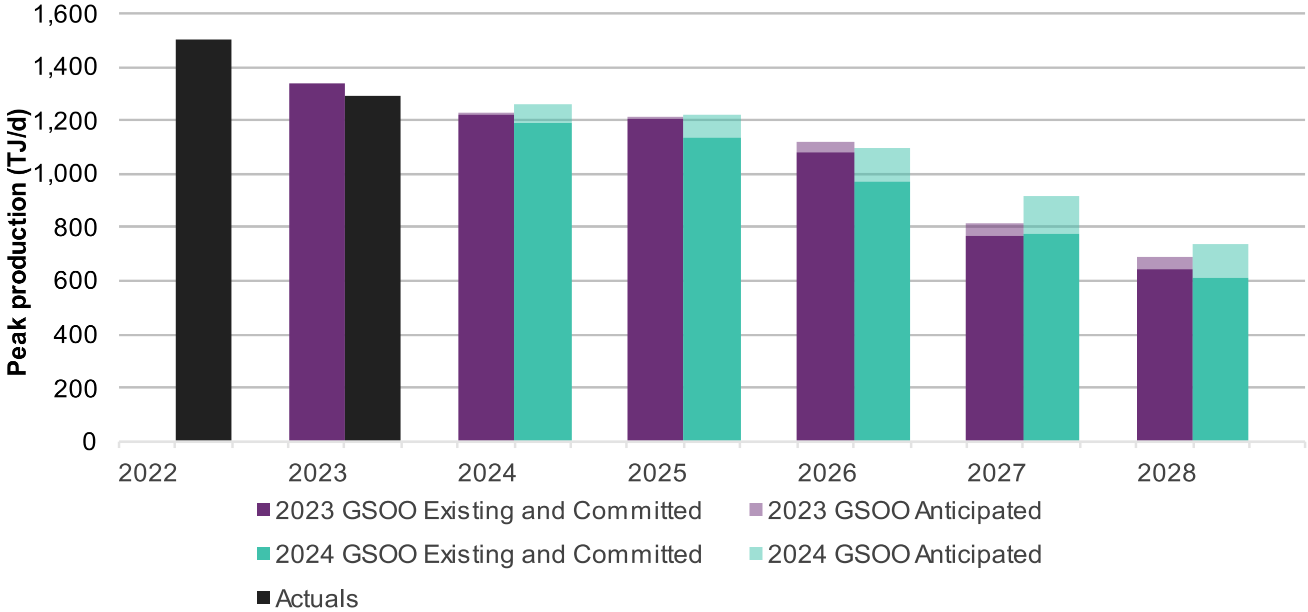
3.2.4 Maximum daily production capacity

Maximum daily production capacity defines the quantity of total gas that can be injected into the system each day. This measurement of capacity is critical to the operation of the gas markets to ensure sufficient gas is available to meet peak winter demands. Most production facilities operate at or near maximum capacity, so annual supply forecasts are proportional to maximum daily or peak production capacity. Maximum daily production capacity is limited by the flows from connected gas fields, and by the maximum daily processing capacity at the gas plant. The combination of field flows and processing capability represents the maximum technical capacity of these facilities. The capability of mid-stream infrastructure to deliver this gas to demand or storage facilities is the other major factor in determining the gas supply adequacy assessments in Section 4.

Southern daily production capacity

Consistent with the forecast decline in annual production (see Section 3.2.2), **Figure 30** shows that the maximum daily production capacity[69] from existing, committed and anticipated southern fields is projected to decrease by 40% from 1,260 TJ/d in 2024 to 740 TJ/d in 2028.

Figure 30 Actual and forecast maximum daily production capacity from southern gas fields, June 2022-28 (TJ/d)



Note: AEMO started collecting monthly maximum daily quantities for the GSOO from 2023 onwards as part of implementation of the Gas Transparency Measures. 2022 GSOO values shown are annual maximum daily quantities. 2023 GSOO values shown for the 2023 calendar year are July quantities.

There is a slight uplift in maximum daily production capacity from committed and anticipated supplies since publication of the 2023 GSOO.

As legacy fields in the Gippsland region deplete, southern daily capacity will continue to decline. Decommissioning works at Longford Gas Plant are already underway, with Gas Plant 1 and Gas Plant 3 planned for shutdown in mid-July 2024 and later in the decade respectively.

69 Maximum daily quantities have been reported as forecast capacities in June each year. Producers will typically plan for maximum throughput over winter months to accommodate high gas demands.

Supply resilience in the south is expected to substantially reduce as:

- **Depletion of legacy Gippsland basin fields continues** – the Longford Gas Plant has historically relied on large legacy fields in the Gippsland basin to scale production up and down to respond to issues with other fields or platforms. As the production capacity of these legacy fields declines, Longford Gas Plant will have reduced ability to maintain production by ramping up these fields to cover a reduction in capacity from other fields.
- **Redundancy in plant capacity reduces** – shutdown of Gas Plant 1 will leave two remaining gas plants, with both required to achieve the 2024 peak day capacity of 700 TJ/d. If either of the two remaining plants is unavailable, the total production capacity of Longford Gas Plant could be reduced by up to 350 TJ/d.

Northern daily production capacity

In the north, production is relatively constant except when maintenance activities are required. Processing facilities operate at near full capacity all year so maximum daily production capacity is proportional to annual production. Northern gas fields are operated predominantly for LNG export demand and domestic demand from local customers does not vary seasonally.

3.2.5 Wells drilled

To support LNG exports and meet domestic gas demand, new wells need to be drilled to explore, appraise and develop gas supply. Exploration wells aim to discover new gas reserves by drilling in areas suggested by geological data. Once gas is found, appraisal wells are used to evaluate the dimensions and commercial potential of the discovery and gather more detailed data on its characteristics. Development wells are then established to optimise gas production and ensure effective reservoir management for sustainable commercial operations.

For the 2024 GSOO it is now mandatory for producers to provide data on exploration, appraisal, and development wells. The data received from producers for development wells is summarised in **Figure 31,** which shows:

- In comparison to 2023, there is forecast to be a slight increase in drilling activity in 2024 and the first half of 2025.
- The majority of drilling activity is concentrated in the Surat and Bowen basins, to access CSG to support LNG exports. Greater drilling activity is typically required in CSG fields than in conventional gas fields.

Figure 32 demonstrates the historical and forecast year-on-year exploration and appraisal activity for all basins. Fewer exploration wells are forecast to be drilled, with producers expecting to drill more than double the number of appraisal wells in 2024 in comparison to 2023.

Figure 31 Historical and forecast number of development wells drilled, 2022 to June 2025

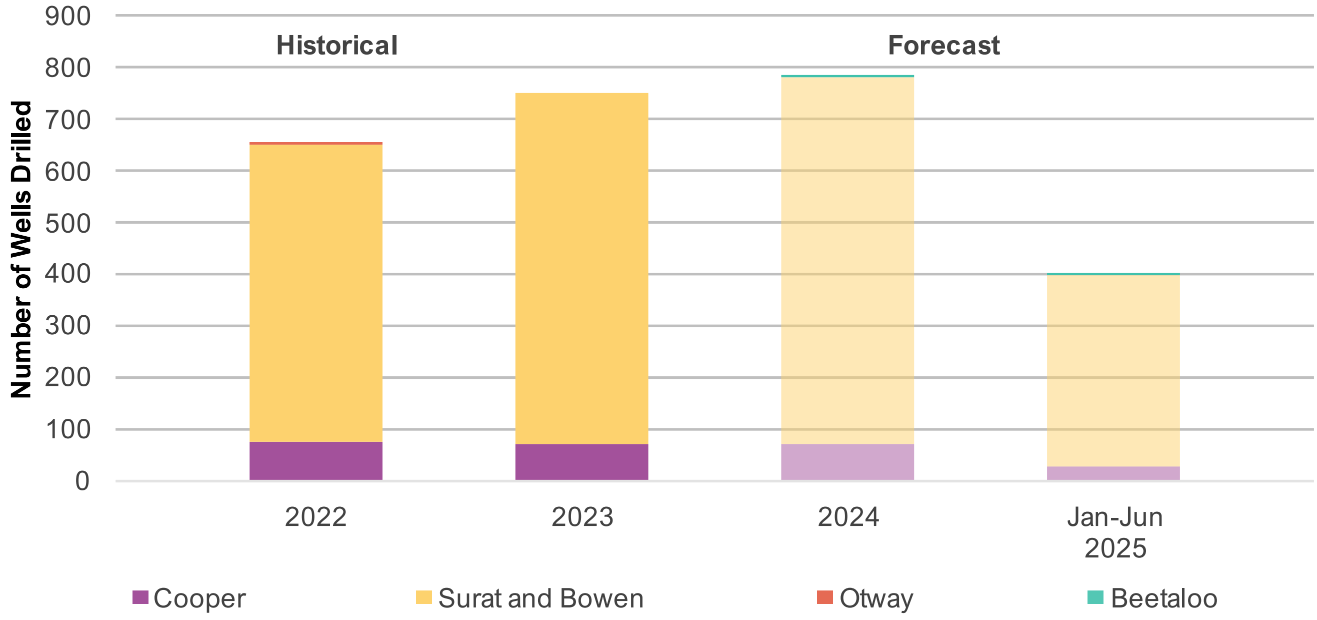
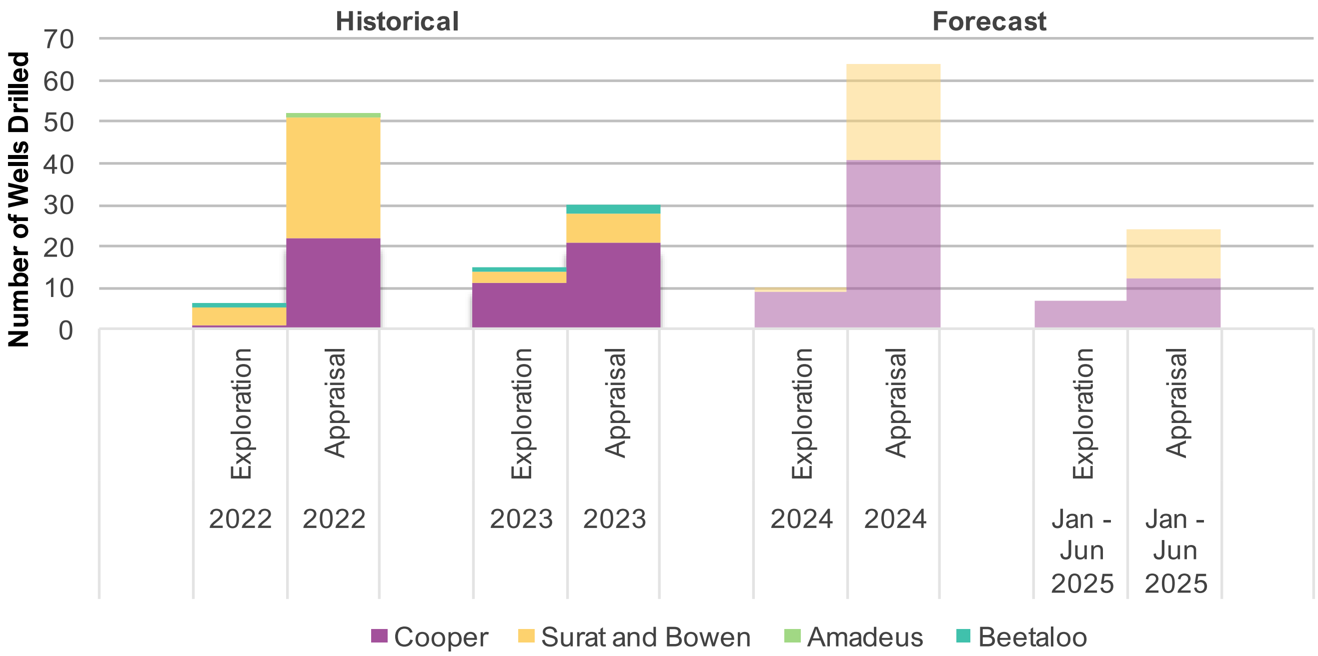


Figure 32 Historical and forecast number of exploration (left column) and appraisal (right column) wells drilled, 2022 to June 2025



3.3 Midstream gas infrastructure

Midstream infrastructure connects the gas producers to end consumers and is key for daily and seasonal balancing of gas supply and demand.

The infrastructure includes pipelines for gas transport, storage facilities and potential LNG import terminals[70].

The shifting dynamics in gas production and consumption patterns are likely to impact on the operation and reliance of midstream infrastructure. The gas adequacy modelling undertaken by AEMO is based on the technical capability of midstream infrastructure and does not consider contracted positions. The Gas Inquiry 2017-2030 Interim Report released by the ACCC in December 2023 provides valuable context on the potential implications of pipeline contracts[71].

Figure 8 in Section 1 is a map of the basins, pipelines, and load centres across the ECGM in this 2024 GSOO.

3.3.1 Major gas transmission pipelines

This section highlights key pipelines that facilitate the transport of gas between the north and south and are integral to the supply adequacy assessment provided in Section 4.

South West Queensland Pipeline (SWQP)

The SWQP extends from Wallumbilla to Moomba and is interconnected with the Carpentaria Gas Pipeline (CGP) that receives gas from the Northern Gas Pipeline (NGP). The SWQP operates as a critical gateway that links the expansive northern gas fields, which supply the Gladstone LNG export facilities, to the southern regions that are characterised by high seasonal gas demand.

The SWQP's availability to facilitate the north-south gas flows is becoming crucial. APA Group[72] has completed Stage 1 of the proposed upgrades to increase southern gas flow capacity through the SWQP and the Moomba – Sydney Pipeline (MSP). The completion of ECGE Stage 1 has delivered an uplift in capacity on the SWQP by 49 TJ/d (and on the MSP by 30 TJ/d). Included in this expansion is a new compressor installation between Moomba and Young, coupled with another on the SWQP.

Moomba – Sydney Pipeline (MSP)

The MSP links the Moomba Gas Hub in northern South Australia with Sydney and intersects with the Victorian Northern Interconnect (VNI) at Young, facilitating gas transfers to Victorian consumers. The MSP is crucial for delivering gas from northern Australia to New South Wales, Victoria and Tasmania. It balances gas supply between regions and flows north to Queensland at times of southern surplus.

During summer, annual inspection works on the MSP can reduce its operational capacity. These works are strategically scheduled to avoid winter when full MSP capacity may be required, whilst still providing appropriate summer capacity. Due to a dynamic of the pipeline that simultaneously delivers between the Young – Sydney route and the VNI lateral, the overall MSP's transport capacity depends on the demand distribution between Sydney and Victoria. In general, the total MSP capacity is higher when the quantities delivered south via the Young – Sydney route are higher.

---

[70] LNG export terminals are considered consumers.

[71] At https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/december-2023-interim-report.

[72] APA is the owner and operator of a number of pipelines in Australia including the MSP.

East Coast Grid Expansion project

APA Group is proposing a series of staged upgrades to expand gas transportation capacity on the East Coast Grid that links Queensland with southern markets.

As noted above, Stage 1 of the ECGE project increased the capacity on the SWQP and MSP by 49 TJ/d and 30 TJ/d respectively, via increased compression. Stage 2 involves further compression on both SWQP and MSP, increasing north-south flow capacity by 59 TJ/d. The project is a committed project, for completion by winter 2024.

Potential future ECGE stages (Stage 3a, 3b and 4) would increase the capacity of both the SWQP and MSP to 615 TJ/d and 657 TJ/d, respectively, through the construction of additional compressors. If these stages are built, they would enable an additional 103 TJ/d of northern produced gas to flow to southern markets. Development of all three stages remains subject to long term customer demand and all necessary project approvals. Depending on the time that a commitment is made, then it is possible that Stage 3a could be completed as early as mid-2025, Stage 3b by mid-2026 and Stage 4 by mid-2027. The 2024 GSOO considers the ECGE Stages 3a, 3b and 4 as uncertain projects.

South West Pipeline (SWP)

The SWP operates as a bi-directional pipeline between Port Campbell and Lara in Victoria, where it links with the Brooklyn – Lara Pipeline (BLP). The SWP is typically utilised for transporting gas from Port Campbell and the Iona UGS facilities towards Melbourne, as well as supporting the refilling of the Iona UGS reservoir. Additionally, it facilitates supply of gas to areas west of Port Campbell, such as the Mortlake Power Station, and to South Australia via the Port Campbell to Adelaide (PCA) Pipeline, during the summer and shoulder seasons when Victorian gas demand is lower.

The SWP's capacity for transporting gas from Port Campbell to Melbourne varies depending on system demand, reaching its peak capacity on a 1-in-20 system demand day. This capacity has recently been increased to 530 TJ/d following the completion of the WORM project, and the installation of an additional compressor at Winchelsea. The capacity for flow from Melbourne to Port Campbell is maximised on days of low demand, with the current maximum at 348 TJ/d, having recently risen by 152 TJ/d following the completion of the WORM.

Northern Gas Pipeline

The Northern Gas Pipeline (NGP) is a unidirectional pipeline that connects Tennant Creek in the Northern Territory to Mount Isa in Queensland. It was commissioned in 2019 to provide a transportation route for gas production facilities in the Northern Territory to provide gas to Mount Isa and eastern Australia, when local production exceeds demand.

Moomba – Adelaide Pipeline System

The Moomba – Adelaide Pipeline System (MAPS) connects the Moomba production facility to Adelaide. The pipeline also supplies regional South Australian load, including via separate laterals that run to Port Pirie and Whyalla, and to Angaston. The MAPS supports limited northerly flow and does not flow into the PCA.

Eastern Gas Pipeline (EGP)

The EGP runs from the gas processing plants located at Longford and Orbost in Victoria's Gippsland basin, extending its reach to Sydney, with an interconnection at Hoskinstown to supply Canberra.

Port Campbell to Adelaide Pipeline (PCA)

The PCA pipeline (called the 'South East Australian Gas (SEAGas) pipeline' in the 2023 GSOO) connects the Adelaide STTM and other South Australian demand points to supply from the Otway basin in Victoria, including Iona UGS. There is an existing capability for gas to flow from the PCA into the MAPS, but the pressure differential between the two pipelines precludes flows from MAPS to the PCA absent the installation of compression. The PCA is the sole source of supply to the Ladbroke Grove power station via the South East South Australia (SESA) pipeline and, to Mount Gambier and surrounds via the SESA pipeline and the South East Pipeline System (SEPS).

EGP reversal project

The EGP is configured for unidirectional flow from Longford towards Sydney. Jemena plans to reconfigure the EGP to allow for bi-directional flow in time for the commissioning of the Port Kembla Energy Terminal (PKET) LNG import terminal.

PCA reversal project

In its current configuration, the PCA is only designed to flow from east to west, but studies have confirmed the pipeline is able to be configured for bi-directional flow, which would enable flows from Adelaide to Victoria if the Outer Harbor LNG Import terminal development proceeds.

Other pipelines

Table 7 lists other major midstream infrastructure servicing domestic consumers.

Table 7 Additional major existing midstream infrastructure

Name	Description and relevant information
Amadeus Gas Pipeline (AGP)	Connects the Amadeus basin in the south of the Northern Territory to Darwin in the north. The pipeline is bi-directional.
Bonaparte Gas Pipeline (BGP)	Connects supply from the Blacktip field to the AGP at Ban Ban Springs.
Carpentaria Gas Pipeline (CGP)	Connects Mount Isa and the NGP to Queensland's pipeline system, at Ballera on the SWQP.
Victoria Northern Interconnect (VNI)	Connects Wollert (on the Melbourne ring) to Young, intersecting with the MSP.
Brooklyn – Lara Pipeline (BLP)	Connects supply from the SWP at Lara to Brooklyn
Longford – Melbourne Pipeline (LMP)	Connects Melbourne to supply from Longford Gas Plant. Does not provide access to the Orbost Gas Plant.
Roma – Brisbane Pipeline (RBP)	Connects Brisbane to supply from Wallumbilla Gas Hub.
Tasmanian Gas Pipeline (TGP)	Connects Bell Bay to supply from Longford Gas Plant.
North Queensland Gas Pipeline (NQGP)	Connects Townsville to supply from Moranbah Gas Plant.
Sydney – Newcastle Pipeline (SNP)	Connects Newcastle to Sydney (and draws supply from the MSP and EGP). Presently this is not considered to be a transmission pipeline but is a large full regulation distribution pipeline. However, given Newcastle proposals for a new LNG import terminal, new gas generation, or the Queensland – Hunter Gas Pipeline (QHGP), the SNP may need expansion or even duplication.
Western Outer Ring Main (WORM)	Connect the SWP/BLP at Plumpton and the Longford Melbourne Pipeline (LMP) at Wollert. The project includes the installation of additional compression. The project was commissioned in February 2024.

3.3.2 Storage facilities

Gas storage facilities are essential for balancing yearly gas production (PJ/y) and fluctuating, seasonal and daily domestic demand (TJ/d), ensuring that gas is available during periods of higher demand when required.

Storage facilities sited near load centres are important so gas can be supplied promptly during peak demand periods, thus maintaining a reliable and efficient gas system. Pipeline capacity constraints can impact storage operations, affecting the ability to refill storage to full capacity and to deliver gas at maximum withdrawal rates.

Table 8 lists existing market-facing storage facilities and proposed upgrades or facilities.

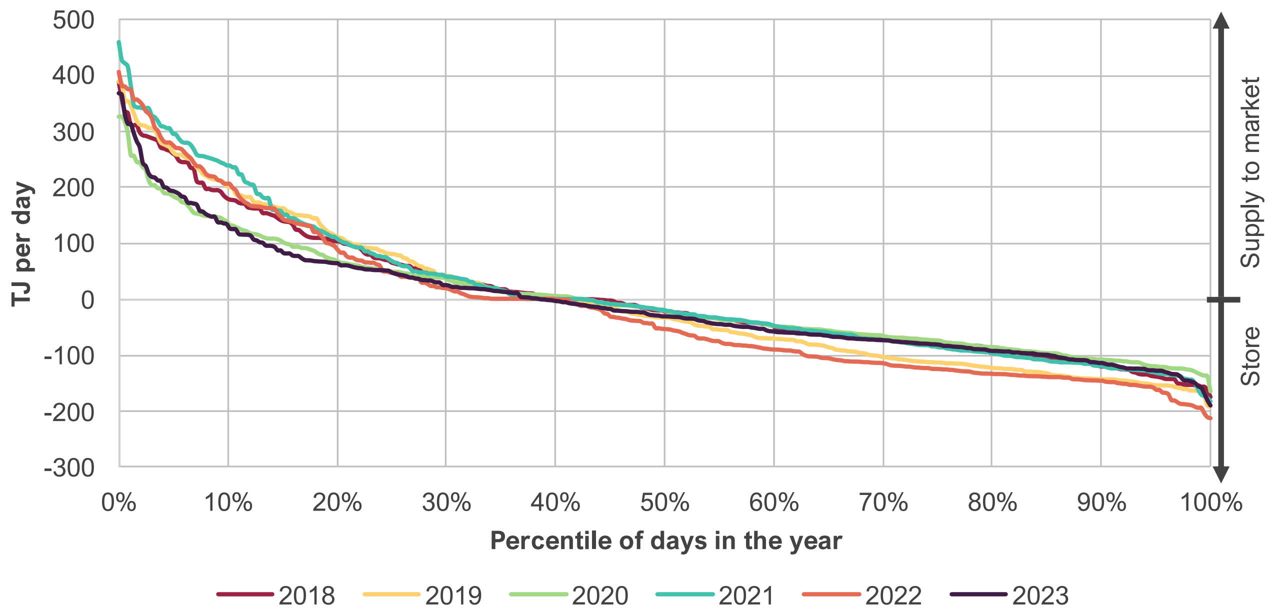
Table 8 Key existing market-facing and proposed storage infrastructure

Name	Maximum storage capacity (PJ)[A]	Maximum withdrawal rate (TJ/d)	Connecting location
Silver Springs	46	25	Wallumbilla, Queensland
Iona UGS • **Existing** • **Upgrade (Proposed)**	 24.4 26-28	 570 570-615	Otway Basin, Victoria
Newcastle LNG Storage	1.5	120	Newcastle, New South Wales
Dandenong LNG Storage	0.68	87[B]	Melbourne, Victoria
Golden Beach Storage (Proposed)	35	250	Gippsland Basin, Victoria

A. The maximum storage capacity includes buffer gas.
B. This storage can supply at faster rates for short periods of time, but that is non-firm supply and not able to be supported across a 24-hour period.

