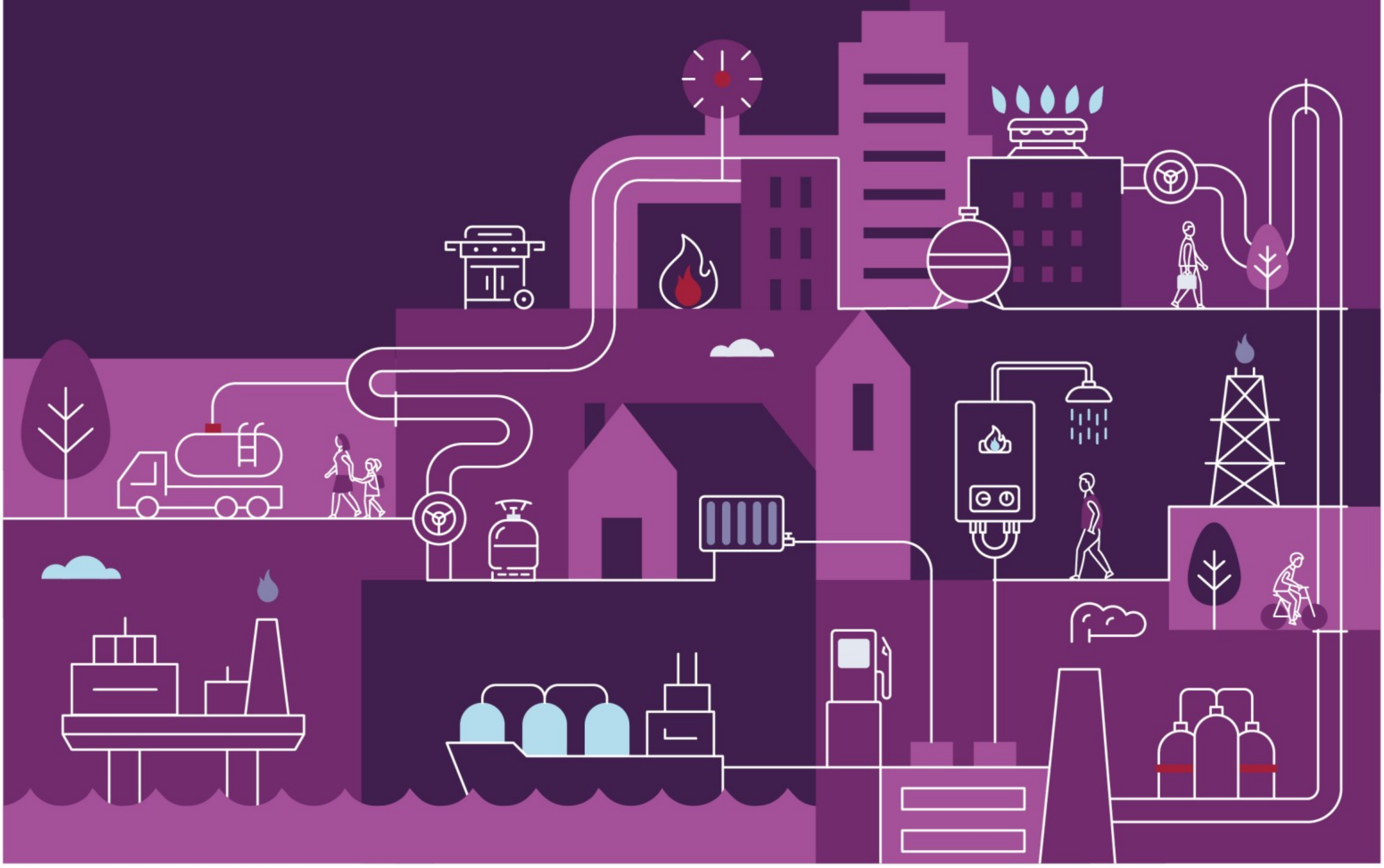
Gas Statement of Opportunities

March 2022

For eastern and south-eastern Australia



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 17 February 2022, unless otherwise indicated.

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Version control

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

Contents

Executive summary

The 2022 *Gas Statement of Opportunities* (GSOO) forecasts the adequacy of gas supplies, based on information from gas industry participants, to meet consumers' changing gas needs from now until 2041 in Australian jurisdictions other than Western Australia and the Northern Territory.

The gas sector is transforming. In the next 20 years, as Australia transitions to a net-zero emissions economy, the type and level of gas use is expected to be impacted by consumer choice, technology advances, public policy and the potential rise of hydrogen. As in electricity, gas will see increased challenges and opportunities in system operation, planning and investment. The future path for gas is uncertain, as the pace of the transformation and its influence on the gas system is not yet clear.

- **Future gas needs are highly uncertain**. AEMO's scenarios capture a wide range of realistic forecasts for peak gas demand and annual consumption. These affect supply adequacy projections as soon as next year, and diverge more over the next 20 years. Flexible resource and infrastructure solutions will be needed to manage risk and address current and future consumer needs.
- **Gas is forecast to have a continuing role in the integrated energy system, including a critical role for gas generation of electricity** in the National Electricity Market (NEM). Especially as coal generation retires, gas generation is projected to support and firm variable renewable energy generation (VRE), help meet the NEM's energy needs if coal generation and other dispatchable sources are unavailable, and provide power system services to support grid security and stability. Gas generation also will continue to provide a dispatchable source of capacity to meet extreme demand conditions.
- **In the short term**, new greenfield infrastructure solutions are unlikely to be operating in time for the earliest identified risk of gas shortfalls, in winter 2023. Brownfield solutions, such as duplication of the Winchelsea compressor on the South West Pipeline (SWP), may still be possible and improve supply available to south-eastern demand centres. Otherwise, the most likely lever to mitigate these risks is demand management at times of peak gas demand (in particular, reducing how much gas is used at these times to generate electricity).
  - In some scenarios, AEMO forecasts a risk of gas shortfalls in extreme weather conditions from winter 2023. The risk arises in south-eastern regions where gas flow is constrained by existing pipeline capacity limits – New South Wales, the Australian Capital Territory, Victoria and Tasmania. The 2021 GSOO identified this risk but expected Port Kembla Energy Terminal (PKET) to be operating by winter 2023. Developers now advise that they remain committed to the terminal and associated pipeline infrastructure, but insufficient customer contracts have delayed the relocation and operation of the floating storage and regasification unit (FRSU), and project works will not be complete until late 2023. AEMO now classifies the project as anticipated supply for winter 2024.
  - South-eastern gas production will drop significantly from 2023, and shallow liquified natural gas (LNG) storages will need to be managed so they can help mitigate shortfall risks. Since last year, some producers now expect more short-term south-eastern supply, and more pipeline capacity to move gas to the south-east has been committed, but this does not remove the risk entirely. .
  - Unlike the NEM, the gas markets have limited mechanisms to deliver broad consumer demand response. Co-ordinating gas and electricity systems will be important to achieve demand response

through minimising electricity generation from gas at peak gas demand times while also delivering reliable supply to electricity and gas consumers.

- **Longer term**, annual domestic consumption is forecast to fall as consumers shift from gas to electricity or zero-emission fuels, but there are forecast to be peak winter days where gas demand may exceed supply.
  - With forecasts showing increasing peakiness and volatility, as gas generation in the NEM plays its firming role for VRE, flexible solutions will be needed to cost-effectively cover peaks that are significant but infrequent.
  - Existing, committed and anticipated supply, including anticipated LNG imports, is forecast to meet declining domestic gas consumption until 2033, in the *Step Change* scenario stakeholders consider 'most likely'. New gas resources will then need to become available to meet forecast consumer needs.

AEMO has modelled the future based on a range of plausible scenarios from the Draft 2022 *Integrated System Plan* (ISP). In this GSOO, ***Step Change*** assumes tangible and rapid change, with gas demand declining quickly and significant electrification (users switching from gas to electricity). ***Progressive Change*** assumes a slower transformation and gas consumption closer to historical levels. ***Hydrogen Superpower*** assumes hydrogen becoming significant for export and domestic energy markets. AEMO has also modelled extra sensitivities to test the impacts of specific changes to scenario assumptions, including stronger electrification and low gas prices.

AEMO's 2022 *Victorian Gas Planning Report* (VGPR) *Update*[1] complements this GSOO, focusing on the gas supply demand balance in Victoria for the next five years.

This GSOO examines the demand for and supply of natural gas, and considers possible alternative fuels such as hydrogen, biogas and other natural gas equivalent or constituent gases as competitors to natural gas. However, as the gas sector identifies pathways to decarbonise, there may be a greater role for these alternative gaseous fuels within the gas system. The Australian Energy Market Commission (AEMC)[2] is consulting on expanding the scope of the GSOO to accommodate natural gas equivalents as part of the hydrogen and renewable gas review, and future GSOOs may apply an alternative treatment, accommodating any changes to the National Gas Rules.

Key changes since the 2021 GSOO

- Compared to the 2021 GSOO, producers in Victoria and New South Wales have reported more committed and anticipated supply from 2022. However this GSOO also highlights greater uncertainty for the long-term needs for gas, and lower annual gas consumption generally expected in response to Australia's commitment to net zero emissions by 2050. For example, after industry consultation, AEMO's scenarios now assume stronger electrification (consumers switching from gas to electricity as a means to lower emissions as the NEM develops renewable energy) than they did last year.
- While both publications demonstrate risks of potential supply shortfalls in 2023, the 2021 GSOO projected shortfalls would be narrowly avoided from new committed supply by winter 2023. The 2022 GSOO conversely identifies that steps to transform gas demand and reduce consumption can narrowly avoid peak day shortfalls, if rapidly deployed as in AEMO's updated *Step Change* scenario.

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

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

- Last year, AEMO noted that there was sufficient supply projected to meet demand provided the first gas from the PKET[3], and associated upgrades to the Eastern Gas Pipeline (EGP), were delivered before winter 2023. Developers now advise that supply from PKET is anticipated by winter 2024, whereas the project was considered committed last year ahead of winter 2023. However, insufficient customer contracting could put anticipated supplies in 2024 at risk.
- Similarly, a new gas production facility at Golden Beach (with potential to convert to storage operation) was identified as an anticipated project targeting operation by the first quarter of 2023. While the project was also identified in the Commonwealth Government's subsequent National Gas Infrastructure Plan (NGIP) as a key project to address short-term risk of gas supply shortfalls, the latest advice to AEMO is that the project will not be available before winter 2023. Project proponent GB Energy recently finalised commercial loan arrangements with the Commonwealth Government[4] to progress development of the project.
- Despite this, new committed projects are under development, with expansions of the Moomba to Sydney Pipeline (MSP) and South West Queensland Pipeline (SWQP) facilitating increased supply capacity to consumers, reducing pipeline constraints.

- Increased uncertainty now exists in international energy markets, following the European energy crisis in the northern hemisphere winter of 2021-22 and the current conflict between Russia and Ukraine. The push in many countries to diversify away from Russian gas may affect Australian LNG exports as well as potential access to LNG imports, and the demand for floating storage and regasification units (FSRUs) which are the infrastructure enabling these imports.

The investment challenge is increased by uncertainty about future domestic gas needs

AEMO's forecasts for domestic gas consumption across different, plausible scenarios shows a range of possible future pathways for gas, with differing rates of change. Uncertainty about future consumer gas needs in the changing domestic market begins immediately and will only grow over time. This increases the challenge for designing solutions and committing to investments in the sector.

Consumers use natural gas in a broad range of areas including industrial processes, manufacturing, heating, and cooking. **Figure 1** highlights the breadth of domestic consumption forecasts, across scenarios and sensitivities, for gas use by industry, businesses and households (excludes LNG exports and gas for generating electricity).

The increased uncertainty represents a significant risk for potential investors in projects that rely on traditional stability in gas consumption magnitude and patterns. It also suggests opportunities for novel solutions that provide greater flexibility to meet less certain, changing consumer needs.