Figure 33 illustrates how the Iona UGS has been critical historically in meeting demand by injecting gas at high rates, particularly in 2021 and 2022, when the facility observed its highest daily withdrawals in six years, exceeding 400 TJ/d. In 2023, due to lower annual demand compared to the previous two years, the facility experienced a decline in daily withdrawals.

Figure 33 Cumulative distribution of net changes in storage level for Iona UGS, 1 January 2018 to 31 December 2023 (TJ/d)



Shallow storage facilities at Dandenong (Victoria) and Newcastle (New South Wales) need to have inventories ready to provide operational flexibility and help mitigate risk of shortfalls. Despite high withdrawal rates, these storages hold limited volumes, so they are unable to sustain high rates of injection for extended periods. These facilities liquify gas prior to storage so have slow re-filling rates.

AEMO currently is required by the National Gas Rules (NGR) to act as both buyer and supplier of last resort in relation to the Dandenong storage facility from 2023 to 2025[73]. This measure has been established to guarantee that the Dandenong LNG tank is full before winter, ensuring efficient operation of the Declared Wholesale Gas Market (DWGM).

Golden Beach Energy Storage Project

GB Energy is proposing a gas production and energy storage project in the Gippsland Basin, approximately 3 kms offshore from the township of Golden Beach. The project would leverage the Golden Beach gas field for storage, with some initial new supply provided before transitioning to a storage project. The proposal outlines a capacity to store up to 35 PJ of gas, although the working volume is nominally 12.5 PJ. If developed, the uncertain project would provide up to 250 TJ/d to southern demand centres.

Heytesbury Underground Gas Storage Project

Lochard Energy has proposed upgrade to the Iona UGS storage facility at Port Campbell, Victoria. The project would expand the current capacity of the Iona UGS to between 26 and 28 PJ, and increase the maximum withdrawal rate to 570 – 615 TJ/d.

3.3.3 Gas processing plants

Natural gas extracted from wells often contains impurities that are either unsafe or not suitable for combustion, including water, nitrogen, carbon dioxide, sulphur and heavier hydrocarbons. Gas processing plants reduce the level of impurities in natural gas to an acceptable level and separate out natural gas liquids, making it suitable for domestic and international consumers. There are a total of 42 existing gas processing facilities in the ECGM. **Table 9** lists the committed and proposed gas processing plant facilities that may be developed in the future, as advised by project proponents.

Table 9 Committed and proposed gas processing plants

Name	Purpose	Region
Girrahween	To support production from Arrow's Surat gas project	Queensland
Golden Beach	To process gas from the Golden Beach gas field in the Gippsland basin	Victoria
Lynwood	To support production from Arrow's Surat gas project	Queensland
Narrabri	To process gas from Santos' Narrabri development	New South Wales

[73] AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

3.3.4 LNG import terminals

LNG import terminals offer pathways to access gas from international and domestic suppliers and can operate as virtual pipelines when domestic supply or existing infrastructure is unavailable to service demand centres. Import terminals require access to a floating storage and regasification unit (FSRU)[74] to store and re-gasify imported LNG. Terminals also require pipelines and other infrastructure to be constructed to deliver gas into the ECGM. In some cases, additional downstream pipeline augmentations may be necessary to ensure imported gas volumes can be delivered efficiently to where it is needed.

LNG import terminal developers have proposed the projects outlined in **Table 10**. No import terminal projects are considered committed or anticipated in the 2024 GSOO, as in all cases uncertainty remains regarding the timing of on-shore infrastructure development, or the location commitment of the FSRU, as outlined in the table below.

Table 10 Proposed LNG import terminals

Name	Region	Timing	Capacity	Additional considerations
Port Kembla Energy Terminal (PKET)[A]	New South Wales	2026	500 TJ/d 130 PJ/y	• Pending firm date for FSRU arrival at Port Kembla. • Secured a long-term contract for an FSRU in 2021. • Located near Sydney with a pipeline connecting into the EGP. The lateral connecting PKET to the EGP has been completed. • Jemena has proposed an upgrade to the EGP to become bi-directional. Early design and procurement works have progressed. If the project is fully developed, it will initially deliver the capacity to deliver 200 TJ/d in reverse flows south to Victoria and could be upgraded to 325 TJ/d.
Venice Outer Harbour, Port Adelaide[B]	South Australia	2026	Up to 446 TJ/d 110 PJ/y	• Pending FID • All necessary approvals acquired. • Stage 1 site preparations are complete[C]. • PCA reversal would allow flow from Adelaide to Port Campbell in Victoria.
Viva, Geelong[D]	Victoria	2027	620 TJ/d 140 PJ/y	• Pending FID • Located adjacent to the Geelong Oil Refinery. • Working to secure an FSRU for the project after losing previous allocation[E]. • Pending State Government Environmental Effects Statement (EES) approval • SWP upgrades would allow coincident maximum injections from LNG imports, Iona storage, and Otway supply.
Vopak Victoria Energy Terminal, Port Phillip Bay[F]	Victoria	2028	Up to 778 TJ/d ~270 PJ/y	• Pending FID • FSRU secured • In August 2023, Minister of Planning published a decision requiring an EES to be completed for the project[G]. • SWP upgrades would allow coincident maximum injections from LNG imports, Iona storage, and Otway supply.

Note: timing and capacity have been advised by project proponents in 2024 GSOO surveys.

A. For more, see https://www.squadronenergy.com/our-projects/port-kembla-energy-terminal.
B. For more, see https://veniceenergy.com/outer-harbor-lng-project/.
C. For more, see https://veniceenergy.com/2024/02/15/chairmans-update/.
D. For more, see https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project.
E. Sonali Paul and Florence Tan, MarketScreener, "Europe's dash for gas puts Australia's LNG import plans at risk", 30 May 2022, at https://www.marketscreener.com/quote/stock/VIVA-ENERGY-GROUP-LIMITED-44388561/news/Europe-s-dash-for-gas-puts-Australia-s-LNGimport-plans-at-risk-40589187/.
F. For more, see https://www.vopak.com/newsroom/news/news-vopak-lng-studies-feasibility-develop-lng-import-terminal-victoria.
G. For more, see https://www.planning.vic.gov.au/environmental-assessments/browse-projects/referrals/Vopak-Victoria-Energy-Terminal.

[74] An FSRU stores and regasifies LNG, before it is injected into a transmission system.

4 Gas supply adequacy assessment

This section provides a gas supply adequacy assessment for the ECGM, based on the demand and supply forecasts in chapters 2 and 3.

Key insights

- **In the south, investments in gas production, storage and transport are urgently needed to reduce the risk of peak day shortfalls and to avoid annual supply gaps.**
  - **From 2025, risks of peak day gas shortfalls are forecast in southern Australia** under extreme demand conditions if high demand for heating coincides with high demand for GPG.
  - The transportation and storage upgrades completed during the past year lower the risk of peak day shortfalls but are not sufficient to avoid these risks completely.
- **In 2026 and 2027, AEMO forecasts the potential for small seasonal supply gaps in southern Australia** under conditions that will lead to sustained high demand, particularly during winter.
- **More structural southern annual supply gaps emerge in 2028** in the forecast, when new supply will be needed, despite declining consumption.
- **Northern producers need to deliver anticipated supplies before 2025 and by 2026 more uncertain supply is required to meet export agreements and domestic supply.**
- Supply has improved in North Queensland and is forecast to be sufficient to meet residential, commercial and industrial consumer demand on most days to 2034. Gas supply to local GPG may be limited subject to operational considerations, as identified in the 2023 GSOO.
- Extended reliance on interim emergency gas arrangements or alternative ongoing agreements will be needed in the Northern Territory if current supply issues continue.
  - In the meantime, gas continues to be supplied to Mount Isa from Queensland reducing the capacity available to transport gas to southern regions.

Definitions

The following definitions apply throughout this chapter when assessing the daily shortfalls and annual supply gaps:

- **Extreme peak day demand** is characterised by coincident very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG.
- A **peak day shortfall** is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day.
- A **seasonal or annual supply gap** is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.

AEMO has modelled total production across the ECGM from all producers, including LNG exporters. This GSOO provides a physical assessment of gas adequacy, assessing the capability of forecast gas production to meet peak day and annual gas demand. LNG exporters are assumed to offer gas (including gas supplied to them by third parties) to the domestic market as required.

The supply adequacy assessments in this chapter:

- Account for all pipeline transmission capacity and constraints, and limitations from production facilities, storage and other relevant infrastructure.
- Do not consider gas stored in pipeline linepack as an available source of supply. Pipeline linepack is primarily an operational tool that can be utilised on a day to supply gas to consumers. The availability of linepack is dependent on system pressures and is not guaranteed, so it is appropriate to exclude it as a source of supply in adequacy assessments.

Use of scenarios for the adequacy assessment

This 2024 GSOO focuses on the *Step Change* scenario for both short- and long-term supply adequacy assessments. The *Step Change* scenario is comparable to the *Orchestrated Step Change (1.8°C)* scenario that was used for adequacy assessments in the 2023 GSOO.

The *Progressive Change* scenario applies weaker economic outcomes and therefore features lower industrial consumption, relatively smaller effective connections growth, and other drivers leading to lower gas consumption.

As detailed in Section 2, the *Step Change* scenario reflects observed and continuing trends impacting residential, commercial, and industrial gas consumption. The GSOO includes a gas supply adequacy assessment across all IASR scenarios to analyse the effect of a range of alternative futures on investment decisions regarding new gas supply. This section also provides insights into seasonal consumption patterns, including monthly variance expected from weather variations in any given scenario.

Use of data in charts

Unless otherwise specified, charts for peak day adequacy modelling refer to **extreme peak demand conditions** using 1-in-20[75] year peak demand conditions and the 2019 reference year which has very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG. The charts therefore forecast a worst-case outcome for peak day shortfalls, across the reference years modelled. Charts showing annual supply gaps show the range of outcomes across reference years, unless otherwise specified.

4.1 Southern supply adequacy

4.1.1 Peak day adequacy

Southern regions are forecast to be at risk of peak day shortfalls from 2025 under extreme peak demand conditions, which is two years later than forecast in the 2023 GSOO. The risk of shortfalls then increases in each year across the horizon. During extreme conditions, low temperatures drive high gas- and electricity- based

[75] Forecasts with a 1-in-20 probability of exceedance are expected to be met or exceeded one in every 20 years, representing more extreme weather. Average conditions assume a 1-in-2 forecast, which is expected to be met or exceeded one in every two years.

heating loads and cloud cover can lower VRE output which intensifies the requirement for gas use for peaking power generation.

Figure 34 shows the forecast capability of existing, committed and anticipated southern production, pipeline capacity and gas storages to meet actual southern gas demand in 2022 and 2023, and forecast capability to meet 1-in-20 demand forecasts from 2024 to 2028 in the *Step Change* scenario.

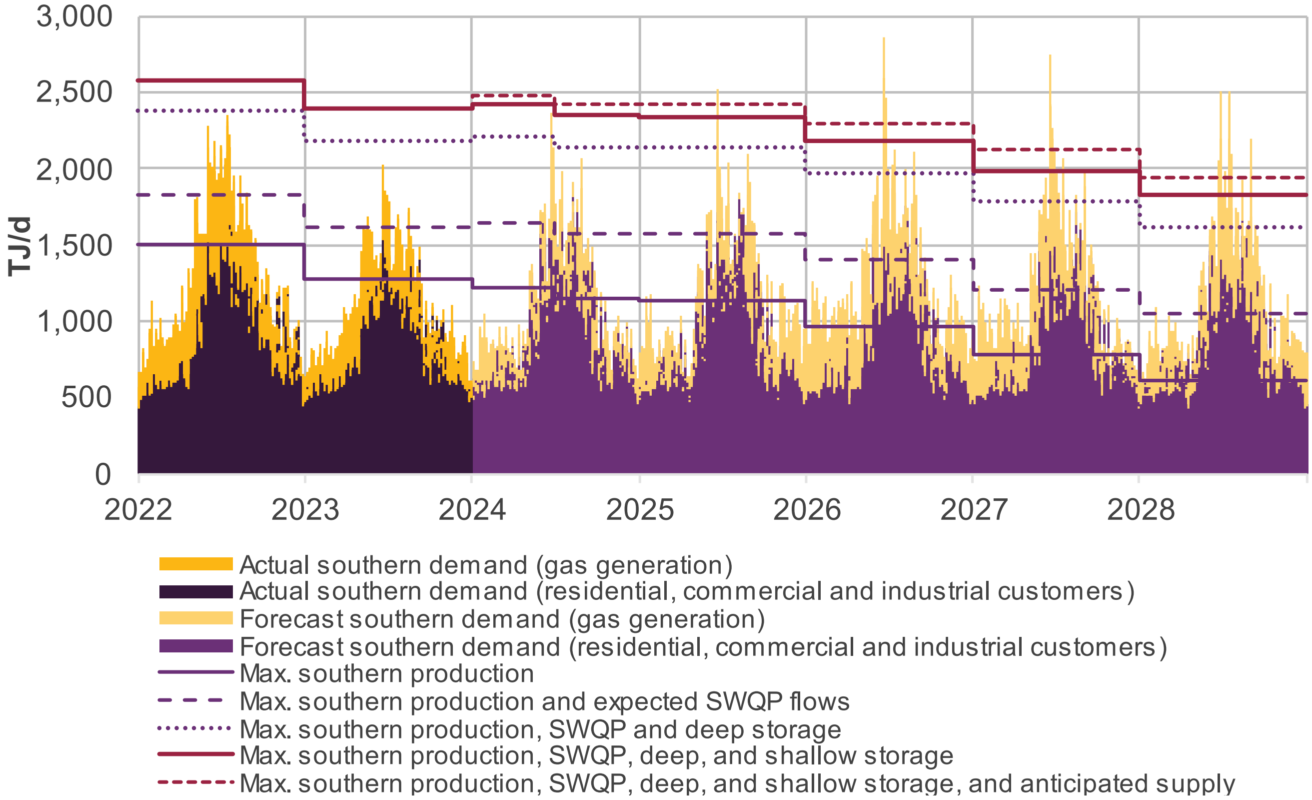
Vertical lines show daily demand volumes from gas users (purple) and from GPG (yellow). Horizontal lines in Figure 34 indicate the maximum capacity forecast to be available to be supplied to meet peak gas demand:

- Existing and committed gas production capacity from southern regions only (solid purple line), plus
- Expected gas imported from Queensland through the SWQP (dashed purple line), plus
- Gas injection capacity from deep storage at Iona UGS (dotted purple line), plus
- Gas injection capacity from shallow LNG storages at Dandenong and Newcastle (solid red line), plus
- Anticipated gas production capacity from southern regions (dashed red line).

This figure illustrates that the ability of the ECGM to deliver adequate gas to southern regions will change over the next five years:

- **The risk of peak day shortfalls in 2024 has eased** since last year's GSOO because of lower forecast peak demand but the supply-demand balance remains tight.
- **The risk of peak day shortfalls starts to appear in 2025** under extreme peak day demand conditions. This is two years later than forecast in the 2023 GSOO, and the supply-demand balance continues to tighten as southern production declines.
- **Southern supply capacity is forecast to continue to decline**, driven by declining production rates from gas fields in the Gippsland Basin. Development of anticipated southern production projects may offer up to 143 TJ/d potential upside in 2027, but total maximum production capacity (including anticipated production) in the south is forecast to decline overall by 40% from 1,260 TJ/d in 2024 to 740 TJ/d in 2028.
- **Pipeline capacity along the SWQP and MSP** has increased following completion of the ECGE Stage 1 project and will increase further upon completion of the committed ECGE Stage 2 project. This north to south transportation capacity is forecast to be increasingly relied on to meet southern gas demand, with gas flows reaching flow limits under high demand conditions from 2026 for around 10-20% of the year.
- **Deep and shallow storages** are forecast to continue to provide critical injection capacity close to large demand centres downstream of north-to-south transmission pipeline constraints. Storage levels will require appropriate management to ensure maximum injection rates can be provided on peak days and/or sustained across multiple high demand days when necessary. Under extreme weather conditions, the existing capacity provided by storages is still forecast to be insufficient to avoid gas shortfalls.

Figure 34 Actual daily southern gas system adequacy since January 2022, and forecast to 2028 using existing, committed and anticipated projects (TJ/d)



Note: Actual maximum southern production and SWQP flow rates are shown for 2022 and 2023.

Figure 35 compares the forecast field production, pipeline flows and storage operations required to fulfil southern gas demand in 2024 under extreme weather conditions, against historical gas flows encountered over 2023 when a mild winter led to low gas usage.

Southern gas consumption during extreme peak demand periods may be up to 330 TJ/d higher than 2023 actuals and 11 TJ/d higher than the 2022 winter peak, when cold weather, VRE lulls, and coal outages led to very high gas use. During winter, the tight supply-demand balance during extreme peak demand periods leaves minimal headroom for any contingencies or unplanned outages. Processing facilities should plan maintenance schedules to ensure maximum capacity is available to supply gas to minimise shortfall risks.

The figure shows SWQP and MSP transmission capacity and the injection of gas from deep and shallow storages will be necessary during periods of extreme peak demand. As the southern supply-balance becomes tighter, deep and shallow storages are forecast to be required to inject at higher rates.

The appropriate seasonal management of storage inventories, including refilling and operations, will be required so storages do not deplete during periods when other gas supply can be made available. This will ensure storages are available to deliver at their maximum injection rates during winter peak days. Storage operators should also make appropriate preparations for their facilities to run at nameplate injection capacity.

Figure 35 Observed gas supply used to meet southern demand in 2023, and forecast committed supply to meet demand in 2024, *Step Change* scenario (TJ/d)

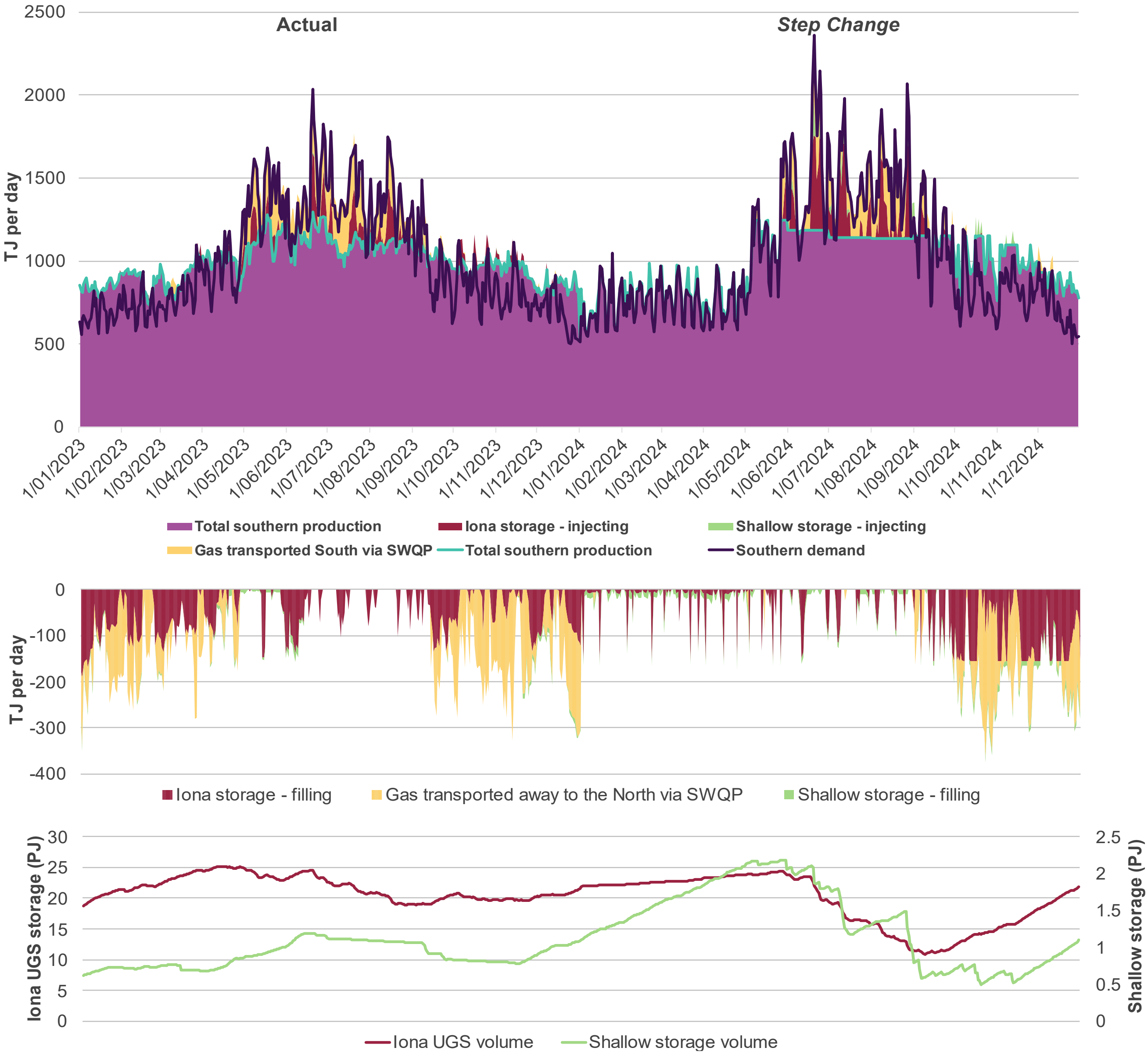
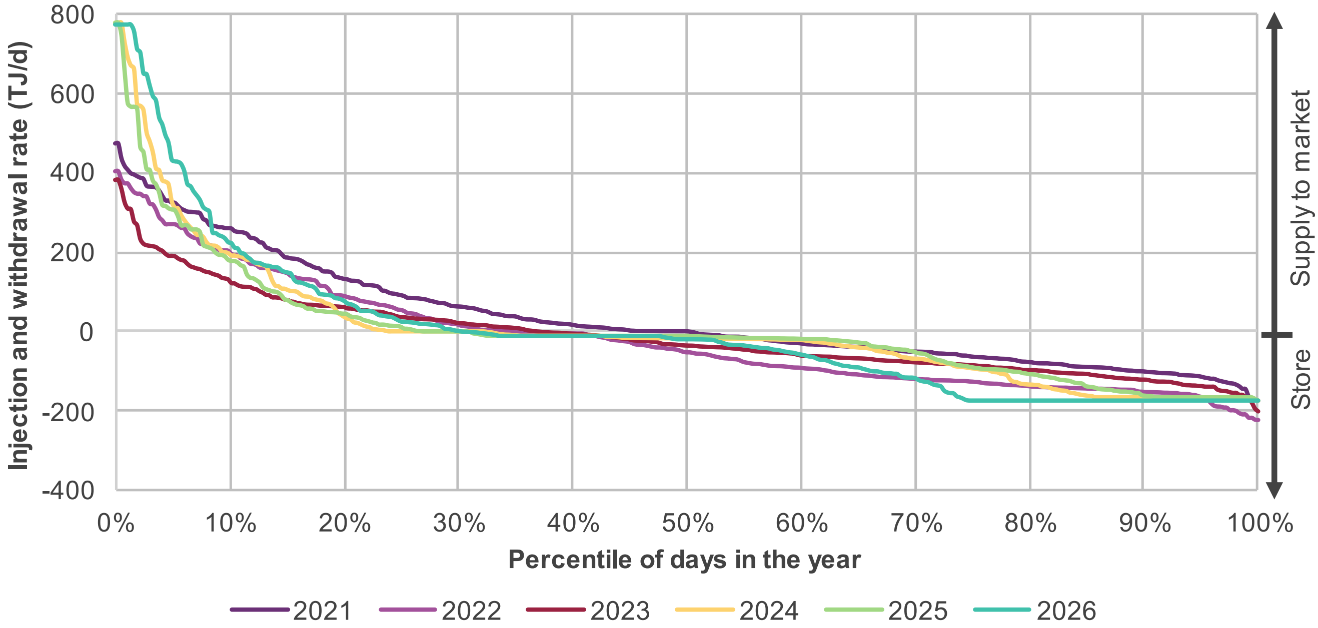


Figure 36 shows future injection rates from storage into the system are forecast to be up to 300 TJ/d above recent maximum rates. This indicates shallow and deep storage facilities may be required to operate at technical limits more frequently in the future. Even under lower demand conditions, injection rates in 2026 are still forecast to exceed 500 TJ/d during winter.

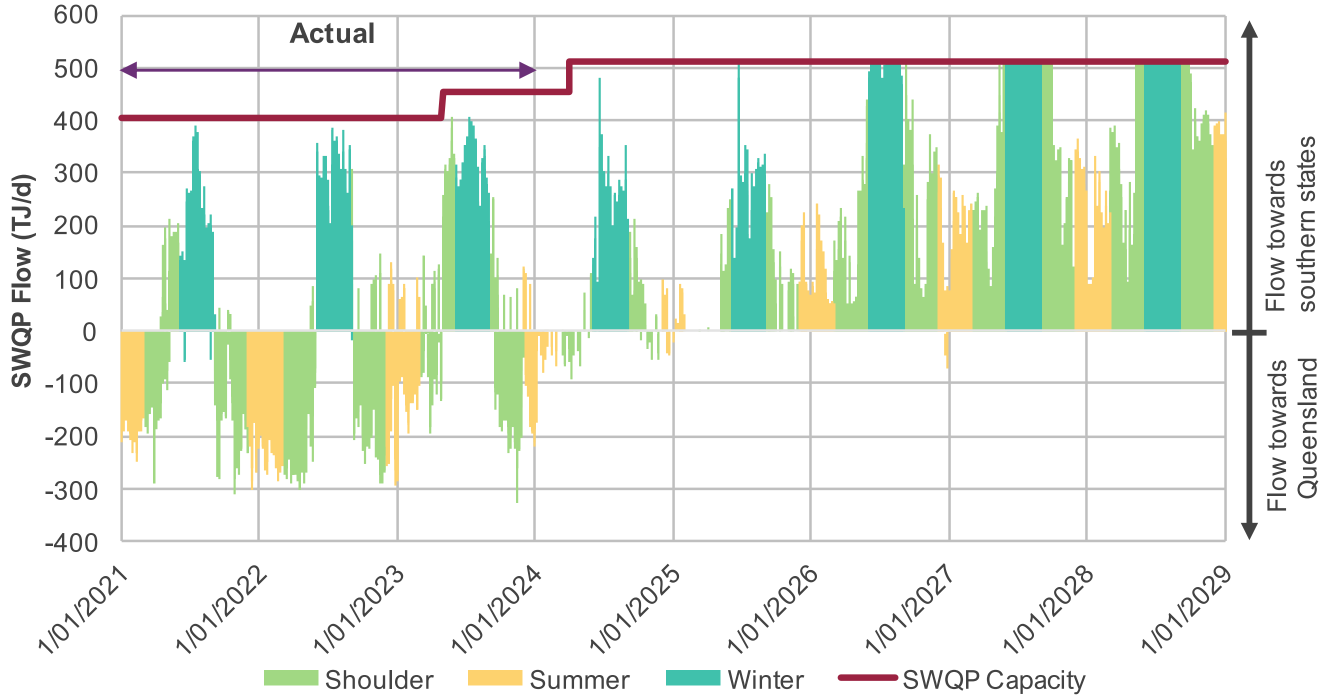
Lower than average gas demand during winter 2023 has resulted in the deep storage facility at Iona UGS starting the 2024 calendar year with a high inventory. This contrasts with shallow gas storage facilities where inventories on 1 January 2024 are low, particularly at Newcastle Gas Storage which was below 50% capacity. Gas storages in the south to cope with extreme weather conditions are critical to maintaining adequacy. Market participants have a clear role in ensuring these currently underutilised shallow storages are filled to their maximum nameplate capacity ahead of the winter period.

Figure 36 Cumulative distribution of actual (2022 to 2023) and projected (2024 to 2026, *Step Change*) storage injection and withdrawal rates for deep and shallow storages (TJ/d)



From 2026, refilling southern storages ahead of winter peak demand periods is forecast to rely more heavily on gas transported from northern fields via the SWQP. **Figure 37** shows that, based on current supply forecasts, there will be a growing trend for more consistent year-round flows on the SWQP towards the southern states. The pipeline is forecast to reach pipeline capacity more frequently from 2026 onwards.

Figure 37 Actual (2022 to 2023) and projected (2024 to 2028, *Step Change*) gas flows along the SWQP (TJ/d) – positive flows are southbound



Factors that may impact the volume of gas supplied

Volumes of gas supplied may be impacted by:

- Maintenance at gas facilities – while planned maintenance typically occurs in summer when demand is low, unplanned maintenance (often the result of equipment failure) results in unexpected and sometimes significant reductions in supply capacity, which must be met from other supply sources, often at very short notice. If unplanned maintenance occurs on key production or transmission facilities during winter and supply is significantly reduced, peak day shortfalls may result.
- UAFG – typically between 3% and 5% of total gas usage, results from gas leakage, or inaccuracies in gas measurement or heating values. (AEMO's gas forecasts presented in Chapter 2 and the supply adequacy modelling presented in Chapter 4 include estimates of losses associated with UAFG.)

Near-term solutions to resolve forecast peak day shortfall risks are limited

Consistent with the 2023 GSOO, it is critical that committed and anticipated supply and infrastructure projects are completed on schedule during the period to 2026 to minimise peak day shortfall risks:

- The committed ECGE Stage 2 project will increase the capacity of the SWQP and MSP to transport gas to southern demand centres from mid-2024. It is important this expansion is completed on time to help mitigate future risk of peak day shortfalls.
- Development of anticipated supply is crucial to alleviate shortfall risks during extreme peak demand conditions. These anticipated supply projects are also necessary to provide supply to meet established domestic and export contracts from 2025.
- Existing storages will continue to need careful preparatory action to ensure the resilience of the gas system through the higher winter demand season. Ensuring all storages are at full capacity prior to winter is critical to reduce shortfall risks. Throughout winter, appropriate operation to manage southern storage depletion is important. In extreme cases where depletion is taking place at an accelerated rate, northern supply should be sourced to ensure depletion is minimised.
  - The DWGM interim LNG storage measures rule change[76] requires that AEMO contract any uncontracted capacity at Dandenong LNG until 2025. This will ensure the Dandenong LNG tank is full prior to winter during this period.
- In the absence of further gas supply solutions, demand-side solutions may be needed to mitigate shortfall risks during extreme peak demand conditions. Given the lead time needed to plan, obtain approval for, and build new greenfield infrastructure, demand flexibility is likely the best solution to address forecast short-term supply shortfall risks.
  - In shortfall conditions, back-up fuels may be required to operate GPG for short periods, so electricity reliability is not compromised.

[76] AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

– Energy Ministers have agreed to progress an administered demand response mechanism as part of the Stage 2 ECGS reforms[77]. This future tool may address short-term projected reliability and supply adequacy threats that the market has failed to address. This will leverage AEMO's existing trading functions, with a rule change request being submitted to the Australian Energy Market Commission (AEMC) as an additional reliability and supply adequacy management tool.

4.1.2 Annual and seasonal adequacy

Gas supply in southern states is falling faster than forecast gas demand, and small seasonal supply gaps are now forecast from 2026, one year earlier than the 2023 GSOO. These gaps are forecast if sustained high demand conditions emerge, but may be managed if GPG utilises secondary fuels, if required.

More structural annual supply gaps begin from 2028 and continue to increase to the end of the horizon as southern production capacity declines. These supply gaps are forecast to occur most frequently in winter when southern demand is highest.

Demand for GPG is a strong contributor to forecast annual supply gaps. The amount of gas that is required for GPG in the next decade will be influenced by the timing of coal generator closures in the NEM. The 2024 GSOO applies the forecast closure schedules from the Draft 2024 ISP, which may bring forward retirements compared to the official closure years, to achieve emissions reduction objectives.

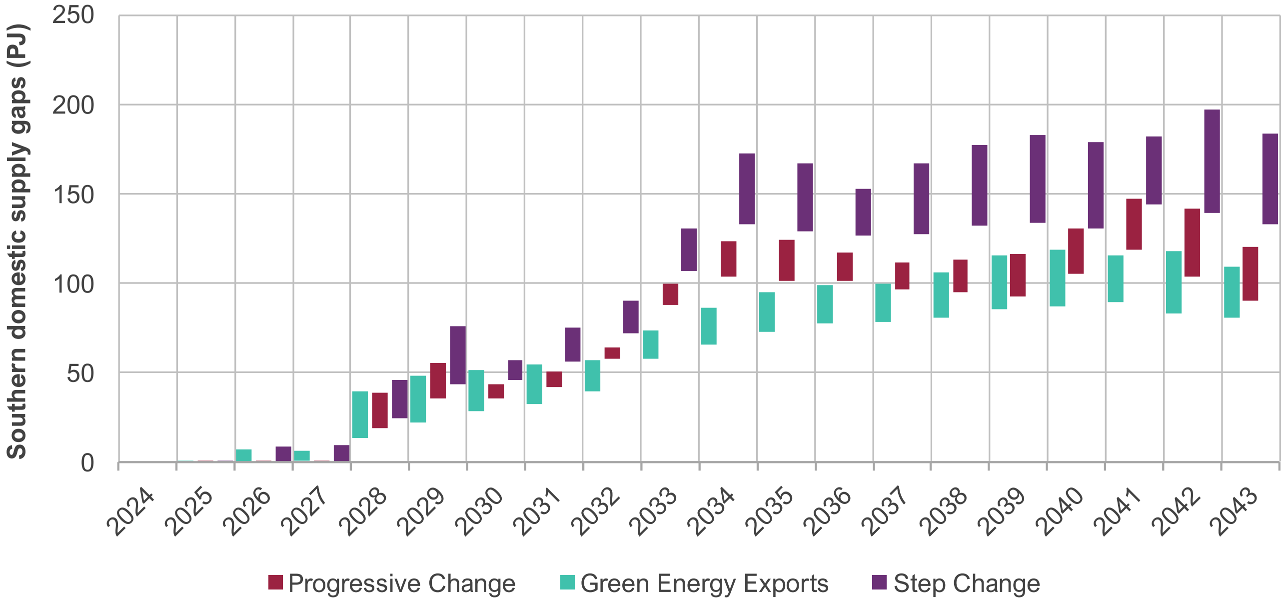
Figure 38 presents forecast domestic annual supply gaps in southern states across all scenarios. The range reflected in these outcomes results from the application of multiple weather patterns to seasonal variations in forecasting demand (including the forecasting of demand for GPG). The extreme peak demand referenced in Section 4.1.1 reflects the upper limit of this range. The forecast adequacy assessment includes all existing, committed and anticipated supply developments.

This annual adequacy assessment shows:

- Small seasonal supply gaps are forecast in 2026 and 2027, driven by an increase in forecast GPG demand. These supply gaps may be avoided if GPG requirements reduce (for example, if the NEM were to rely on alternate sources of generation, if GPG used secondary fuels, or if coal availability was higher than forecast in the Draft 2024 ISP).
- An annual supply gap, estimated at around 50 PJ/y, is forecast consistently between 2028 and 2032 in southern regions, demonstrating a structural need for more supply.
- This supply gap may increase to as much as 100-200 PJ/y from 2033 due to ongoing reductions in gas supply (see Section 3.2.2), particularly if GPG is forecast to be needed regularly in the NEM as further coal generation is forecast to retire and more loads are forecast to electrify, thereby increasing winter electrical loads (see Section 2.5.1).
- The range of forecast annual supply gaps is greater than in the 2023 GSOO, reflecting more variability in the highly weather-dependent forecast of GPG (see Section 2.5.2 – Weather variability).

[77] See https://www.energy.gov.au/news-media/news/energy-ministers-agree-final-package-stage-2-reliability-and-supply-adequacy-reforms.

Figure 38 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, all scenarios, 2024-43 (PJ)



Examining forecast supply gaps in the *Step Change* scenario in southern regions

Based on current production forecasts, **Figure 39** and **Figure 40** demonstrate the utilisation of existing, committed, and anticipated supplies to meet southern demand in 2025 and 2030 in the *Step Change* scenario. They show that:

- In 2025, AEMO forecasts indicate local gas production, imported northern supplies via the SWQP and use of storage facilities will likely meet forecast southern demand for most days of the year. During winter there remains a risk of shortfall if extreme peaks in demand occur. Outside of winter operations, any excess southern production not directed towards replenishing southern storages may be directed to flow northwards to support demand from northern regions.
- In 2030, AEMO forecasts indicate supply gaps during winter months, and smaller shortfalls are forecast outside of winter, as southern production is forecast to decline by approximately 60% compared to 2025, and there is not sufficient investment in flexible southern production or pipeline capacity to transport northern gas towards southern markets.

Figure 39 Forecast gas supply sources to meet southern daily demand, *Step Change* scenario, 2025 (TJ/d)

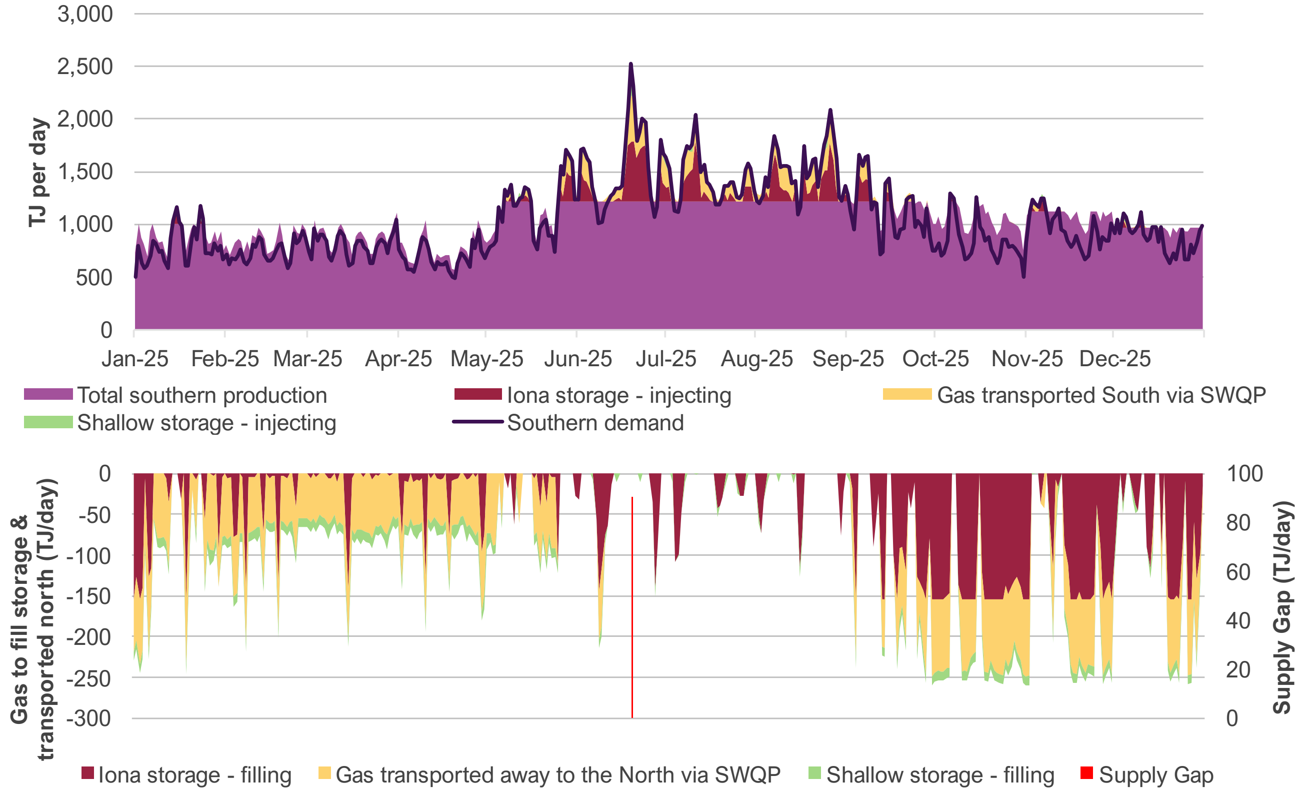


Figure 40 Forecast gas supply options to meet southern daily demand, *Step Change* scenario, 2030 (TJ/d)

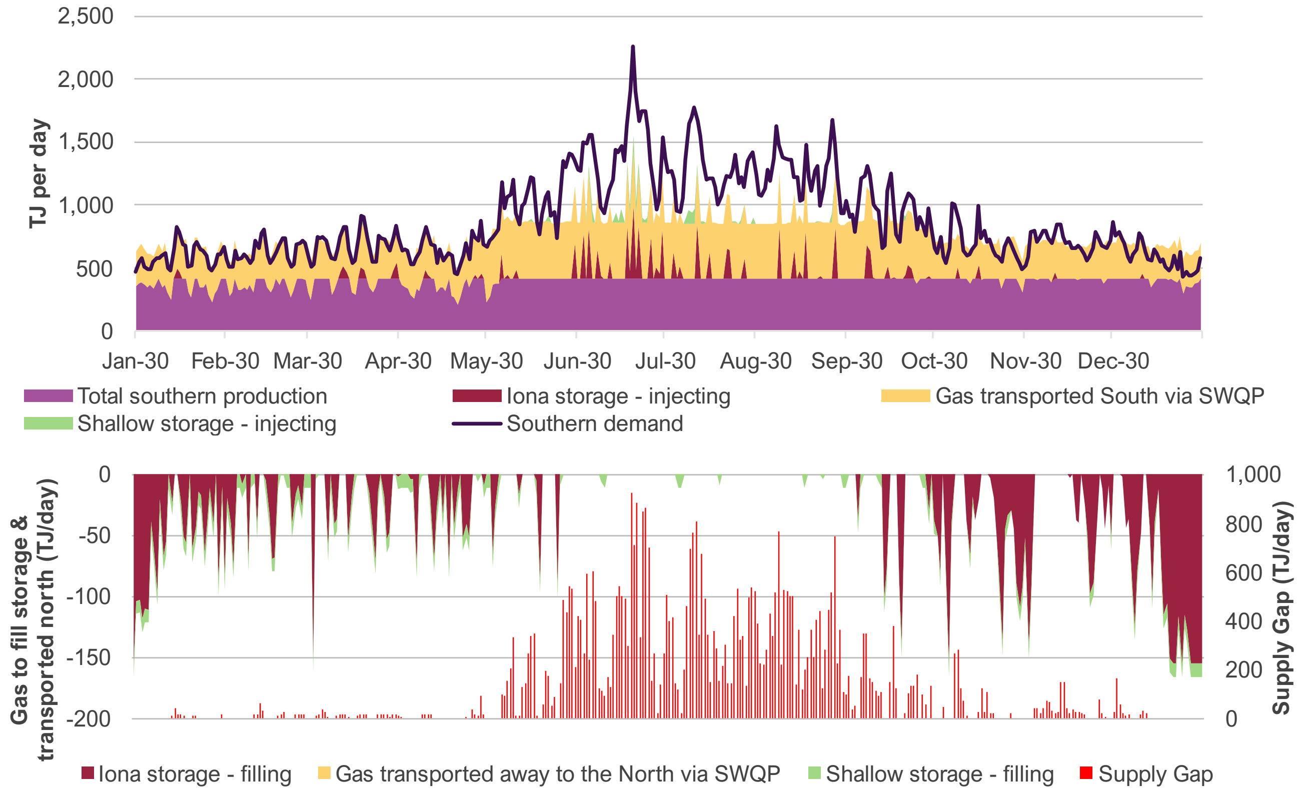
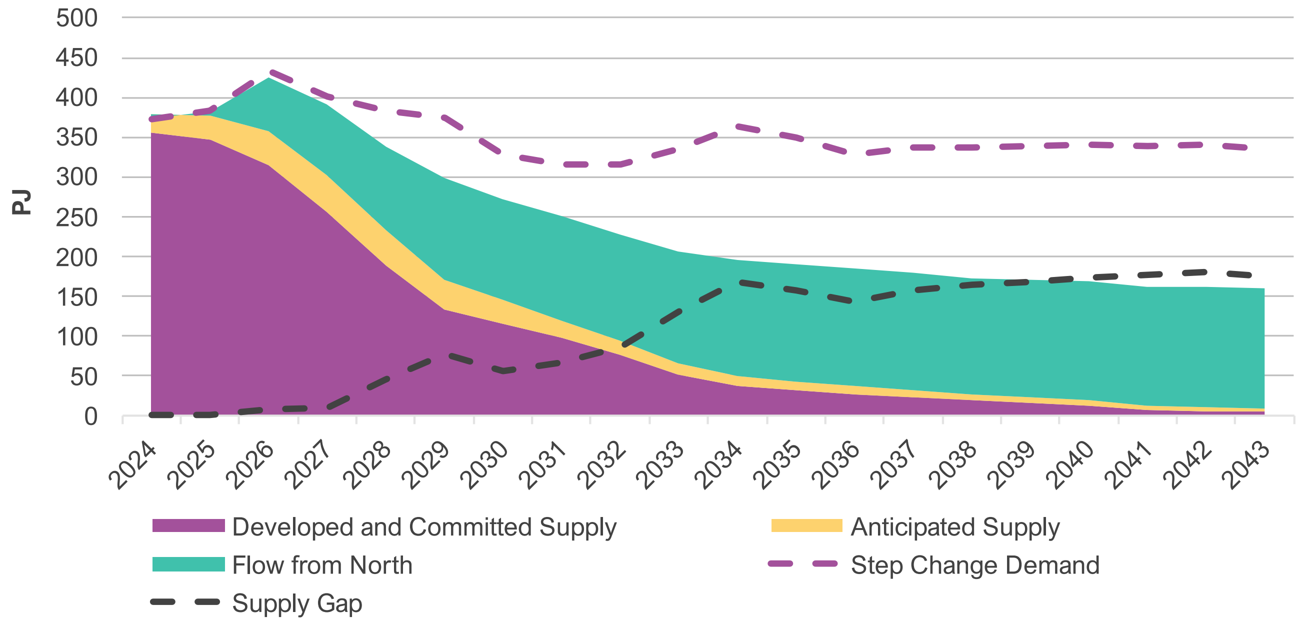


Figure 41 illustrates the growing forecast annual gas supply inadequacy with existing, committed, and anticipated supplies in the *Step Change* scenario.