Key emerging drivers that may impact future gas consumption levels include:

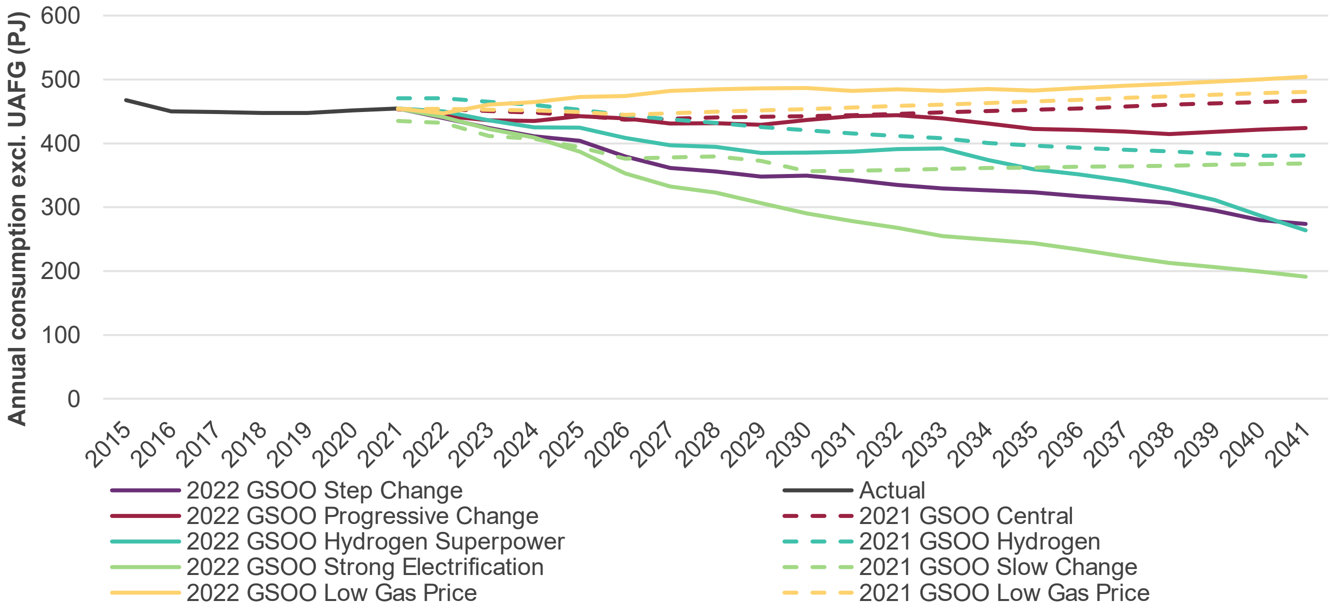
- Public policy and private investment in energy efficiency and electrification, which would reduce gas consumption. The extent to, and speed at, which business and household consumers switch from gas to electricity is uncertain. While governments are moving to increase electrification and improve the energy efficiency of gas appliances (for example, Victoria's Gas Substitution Roadmap and Victorian Energy Upgrades program), such action would need to speed up to rapidly reduce gas consumption.

[3] In the 2021 GSOO, the project was referred to by its earlier name of Port Kembla Gas Terminal.

[4] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/unlocking-critical-local-gas-production-and-storage.

- The potential growth of hydrogen as an alternative fuel for transport, industry and households. The pace and impact of hydrogen deployment will rely on technology improvement and consumer uptake. Adding further uncertainty, hydrogen could be produced through steam methane reforming (SMR), which uses natural gas, or through other technologies that do not use gas. AEMO has assumed some level of gas consumption for SMR hydrogen in all scenarios and sensitivities apart from the *Low Gas Price* sensitivity.

Figure 1 Actual and forecast annual domestic consumption, excluding gas generation, all scenarios and sensitivities, and compared to 2021 GSOO forecasts, 2015-41 (PJ)



Note: UAFG means "unaccounted for gas". It is gas lost in the network and not delivered to consumers. PJ stands for petajoules.

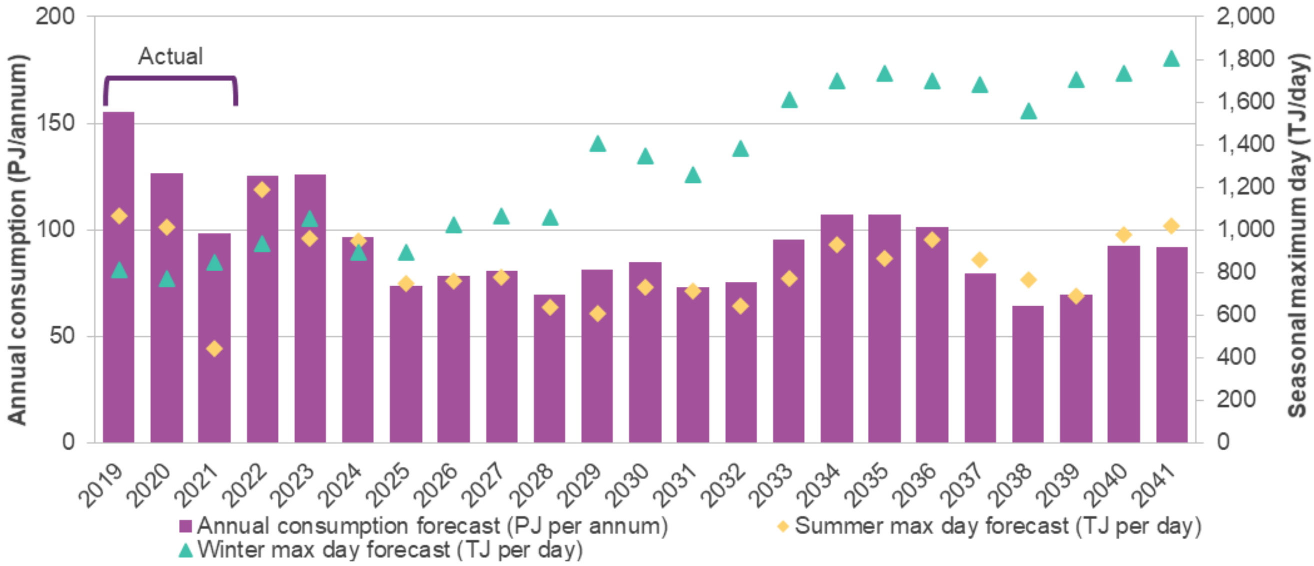
The other main component of domestic gas consumption, not shown in Figure 1, is gas used for gas generation of electricity. As AEMO's Draft 2022 ISP reported, gas generation is expected to play an important, continued role in the NEM. Especially as coal generation retires, gas generation can support the power system by responding to sudden changes in the supply demand balance, helping manage extended periods of low renewable generation, helping meet the NEM's energy needs if coal generation and other dispatchable sources are unavailable, and providing critical power system services to maintain grid security and stability.

Since 2010, gas consumption for generating electricity in the NEM has trended down, as renewable generation (particularly wind and solar photovoltaic [PV] technologies) has grown and displaced both coal and gas.

Figure 2 shows (for *Step Change*) that in the next 20 years:

- Annual volumes of gas consumed for electricity generation (shown by the bars) are forecast to continue their recent decline until the mid-2020s, but then remain flat and potentially increase. Actual consumption in future years could vary significantly from the forecast average. Gas generation can often be event-driven, increasing or reducing depending on the availability of alternatives such as wind, solar, coal and hydro generation.
- Winter peak day gas generation demand is forecast to grow, demonstrating an increasingly 'peaky' profile as annual volumes are forecast to remain relatively steady. The volatility of conditions that drive significant need for gas generation is forecast to result in total monthly gas consumption being consumed on only a few days in those months. This increasing volatility supports the need for increasingly flexible solutions, such as localised gas storage and dual-fuel capability of new gas generation plants.

Figure 2 Actual and forecast gas generation annual consumption (PJ/annum) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-41



Note: The forecast maximum daily demand shown for summer and winter represents the median across different modelled weather patterns.

Gas supply has increased since 2021, but the adequacy outlook still highlights a tight supply demand balance in the south-east

The short-term supply assessment focuses particularly on the south-eastern regions of New South Wales and the Australian Capital Territory, Victoria[5], and Tasmania.

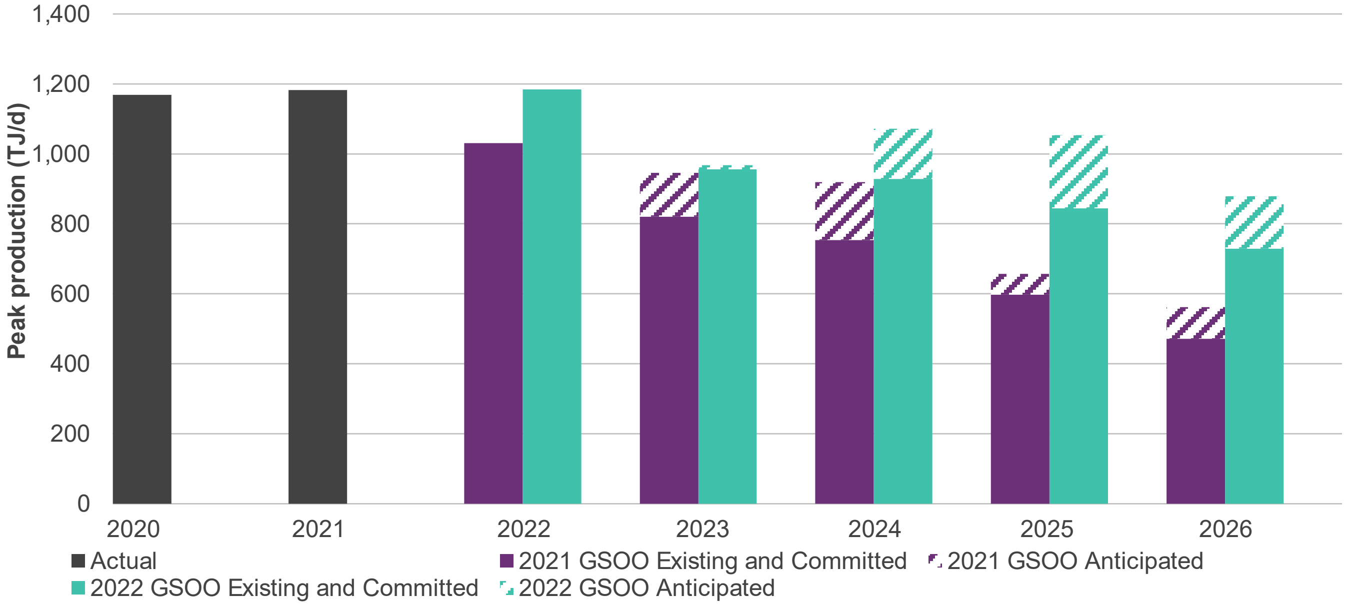
As **Figure 3** shows, producers in these regions have reported more committed and anticipated daily production from 2022 than they did in the 2021 GSOO.

The context, however, is a growing gas supply scarcity challenge in the south-east from 2023, driven by:

- The ongoing decline (and sustained drop from 2023) of traditional supply from Bass Strait, mainly processed through the Longford Gas Plant and flowing to consumers via the Victorian gas network, the Eastern Gas Pipeline (EGP) to New South Wales and the Australian Capital Territory, and the Tasmanian Gas Pipeline (TGP).
- Limitations on the capacity of pipelines to transport gas from supply centres to the south-east demand centres (where shortfalls are forecast). The MSP limits how much gas can be sent from northern producers to the south-east, and is undergoing Stage 1 of a planned upgrade. The SWP limits how much supply from Port Campbell production capacity and the Iona gas storage facility can reach south-eastern gas consumers on peak demand days.

[5] Victorian gas customers west of Port Campbell, including Mortlake Power Station, are excluded from this geographical definition, as they are outside the area with constrained supply.

Figure 3 Actual and forecast maximum daily production capacity from south-eastern gas fields (excluding LNG imports), 2020-26 (TJ/d)



These challenges are reflected in AEMO's supply adequacy assessment, which from winter 2023 forecasts shortfall risks in the south-eastern regions in extreme weather conditions, in some scenarios.

Figure 4 illustrates[6] the ability of south-eastern production, pipeline capacity, and stored gas to meet actual gas demand in 2020 and 2021, and its projected ability to meet one-in-20[7] demand forecasts to 2026 in two GSOO scenarios, *Step Change* and *Progressive Change*.

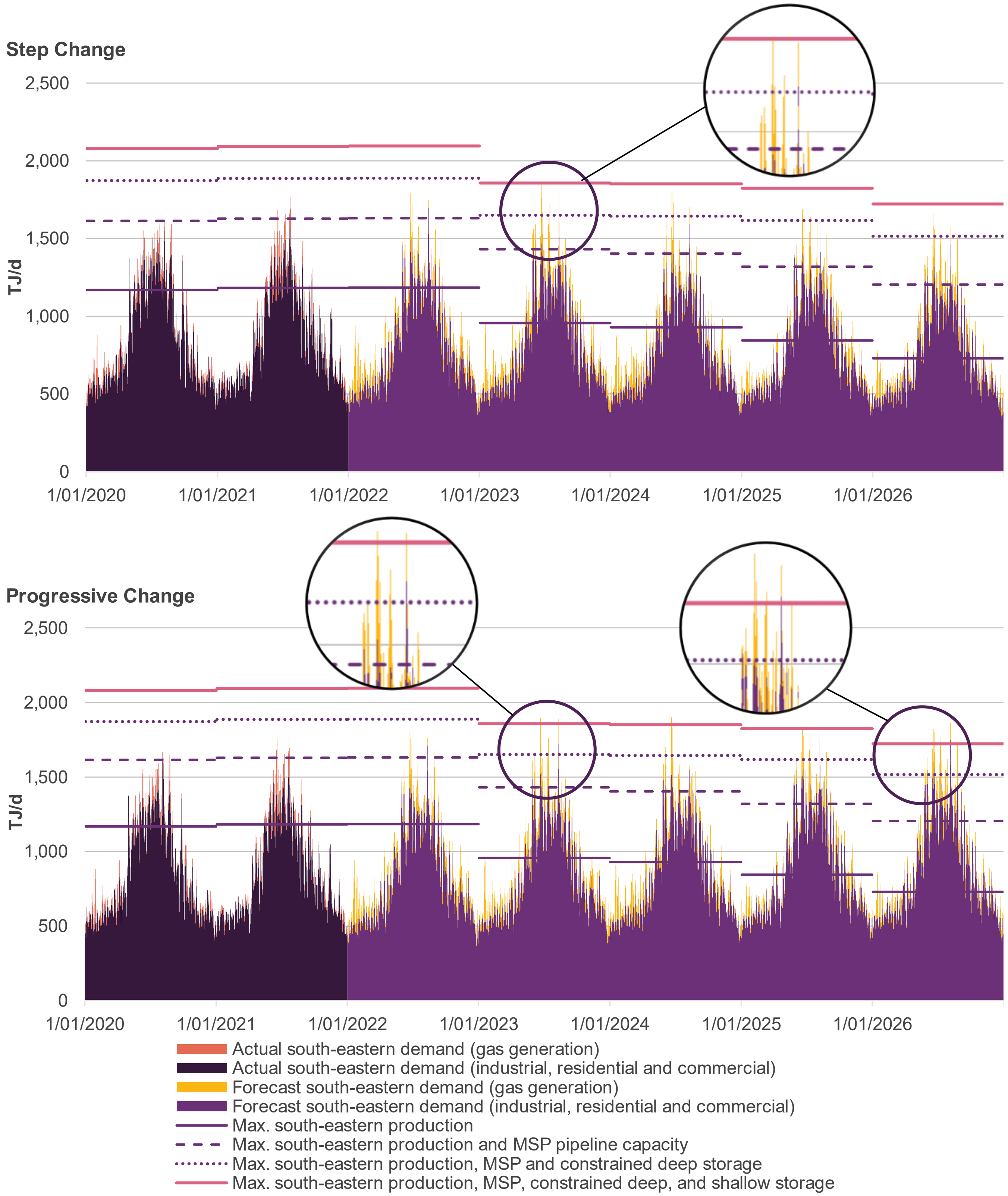
The horizontal lines show, for each year, how much supply has been and is forecast to be available to meet projected daily demands, based on:

- Maximum gas production in the south-eastern regions only (solid purple line), plus
- Gas supplied from Moomba and imported from Queensland through the MSP (dashed purple line) assuming the pipeline is operating at maximum capacity, plus
- Deep storage (supply from Iona storage constrained by SWP capacity, noted above – dotted purple line), plus
- Shallow LNG storages at Dandenong and Newcastle (solid red line).

[6] The figure provides an illustration of available supply, demonstrating the maximum supply capacity as a fixed value for each supply category (each horizontal line). AEMO's gas adequacy methodology calculates the adequacy of supply on a daily basis, allowing for dynamic infrastructure limits and the energy available in storage, and supply capacity may differ from this illustration.

[7] Forecasts with a one-in-20 probability of exceedance are expected to be met or exceeded one in every 20 years, representing more extreme weather than the average conditions assumed in a one-in-two forecast, which is expected to be met or exceeded one in every two years.

Figure 4 Actual and forecast daily gas demand, *Step Change* (top) and *Progressive Change* (bottom), and production capability in south-eastern regions with existing and committed projects only, 2020-26 (TJ/d)



Source: Gas Bulletin Board (GBB), GSOO surveys, and AEMO forecasts of one-in-20 south-eastern demand.

The key points highlighted in Figure 4 are that, in the south-east:

- Gas adequacy is tight in both scenarios in 2023. In *Step Change*, a gas shortfall is narrowly avoided, assuming actions and investments that reduce gas demand (like switching residential gas heating to electric, and improving buildings' energy efficiency) are taken quickly. While these are likely over time, the pace so far has been relatively slow, and urgent action would be needed to put south-eastern regions on the *Step Change* path by next winter. If by winter 2023 this has not happened, and peak demand is as forecast in *Progressive Change* (up to 54 terajoules a day [TJ/d] higher than in *Step Change*, equivalent to the demand of some 100,000 residential households[8]), there are risks of small, infrequent gas shortfalls under extreme one-in-20 year demand conditions.
- South-eastern gas production (the solid purple lines) will fall significantly from 2023 and stay at lower levels. With reduced local production, operational management of shallow LNG storages will be increasingly important, to ensure these facilities have sufficient stored energy to mitigate shortfall risks.
- Gas for electricity generation (actuals shown in dark orange, forecasts in yellow) is forecast to be a significant contributor to total peak day demand. It is forecast to create peaks where demand exceeds available supply already from 2023, driven by the needs of the NEM and the availability of alternative generation sources.
- In 2026, in *Progressive Change*, forecast peaks start to exceed projected supply capacity more frequently, and also start exceeding supply capacity even with no gas generation.

No domestic shortfall risks have been identified in the short term outside the south-eastern regions of New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Solutions will need to provide flexibility

The 2022 GSOO reports on a changing gas sector, a wide range of plausible futures for gas demand, and the impacts of uncertainty on market responses.

In the short term to 2026, forecast risks can be mitigated by completion of committed infrastructure, development of anticipated projects, and – especially for winter 2023 – demand side solutions:

- With the first forecast scarcity risks now just over a year away, it is important that committed infrastructure developments, such as the Western Outer Ring Main (WORM) in Victoria and the Stage 1 upgrade of the SWQP and MSP, are delivered on schedule. By increasing how much gas can flow from Queensland to south-east consumers and removing constraints on injecting from or refilling Iona gas storage, these upgrades will increase the operability of the gas network and provide more flexibility to meet a variable and infrequent need under extreme circumstances.
- Given the lead time needed to plan, obtain approval for, and build new greenfield infrastructure, demand flexibility is the likely best lever to address forecast supply scarcity risks from winter 2023. Brownfield solutions, such as duplication of the Winchelsea compressor on the SWP, may still be possible and improve supply available to south-eastern demand centres. Otherwise, there are some options available in the short term that can reduce gas use at peak times:
  - If gas generation drew less gas than forecast, and was actively managed at times of peak gas demand, the forecast gas shortfalls during extreme conditions may be avoidable without compromising electricity reliability, but adequacy would be tight.

8 In practice, industrial users would be expected to contribute some of this demand difference between the scenarios.

  - Curtailment of gas generation is a key mechanism available to avoid peak day gas supply shortfalls. Some gas generators have dual-fuel capability so they can generate electricity even if they are subject to gas curtailment.
  - Voluntary demand side participation in the electricity market may reduce electricity demand, lowering demand for gas generation and reducing the risk of gas supply shortfalls.
  - The impact of gas generation curtailment on reliable electricity supply would depend on the state of the electricity system. If high winter electricity demand, low wind/solar conditions and/or unplanned coal generation outages coincided, gas curtailment could create electricity supply scarcity risks if available hydro, coal, renewable generation and demand side participation was already fully utilised. Coincident electricity scarcity risks are less likely while mainland NEM regions are summer peaking, as they currently are.
- Jurisdictions could also ask household consumers through the media to voluntarily reduce their use of gas during forecast extreme peak day events.

- After winter 2023, to 2026, shortfall risks are expected to be further reduced by anticipated projects including PKET, Golden Beach and some additional Victorian offshore field developments starting up.

In the longer term, new sources of supply will be needed, even though annual domestic gas consumption is forecast to decline:

- More frequent gas supply gaps are evident in all scenarios, but the timing, profile and magnitude of these gaps varies. Solutions must consider the changes and uncertainty described in this GSOO.
- Specifically, as south-eastern gas supply continues to fall, AEMO forecasts that:
  - There is enough existing and currently committed supply available domestically to meet overall forecast annual domestic consumption (including for gas generation) until 2028 (or 2026 if electrification is slower than forecast in *Step Change*). As discussed above, however, MSP and SWP constraints mean not enough gas may be delivered to meet peak demand in the south-east under some conditions from 2023.
  - After 2028 (or 2026 in *Progressive Change*), supply resources beyond existing and committed – such as those reported in the NGIP – would need to be developed to meet forecast annual consumption. Although consumption is forecast to decline, projected supply is declining faster and gaps are expected.
  - If the assessment assumes all currently anticipated gas supplies are also brought to market, forecast annual domestic supply gaps are delayed five years, until 2033 in *Step Change*. This deferral relies on full utilisation of LNG imports from the PKET project anticipated to be developed by winter 2024.
- The potential use of alternative zero-emissions fuels in the gas system to complement and/or substitute gas use (including in generation) will impact the type and magnitude of additional gas supply required.
- Beyond domestic consumption, significant levels of LNG export are forecast by the Queensland LNG producers. Sustaining this level of export relies on the LNG producers bringing online significant levels of anticipated and uncertain supply that is not yet committed.

While consumption uncertainty is highlighted by differences across scenarios, increasing "peakiness" of gas demand is a common trend:

- In this context, opportunities for response are likely to come from more flexible, agile solutions that can support gas demand that is uncertain and increasingly peaky. Challenges can arise on days when gas generation needs to operate at high volumes to deliver electricity to consumers (potentially days where both electricity and gas demand are at peak levels).

- As well as flexible utilisation of infrastructure, demand response could potentially play a growing role in managing peak gas demand, as it does in the NEM. If new instruments are developed in the south-east that emulate contingency gas in the Short Term Trading Markets (STTMs) or the NEM's Reliability and Emergency Reserve Trader (RERT), this may help enable greater operational control of loads to reduce gas demand during extreme demand events. Any new instrument will be a shift from current practice. It would take time for the mechanism to be appropriately developed, and for contracts to roll over to new terms if customers were willing to accept curtailment.

This GSOO reinforces the importance of sector coupling (interaction between electricity, gas and potentially hydrogen in future) in navigating the transition towards net zero emissions. The flexibility of the electricity system and its existing mechanisms could, at times of gas supply scarcity, help reduce demand for electricity through voluntary load shedding, meaning less need for gas generation. Existing instruments such as the Gas Supply Guarantee and LNG Heads of Agreement will remain important for the gas and electricity sectors to optimally use available energy resources and reduce security and reliability risks in both systems while protecting domestic gas consumers. Addressing pipeline constraints can increase the effectiveness of these mechanisms, especially to reduce south-eastern shortfall risks.

1 Introduction

In this *Gas Statement of Opportunities* (GSOO), AEMO assesses the adequacy of reserves, resources, and infrastructure to meet domestic and export needs for gas over a 20-year outlook period across all Australian jurisdictions other than Western Australia and the Northern Territory. The GSOO analyses a range of potential futures, focusing on the adequacy of the system to meet changing gas needs from now until 2041.

In this GSOO, "gas" means natural gas unless otherwise specified. This GSOO does not include blended gas from hydrogen, biogas or any other natural gas equivalent or constituent gas in its modelling of gas supply. Where appropriate, scenarios may consider offsets to demand from hydrogen, as outlined in Section 2. The Australian Energy Market Commission (AEMC) is consulting[9] on expanding the scope of the GSOO to accommodate natural gas equivalents as part of the hydrogen and renewable gas review and AEMO is engaging with this process to understand the impacts of any recommendations for future GSOOs.