Figure 41 Projected annual adequacy in southern regions, *Step Change* scenario, with existing, committed and anticipated developments, 2024-43 (PJ)



4.1.3 Adequacy under various market conditions

A range of market conditions and events may affect the volume of gas produced or consumed in the ECGM across the 20-year outlook period. These conditions and events are examined through a range of sensitivities impacting both the timing and magnitude of peak day shortfall and annual supply risks.

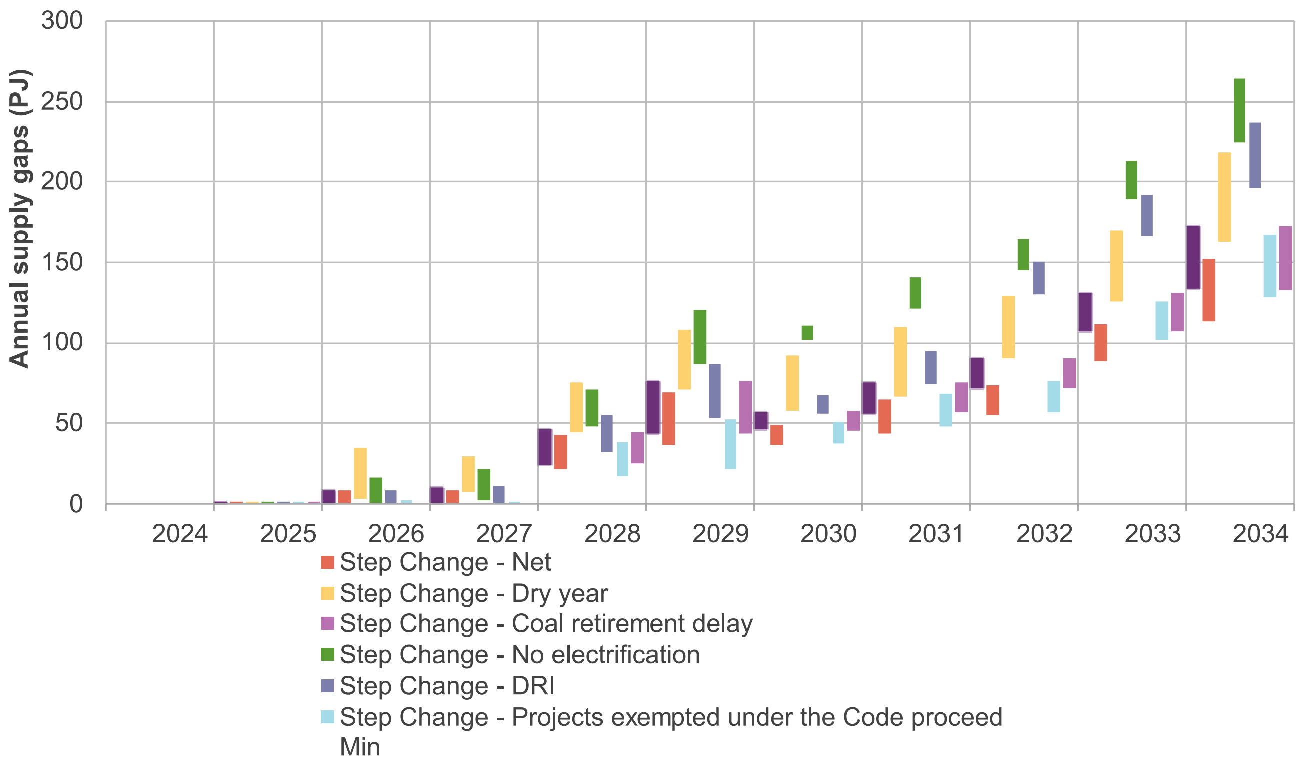
AEMO has assessed a range of plausible sensitivities built on the *Step Change* scenario and their impacts on southern annual adequacy, as shown in **Figure 42**:

1. ***Step Change – Net*** – assumes renewable gas developments are built to supply up to 30 PJ/y of renewable gas into the ECGM (as per the 2023 IASR), lowering the corresponding requirement for natural gas to supply all consumer gas demand. This sensitivity marginally reduces the magnitude of peak day shortfalls and annual supply gaps.
2. ***Step Change – No electrification*** – presents an unlikely future where no electrification occurs, either through market-driven investments or policy constraints on new connections, and results in a slower decline in gas consumption over the horizon. If electrification does not occur at the rate forecast, shortfall risks increase.
3. ***Step Change – Dry year*** – examines the effects of extended drought conditions akin to the water inflows from the 2006-07 millennial drought, which impacts the availability of hydro, and increases gas consumption for GPG. This increases peak day shortfall risks from 2026, and the magnitude of forecast supply gaps from 2027.
4. ***Step Change – Coal retirement delay*** – explores the possibility of a two-year delay in the retirement of Eraring coal power station, which reduces forecast GPG requirements particularly in 2026 and 2027 and delays annual supply gaps to 2028.

5. ***Step Change – DRI*** – examines the effects of steel manufacturers converting to a DRI steelmaking process using natural gas instead of coal, increasing industrial gas demand by up to 80 PJ per annum from 2028 to 2032 (see Section 2.2.2). The magnitude of forecast annual supply gaps during this period is higher than in *Step Change*.
6. ***Step Change – Projects conditionally exempted under the Code proceed*** – explores the impact of all supply exempted under the Code being developed at the timing indicated by proponents.
   - At the time of writing, the Federal Government has provided conditional exemptions under the Code to APLNG and Senex[78], Esso and Woodside[79] for a total of 564 PJ of potential new domestic gas supply to 2033. The exemptions apply to projects that are yet to progress to a final investment decision, as well as referring to some supply that are already classified by AEMO in the 2024 GSOO as anticipated. In total, the majority of the additional gas expected to be provided by the Code exemptions is already considered in the gas adequacy analysis presented in Section 4.1.
   - The Code may help accelerate development of anticipated and uncertain projects moving them closer towards achieving FID. If projects conditionally exempted under the Code proceed, annual supply gaps are forecast to be delayed by two years to 2028, and the magnitude of peak day shortfall risks is reduced (but not eliminated).

Further information on demand sensitivities can be found in Chapter 2.

Figure 42 Forecast annual supply gaps for *Step Change* and other sensitivities, 2024-34 (PJ)



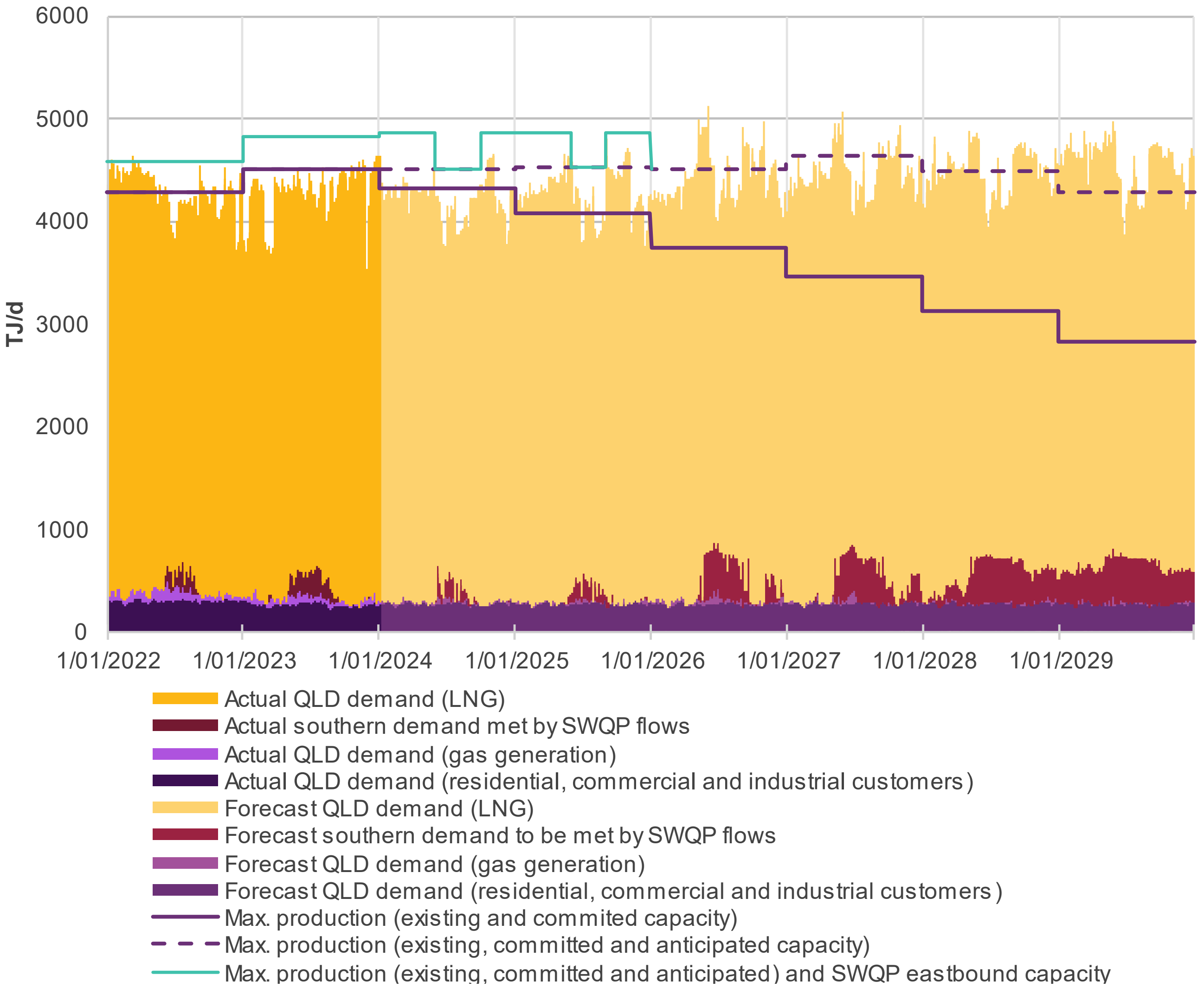
78 See https://www.minister.industry.gov.au/ministers/king/media-releases/joint-media-release-gas-code-secures-supply-domestic-market.

79 See https://www.minister.industry.gov.au/ministers/king/media-releases/gas-market-code-secures-supply-domestic-market.

4.2 Northern supply adequacy

Current projections indicate anticipated northern supplies will need to be developed from 2025, and uncertain supplies from 2026, to meet LNG export demand, northern domestic demand, and to support southern demand via flows on the SWQP. **Figure 43** shows the actual and projected supply and demand of Queensland gas from 2022 to 2029 under *Step Change*.

Figure 43 Actual and forecast Queensland gas demand and supply, including existing, committed and anticipated projects, and flows along the SWQP, 2022-29, *Step Change* (TJ/d)

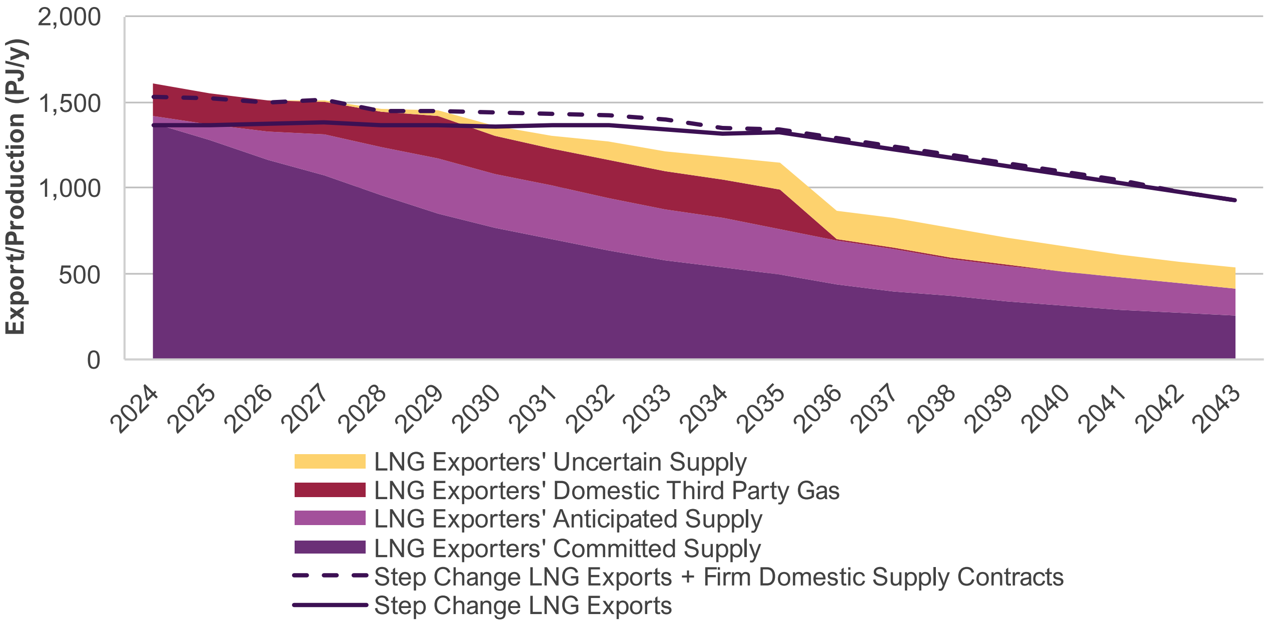


In the northern regions, the majority of gas is produced to supply LNG export demand. Operation of LNG facilities will need to be flexibly managed to avoid high drawdown from the gas network at the same time as peak domestic demand, particularly over the winter season. While northern domestic demand displays little seasonality, gas flows along the SWQP towards southern regions are typically higher over winter as higher consumption occurs in southern regions. Gas flowing towards northern regions along the SWQP is forecast to cease from 2026, so the requirement to access more anticipated northern supply increases.

Figure 44 focusses only on LNG producers' supply and demand balance, showing their production, third-party gas, expected export contracts and firm domestic supply commitments.

It shows that the LNG exporters have committed to firm contracts to supply substantial volumes of gas domestically in the near term. LNG producers' existing and committed developments, and domestically sourced third-party supply, can meet these contractual obligations until 2025, and may have a relatively small surplus of committed production in 2024.

Figure 44 LNG exporters' committed, anticipated and uncertain production and domestic third-party gas in comparison to forecast exports and firm domestic supply contracts, *Step Change* scenario, 2023-43 (PJ/y)



Reliance on alternative and interim gas arrangements may persist in the Northern Territory

Supply from the Blacktip field in the Northern Territory reduced during 2023 and it is currently unknown when production may be restored to previous levels. If supply cannot be restored, Power and Water Corporation (PWC), which manages large wholesale gas supply and transportation, may need to continue to purchase gas from Darwin LNG exporters[80] in the near term, and make arrangements for alternative sources of supply in the longer term.

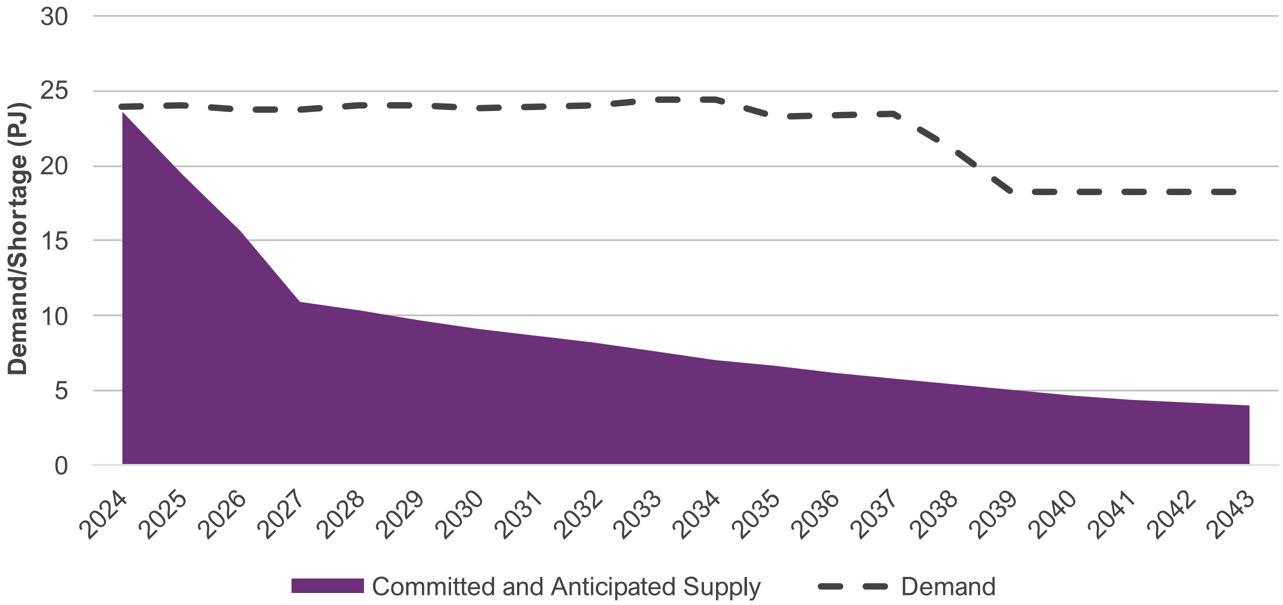
The 2024 GSOO considers supply adequacy for Northern Territory domestic customers and does not include adequacy of exported gas exported through Darwin LNG. Northern Territory customers are effectively islanded. The Northern Gas Pipeline (NGP) which transports gas eastward to Mount Isa from the Northern Territory is currently not flowing, and this GSOO does not forecast the resumption of these flows. Mount Isa is currently supplied from east coast suppliers via the CGP which reduces the gas available to southern markets, both seasonally to replenish storages, and for critical supply under peak demand conditions.

[80] Detail on this arrangement can be found at https://www.aemc.gov.au/sites/default/files/2019-08/Information%20sheet.pdf.

When in operation, the NGP is designed to flow from the Northern Territory to Queensland, and is not bi-directional, which means that the Northern Territory currently has no access to inflows of gas from the ECGM. To manage the risk of insufficient gas supply to Northern Territory customers, Jemena and PWC are investigating the possibility of modifying the NGP to support flow from Queensland into the Northern Territory at a capacity of up to 60 TJ/d. This project is still in its early stages, but it is possible that reverse flow capability could be available from mid-2024. It is expected that Queensland supply will only be accessed when other gas supply from Northern Territory producers is unavailable.

Figure 45 shows the supply gap in the Northern Territory that may be required to be filled by the emergency gas supply arrangements or alternative sources during the period to 2043.

Figure 45 Forecast annual demand and shortage in the Northern Territory, *Step Change*, 2024-43 (PJ)



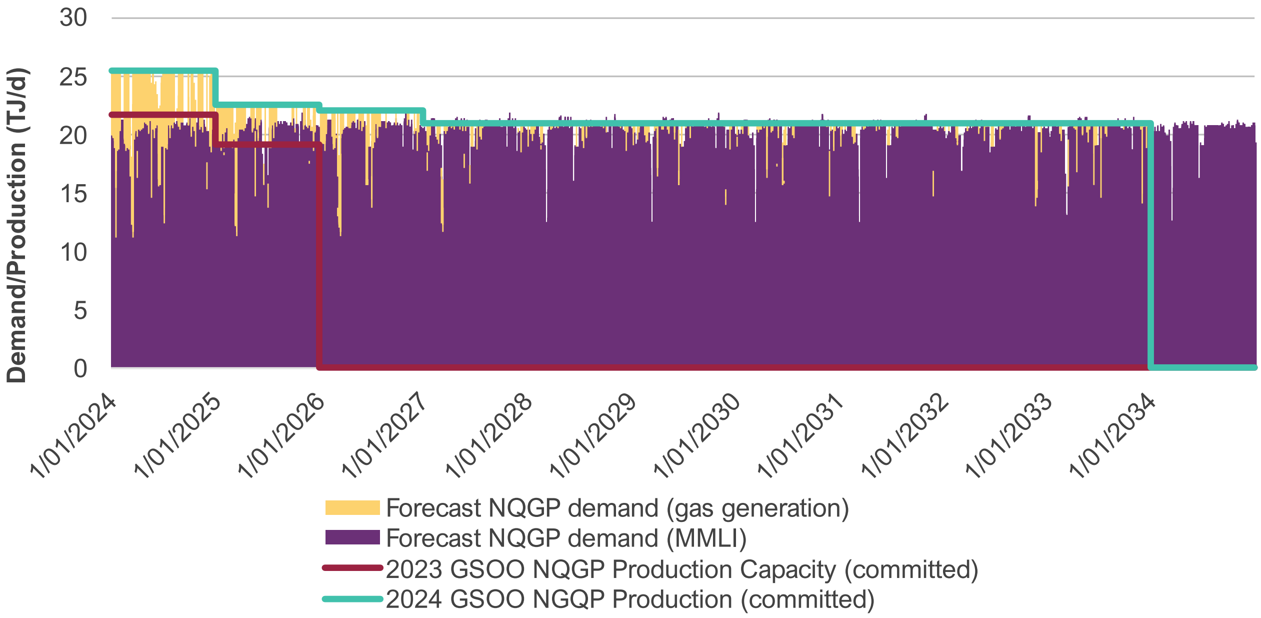
Supply forecasts for the Northern Queensland region have improved but supply to GPG may be limited

The 2023 GSOO reported that limited gas supply was forecast to be available to the North Queensland Gas Pipeline (NQGP), and that anticipated and uncertain supply must be developed prior to late 2024 to maintain supply to gas consumers in the Northern Queensland area. Since then, firm commitments have been made by producers to supply residential, commercial and industrial customers until 2034, which have been included in this GSOO's production forecast as committed supply. Despite this, as shown in **Figure 46**, AEMO forecasts that:

- This new committed supply may not be sufficient to supply residential, commercial and industrial customers on all days out to 2034. Demand is forecast to be at risk of exceeding supply capacity from 2027, even without material operation of GPG. There is currently no anticipated production available to supply the NQGP, so the development of more uncertain supply is required from 2027 to avoid shortfalls.
- There is limited gas supply to meet GPG consumption on the NQGP across the entire horizon. The Draft 2024 ISP forecasts the Townsville gas generator, supplied by the NQGP, will remain in operation beyond the

GSOO's forecasting horizon. Alternative electricity generation sources exist in North Queensland, and the *Queensland Energy and Jobs Plan*[81] identifies further development opportunities in the region.