1.1 Forecasting in the context of a changing gas sector

The gas sector in Australia is transforming, driven by two significant trends. The first trend has been underway for some years. The second is emerging rapidly and is speeding up the rate of transformation:

- **Change in supply –** supply from conventional sources in the south[10], in particular offshore Victoria, continues to decline. Alternative supply sources required to meet domestic customer needs are mainly in the north[11], such as coal seam gas (CSG) from Queensland and gas supplied from Northern Territory. This gas will need to be transported to the main consumer centres in the south, in particular Victoria, New South Wales and the Australian Capital Territory, and South Australia. To supplement domestic gas supply in those areas, liquified natural gas (LNG) import terminals are being investigated.
- **Gas in a low carbon future** – Australia's pursuit of economy-wide carbon emissions reduction targets will have a transformative effect on the role of gas in the GSOO's 20-year outlook and beyond. Like the transformation of the electricity power system in the National Electricity Market (NEM) and globally, the pace and impacts of change on the gas sector will depend on advances in technology, developments in the integrated energy system, and choices made by industrial, commercial and household consumers.

The impacts of changes in southern supply and connections with other gas markets have been the theme of recent GSOOs, as well as studies by the Commonwealth Government and the Australian Competition and Consumer Commission (ACCC). For example, the Commonwealth Department of Industry, Science, Energy and Resources (DISER) published a draft and final *National Gas Infrastructure Plan* (NGIP) in 2021, identifying short-, medium- and long-term priorities for infrastructure developments to deliver enough gas in the domestic market.

The gas sector transformation underway may increase challenges for system operation, planning and investment, especially because – as this GSOO explores – there is considerable uncertainty about the pace and impacts of the transformation:

[9] See https://www.aemc.gov.au/market-reviews-advice/review-extending-regulatory-frameworks-hydrogen-and-renewable-gases.

[10] Southern regions refers to developments, consumers, and existing facilities in South Australia (including the Queensland component of the Cooper–Eromanga basin), New South Wales, the Australian Capital Territory, Victoria, and Tasmania.

[11] Northern regions refers to developments, consumers, and facilities in Queensland (excluding any component of the Cooper–Eromanga basin, which is part of the southern regions) and Northern Territory assets with access to the Northern Gas Pipeline (NGP). This is the area with the majority of anticipated and prospective future gas supply.

- The forecast level of annual domestic gas consumption[12] varies widely across the range of plausible scenarios modelled in this GSOO, which assume different pathways for use of gas by industry, businesses and households. The variation in future gas use between scenarios is apparent as early as next year and widens over the 20-year outlook period.
- AEMO forecasts increased 'peakiness' and volatility in gas demand[13] across most scenarios, as gas generation is used to provide 'firming'[14] of renewable energy (such as wind and solar generation) in the NEM. This forecast trend projects gas demand on peak days (especially in winter) growing even when annual consumption falls or stays steady, and potentially will see the total gas used in a month consumed in just a few days.
- The growing focus on development of a hydrogen industry in Australia means that users switching from gas to hydrogen fuels, or general blending of hydrogen into the gas network, may impact future gas and investment needs. The different technologies that could be used to produce hydrogen consume different amounts of gas, so uncertainty about future hydrogen technology choices adds extra uncertainty to gas consumption forecasts, even within scenarios. Other zero or low-carbon alternatives to natural gas also exist, such as direct use of biogas or biomass.

1.2 Scenarios and sensitivities

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 2022 GSOO, AEMO modelled the next 20 years using scenarios from the *Draft 2022 Integrated System Plan* (ISP) that are most relevant to the gas sector – *Progressive Change*, *Step Change* and *Hydrogen Superpower*. To complement the scenarios, AEMO also explored two key sensitivities – *Strong Electrification* and *Low Gas Price* – to assess the impacts of changes to specific scenario assumptions.

These scenarios and sensitivities are described in detail in AEMO's 2021 *Inputs, Assumptions and Scenarios Report* (IASR)[15]. In summary:

- ***Step Change*** is a future with a rapid transition towards net zero emissions economy wide. This includes significant levels of electrification (consumers shifting from gas to electricity) early on, as the electricity sector decarbonises with increasing renewable energy penetration and retiring coal generation.
- ***Progressive Change*** also targets net zero emissions, but the trajectory to achieve it is quite different from *Step Change*. The scenario reflects slower action across the economy, allowing time for technologies to develop, but relies on very strong transformation efforts later to get to net zero by 2050.
- ***Hydrogen Superpower*** describes a future with very strong environmental objectives globally, where Australia leverages its low-cost renewable resources to become a major exporter of hydrogen to countries that rely on imported energy. The scenario assumes higher growth in population and the economy overall as a result. Hydrogen is also used domestically to offset gas consumption, with reduced focus on electrification.

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[12] Consumption means gas consumed over a period of time, usually a year but sometimes a month.

[13] Demand means the amount of gas used on a daily basis. The peak across a season is called maximum demand or peak day demand.

[14] The firmness of a resource relates to its ability to confirm energy availability and dependably supply the system when requested.

[15] AEMO publishes and regularly updates the scenarios, inputs and assumptions it uses in its modelling. For those used in this GSOO, see the 2021 IASR, published July 2021, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

- ***Strong Electrification*** reflects a similar high-growth future to *Hydrogen Superpower*, retaining the higher economic and population growth assumptions, but with minimal hydrogen adoption. Instead, a very high level of electrification is assumed.
- ***Low Gas Price*** is a sensitivity that examines a likely upper bound to gas demand, with lower gas prices and no coordinated action for the gas sector to contribute to Australia's net zero commitment.

The scenarios have been defined based on specific assumptions, refined through extensive consultation with stakeholders. These include assumptions about the degree of electrification of existing gas demand, uptake of energy efficiency measures, hydrogen demand, and the technology used to produce hydrogen.

In consultation for the 2022 ISP, stakeholders identified *Step Change* as the scenario they considered the most likely pathway for Australia's energy sector. For the gas sector, *Step Change* projects tangible and rapid reductions in gas consumption, particularly as consumers electrify their energy needs.

This GSOO highlights the adequacy of gas supply for both the *Step Change* and *Progressive Change* scenarios, to clearly show the opportunities and risks for the gas sector and consumers of faster and slower transformation.

Table 1 below summarises the key drivers affecting energy consumption considered most relevant to the gas market across the scenarios and sensitivities modelled.

Table 1 Scenario drivers of most relevance to the gas market

Driver	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Strong Electrification*	*Low Gas Price*
Economic growth, population, and gas connections outlook	Moderate	Moderate	High	High	Moderate
Energy efficiency gains	High	Moderate	High	High	Moderate
Fuel-switching from natural gas	High	Moderate	High	Very high	Low-moderate
Hydrogen adoption	Growing domestic use only	Growing domestic use only	Large NEM connected export and domestic use	Limited domestic use only (mainly for transportation)	Limited domestic use only (mainly for transportation)
Natural gas price	Moderate	Moderate	Moderate	Moderate	Low
Renewable energy generation	High	Moderate	Very high	High	Low

Forecasts for other scenarios and sensitivities are also presented throughout the report to highlight the wide range of plausible pathways for gas in the next 20 years, and the risks and opportunities arising from this uncertainty.

1.3 Improvements in the 2022 GSOO

In this GSOO, AEMO has:

- Improved the representation of operational limitations of the Moomba to Sydney Pipeline (MSP) supply to New South Wales and Victoria, as well as seasonal variations. This change improves AEMO's assessment around peak day shortfalls in south-eastern[16] regions.

[16] "South-eastern" regions means developments, consumers, and facilities in New South Wales, the Australian Capital Territory, Victoria and Tasmania. This part of the south is limited by pipeline constraints, particularly for the South West Pipeline (SWP) and MSP.

- Incorporated the multi-sector analysis of the 2021 IASR to capture the spread of forecast fuel-switching due to decarbonisation actions, including forecast hydrogen production from steam methane reformation (SMR) processes for each scenario.
- In forecasting consumption for gas generation, AEMO has adjusted availability of coal-fired generation to account for unexpected events that can impact the NEM generation mix. This has been done to improve the accuracy of the gas generation forecast (see Appendix A1.5), which has not reflected such events in previous GSOO central estimates, based on analysis of power station failures, coal supply-chain disruptions, and major environmental interruptions affecting the NEM in recent years.

1.4 Supplementary information

Supporting material – including supply input data files, methodology reports, and figures and data – is available on AEMO's website[17], along with previous GSOO reports.

The supply input data files provide information (including capacity) about pipelines, production facilities, storage facilities, field developments, and any new projects or known upgrades considered in this GSOO analysis. These files also provide an update of reserves and resources and cost estimates used for the GSOO modelling[18].

AEMO's 2022 *Victorian Gas Planning Report* (VGPR) *Update*[19] complements the GSOO by providing a focused assessment of the supply demand balance to 2026 in Victoria's Declared Transmission System (DTS).

Other relevant reference materials are listed in **Table 2** below.

Table 2 Other relevant reference materials

Information source	Website address and link
Demand forecasting data portal	http://forecasting.aemo.com.au
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb
2021 *Inputs, Assumptions and Scenarios Report*, and Excel Workbook	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
BIS Oxford Economics, 2021 Macroeconomic forecasts	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf
CSIRO and ClimateWorks, Multi-sector energy modelling	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf
Strategy.Policy.Research, Energy Efficiency Forecasts 2021 – Final Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/strategy-policy-research---energy-efficiency-forecasts-2021.pdf
Lewis Grey Advisory, Gas Price Projections for Eastern Australia Gas Market 2022 - Report	https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/lewis-grey-advisory-gas-price-projections-report.pdf
Lewis Grey Advisory, Gas Price Projections for Eastern Australia Gas Market 2022 - Workbook	https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/lewis-grey-advisory-gas-price-projections-workbook.xlsx

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

[18] The published file showing reserves and resources are based on AEMO's survey of gas producers and information from Rystad Energy, supplemented by 2021 GSOO data if required.

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

2 Gas consumption and demand forecasts

This chapter outlines forecasts of annual gas consumption and the maximum daily gas demand across the various customer sectors of gas.

Consumption and demand forecasts are available on the AEMO Forecasting data portal[20].

Key forecast trends

- **The gas sector is transforming, with the pace and scale of transformation affecting the gas sector currently highly uncertain.** Australia's transition to a net-zero emissions economy is expected to lead to a shift in consumer choice, technology and public policy which will affect future gas system needs.
- **Future annual gas consumption** is affected by many drivers, and the 2022 scenario forecasts capture a wider spread between the scenarios than in previous years, across the forecast horizon and as soon as next year. In most cases, gas consumption is forecast to reduce as consumers embrace energy-efficient appliances and switch energy use towards electricity and potentially hydrogen.
- **Maximum daily gas demand** is highly seasonal, and southern states in particular have significant gas use from heating appliance loads in winter. For scenarios where heating appliances are largely replaced with electric alternatives, such as *Step Change*, winter peaks are forecast to decline significantly. As that leads to an increase in gas generation on those days (see below), combined winter daily peaks will remain high.
- **Gas for generation of electricity** is projected to become increasingly peaky. Annual gas consumption for gas generation in the NEM is forecast to decline as renewable energy penetration grows, but maximum daily demands will continue to be high as gas generation plays an increasingly important role in firming renewable energy as coal generation retires.
  - Gas is expected to retain a key role in maintaining the reliability and security of the NEM, especially during periods of low variable renewable energy (VRE) generation or prolonged outages impacting other dispatchable generation.
  - The forecast sees higher winter NEM demands from electrification of heating loads increasing the need for gas generation in winter, with gas generation moving from summer peaking to winter peaking.

2.1 Total gas consumption forecasts

Figure 5 and **Figure 6** show the 20-year total consumption forecasts under the *Step Change* and *Progressive Change* scenarios respectively, broken down by consumer type.

The drivers and trends for each sector are discussed in sections 2.2.1-2.2.4.

[20] At http://forecasting.aemo.com.au/ – after selecting either annual consumption or maximum demand under the Gas section, select 'GSOO 2022' from the publication drop-down.

Figure 5 Actual and forecast total annual gas consumption, all sectors, *Step Change* scenario, 2015-41 (PJ)

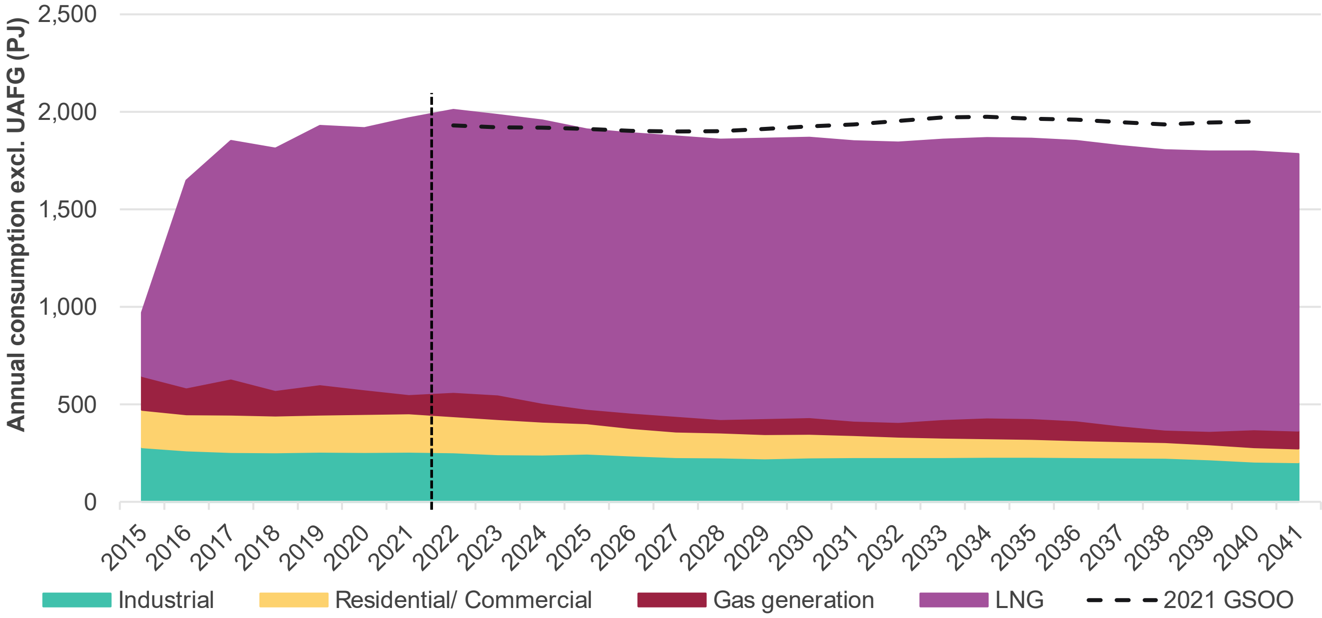


Figure 6 Actual and forecast total annual gas consumption, all sectors, *Progressive Change* scenario, 2015-41 (PJ)

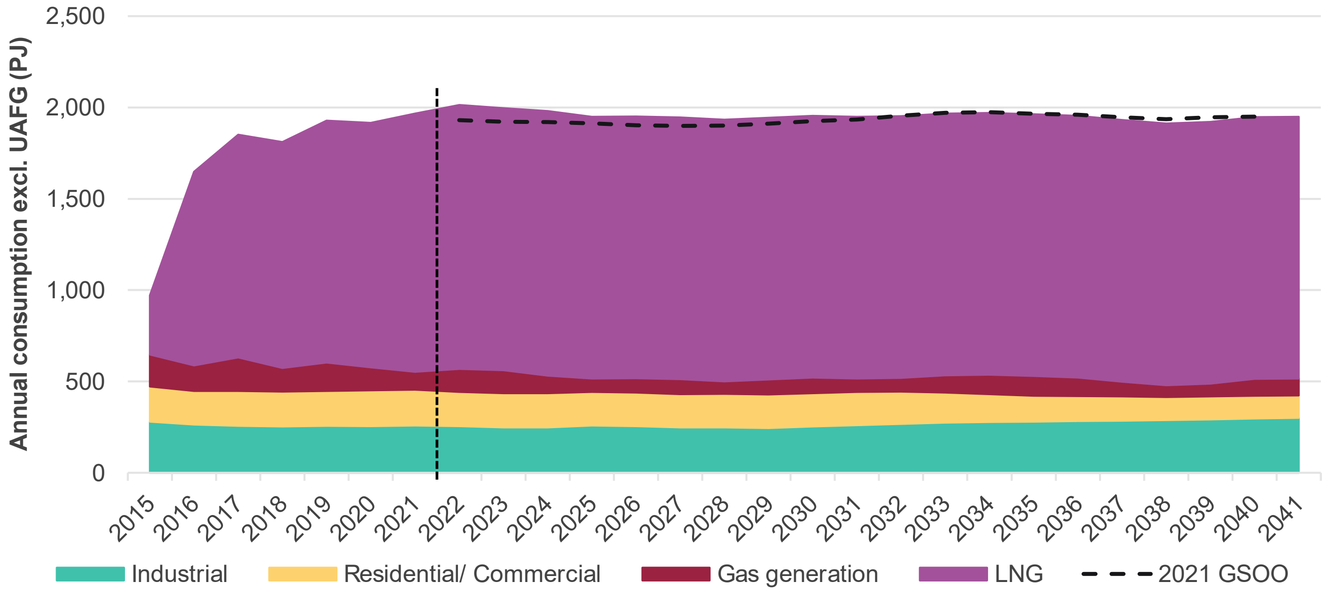


Figure 7 compares forecasts for the 2022 GSOO scenarios with those modelled in the 2021 GSOO.

The relative reduction in the 2022 forecasts show the projected impact of fuel-switching by consumers, from gas to electricity and hydrogen. AEMO's scenarios capture anticipated consumer preferences to reduce the emissions intensity of residential, commercial and industrial processes. In some scenarios, falling gas consumption may be offset by an increase in gas used in SMR hydrogen production to meet domestic hydrogen demand (see **Table 3** below).

Figure 7 **Actual and forecast total gas consumption, all sectors, all scenarios, and compared to 2021 GSOO, 2015-41 (PJ)**

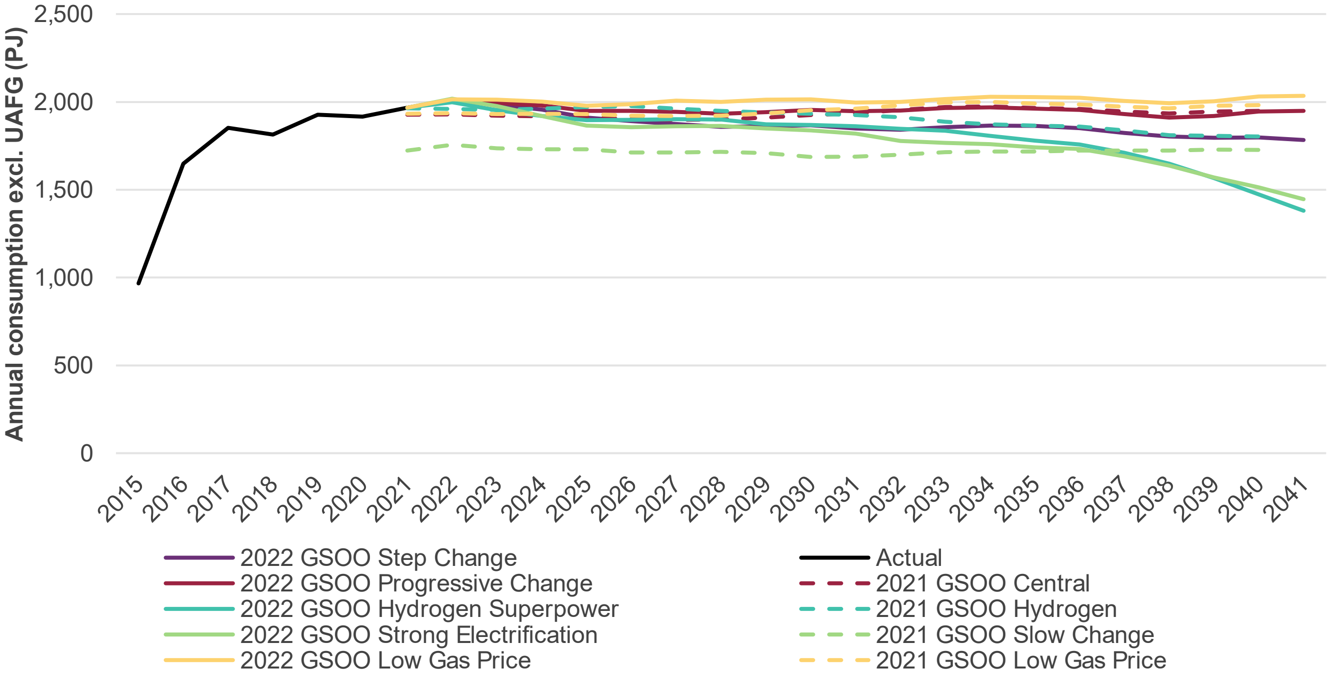
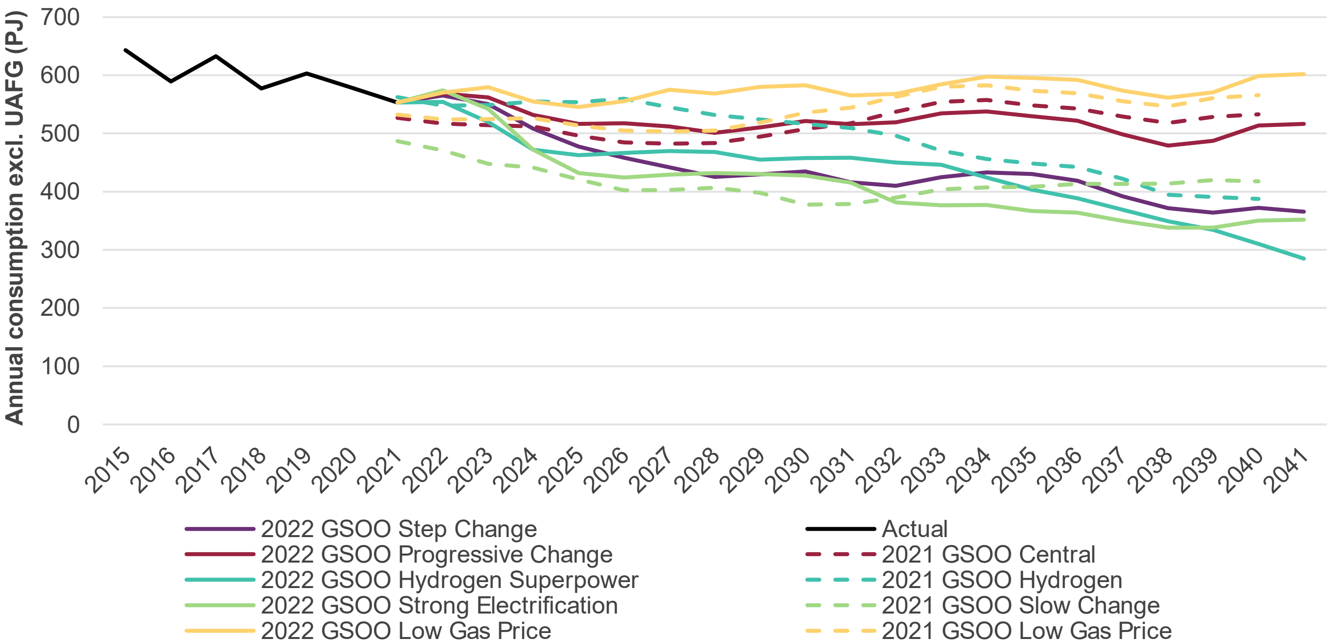


Figure 8 below shows domestic-only annual consumption forecasts, excluding LNG exports, so it is easier to see projected domestic trends.

Figure 8 **Actual and forecast domestic gas consumption, all scenarios, and compared to 2021 GSOO scenarios, 2015-41 (PJ)**



This figure highlights that:

- The dispersion of the forecasts increases over time, and the range is wider by the end of the forecasting period than was forecast in the 2021 GSOO.
- Variation in gas generation continues to be a major influence on annual fluctuations in domestic gas consumption. Developments in the NEM are anticipated to have a key influence on how much gas is used.
- Consumption is generally forecast to fall in all scenarios as consumers switch from natural gas to lower or zero emissions alternatives, including electricity and hydrogen. Investments in energy efficiency, such as building quality improvements, are also key drivers for reducing gas consumption. If gas prices reduce and remain low, some potential growth in gas consumption is plausible.

Table 3 shows domestic consumption forecasts excluding gas generation, including the scale of assumed gas consumption to produce hydrogen using SMR. It highlights the opportunity for gas to be used in the production of 'blue hydrogen' (the creation of hydrogen via SMR with processes to capture emitted CO_2 via carbon-capture and storage technologies).

The GSOO scenarios assume SMR-produced hydrogen is complemented with electrolyser-produced hydrogen (utilising renewable energy from the NEM). The potential emergence of hydrogen loads (for use in transport, industrial applications and blending into the reticulated gas network), and the different implications for gas demand of the technology used to produce hydrogen, increases current uncertainty regarding the future needs of the gas system.