Figure 46 Forecast supply and demand on the NQGP for the *Step Change* scenario, comparison production between the 2023 and 2024 GSOOs (TJ/d)



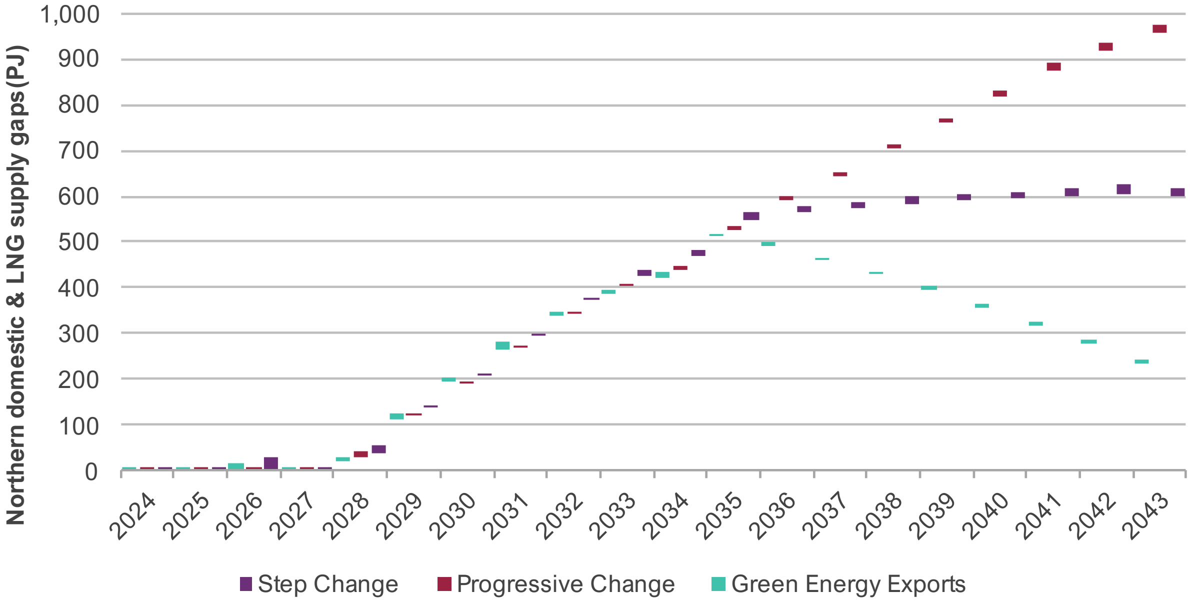
New supply is required in the north to address forecast annual supply gaps

To address annual supply gaps, new northern supply above what is considered committed and anticipated is required to be developed from 2026. In the longer term, as **Figure 47** shows, substantial annual supply gaps are forecast in Queensland as forecast production declines.

Pipeline augmentations, plant expansions, field or basin expansions, or the development of flexible injection capacity (such as storage), may need to be developed in Queensland from the mid-2030s to address emerging local transportation constraints affecting GPG.

[81] See https://www.epw.qld.gov.au/energyandjobsplan.

Figure 47 Forecast domestic and LNG annual supply gaps in Queensland, assuming that gas is made available to southern customers from northern producers and LNG producers as required, 2024-43 (PJ)



5 Options to address forecast supply challenges

As identified in Chapter 4, the market requires solutions to be found to address the risk of gas supply shortfalls during peak periods, and to address annual supply gaps. The options currently under consideration by market participants include transportation developments, LNG import terminals, new domestic gas supply sources (including renewable gases), and gas storages. A combination of these options is likely to be required to address supply issues during the period to 2043.

As part of AEMO's assessment of supply and pipeline capacity to meet existing and foreseeable demand, this chapter provides preliminary *what if* analyses of potential future supply, transportation, and storage developments currently being explored by market participants. The options are not exhaustive and are intended to assess the effectiveness of various options to address forecast supply challenges. This analysis does not consider all factors such as costs, regulatory approvals, land use, social license, safety, or operational challenges of each option, and does not amount to a recommendation or representation regarding any projects or investments. As each assessed project is not committed or confirmed, the technical specifications reflect AEMO's best understanding of each project, informed by GSOO Survey information where available. These details may change as each proponent progresses each project.

Key insights

- **AEMO modelling indicates a range of supply and infrastructure options will delay annual supply gaps and help to mitigate the risk of peak day shortfalls, particularly when paired with increased storage capacity.**
- A portfolio of solutions is likely to be required in the long term to address the risks identified in Chapter 4, including:
  - **Upgrades and expansions of existing pipelines** that may delay annual gaps to 2029 but will require additional solutions to increase supply and provide peak day flexibility.
  - **Uncertain 2C southern supply and renewable gas projects** that may delay annual supply gaps to 2033 and help mitigate peak day shortfall risks.
  - **LNG import terminal(s)** which may require associated pipeline infrastructure depending on the terminal may delay supply gaps until 2033 and help mitigate peak day shortfall risks, depending on the availability of LNG cargoes.
  - **Increased storage** to cater for peak seasonal loads is likely a good complement to all other developments. Demand response mechanisms may also mitigate peak supply shortfall risks.
- In total, up to 7,000 PJ of new northern supply above committed and anticipated projects is expected to be required during the period to 2043 to meet forecast LNG exports and domestic demand.
- Investments in infrastructure from the mid-2030s are highly dependent on the volume and rate at which gas is required for GPG as forecast in Section 2.5.

5.1 Potential future supply, transportation, and storage projects

The supply, transportation and storage projects considered in this section have been proposed but are not sufficiently progressed to be classified as 'committed' or 'anticipated' and are therefore not included in the gas adequacy assessments in Chapter 4. The assessments in this chapter provide an indication of the impact of several uncertain projects on addressing the gas adequacy risks identified across the GSOO horizon.

Table 11 details the challenges highlighted in Chapter 4 and explores the types of solutions that may be effective at resolving them.

Table 11 2024 GSOO supply challenges and options for resolving them

Supply challenge	Types of options assessed
Annual and seasonal supply gaps	Annual supply gaps require **new supply** to be developed to provide sufficient volumes of gas domestically and for export: • Southern supply options include LNG import terminals, increased southern supply, infrastructure to transport gas produced in northern regions, or renewable gas projects. • Northern supply options include expansions or new supply from fields in the Surat and Bowen basins, or from new basins such as the Beetaloo sub-basin, the South Galilee or North Bowen basins, or from renewable gas projects. Seasonal supply gaps require **new flexible capacity** to support increased southern winter demand for heating and GPG. This may be addressed through a number of options, including: • New deep storage(s) in the south. • Upgrades to existing southern storage(s). • Import terminal(s) operated during winter. • Increased north to south pipeline capacity.
Daily or multi-day peak day shortfalls	**Increased injection capacity** is required to satisfy extreme daily peaks in demand. This risk is most observed in southern regions. For southern customers this supply challenge may be addressed by providing new southern supply and/or increased north-to-south pipeline transportation capacity. For a pipeline solution to be effective, progressively more northern supply would be required. Depending on the magnitude of gas demand peaks and the capacity for injection from either solution, southern storages may still be needed to adequately resolve peak day shortfall risks. Options therefore include: • New or expansion of existing storage(s), including shallow and deep facilities. • Onsite storage at gas generators to reduce withdrawal rates from the gas system at peak times. • Pipeline augmentations, including reversals of existing infrastructure to increase transportation flexibility. • Import terminal(s) to provide both additional supply and injection capacity. • Demand-side management mechanisms to reduce peak day demand.

Northern supply

Northern regions hold the most substantial reserves and resources, as described in Section 3.2.1. New Northern supply from projects currently classified as uncertain is required in all options assessed, and may include expansions within existing basins, or developments in new basins such as the Beetaloo sub-basin, South Galilee, or North Bowen basins.

The level of regional infrastructure investment required will depend on the proximity of the developments to existing processing and transportation infrastructure. The capacity to bring this gas south will also become more constrained by the capacity available along existing pipeline corridors (SWQP, MSP and MAPS).

North to south pipeline capacity

Increased north to south pipeline capacity provides southern demand centres with improved access to northern gas production, including existing, committed, anticipated and as yet undeveloped uncertain production (see Section 3.2.1). APA's ECGE Stage 3a, 3b and 4 expansions of the SWQP and MSP (see Section 3.3.1) continue to be identified as development opportunities. Additional pipeline capacity would provide improved capability to transport gas south throughout the year and may be complimented by reversals to the PCA and EGP pipelines, to provide increased peak day transportation capacity to the major load centre of Victoria.

Southern supply and renewable gas opportunities

Southern (2C) contingent resources are known accumulations of gas that are not currently considered commercially recoverable. Projects are included in the Gunnedah, Otway, Gippsland, Cooper and Bass basins.

Based on information submitted to AEMO in the 2024 GSOO surveys, producers may increase supply from 2C resources to 200 PJ/y by 2031, before supply starts declining to around 100 PJ/y by the end of the GSOO horizon in 2043[82]. Each of these uncertain 2C projects face a unique set of challenges including requirements for additional gas processing capacity and pipeline infrastructure to reach full delivery potential.

Renewable gas refers to biomethane[83], or hydrogen produced via electrolysis using renewable energy resources. The 2024 GSOO[84] includes current and future supply from a small number of existing or committed renewable gas projects. These include Jemena's Malabar biomethane project[85], Fortescue's Gladstone PEM50 project[86], and AGIG's Hydrogen Park South Australia[87], Hydrogen Park Gladstone[88] and Hydrogen Park Murray Valley[89] projects.

The development of many of the proposed but uncertain renewable gas supply projects identified to AEMO in the 2024 GSOO surveys is subject to a range of economic, regulatory and technical uncertainties (see Section 4.3 of the 2024 VGPR Update). The timing and volumes of gas available from renewable sources is therefore challenging to forecast. AEMO estimates annual volumes of renewable gas available from reported projects above those existing and committed may be up to 30 PJ/y by 2031, depending on the timing of these development opportunities.

Opportunities for renewable gas are likely to rise in future, which may stimulate more identified resources. The Federal Government is reviewing its National Hydrogen Strategy[90], and some state governments are considering establishment of a Renewable Gas Target coupled with the nationwide biomethane certification program[91]. State

[82] These production rates and timing reflect advice received from project proponents, but are subject to development timing, and further appraisal and feasibility studies. The rate of production and timing of decline from these resources is dependent on the rate of extraction from reservoirs, which is uncertain and may change.

[83] Biomethane is produced by the anaerobic decomposition of organic matter, and can be produced from multiple feedstocks, including agricultural and municipal waste streams, wastewater treatment facilities and forestry residues.

[84] Survey responses are provided voluntarily so additional renewable gas production facilities may be in operation or under development. For the 2025 GSOO, renewable gas projects will be obligated to provide forecasts for expected current and future production.

[85] See https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/.

[86] See https://fortescue.com/what-we-do/our-projects/gladstone-pem50-project.

[87] See https://www.agig.com.au/hydrogen-park-south-australia.

[88] See https://www.agig.com.au/hydrogen-park-gladstone.

[89] See https://www.agig.com.au/hydrogen-park-murray-valley.

[90] See https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf.

[91] See https://www.greenpower.gov.au/about-greenpower/renewable-gas-certification-pilot/about-pilot.

governments have developed hydrogen strategies and plans, which are designed to develop the industry and encourage further investment in commercialisation. These include the South Australia Hydrogen Jobs Plan, the Queensland Energy and Jobs Plan, New South Wales Hydrogen Hubs and Renewable Fuels Scheme, and Victoria's Gas Substitution Roadmap.

LNG import terminals

LNG import terminal projects are at various stages of development close to southern demand centres (at Port Kembla, Adelaide and Geelong, see Section 3.3.4). LNG import terminals would provide significant peak day injection capability and could be operated seasonally during winter months when supply would be more available due to the northern hemisphere summer. During summer months when there is less demand for imported LNG, FSRUs could either continue to supply domestic consumers or be relocated to service alternative worldwide locations.

Import terminals will rely on existing or new pipeline infrastructure to enable delivery of supply and injection capacity to domestic consumers. This varies for each proposed development:

- **PKET** – Jemena plans to modify the EGP to enable bidirectional flow (providing north to south flow capability), and future expansion options exist to increase compression to increase transport capacity, subject to market requirements.
- **Venice's Outer Harbour LNG import terminal** – SEA Gas and Venice Energy have confirmed that the PCA can be reconfigured to support bidirectional flows from South Australia towards Victoria[92].
- **Viva** and/or **Vopak developments** – an increase in the capacity of the SWP would allow increased coincident injections from an LNG import terminal in Geelong and production facilities in Port Campbell (see Section 4.2 of the 2024 VGPR Update for further information), however there are currently no active development plans for this pipeline.

Storage

Gas storage capacity increases operational flexibility by providing load shifting of gas produced during summer to be used in winter when demand is higher. The ECGM currently relies on both deep and shallow storages to store gas and provide it when required during high demand periods.

There are two storage projects in close proximity to southern load centres currently under consideration for development – the Golden Beach Storage Project and the Heytesbury Underground Gas Storage (HUGS) project upgrading the Iona UGS facility (see Section 3.3.2).

Gas storage capacity requirements are uncertain in the longer term. As demonstrated in Chapter 2 and Chapter 4, gas demand for residential and commercial customers is more variable on a daily basis and more uncertain seasonally.

The 2024 Draft ISP forecasts that GPG will complement renewable generation sources and electricity storages to support electricity consumers during peak demand periods and when renewable resources are less available. This may lead to potentially significant peaks in gas demand, which increases the need for some form of additional gas

[92] See https://veniceenergy.com/2023/05/04/marketing-in-a-crowded-market/.

storage capacity. Pipelines (via linepack) and LNG import terminals (via the FSRU) provide storage capacity that can improve operational flexibility but do not represent a firm storage solution comparable to dedicated deep or shallow storage solutions (including on-site storage options at gas generators).

5.2 All options delay and reduce annual supply gaps and peak day shortfalls

AEMO has assessed a range of development options currently under consideration by gas market participants to address potential future supply challenges.

The options presented in **Table 12** and shown in **Figure 48** have been modelled individually, but no single solution is forecast to be sufficient to resolve all forecast annual and seasonal supply gaps, and fully address the risk of daily peak shortfalls during the period to 2043.

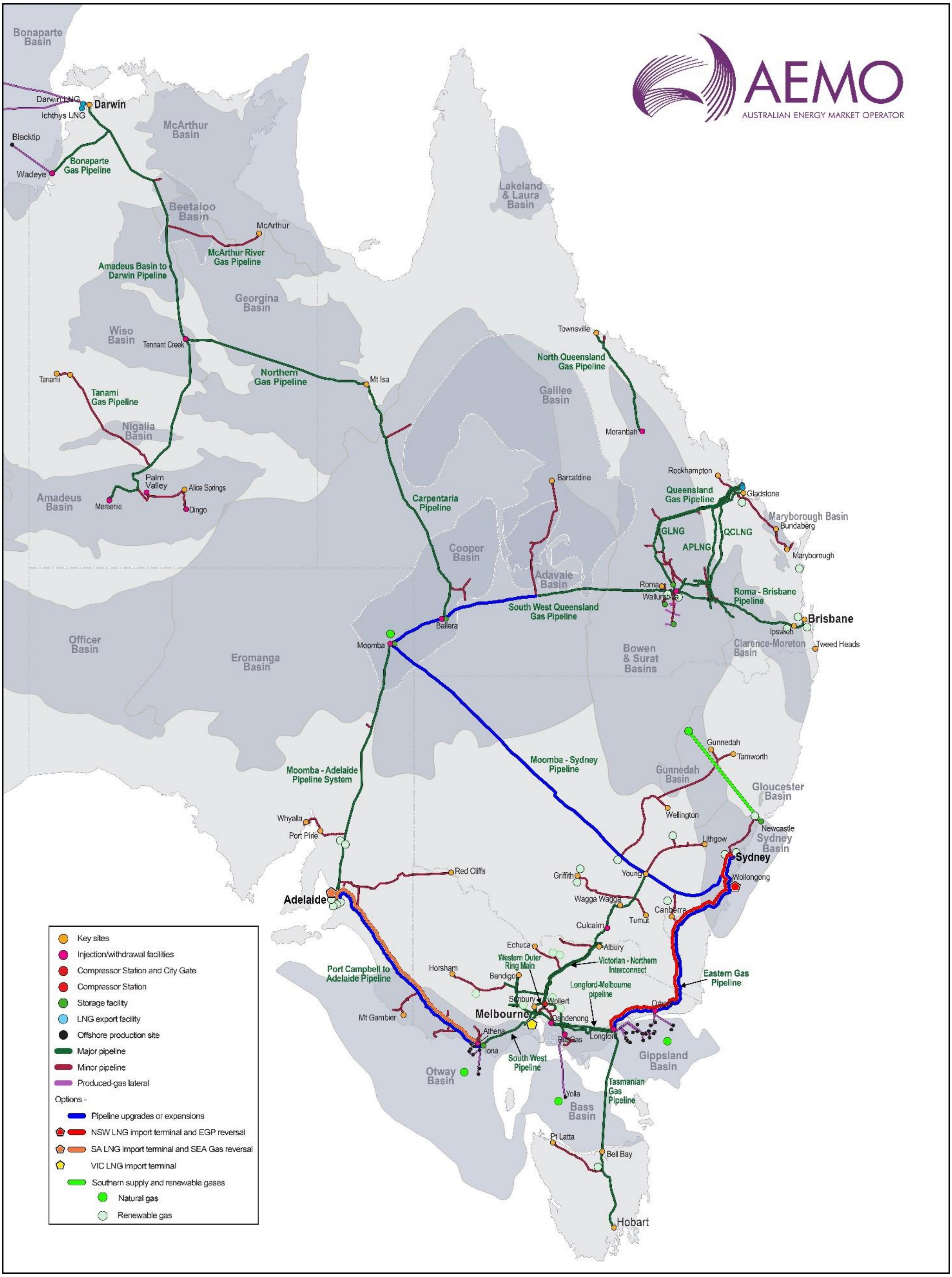
This assessment does not represent a ‘best’ or ‘most economic’ assessment of the options. Each project is presented individually with associated downstream pipeline augmentations currently reported to be under active consideration by market participants in 2024 GSOO surveys.

Table 12 Future supply, transportation and storage options assessed, and key results

Option name	New southern supply		Transportation capacity (if relevant)		Southern annual supply gaps delayed until	Optimal storage depth (PJ)[A]	Northern Supply (PJ/y)[B]
	Detail	Capacity	Detail	Capacity			
LNG import terminal	NSW (Port Kembla) from 2026	500 TJ/d, 130 PJ/y	EGP reversal Stages 1 and 2	Stage 1: 2026 – 200 TJ/d Stage 2: 2027 – 325 TJ/d	2033	35 PJ	Increasing to ~600 PJ/y from mid-2030s
	SA (Outer Harbour) from 2026	446 TJ/d, 110 PJ/y	PCA pipeline reversal, from 2026	250 TJ/d			
	VIC (Geelong[C]) from 2027	620 - 778 TJ/d, 140 - 270 PJ/y	None modelled[D]	N/A			
Pipeline expansions and upgrades	None	N/A	ECGE Stages 3a, 3b and 4	615 TJ/d SWQP, 657 TJ/d MSP in 2027	2029	50 PJ	Increasing to ~670 PJ/y from mid-2030s
			EGP reversal Stages 1 and 2	2026 – 200 TJ/d, 2027 – 325 TJ/d			
			PCA reversal from 2026	250 TJ/d			
Southern supply and renewable gases	2C southern supply, from 2028	Ramping to 200 PJ/y by 2030, then 100 PJ/y in the long term	Hunter Gas Pipeline (Narrabri to Newcastle) – by 2028	200 TJ/d	2033	35 PJ	Increasing to ~560 PJ/y from mid-2030s
	Renewable Gases	Ramping to 31 PJ/y by 2031					

H. New storage capacity is forecast to be needed to address seasonal adequacy challenges. The figures in this column represent the storage depth required to meet seasonal winter demand before annual supply gaps emerge.
I. New northern supply is developed as required to service northern (including LNG exports) and southern markets. It is assumed new pipelines or pipeline expansions will be developed to connect this new supply to existing northern pipelines.
J. This could be either Viva's or Vopak's proposed LNG import terminal project.
K. Although none are modelled here, Section 4.2 of the 2024 VGPR Update presents a number of potential options for increasing the capacity of the SWP, including extra compression and pipeline looping.

Figure 48 Map of future supply, transportation and storage options assessed



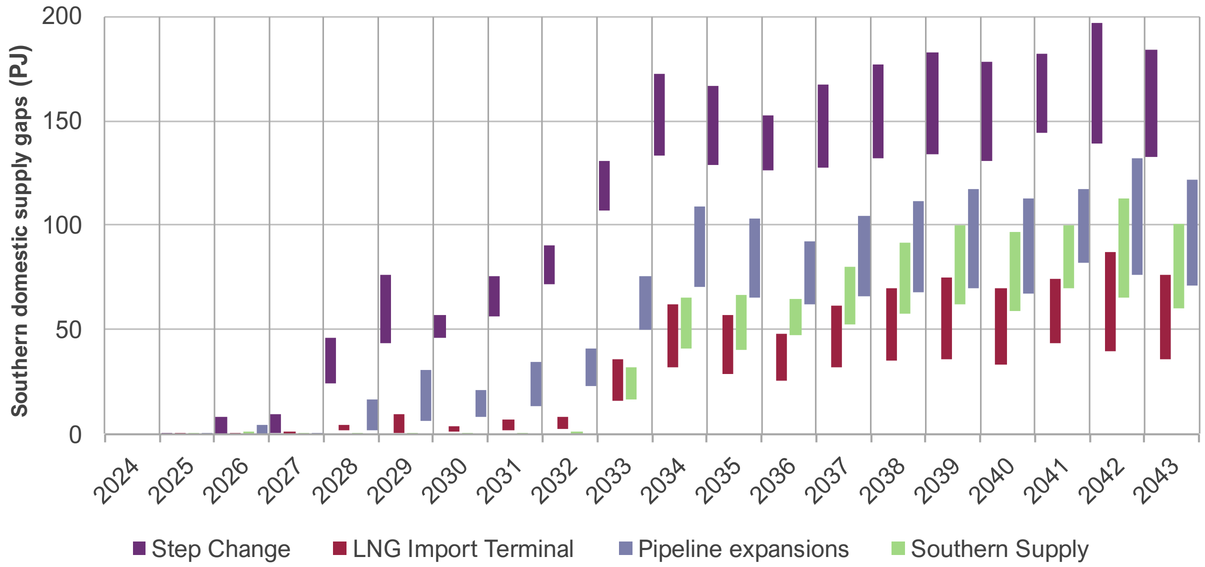
Annual supply gaps are reduced and delayed by all options assessed

Figure 49 shows the range of southern annual supply gaps forecast for the options assessed in Table 12, when only the new southern supply and transportation capacity increases are considered. The figure presents forecast gas adequacy without development of additional storage which may further mitigate these gaps if developed.

Annual supply gaps are delayed but are forecast to persist throughout the horizon for all options assessed without optimised storage build. Small annual supply gaps are forecast to emerge between 2028 and 2032 in the LNG Import Terminal option. The Pipeline Expansions and Upgrades option addresses annual supply gap concerns in 2027, though risks emerge again in 2028. Unsurprisingly, local production that increases southern supply capacity is forecast to be more effective, delaying southern annual supply gaps until 2033.

From 2033 onwards annual supply gaps increase across all options substantially, coinciding with a steep increase in forecast gas consumption for GPG.

Figure 49 Range of annual supply gaps for future supply options assessed in comparison to the *Step Change* scenario, without optimal storage build, 2024-43 (PJ)



Peak day shortfall risks are reduced by all options

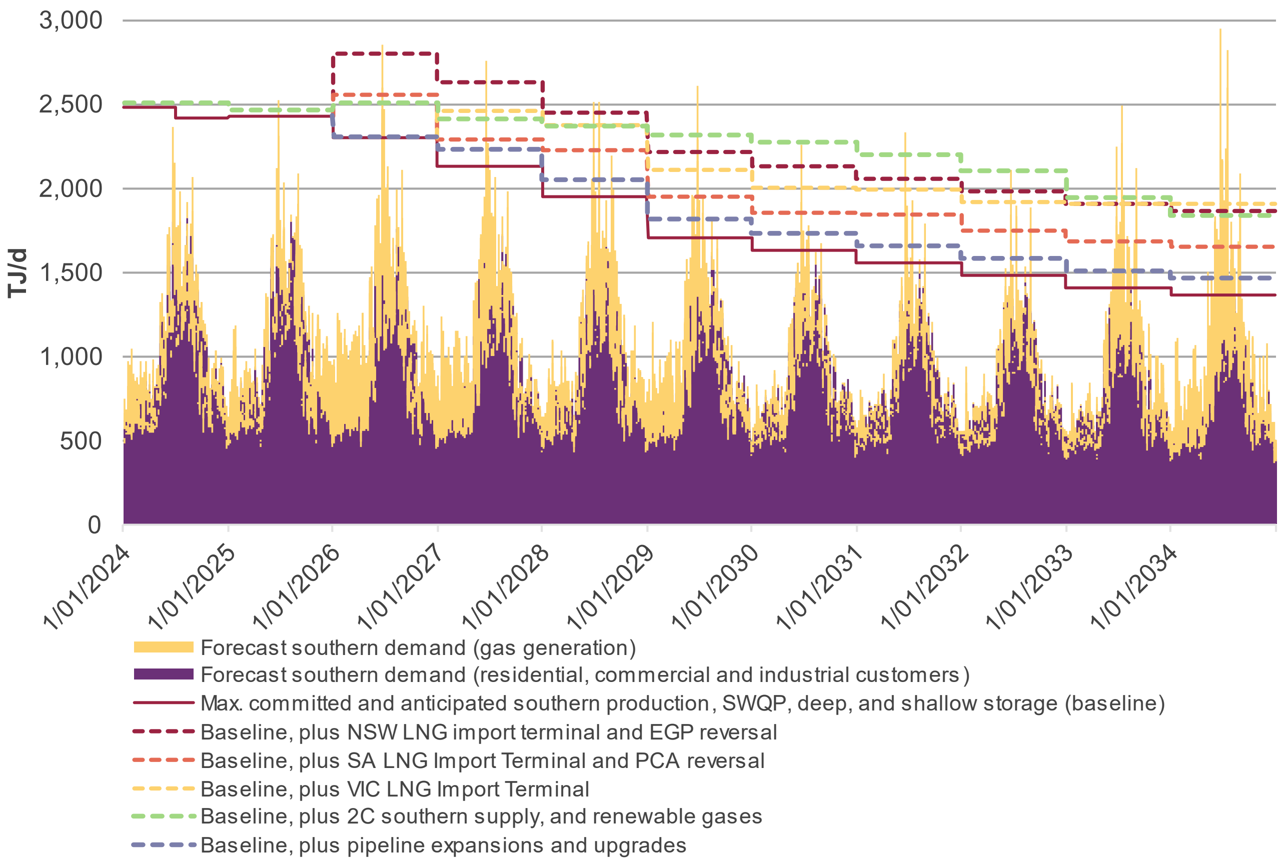
The New South Wales LNG import terminal and Southern Supply options are most effective at mitigating the risk of peak day shortfalls. **Figure 50** shows that all options assessed are effective in reducing peak day shortfall risks during the period to 2032. Each LNG import terminal is shown separately in this figure, given that they are capable of providing different volumes of peak day capacity to demand centres. The Victoria and South Australia LNG import terminal options offer reduced effectiveness to mitigate against peak day shortfall risks, due to:

- The South Australian LNG import terminal sits behind the SWP in Victoria. The SWP reaches its pipeline capacity on peak demand days, limiting the delivery capacity of the South Australian LNG import terminal during peak periods.
- The Victorian LNG import terminal, Iona and Port Campbell production facilities inject into the SWP. When this pipeline is constrained, it is not possible for all injection sources to inject at maximum capacity simultaneously.

Although not included in the assessment presented here, capacity augmentations that would increase SWP transport capacity and market flexibility in the event of a South Australian or Victorian LNG import terminal connecting are explored in Section 4.2 of the 2024 VGPR Update.

When considered in isolation of any other options assessed, the Pipeline Expansions and Upgrades option increases peak day supply capacity by approximately 100 TJ/d.

Figure 50 Forecast southern daily adequacy for each of the future options assessed, without optimal storage build, 2023-35 (TJ/d)



Notes:

- The difference between each line and the baseline represents the peak day capacity added over and above existing peak day capacity.
- The additional peak day capacity provided by the SA LNG import terminal and PCA reversal, and by the VIC LNG import terminal is dependent on several factors, including South Australian and Victorian demand on peak demand days and available production capacity at other facilities. The values presented in this figure are an estimate only.

While the risk of daily shortfalls under extreme peak demand conditions is reduced, additional investments above those assessed are needed to address the risk of daily peak supply shortfalls from 2025. The requirement for investment in peak day capacity increases dramatically from 2033 and could be delivered by a combination of the options assessed, new capacity from storage or gas plants in the south, or new pipelines which could provide alternative north to south transportation.

Demand reduction measures, including alternative on-site fuel sources for gas generation, may also assist in mitigating peak-day gas shortfall risks.

5.3 Significant new northern supply is required in all options assessed

Significant new northern supply is required across all options assessed to support forecast LNG export demand, and domestic consumption in northern (including the Northern Territory) and southern load centres. The southern region is forecast to rely heavily on gas supplied from northern fields via the SWQP in all options.

The scale of northern gas forecast to be required is heavily influenced by forecast LNG exports. The supply required above committed and anticipated volumes is forecast to increase to approximately 600 PJ/y from the mid-2030s. Some variation in the required amount of northern supply exists as southern demand is met to a varying extent by northern supply (that is, options which include more southern supply require less from the north via the SWQP), as shown in Table 12).

Current LNG export contracts are due to expire during the mid-2030s, meaning the level of residual demand following that period for exports is highly uncertain. The continuation of LNG exports, and the magnitude of support that northern LNG producers can offer to domestic consumers, will be largely dependent on the development of supply volumes subject to renewed export contracts.

In total, the 2024 GSOO indicates approximately 7,000 PJ of extra northern gas (above what AEMO considers committed and anticipated) will be required during the period to 2043. The uncertain supply developments reported to AEMO via 2024 GSOO survey responses is nearly equivalent to this requirement. Further exploration, development and appraisal in northern regions is likely to be required to prove and commercialise reserves and resources.

5.4 Increased storage capacity is critical in all options

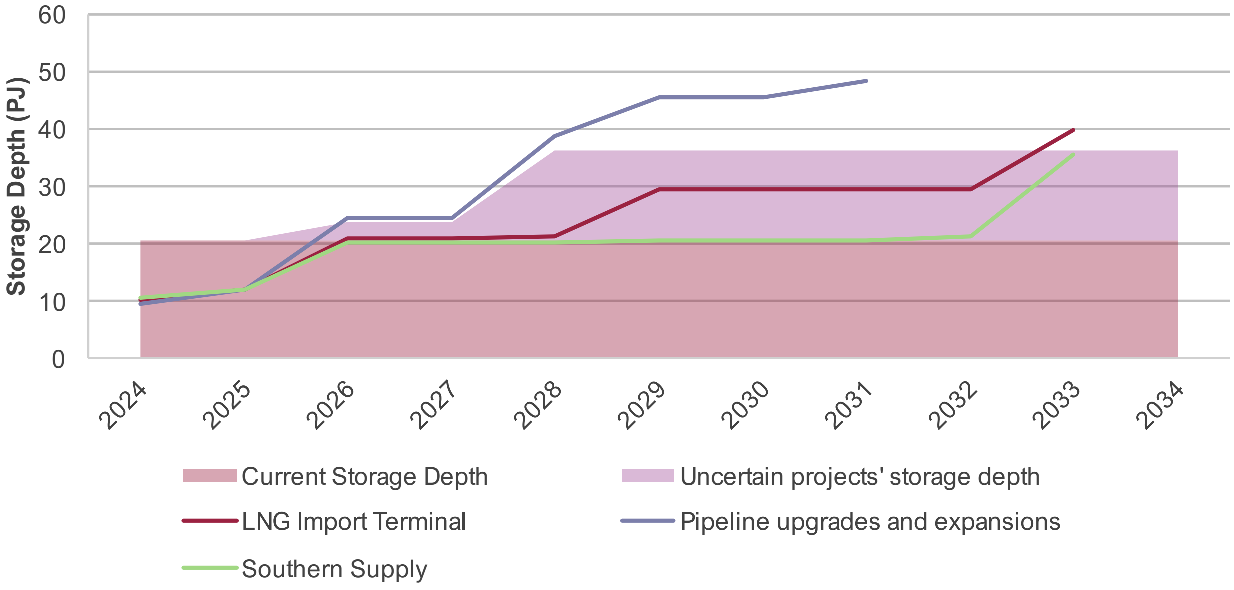
Storage provides increased flexible injection capacity at peak times with the capability to rapidly ramp up and down, and the potential to relieve existing bottlenecks in network capacity. All forms of storage will be critical to address the seasonal adequacy challenges and winter peaks, including those forecast for GPG during the early 2030s (see Section 2.5).

Storage capacity required varies across options

The optimal timing and depth of storage capacity in each option varies across the range of options assessed. Considered in isolation, new storage capacity provides little deferral of peak day shortfall or annual supply gaps if insufficient gas is available to fill inventories at storage facilities. The location for storages is dependent on gas generation requirements, and the range of upstream supply and transportation options being developed.

Figure 51 shows the optimal storage depth required for each option and represents the storage depth required to meet seasonal winter demand, up until the point that significant annual supply gaps emerge.

Figure 51 The total optimal depth of new storage for all options assessed, 2024-34 (PJ)



Note: the figure stops showing forecast storage depth when large annual supply gaps are forecast in each option. Beyond this point, increasing storage depth is not forecast to be able to resolve the gaps that are forecast, as there are insufficient amounts of gas to both deliver to consumers and refill storage facilities.

Figure 51 highlights that during the period to 2034:

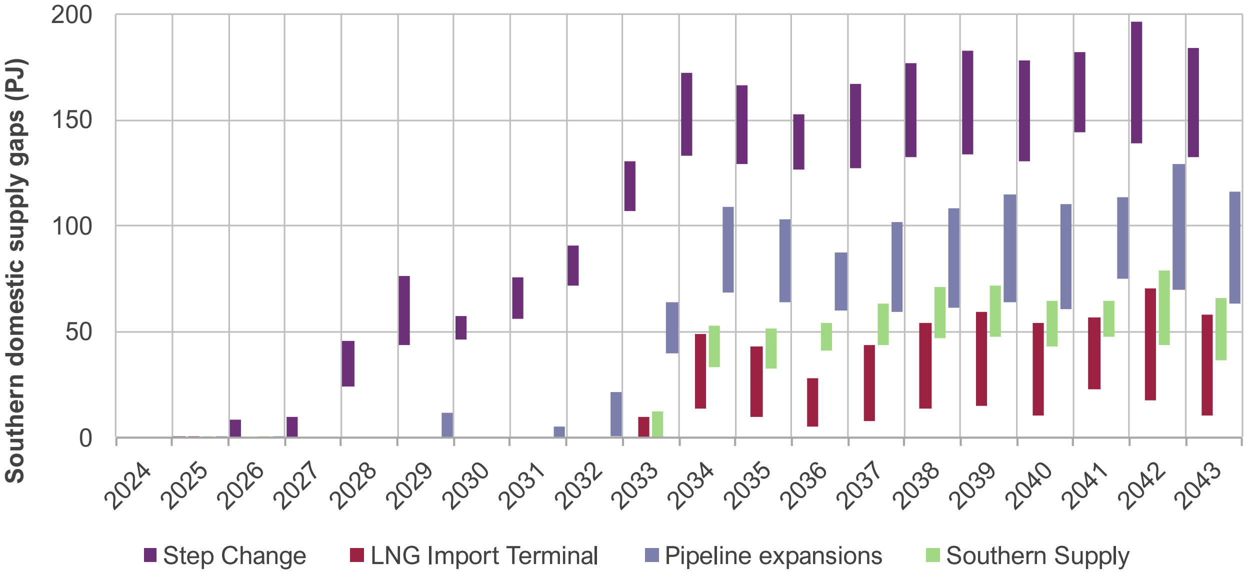
- The volume of uncertain storage projects identified in the 2024 GSOO survey process would provide sufficient storage depth until 2032 in the LNG Import Terminal option and until 2033 in the Southern Supply option, if these are developed in a timely manner. At present, only two uncertain storage projects, Golden Beach Storage Project and Lochard's Heytesbury storage upgrade at Iona, have been identified.
- The depth and timing for new storage required by the system varies due to individual options' supply capacity and capabilities for flexible operation and injection. The level of storage also varies according to the degree of transport capacity that is available across the options to bring new supplies to demand centres.
- Demand factors including weather patterns and GPG requirements influence the level and location of storage required across all options assessed.
- The Southern Supply option will require marginally less storage depth during the period to 2032 than the LNG Import Terminal option to store gas supplied during periods of low demand and deploy it when required during winter.
- The LNG Import Terminal option has increased operational flexibility and therefore require less storage depth than the less flexible Pipeline Upgrades and Expansions option.
- The Pipeline Expansions and Upgrades option carries less capacity and is less flexible so requires significant infrastructure developments to provide storage services in addition to uncertain projects.

From the mid-2030s, the optimal amount of storage is highly uncertain, and is dependent on numerous factors including, most prominently, the demand requirements and the location of gas generators forecast to be required in the Draft 2024 ISP. Storage capacity to service high levels of GPG and increasingly extreme peak demand may be required in Victoria, New South Wales and Queensland.

Storages provide flexible capacity and further delay annual supply gaps

When flexible capacity developments are paired appropriately with supply and transportation upgrades, annual supply gaps can be further delayed. As shown in **Figure 52,** building appropriate storage capacity highlighted for each option assessed (shown in Table 12 and Figure 51) delays annual supply gaps from 2028 to the early 2030s for the LNG Import Terminals option, and delays the forecast supply gaps for the Pipeline Upgrades and Expansions Option from 2028 to 2029. In all options assessed, the magnitude of forecast supply gaps is reduced.

Figure 52 Range of southern annual supply gaps for future supply options assessed, including optimal storage build, in comparison to the *Step Change* scenario, 2024-43 (PJ)



5.5 Examining the year-round future supply and demand balance

The future year-round supply and demand balance will vary under each modelled development option. This section forecasts the capability of all options assessed with optimised storage included to deliver gas during the year 2033.

Figure 53, Figure 54 and **Figure 55** show:

- Gas from the SWQP will be relied on heavily to meet southern demand in the LNG Import Terminal option (Figure 53). Reliance on gas delivered by the SWQP is reduced during summer and becomes more variable during winter in the Southern Supply option (Figure 55). If pipeline upgrades and expansions are developed instead of southern supply options, flow on the SWQP is at capacity for most of the year (Figure 54).
- All options assessed need additional flexible production or storage capacity, but in this example more flexible capacity is required in the Southern Supply option in comparison with the LNG import terminal option where imported supply can vary throughout the year is response to system needs. In the Pipeline Upgrades and Expansions option there is insufficient annual supply of gas in 2033, and so storages cannot be fully utilised.
- Storage filling will occur heavily throughout the summer months and discharge completely between June and September.

- Although it is not shown explicitly in Figure 55, localised gas transportation constraints on the Victorian Northern Interconnect between Victoria and New South Wales mean that gas from the north cannot be fully utilised. This highlights the importance of developing appropriate local gas transportation solutions, which will vary depending on the future supply, transportation and storage options developed.

These observations are specific to the assessed options only. Development of alternative supply, transportation or storage options, or similar options of different capacities, may drastically change way in which demand is met from various sources of supply.

Figure 53 Supply-demand balance for the LNG import terminal option, 2033, *Step Change* (TJ/d)

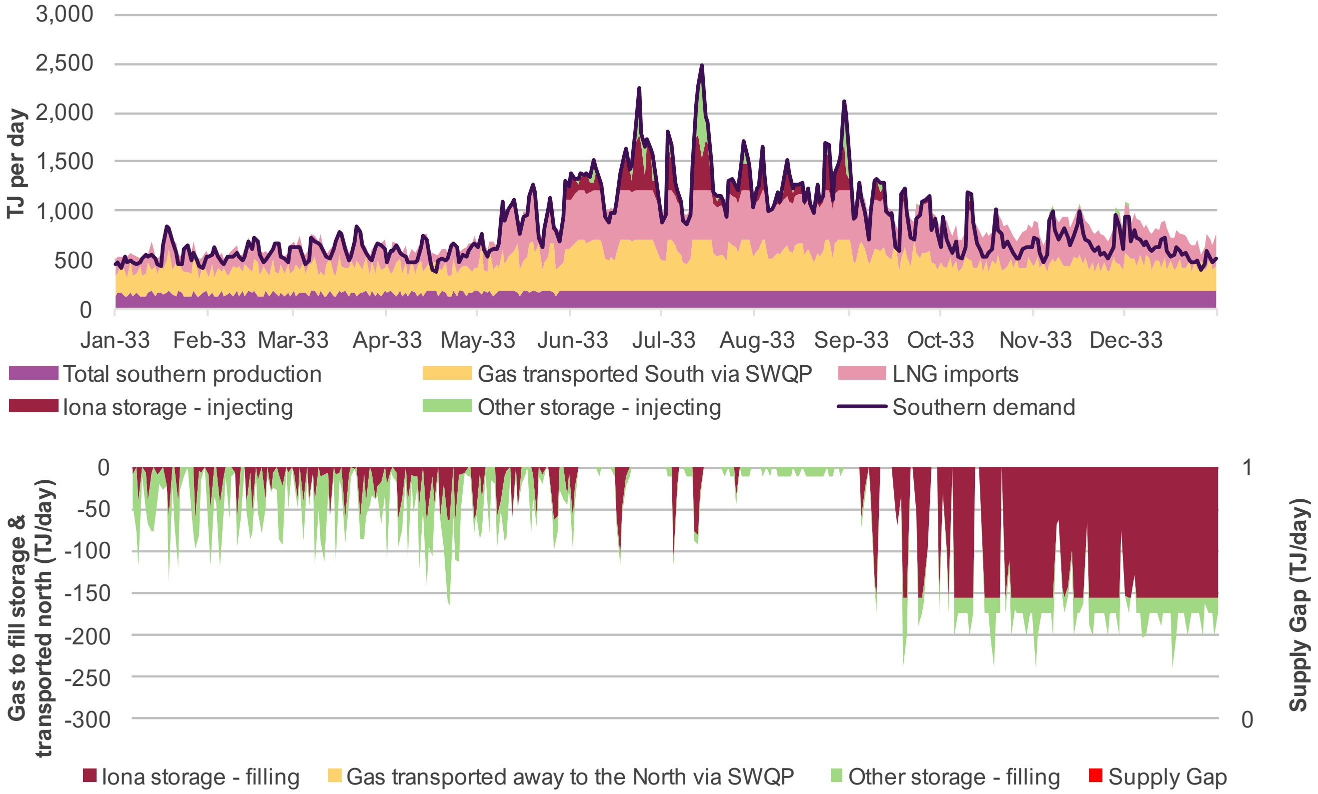


Figure 54 Supply-demand balance for the Pipeline Upgrades and Expansions option, 2033, *Step Change* (TJ/d)