Table 3 Forecast domestic gas consumption, excluding gas generation, showing forecast consumption of gas for SMR in the *Step Change*, *Progressive Change* and *Hydrogen Superpower* scenarios (PJ)

	Domestic demand excluding gas generation and SMR (PJ)	SMR load (PJ)	Total (PJ)
Step Change			
2022	440	0	440
2025	395	8	404
2030	327	22	349
2035	292	31	323
2040	246	34	280
Progressive Change			
2022	443	0	443
2025	431	12	442
2030	400	36	436
2035	360	62	422
2040	341	80	422
Hydrogen Superpower			
2022	450	0	450
2025	412	13	424
2030	307	78	385
2035	240	120	360
2040	165	122	287

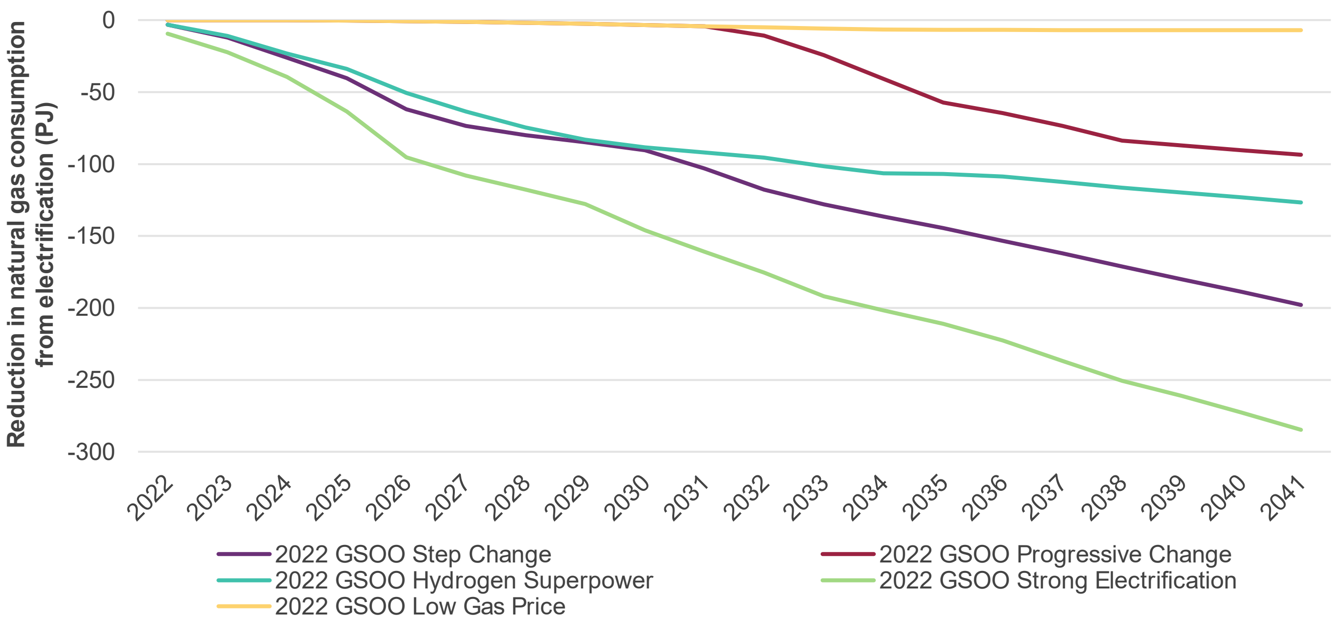
2.1.1 Trends in consumption drivers

Electrification and hydrogen uptake

AEMO engaged consultants CSIRO and ClimateWorks Australia to conduct multi-sector modelling to establish least-cost pathways for Australia's economy, to achieve emissions targets while meeting scenario-based demand drivers[21]. The 2021 IASR discusses the key assumptions and outcomes of the modelling. The 2022 GSOO applies outcomes related to fuel-switching from gas to electricity and hydrogen.

Electrification is forecast to occur across the residential, commercial and industrial sectors, although some types of consumer are not considered appropriate to electrify (for example, steel and aluminium manufacturing may have technical barriers to electrification). **Figure 9** demonstrates the wide range of uncertainty affecting the forecast pace and scale of electrification, reflecting the challenge for Australia's gas sector to contribute to Australia's net zero emissions objectives by 2050. More rapid electrification may more quickly enable achievement of that objective, but would require more significant policy intervention to expedite technology change.

Figure 9 Forecast reduction in gas consumption from electrification by scenario, 2022-41 (PJ)

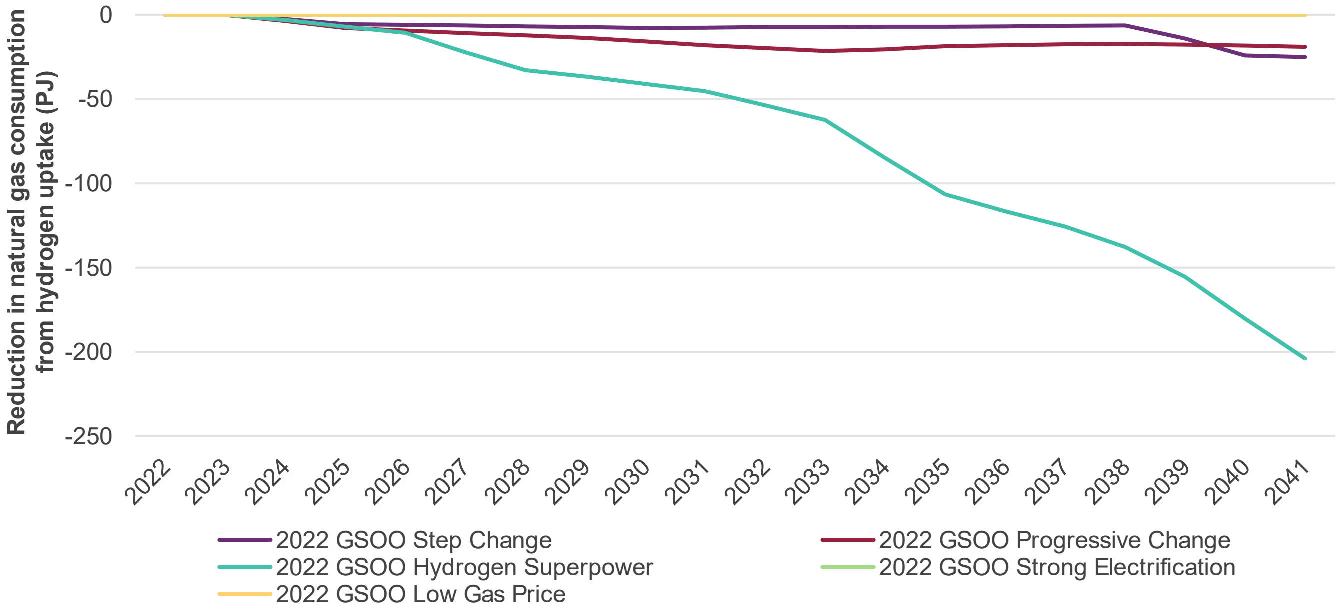


Hydrogen uptake provides an opportunity for direct replacement of natural gas and alternative fuels in transport as well as direct fuel-switching from gas to hydrogen for larger industrial customers. There is also an opportunity for gas blends to penetrate the gas distribution system.

Figure 10 shows the forecast reduction in natural gas consumption by scenario due to consumers' hydrogen uptake. These reductions in gas consumption may be offset by potential gas consumption for production of hydrogen from SMR in some scenarios, as discussed and shown above in Section 2.1 and Table 3.

[21] Detailed in CSIRO and ClimateWorks' report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf.

Figure 10 Forecast reduction in gas consumption due to hydrogen uptake by scenario, 2022-41 (PJ)



Commonwealth, state and territory governments have committed to achieving emissions reduction targets of net zero by 2050 or earlier, and these commitments will need specific policy incentives to see the scale and pace of fuel switching increase to match the pace of transition forecast in some scenarios. For example:

- **Victoria's Gas Substitution Roadmap** (presently under development)[22] aims to identify pathways for the gas industry to contribute to the state's net zero by 2050 target. Insights from consultation and analysis to date identify electrification and energy efficiency as best placed to reduce emissions in the short term. In the longer term, a combination of technologies, including zero or low carbon-alternatives to natural gas such as hydrogen and biogas, would be required for Victoria's diverse gas users.
- The **Australian Capital Territory's Climate Change Strategy** sets a pathway towards net zero emissions by 2045. Removal of mandatory gas connections to new residential suburbs and infill developments under the Strategy will provide an incentive for these areas to transition to the territory's 100% renewable electricity supply[23]. The forecast rate of electrification reflects a similar transitioning of customers from natural gas.

Economic and population outlook

In 2021, AEMO engaged BIS Oxford Economics to develop long-term economic and population forecasts for Australia[24]. The forecasts, conducted in April 2021[25], reflect the observations of COVID-19 economic impact, and forecast the eventual emergence of the Australian economy from the pandemic. International borders, for example, were assumed to re-open gradually from 2021-22 in some scenarios.

In 2021-22, the pandemic recovery is forecast to drive positive economic growth, with the services sector leading the rebound in activity after periods of stifled growth in 2020-21. Through the mid-2020s, the full impact of

[22] Consultation information may be found at https://engage.vic.gov.au/help-us-build-victorias-gas-substitution-roadmap.

[23] See https://www.cmtedd.act.gov.au/open_government/inform/act_government_media_releases/rattenbury/2020/act-gas-phase-out-gaining-momentum.

[24] BIS Oxford Economics Macroeconomic Projections Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf.

[25] The impact of subsequent variants (namely Delta and Omicron) is not reflected in these forecasts.

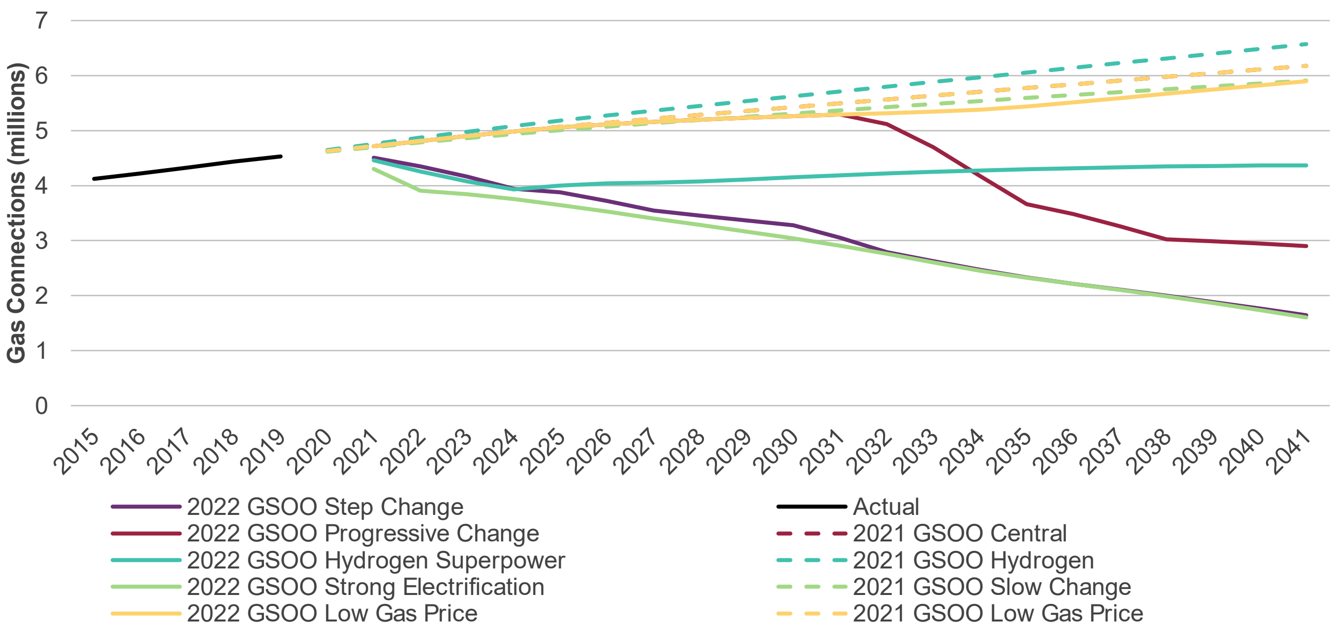
government fiscal policy during the pandemic is expected to pass through to the construction and manufacturing sectors, increasing their shares of economic activity.

Population growth has been revised down since the 2021 GSOO, driven by a reduction in birth rates offset by temporary above-trend growth in immigration intake. Over the GSOO's 20-year forecast horizon, Victoria and Queensland are expected to see relatively strong growth in population, while New South Wales and South Australia are forecast to experience relatively lesser growth over this period. Overall, these economic and population forecasts have a direct impact on the forecast number of connections to the gas system.

As **Figure 11** shows, the number of households and commercial businesses connected to gas is forecast to fall under all scenarios and sensitivities except *Low Gas Price,* and to be lower than the 2021 GSOO forecasts in all scenarios and sensitivities.

The projected decline in households and commercial business connections is a direct result of the forecast rise of electrification. It is unclear yet whether greater electric appliance penetration and use will result in physical disconnections from the gas network, and whether new households will not connect to the gas network (in regions that traditionally do provide gas connection upon construction) in future. AEMO's connection forecast represents the equivalent connection forecast if electrification disconnected consumers from the gas network, however connections may not decline as steeply as forecast if electrification was to lead to reduction in *gas use*, but retention of gas connections. In summary, the forecast number of connections falls from 4.4 million in 2022 to 1.6 million in 2041 under *Step Change* and from 4.8 million in 2022 to 2.9 million in 2041 under *Progressive Change* (4.5 million lower and 3.3 million lower, respectively, than the 2021 GSOO *Central* scenario).

Figure 11 Actual and forecast household and commercial business connections, all scenarios and compared to the 2021 GSOO, 2015-41



Energy efficiency

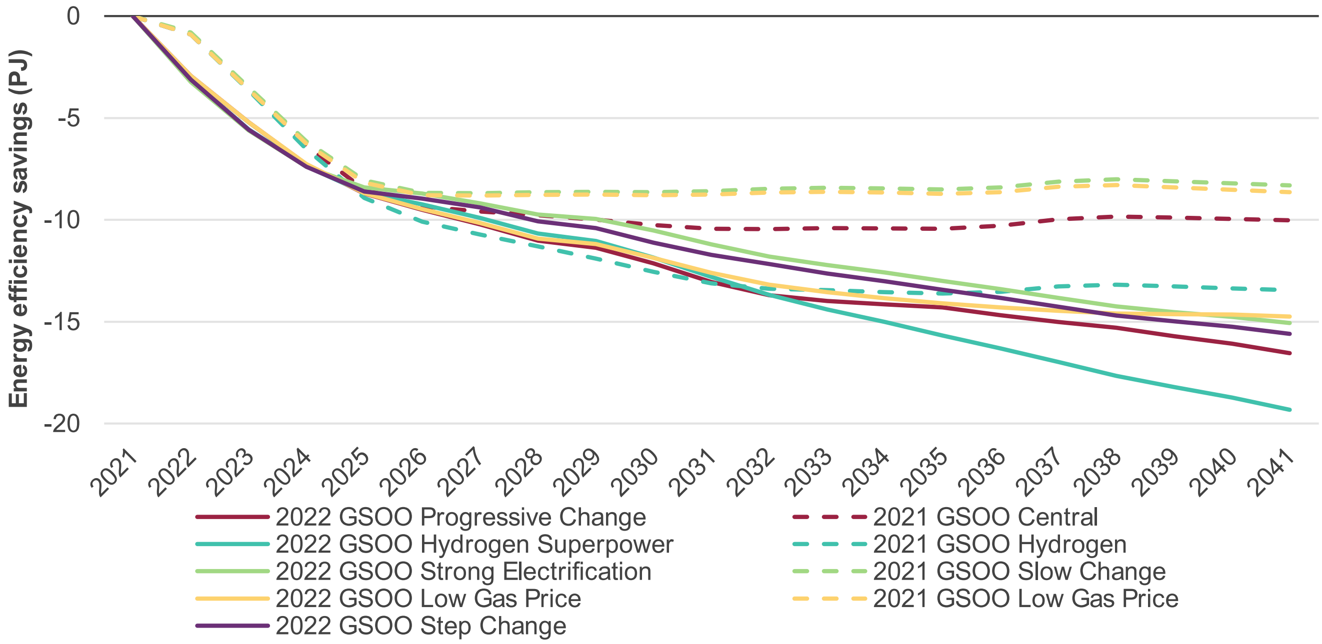
In 2021, AEMO engaged Strategy.Policy.Research to develop forecasts of gas savings from current and planned energy efficiency measures, including:

- The National Construction Code.
- State-based measures, such as the New South Wales Energy Savings Scheme, the Victorian Energy Upgrades Program, Victoria's Household Energy Savings Package, and South Australia's Retailer Energy Productivity Scheme.
- Disclosure measures including Commercial Building Disclosure and the National Australian Built Environment Rating System.
- Industrial assessments, including Victoria's Business Recovery Energy Efficiency Fund.

Additional (hypothetical) state-based measures and industrial assessments were also adopted for scenarios with high energy efficiency settings[26]. AEMO further adjusted the energy efficiency savings to avoid double counting from the influence of electrification

Figure 12 shows the energy efficiency forecasts in aggregate[27].

Figure 12 Forecast reduction in gas consumption from energy efficiency savings, by scenario and compared to the 2021 GSOO, 2021-41 (PJ)



The energy efficiency savings are higher than forecast in the 2021 GSOO, to support the achievement of decarbonisation targets and the gas sector's contribution to a net-zero economy. For all scenarios, state-based schemes now apply growing targets[28] from existing levels, whereas in the 2021 GSOO these targets were held fixed in line with existing policy levels. The increase occurs at a more rapid pace in *Step Change*, *Hydrogen Superpower* and *Strong Electrification*, which assume higher energy efficiency policy settings and greater savings from additional (hypothetical) measures, which were not present to the same extent in the 2021 GSOO.

[26] Detailed in the 2021 IASR and Strategy.Policy.Research Final Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/strategy-policy-research---energy-efficiency-forecasts-2021.pdf.

[27] Savings are shown as negative because they reduce the gas consumption forecasts.

[28] Depending on scheme, the targets aim to save energy or reduce carbon emissions.

Retail prices

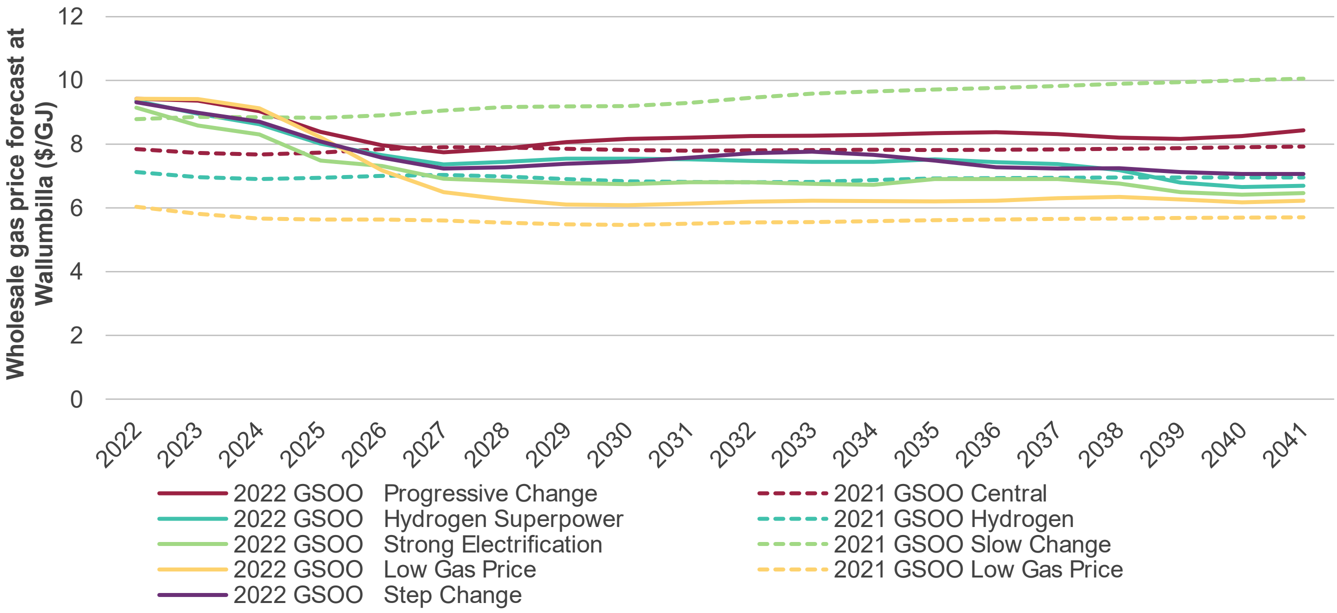
Retail prices influence the affordability of gas, with higher prices generally causing consumers to use less. Wholesale gas prices represent the key driver of change for retail prices over the forecast period.

AEMO engaged Lewis Grey Advisory (LGA) to prepare the wholesale contract gas price forecasts for the 2022 GSOO[29]. LGA forecasts for wholesale gas prices at the Wallumbilla Hub are shown in **Figure 13**.

The main gas market changes reflected in LGA's modelling are:

- Economic recovery following the COVID-19 pandemic has stimulated significant energy price increases. This is particularly true for the international LNG market, where prices have risen in response to a rebound in economic activity, below-average levels of gas in storage in Europe, and Russia leveraging its dominant position in European gas supply.
- The anticipated emergence of LNG imports into Australia's domestic market will introduce competitively priced imports, increasing competition and driving down domestic prices in some scenarios.
- Since the COP-26 climate conference in Glasgow in November 2021, the energy sector has become increasingly focused on net zero emissions targets and lowering emissions. Uncertainty over the role fossil fuels will play in this transition is making the gas market more difficult to forecast. As a result, LGA considered and applied a wider range of inputs, creating a wider range of price projections.

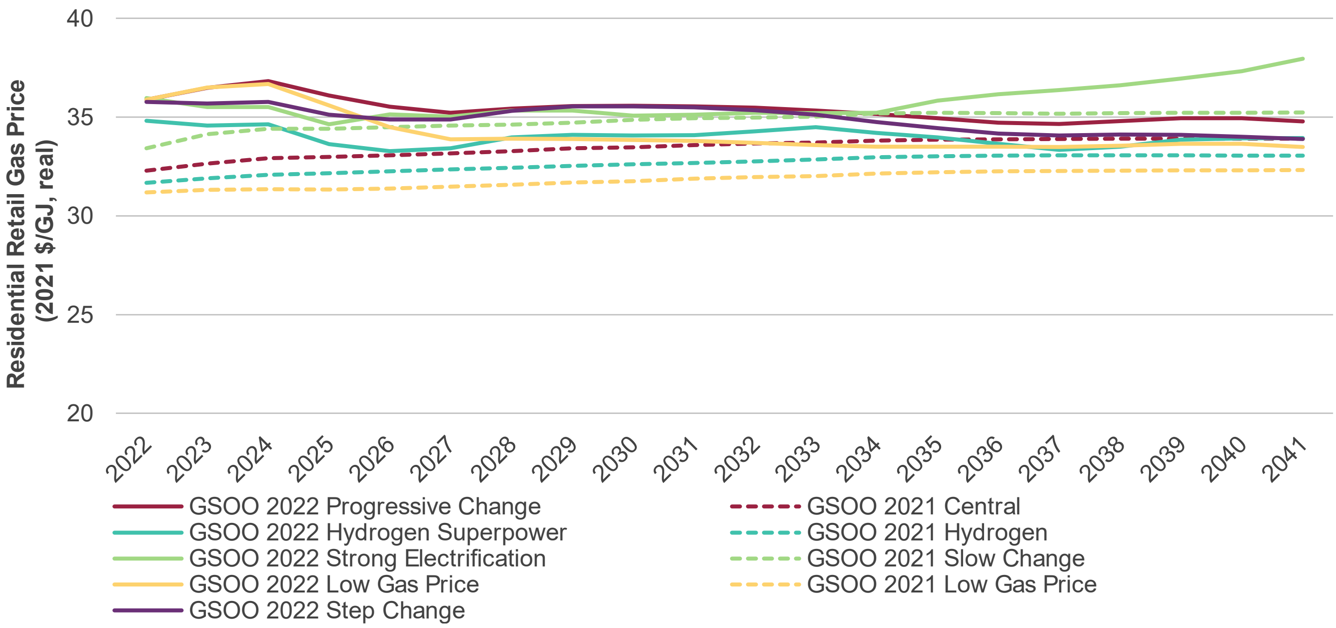
Figure 13 Forecast wholesale prices at the Wallumbilla Hub, all scenarios and compared to the 2021 GSOO, 2022-41 ($/gigajoule [GJ])



As **Figure 14** shows, the price is higher from the beginning of the forecast period than in the 2021 GSOO. This has been driven by an increase in standing offers and distribution costs, in addition to increased wholesale prices.