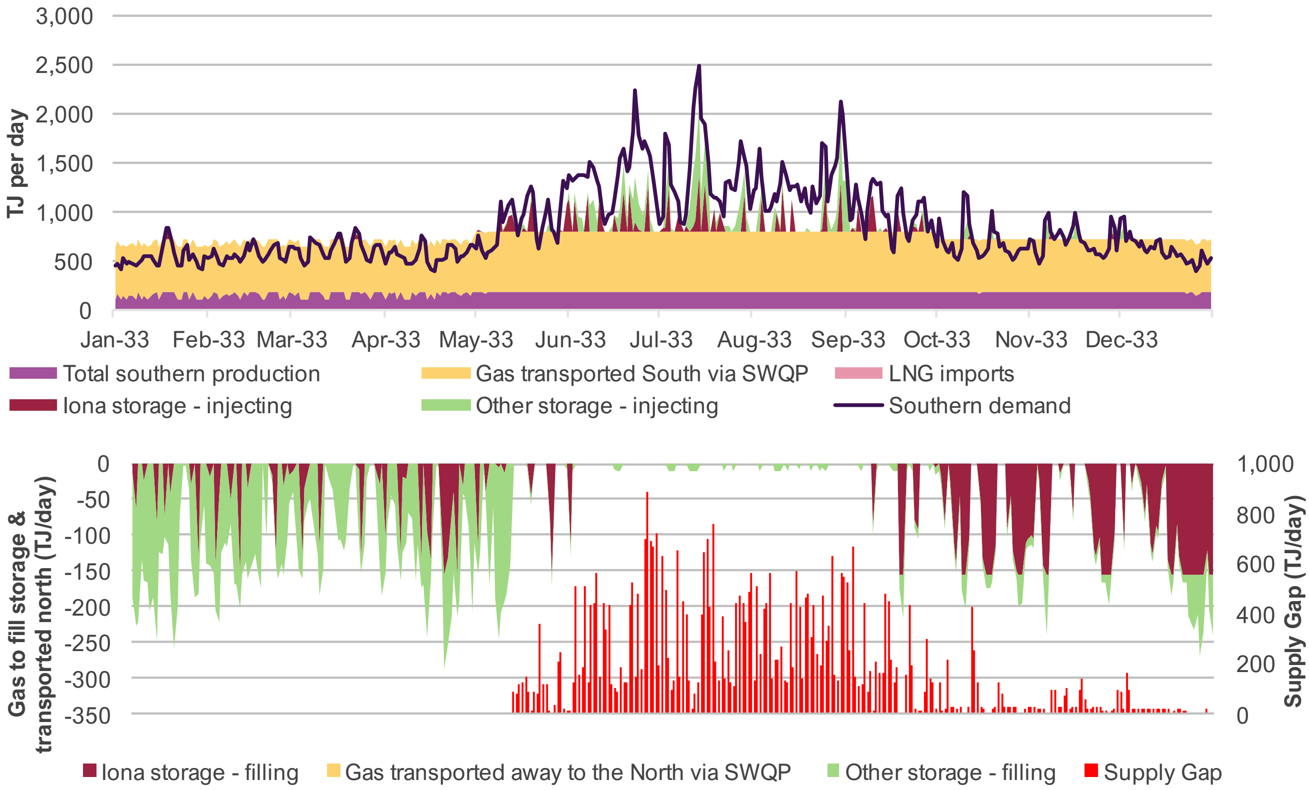
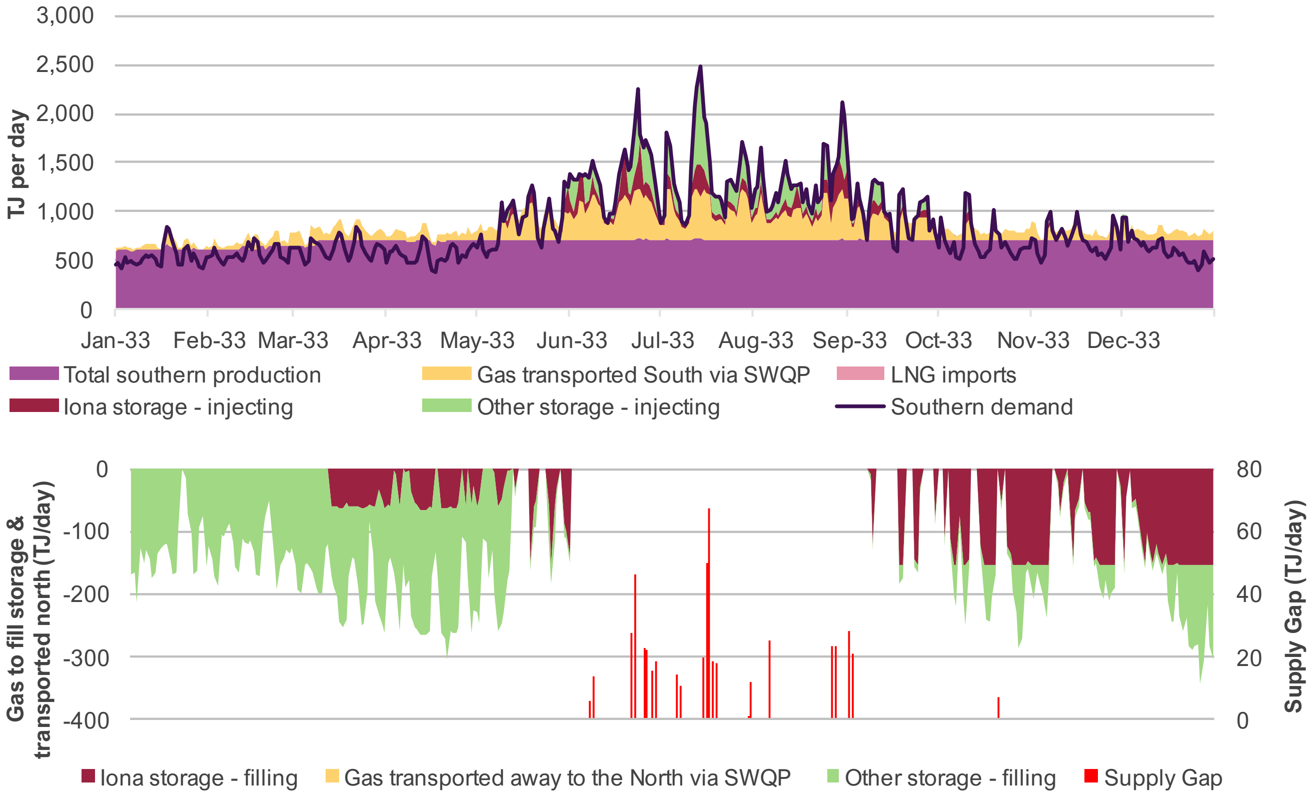


Figure 55 Supply-demand balance for the Southern Supply option, 2033, *Step Change* (TJ/d)



A1. Forecast accuracy

AEMO publishes its forecasting accuracy data to build confidence in the forecasts it produces and to help inform its approach to continuous improvement. Assessing the historical performance of the forecasts can help identify any bias in recent forecasts and improve understanding of forecast risks.

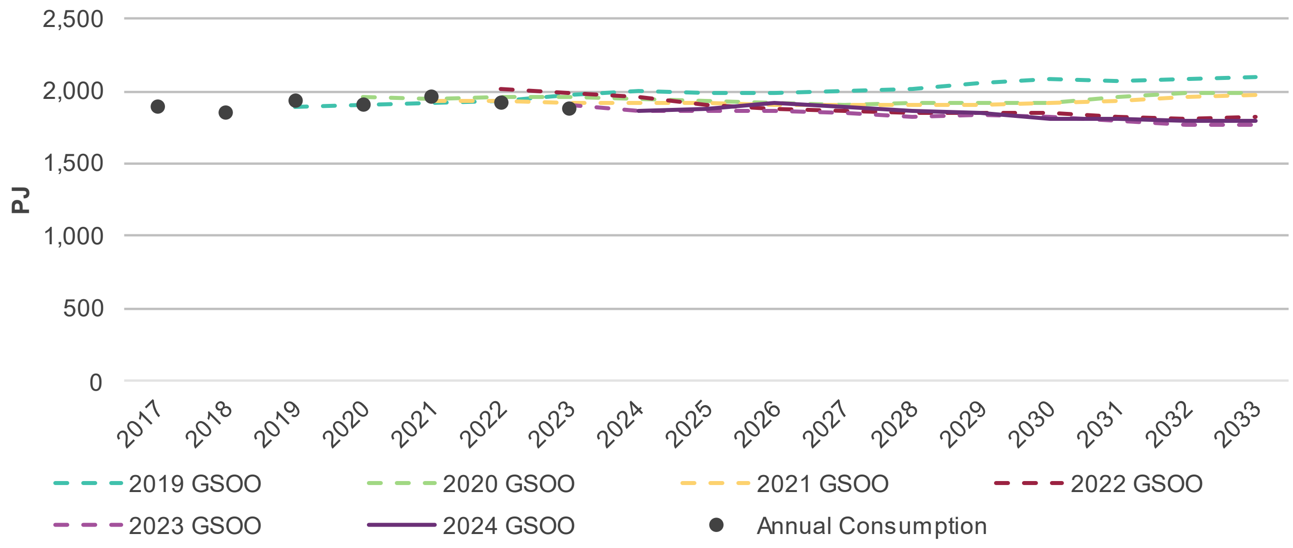
The following charts show AEMO's gas consumption forecasts since 2019, compared to actual recorded consumption in the ECGM spanning central and eastern Australia. These charts can be used to assess the performance of the forecasts by comparing actual consumption against forecasts in each year. Only the historical Central/Neutral scenario forecasts are presented. For the 2023 GSOO, the central scenario was the *Orchestrated Step Change (1.8°C)* scenario. For the 2024 GSOO, the *Step Change* scenario is presented.

Actual gas consumption is partly driven by weather conditions in a given year. For example, in a very cold year, gas consumption will be higher due to increased use of space heating. AEMO's forecasts are developed on a weather-normalised basis that assumes typical weather conditions, so some misalignment between forecast and actual consumption is expected in years that are particularly hot or cold.

A1.1 Total gas consumption forecasts

Figure 56 shows total gas consumption forecasts, including consumption for LNG export.

Figure 56 Annual gas consumption forecast comparison to actuals in the ECGM spanning central and eastern Australia (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Key observations include:

- The 2020 GSOO and 2022 GSOO both over-estimated gas consumption for the corresponding calendar year, mainly driven by actual LNG export volumes being lower than identified by the LNG producers in that GSOO's surveys.
- The 2021 GSOO under-estimated consumption in that calendar year, mainly due to two major power system events which increased the use of GPG in Queensland, New South Wales and Victoria.
- The 2023 GSOO marginally over-estimated consumption in the 2023 calendar year. The variance mainly resulted from the lower than forecast consumption from GPG as well as from the residential and commercial sectors due to an atypically warm winter reducing heating loads.

Table 13 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. Forecast accuracy in this case is measured as the percentage error, calculated as:

Percentage error = (Forecast - Actual) / Actual[93]

A positive number represents an over-forecast (that is, where the forecast was higher than actual consumption turned out to be). Due to the large size of the LNG export sector (which represents approximately 70% of total gas consumption), small changes in operations from individual facilities make a large contribution to forecast error.

Table 13 Year ahead historical forecast accuracy, total consumption (PJ)

	2019	2020	2021	2022	2023
Year ahead forecast	1,889	1,961	1,928	2,009	1,904
Actual consumption	1,937	1,915	1,961	1,928	1,882
Forecast accuracy	-2.5%	2.4%	-1.7%	4.2%	1.2%
Source	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO

The following sections break down gas forecast accuracy into individual sectors to enable a closer inspection of individual drivers contributing to forecast uncertainty.

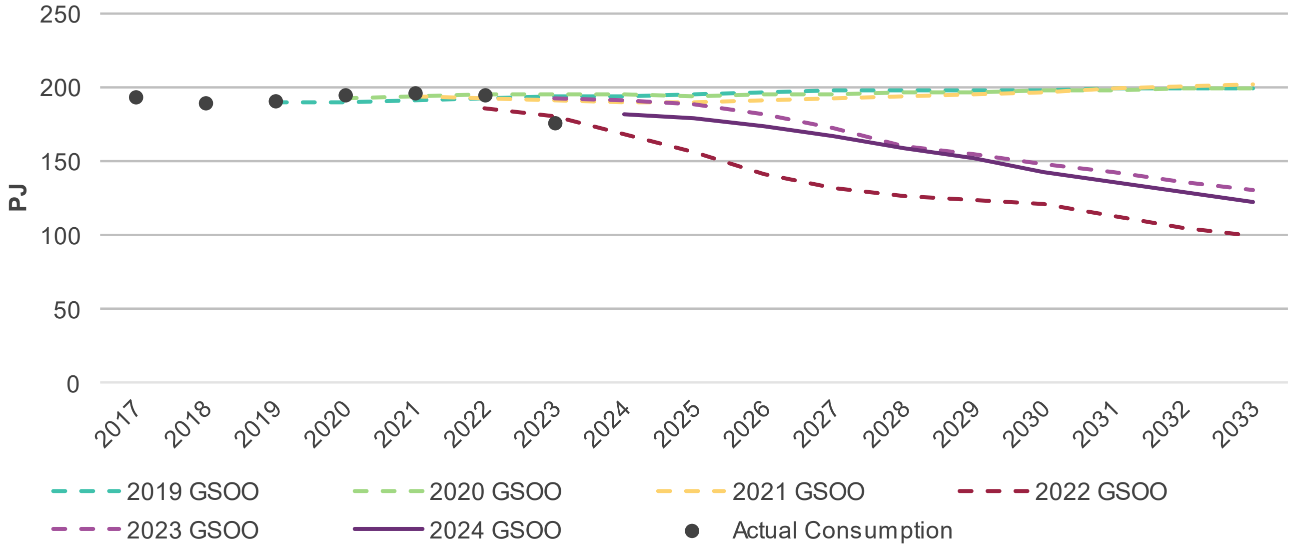
A1.2 Residential and commercial gas consumption forecasts

Figure 57 shows AEMO's residential and commercial gas consumption forecasts. The starting point of the 2024 GSOO forecast has been calibrated to recent weather-normalised consumption in calendar year 2023, and therefore is higher than the actual consumption in this calendar year as the forecast assumed a return to normal weather conditions, rather than the atypically warm winter of 2023.

The overall trend reflects AEMO's assumptions relating to connections and population growth and the impacts of energy efficiency investments, gas fuel-switching such as electrification, gas prices, and climate change. These factors are described in more detail in Section 2.2.1.

[93] Actual consumption used in the percentage error calculation is not weather normalised; that is, forecast variance due to atypical weather is reflected as part of the percentage error.

Figure 57 Annual gas consumption forecast comparison to actuals in the residential and commercial sectors (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 14 provides an overview of residential and commercial gas consumption forecast accuracy for the calendar year immediately following the forecast. AEMO's 2023 GSOO residential and commercial projection was 10.1% higher than actual consumption levels in calendar year 2023. A large part of this variance was due to 2023 being one of the warmest winters on record[94] which led to lower than forecast gas consumption for heating. AEMO estimates that atypical weather resulted in an 8 PJ reduction in gas consumption compared to a standard weather year[95]. Excluding this weather impact, AEMO's 2023 GSOO residential and commercial projection was over-forecast by 5.5% compared to estimated weather-normalised actual consumption. In addition to mild weather, consumer response to sharp increases in retail gas prices and the emergence of fuel-switching from gas to electricity[96] has likely further reduced residential and commercial gas consumption, compared to the 2023 GSOO forecast.

Table 14 Year ahead historical forecast accuracy, residential and commercial total consumption (PJ)

	2019	2020	2021	2022	2023
Year ahead forecast	190	192	194	185	193
Actual consumption	191	195	196	194	175
Forecast accuracy	-0.4%	-1.6%	-1.2%	-4.6%	10.1%
Source	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO

[94] Mean winter temperatures in 2023 were the warmest on record for Queensland, New South Wales and Tasmania, and second warmest for Victoria and South Australia. See http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml for further details.

[95] AEMO uses an EDD weather standard for Victoria and a Heating Degree Days (HDD) weather standard for other states. Refer to the AEMO Gas Methodology Paper at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo for details on EDD and HDD formulation, historical climate change adjustment, and use as a weather standard.

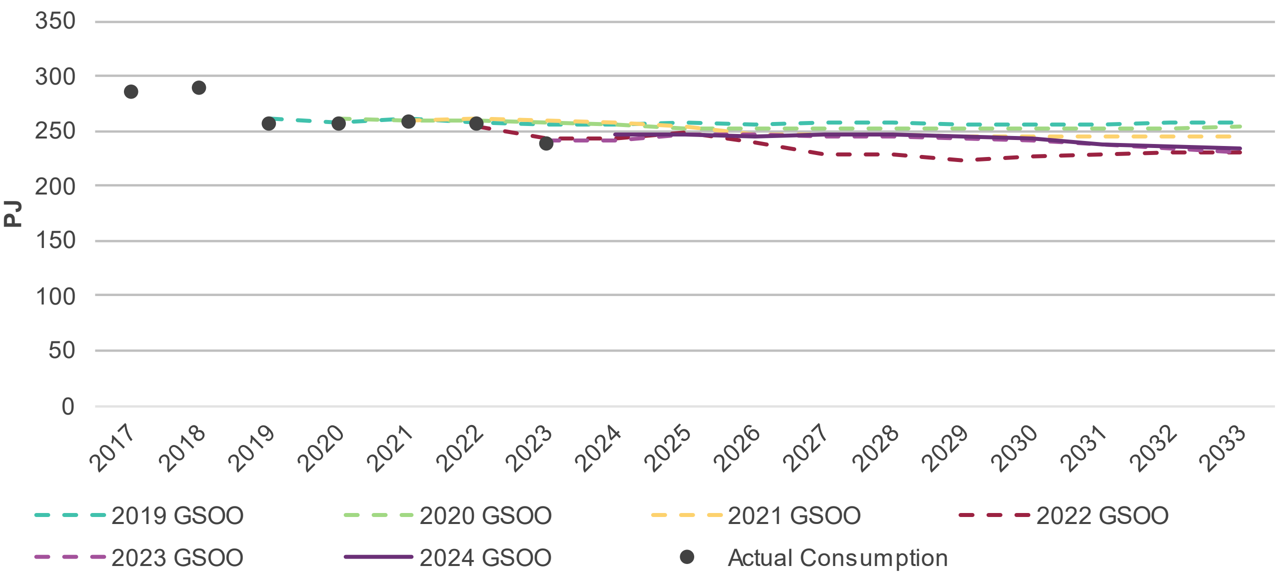
[96] AEMO carried out a high-level analysis of Victorian households and businesses, which showed a trend towards increasing temperature sensitivity for electricity consumption and simultaneously a trend towards decreasing temperature sensitivity for gas consumption in recent years. This is likely driven in part to electrification. Electrification of gas load can take many forms, including uptake of reverse-cycle air-conditioners with markedly reduced running costs when coupled with distributed PV.

A1.3 Industrial gas consumption forecasts

Figure 58 shows AEMO's industrial gas consumption forecasts. AEMO's industrial consumption projection is based on two categories – large industrial loads (LIL) and small to medium industrial loads (SMIL)[97] – and incorporates assumptions on forecast changes to economic drivers and data obtained by surveying large gas users. The two categories and assumption factors are described in more detail in Section 2.2.2.

Table 15 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

Figure 58 Annual gas consumption forecast comparison to actuals in industrial sector (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 15 Year ahead historical forecast accuracy, industrial total consumption (PJ)

	2019	2020	2021	2022	2023
Year ahead forecast	261	262	260	254	242
Actual consumption	257	256	259	257	238
Forecast accuracy	1.5%	2.2%	0.3%	-0.9%	1.4%
Source	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO

In the 2023 GSOO, over 70% of large industrial customers (by energy consumed) were surveyed for consumption forecasts. In accordance with AEMO's gas demand forecasting methodology[98], AEMO adopts an econometric modelling approach to forecast the remaining in aggregate[99], which includes allowances for potential

[97] Note that consumption for LNG export is not considered an industrial load.

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

[99] Refer to the AEMO Gas Methodology Paper at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo for details on AEMO's econometric modelling.

fuel-switching to electricity and hydrogen from gas[100]. Since the 2019 GSOO, the industrial consumption forecast shows a long-term flattening trend, as surveyed industrials indicate expectations of stable consumption, with many industrials also indicating in their surveys that there is an expected impact from emissions reduction goals[101].

Variations from forecasts to actual industrial consumption arise primarily due to unpredictable factors such as weather variations, market shocks, or operational issues that result in unforeseen changes in industrial loads, both temporary and permanent.

AEMO's 2023 GSOO industrial projection was 1.4% higher than actual consumption in the 2023 calendar year, with the difference attributed to:

- In the SMIL sector, reduced consumption levels driven by warmer than average weather conditions in winter.
- In the LIL sector, lower than forecast consumption in New South Wales and Victoria caused by temporary outages and operational variations from a few facilities[102].

A1.4 LNG export segment consumption forecasts

In 2023, gas consumption by LNG export facilities in Queensland represented 71% of total gas consumption across the ECGM.

LNG export consumption is driven by factors including:

- Operational considerations affecting CSG production.
- Operational considerations affecting LNG operations at Gladstone.
- Global market dynamics impacting the price and competitiveness of Australian LNG relative to other supplies of LNG globally (including from within each facility operator's global portfolio).
- Global market dynamics impacting the demand for energy and supply of alternative forms of energy, particularly in America, Europe and Asia.
- Contractual considerations affecting local production.

Near-term forecasts of LNG export consumption are directly as advised by LNG producers via the GSOO survey process. Prior to the 2024 GSOO, information was provided to AEMO on a voluntary basis. The Gas Transparency Measures package of reforms mandated the collection of gas production information under the NGR, from February 2023.

The GSOO does not include any LNG export quantities produced within and exported from the Northern Territory.

---

[100] Consumption impacts of potential fuel-switching to electricity and hydrogen from gas are based on multi-sector modelling conducted by consultants CSIRO and ClimateWorks.

[101] Such as through the reformed Safeguard Mechanism that commenced on 1 July 2023; see https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

[102] Examples include Orica Kooragang Island's October 2023 maintenance shut down in New South Wales (see https://www.orica.com/ArticleDocuments/503/7572%20-%20Community%20Newsletter%20Issue%203,%202023%20DIGITAL.pdf); shut down of Qenos Botany's polyethylene plant since an incident in February 2023 in New South Wales (see https://www.packagingnews.com.au/materials/qenos-plant-shut-down-impacts-pe-supply), and reduced gas consumption from Maryvale paper in Victoria since its white paper manufacturing ceased from 2023 (see https://www.abc.net.au/news/2023-02-14/white-paper-production-stops-maryvale-paper-mill/101973646).

Figure 59 and **Table 16** compare LNG export forecasts against actual LNG exports from Queensland LNG facilities.

Figure 59 Gas annual consumption forecast comparison, Queensland LNG (PJ)

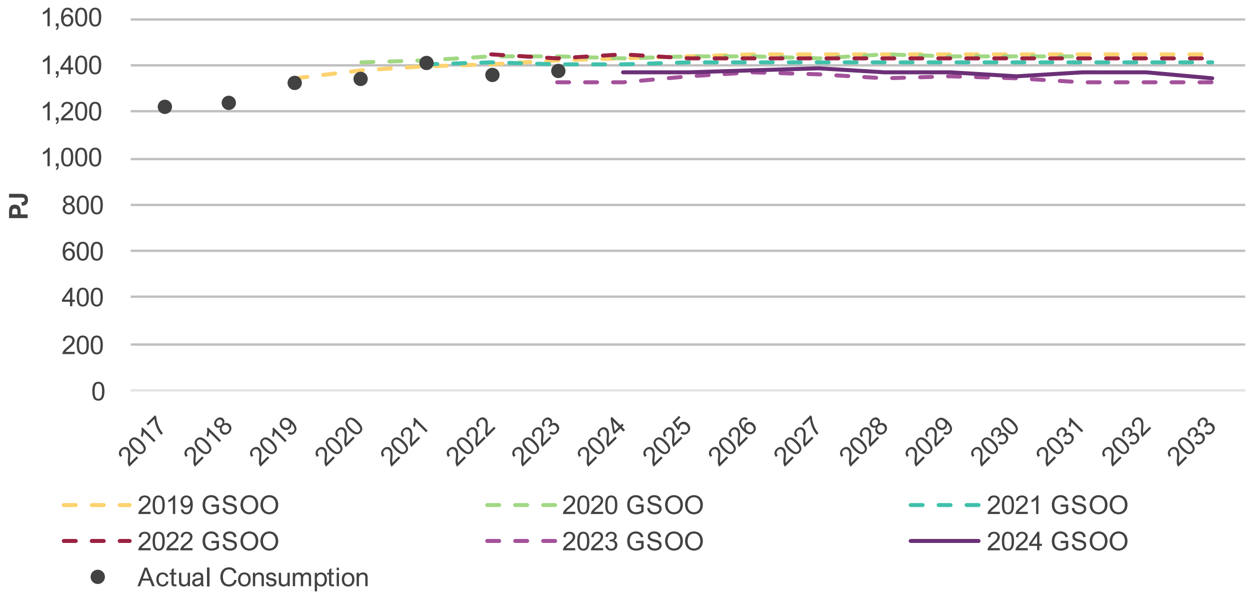


Table 16 Year ahead historical forecast accuracy, all Queensland LNG facilities total consumption (PJ)

	2019	2020	2021	2022	2023
Year ahead forecast	1,346	1,415	1,401	1,444	1,326
Actual consumption	1,325	1,338	1,407	1,358	1,371
Forecast accuracy	1.6%	5.8%	-0.5%	6.4%	-3.3%
Source	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO

Table 16 shows that year-ahead forecasts produced in the 2019 and 2021 GSOO publications were within 2% of actual consumption. However, forecasts over-estimated LNG export consumption in the 2020 and 2022 calendar years by 5.8% and 6.4% respectively, while the 2023 forecast featured a 3.3% under-estimation. These forecast errors may be in part attributable to the following dynamics:

- In 2020, the COVID-19 pandemic led to reduced global economic activity.
- In 2022, despite strong Asian LNG demand and high international energy prices resulting from sanctions against Russia, there was an appreciable decrease in Queensland LNG export while domestic demand for natural gas was strong. LNG export train availability was also reduced in 2022, reducing export volumes.
- In 2023, lower domestic gas demand over winter enabled the highest Queensland LNG winter exports on record at 331 PJ (compared to an average of 315 PJ over previous winters).

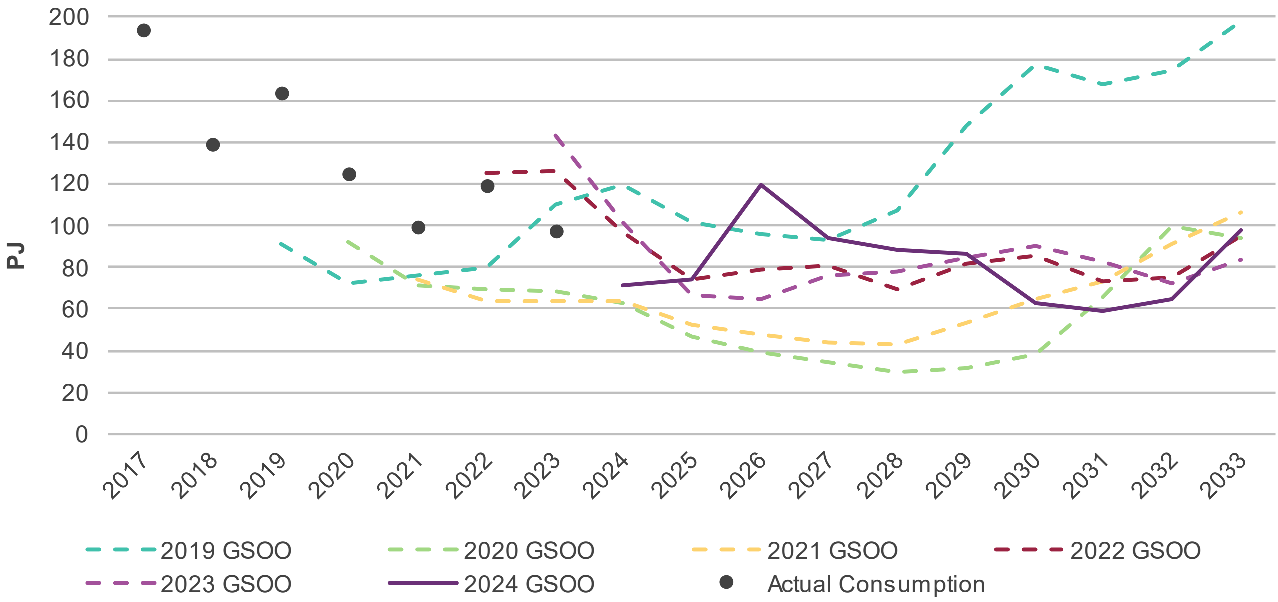
A1.5 Gas-powered generation consumption forecasts

Forecasting consumption of gas for electricity generation is challenging because gas generation is often significantly affected by events affecting the electricity sector, such as extreme weather or outages at major electricity generators. These events are difficult to predict and can lead to significant variations in forecasts.

The 2023 GSOO presented GPG consumption forecasts and actuals in charts and in the forecasting accuracy appendix for the NEM only. The 2024 GSOO includes the Northern Territory consumption forecasts and actuals along with the NEM in all charts and analysis, unless specified.

Figure 60 and **Table 17** compare AEMO's GPG forecast accuracy against actual consumption in the NEM and the Northern Territory. This comparison shows that all forecasts prior to the 2022 GSOO significantly under-estimated annual consumption; however, the 2022 GSOO slightly over-forecast consumption, and the 2023 GSOO significantly over-estimated annual consumption.

Figure 60 Annual gas consumption forecast comparison to actuals for gas generation (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in forecast and actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 17 Year ahead historical forecast accuracy, gas generation in the NEM and Northern Territory, total consumption (PJ)

	2019	2020	2021	2022	2023
Year ahead forecast[A]	91	92	74	125	143
Actual consumption	164	126	99	119	98
Forecast accuracy	-44%	-27%	-26%	5%	46%
Source	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO

A. Values presented here are for the NEM for 2019-2022, and for the NEM and Northern Territory from 2023. The 2023 year ahead forecast values include the 123PJ quoted in the 2023 GSOO, as well as a 20 PJ forecast for Northern Territory which was not included in the 2023 GSOO publication.

Gas consumption for electricity generation exhibits a general declining trend from 2019, but several spikes in consumption have occurred as a result of unexpected events during the past five years. These include:

- In 2019, prolonged high temperatures and bushfires affected New South Wales and Victoria with outages at Victorian coal generators, and fuel supply shortages affected coal generators in New South Wales
- In 2020, the collapse of transmission towers affected the Heywood interconnector (connecting South Australia and Victoria) and extended outages for coal-fired power stations in Queensland.
- In 2021, flooding at the Yallourn coal mine affected coal generation in Victoria and the unexpected explosion at the Callide power station in Queensland (impacted unit remains offline until July-2024).
- In 2022, the war in Ukraine increased international prices for both gas and coal. This coincided with flooding events affecting coal production and an extended period of low renewable output. This increased the requirement for gas generators to purchase gas at short notice. However, on a yearly basis during 2022, the increased consumption by GPG during winter was offset by a mild summer resulting in lower than forecast GPG in that period.

Considering the NEM only (excluding the Northern Territory), the 2023 GSOO's forecast for GPG consumption was 123 PJ for 2023. This forecast was 43 PJ (54%) higher than the actual 2023 total GPG consumption, driven by:

- **Lower operational demand, driven by growth in distributed PV and low underlying demand**. Victoria and South Australia recorded all-time lows in operational sent-out demand in Q4 2023, with South Australia recording negative demands for the first time[103]. AEMO over-estimated distributed PV generation by between 30 GWh and 300 GWh per month, but this error was more than offset by the low levels of underlying demand observed.
- **High output from low-cost large-scale renewables**, as new plants were commissioned and favourable wind and solar conditions enabled higher available output from existing units.
- **Improved availability from coal generation**. Despite closure of Liddell Power Station in late April 2023 and delays in the return-to-service date of units at the Callide Power Station[104], there were fewer planned and unplanned coal unit outages. Total coal availability increased and offered more volume at lower price bands, more than AEMO had forecast.

Beyond these trends, unexpected events in the power system are still expected to require firming support from gas generation. Notably, in August 2023, several planned outages on the Heywood interconnector coincided with low wind outside daylight hours, resulting in increased GPG. Gas peaking plants saw a smaller decline in generation compared to mid-merit gas generators.

[103] See more information here: https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf.

[104] See: https://www.csenergy.com.au/news/updated-return-to-service-dates-for-callide-c-generating-units.

A2. Monthly demand forecast for 2024

Table 18 details the monthly demand forecast by region and sector for 2024. Forecast are provided for the *Step Change* scenario, 2019 reference year, with potential variation due to weather shown in brackets.

Table 18 Forecast monthly demand by region and sector (GPG and residential, commercial and industrial [RC&I]) for each month in 2024 (PJ)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Territory	GPG	1.6 [+0,-0]	1.5 [+0,-0]	1.6 [+0,-0]	1.4 [+0,-0]	1.4 [+0,-0]	1.3 [+0,-0]	1.3 [+0,-0]	1.4 [+0,-0]	1.6 [+0,-0]	1.7 [+0,-0]	1.7 [+0,-0]	1.7 [+0,-0]
	RC&I	0.6 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.3 [+0,-0]	0.4 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Queensland	GPG	2.7 [+0,-1]	2.1 [+1,-1]	1.7 [+1,-0]	0.9 [+1,-0]	1.5 [+0,-1]	1.9 [+0,-1]	2.7 [+0,-1]	2 [+1,-1]	1.3 [+1,-1]	1.6 [+0,-1]	1.1 [+1,-0]	0.8 [+1,-0]
	RC&I	9.1 [+0,-0]	8 [+0,-0]	8.2 [+1,-0]	8.1 [+1,-0]	9.1 [+0,-1]	9.2 [+0,-1]	8.8 [+0,-0]	8.4 [+1,-0]	8.3 [+1,-0]	9.1 [+0,-1]	9.1 [+0,-1]	9 [+0,-1]
Total Northern		**16.9 [+2,-1]**	**14 [+0,-2]**	**12.1 [+1,-1]**	**12.1 [+2,-0]**	**11 [+2,-0]**	**12.5 [+0,-1]**	**12.8 [+0,-1]**	**13.1 [+0,-1]**	**12.2 [+0,-1]**	**11.6 [+1,-1]**	**12.8 [+0,-2]**	**12.5 [+1,-1]**
New South Wales	GPG	1.2 [+0,-1]	0.8 [+0,-0]	0.3 [+0,-0]	0.1 [+1,-0]	0.9 [+0,-1]	1.4 [+0,-1]	1.4 [+0,-1]	1.4 [+0,-1]	0.8 [+0,-1]	0.5 [+0,-1]	0.3 [+0,-0]	0.2 [+1,-0]
	RC&I	6.8 [+0,-0]	7.5 [+0,-1]	8.4 [+0,-2]	7.5 [+0,-1]	10.9 [+0,-1]	11.5 [+1,-1]	11.5 [+2,-0]	11.8 [+1,-1]	9.5 [+1,-1]	7.5 [+1,-1]	7 [+2,-0]	6.7 [+1,-0]
Victoria	GPG	0.4 [+0,-0]	0.3 [+0,-0]	0.2 [+0,-0]	0.1 [+0,-0]	0.2 [+0,-0]	0.7 [+0,-1]	0.7 [+0,-0]	0.7 [+0,-1]	0.4 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0.2 [+0,-0]
	RC&I	8.6 [+1,-0]	9.2 [+0,-1]	9.9 [+1,-1]	10.3 [+2,-1]	17.1 [+3,-0]	24.6 [+0,-2]	25 [+3,-0]	26 [+0,-3]	17.9 [+1,-2]	12.1 [+0,-3]	12.8 [+0,-3]	10.2 [+0,-1]
South Australia	GPG	2.2 [+0,-0]	1.6 [+0,-0]	1.6 [+0,-0]	1.4 [+1,-0]	2 [+1,-0]	3 [+1,-1]	2.5 [+0,-0]	2.1 [+1,-1]	2.4 [+0,-1]	1.5 [+0,-0]	1.4 [+0,-0]	1.4 [+0,-1]
	RC&I	2.2 [+0,-0]	2.4 [+0,-0]	2.7 [+0,-0]	2.4 [+0,-0]	3.6 [+0,-0]	3.8 [+0,-0]	3.8 [+0,-0]	3.8 [+0,-0]	3.2 [+0,-0]	2.5 [+0,-0]	2.7 [+0,-0]	2.6 [+0,-0]
Tasmania	GPG	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]
	RC&I	0.4 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]	0.5 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.5 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.5 [+0,-0]
Total Southern		**26.1 [+1,-0]**	**21.9 [+2,-1]**	**22.3 [+0,-2]**	**23.4 [+0,-3]**	**22.1 [+3,-1]**	**35.3 [+4,-1]**	**45.7 [+0,-6]**	**45.4 [+5,-0]**	**46.3 [+0,-7]**	**34.7 [+1,-5]**	**24.9 [+1,-5]**	**24.8 [+0,-1]**
Total Domestic		**42.9 [+2,-1]**	**35.9 [+2,-2]**	**34.4 [+0,-3]**	**35.5 [+2,-2]**	**33.1 [+5,-1]**	**47.7 [+5,-2]**	**58.5 [+0,-7]**	**58.5 [+5,-0]**	**58.5 [+0,-7]**	**46.3 [+3,-5]**	**37.7 [+1,-6]**	**37.3 [+0,-2]**
Queensland	LNG	**118 [+3,-0]**	**110 [+4,-0]**	**116 [+3,-1]**	**114 [+5,-0]**	**112 [+11,-4]**	**107 [+0,-9]**	**110 [+0,-5]**	**110 [+1,-4]**	**114 [+5,-0]**	**124 [+4,-5]**	**116 [+3,-4]**	**120 [+4,-9]**
Total		**153 [+3,-1]**	**144 [+4,-0]**	**152 [+4,-3]**	**147 [+6,-0]**	**160 [+13,-3]**	**165 [+0,-11]**	**169 [+2,-3]**	**169 [+0,-11]**	**160 [+7,-2]**	**161 [+2,-10]**	**153 [+2,-4]**	**153 [+3,-8]**

Note: Data is shown for the 2019 reference year. Data in the brackets represents differences in forecast demand for that component of demand due to weather variation. Totals may not add up due to rounding. Variation due to weather for total rows (for example, Total Northern), may not necessarily equal the sum of the variation of the individual components (for example, the lower bound for Total Northern demand may not equal the sum of lower bounds for GPG and RC&I for Queensland and Northern Territory), because these values may not occur in the same reference year.

Figure 61 and **Figure 62** show forecast monthly demand in petajoules a month (PJ/m) for 2024, for the 2019 reference year, by region and by sector respectively.

Figure 61 Forecast monthly domestic demand by region for 2024, *Step Change*, reference year 2019 (PJ/m)

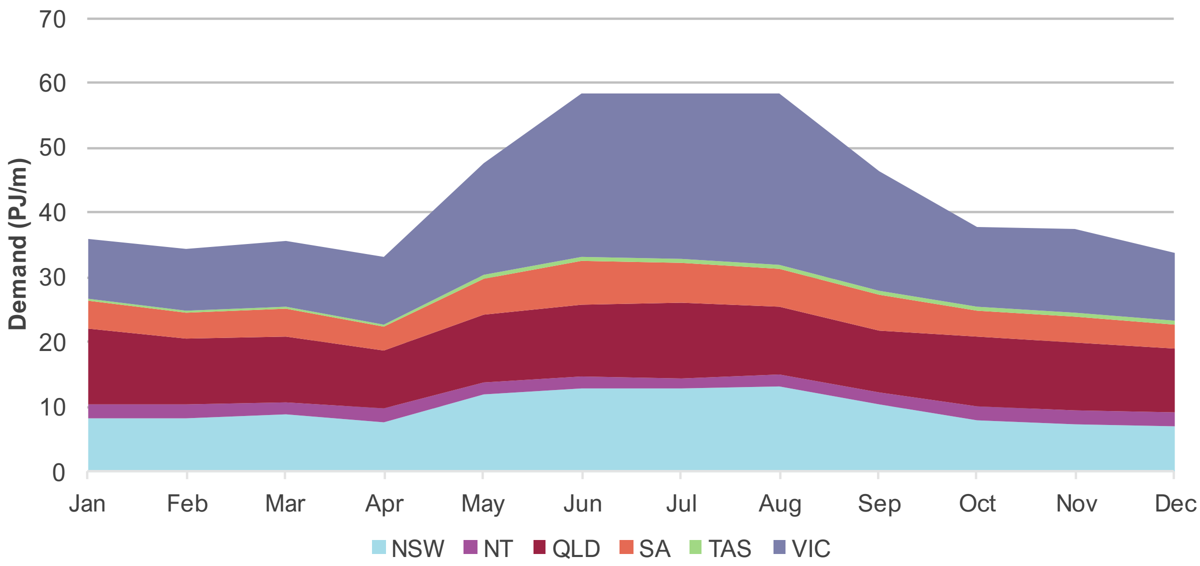
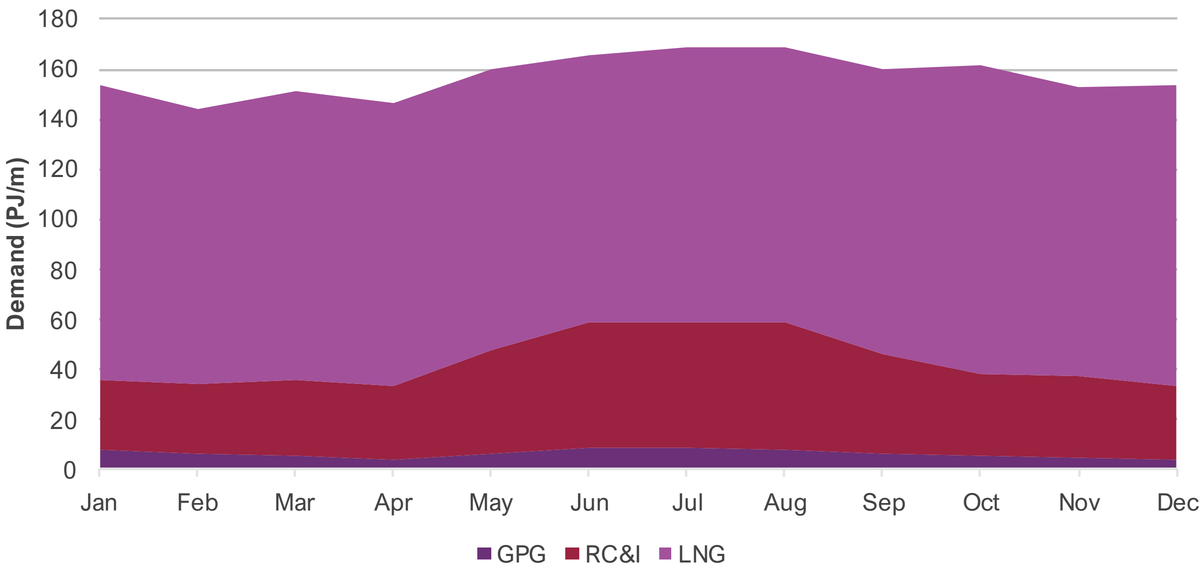


Figure 62 Forecast monthly demand by sector for 2024, *Step Change*, reference year 2019 (PJ/m)



List of tables and figures

Tables

Figures

Glossary, measures and abbreviations

Units of measure

Term	Definition
EDD	effective degree day/s
GJ	gigajoule/s
PJ	petajoule/s
PJ/m	petajoules per month
PJ/y	petajoules per year
TJ	terajoule/s
TJ/d	terajoules per day

Abbreviations

Term	Definition
2C	best estimate of contingent resources
2P	proved and probable
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
APLNG	Australia Pacific LNG Pty Ltd.
BLP	Brooklyn–Lara Pipeline
BGP	Bonaparte Gas Pipeline
CCS	carbon capture and storage
CGP	Carpentaria Gas Pipeline
CSG	coal seam gas
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECGM	East Coast Gas Market
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
FID	final investment decision
FSRU	floating storage regasification unit
GLNG	Gladstone LNG
GSOO	*Gas Statement of Opportunities*
IASR	*Inputs, Assumptions and Scenarios Report*
IEA	International Energy Agency
ISP	*Integrated System Plan*

Term	Definition
LIL	large industrial load
LMP	Longford Melbourne Pipeline
LNG	liquefied natural gas
MAPS	Moomba Adelaide Pipeline System
MSP	Moomba – Sydney Pipeline
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NGSF	Newcastle Gas Storage Facility
NQGP	North Queensland Gas Pipeline
ODP	optimal development path
PCA	Port Campbell to Adelaide pipeline
PKET	Port Kembla Energy Terminal
POE	probability of exceedance
PRMS	Petroleum Resources Management System
PV	photovoltaic/s
QCLNG	Queensland Curtis LNG
QHGP	Queensland – Hunter Gas Pipeline
RBP	Roma – Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SEA Gas	South East Australia Gas (pipeline)
SMIL	small to medium industrial load
SMR	steam methane reforming
SNP	Sydney – Newcastle Pipeline
STTM	Short Term Trading Market
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
UAFG	unaccounted for gas
UGS	underground gas storage
VGPR	*Victorian Gas Planning Report*
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
WEO	World Economic Outlook
WOH	whole of home
WORM	Western Outer Ring Main

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.
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.
anticipated projects	Gas field and production facility projects that developers consider justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
biomethane	Methane captured from biological processes such as wastewater treatment, landfill or biodigesters (also known as biogas) and purified to meet gas quality standards. Biomethane can be used interchangeably with natural gas.
commercial customers	See residential and commercial customers.
committed projects	Gas field and production facility projects that have obtained all necessary approvals, with implementation ready to commence or already underway.
consumption	Gas consumed over a period of time, usually a year but sometimes a month.
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.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the Declared Wholesale Gas Market [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.
demand	The amount of gas used on a daily basis. The maximum across a season is referred to as maximum demand or peak day demand.
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 (EGP)	The east coast pipeline from Longford to Sydney.
effective degree day (EDD)	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.
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.
industrial customers (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 being on demand tariffs

Term	Definition
	(Tariff D) in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
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 (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is at Dandenong.
natural gas	A naturally occurring hydrocarbon comprising methane (CH4) (between 95% and 99%) and ethane (C2H6).
participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
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.
prospective resources	Estimated volumes associated with undiscovered accumulations of gas, highly speculative and not yet proven by drilling.
probability of exceedance (POE)	The statistical likelihood that a peak demand forecast will be met or exceeded.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
reserves	Quantities of gas expected to be commercially recovered from known accumulations.
residential and commercial customers (Tariff V)	The gas transportation tariff applying to consumers on volume-based tariffs (Tariff V). This includes residential and small to medium sized commercial gas consumers.
resources	Less certain, and potentially less commercially viable sources of gas, than reserves.
retailer	A seller of bundled energy service products to a customer.
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 Dandenong LNG storage facility and Iona Underground Gas Storage (UGS) in Victoria, and Newcastle Gas Storage Facility (NGSF) in New South Wales.
summer	December to February.
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.
Tasmanian Gas Pipeline (TGP)	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 (UAFG)	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising gas losses, metering errors, timing, heating value error, allocation error, and other factors.
uncertain projects	Gas field and production facility projects that are at earlier stages of development or face challenges in terms of commercial viability or approval.
Underground Gas Storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
winter	June to August.