[29] Lewis Grey Advisory, Gas Price Projections for Eastern Australia Gas Market 2022, at https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/lewis-grey-advisory-gas-price-projections-report.pdf.

Figure 14 Forecast residential retail prices (load weighted), all scenarios and compared to the 2021 GSOO, 2021-41 ($/GJ)



2.2 Consumption forecasts by sector

2.2.1 Residential and commercial consumption

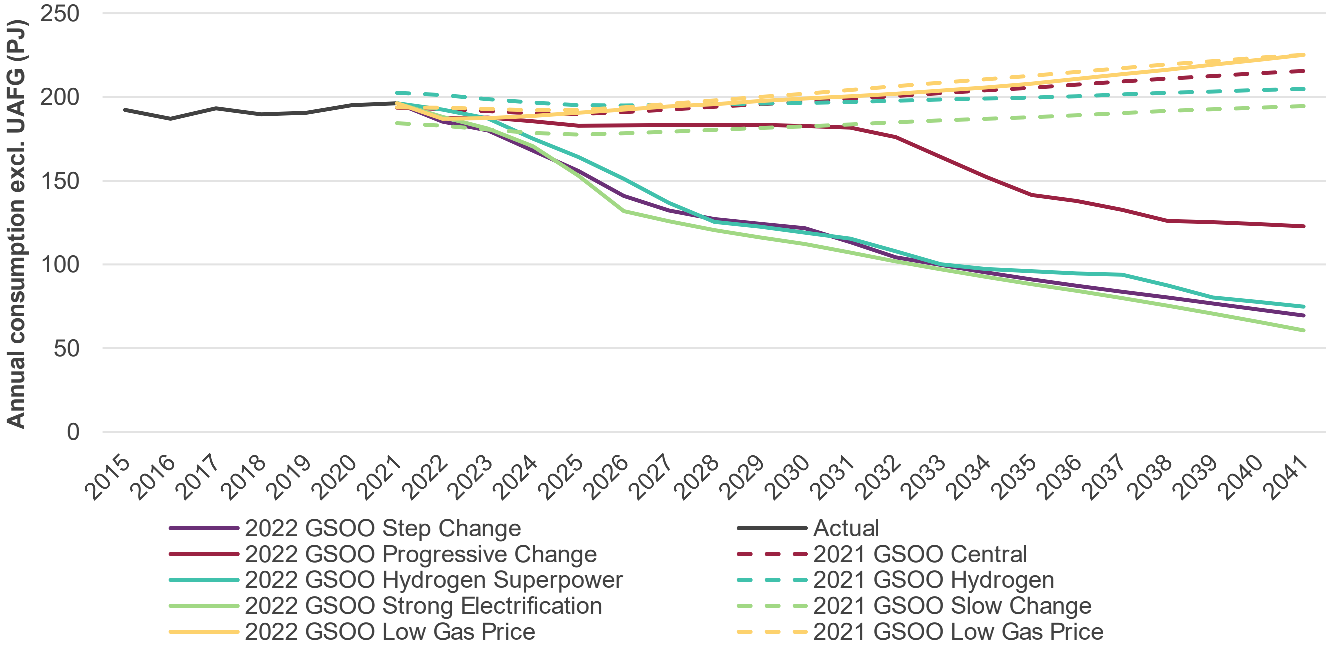
Residential and commercial consumers are gas consumers with relatively small gas volumes using less than 10 TJ of gas per annum, or customers with a basic gas meter.

AEMO forecasts residential and commercial gas consumption on a per connection basis. The growth trajectory is driven by the gas connections forecast, with adjustments made for fuel-switching to electricity and hydrogen, energy efficiency savings, climate change impact, and behavioural response to retail prices.

Figure 15 shows forecasts for this sector across scenarios and compared to 2021 GSOO forecasts.

The drop from 2021 to 2022 reflects higher than average consumption in 2021, from overall colder weather conditions and extended lock downs and working from home arrangements due to COVID-19, particularly in Victoria. The energy efficiency forecast also lowers consumption by around 3 petajoules (PJ) across the scenarios in 2022. Additional notes on outcomes and drivers are below the figure.

Figure 15 Actual and forecast residential and commercial annual consumption, all scenarios and compared to 2021 GSOO, 2015-41 (PJ)



In the *Step Change* scenario:

- Residential and commercial consumption is forecast to decline strongly from 196 PJ to 70 PJ over the outlook period. The primary drivers of the decline are new buildings transitioning to electric-only connections, and electrification of existing customers moving away from gas to electricity for heating, hot water, and to a lesser extent, cooking.
- Energy efficiency savings and hydrogen blending[30] are forecast to have a more modest impact on reducing consumption, by 14 PJ and 5 PJ respectively, by the end of the outlook period. In the case of energy efficiency, the potential for measures to lower consumption will reduce as customers fuel-switch to electricity.

In the *Progressive Change* scenario:

- The consumption forecast declines significantly from the 2030s, to 123 PJ by the end of the outlook period, as consumers shift towards electric alternatives more slowly than in *Step Change*.
- Hydrogen blending is forecast to offset gas consumption by up to approximately 20 PJ in the mid-2030s, and to stay around this level to the end of the outlook period.
- Energy efficiency savings result in modest declines in gas consumption in the short term, with the potential for measures to lower consumption reducing towards the end of the outlook period. Energy efficiency savings lower consumption by 15 PJ by the end of the outlook period.

In the *Strong Electrification* and *Hydrogen Superpower* scenarios:

- The consumption forecasts show a similar trajectory to *Step Change*, resulting in significant declines to 75 PJ and 61 PJ by the end of the outlook period respectively.

[30] Blending hydrogen gas into the gas network, substituting for natural gas, within the technical limits of the pipelines and what is safe for gas appliances to use.

- Fuel-switching to electricity is the primary driver of this decline in the *Strong Electrification* scenario, while energy efficiency savings (tempered by a significant portion of connections moving to electrify) contribute to a modest reduction of 13 PJ by the end of the outlook period.
- The *Hydrogen Superpower* scenario shows declines from electrification in the short to medium term, and hydrogen blending becomes a more dominant driver for a decline in consumption from the mid-2030s. Energy efficiency contributes to a modest reduction of 18 PJ by the end of the outlook period.

In the *Low Gas Price* sensitivity:

- Consumption is forecast to grow steadily, as there is little price incentive to fuel-switch to electricity and no hydrogen blending is assumed. Energy efficiency savings reduce consumption by 13 PJ by the end of the outlook period.

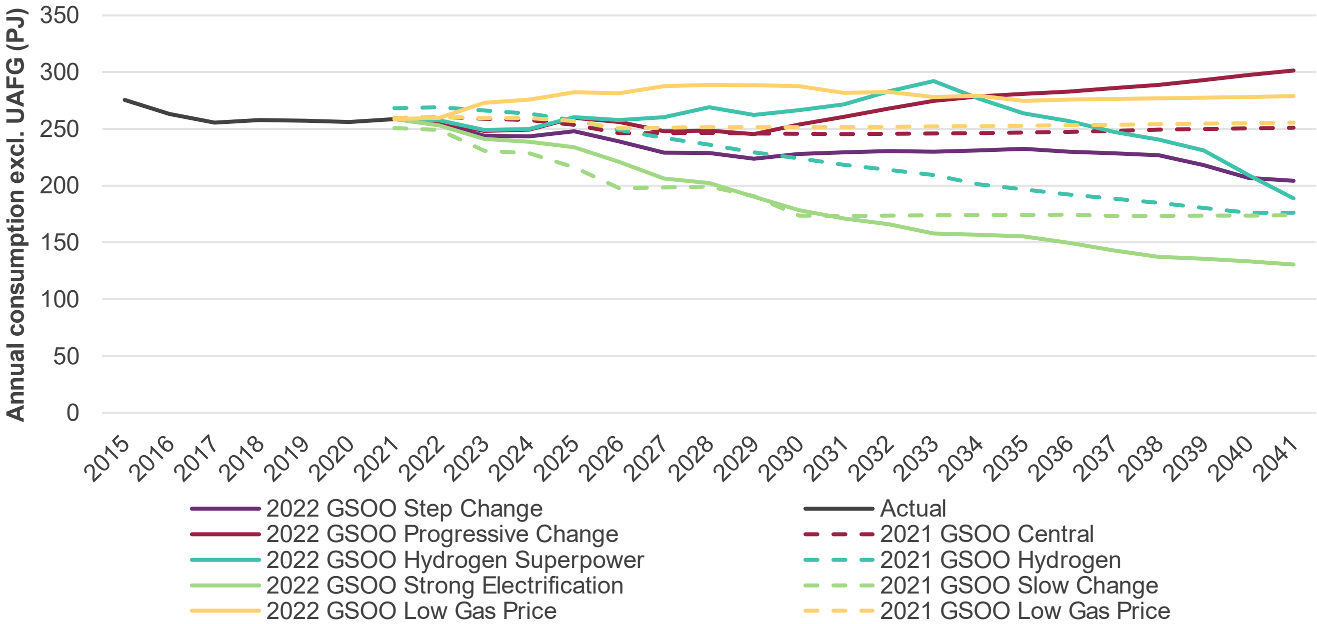
2.2.2 Industrial consumption

AEMO forecasts industrial sector consumption based on two categories:

- Large Industrial Loads (LILs) – this includes customers with consumption greater than or equal to 500 TJ per annum. Customers are forecast individually. LILs represent over 70% of total industrial sector consumption, and comprises mineral processing, primary metal, paper and chemical producers, oil refineries, large food processors, and mining[31].
- Small to Medium Industrial Loads (SMILs) – this includes customers with consumption between 10 TJ and 499 TJ per annum at individual sites, and is forecast in aggregate.

Figure 16 shows the combined industrial sector consumption forecast for all scenarios and compared to the 2021 GSOO. Notes on outcomes and drivers are below the figure.

Figure 16 Actual and forecast industrial annual consumption, all scenarios and compared to 2021 GSOO, 2015-41 (PJ)



[31] 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.

In the *Step Change* scenario:

- Consumption is forecast to decline in the short term, before holding around 230 PJ from 2027 onwards. By 2039, forecast hydrogen consumption offsets the needs for natural gas, reducing gas consumption by 20 PJ in the final years of the forecast.
- The downward trend is partially driven by the electrification forecast, which reduces industrial gas consumption by 30 PJ at the end of the forecast period.
- Reduced gas consumption due to hydrogen fuel-switching and assumed LIL closures (informed by survey responses) in chemical manufacturing, mining, paper, and mineral processing sectors in Queensland and South Australia contribute to the forecast decline.

Under the *Progressive Change* scenario:

- Industrial consumption is projected to hold at around 250 PJ in the near term, before trending upwards from 2029 and peaking at 300 PJ in the final year of the forecast. Less rapid action to electrify existing gas loads provides the primary short term dispersion driver with *Step Change*.
- The forecast incorporates a forecast decline across the chemical and paper manufacturing (including an associated decline in on-site electricity generation), partially offset by a slight increase in SMILs.
- The longer-term forecast increase is driven by substantial growth in gas consumed in SMR hydrogen production. This is projected to grow to 83 PJ by 2041[32].

In other scenarios:

- The *Hydrogen Superpower* scenario captures a moderate short-term increase in consumption due to higher economic outcomes inherent in the scenario. The growth in gas is tempered by the increasing availability of hydrogen (direct fuel-switching, or hydrogen blending within distribution networks), offsetting the need for gas.
- The *Strong Electrification* sensitivity features the most rapid decline in consumption, as electrification reduces industrial gas consumption.
- The *Low Gas Price* sensitivity provides increased output from industrials with lower input costs, and lower costs reduces the incentives to fuel-switch away from gas.

2.2.3 LNG consumption

To produce LNG export forecasts, AEMO surveys LNG producers for the expected, minimum, and maximum volumes of gas required for their export facilities over the next five years (and to 2041 where available). These surveys also include information about their expected CSG production, which is used in determining the supply demand balance. These responses are linked; increased LNG exports will increase gas consumption, but this will also likely result in acceleration of production from the CSG fields.

LNG consumption in 2021 was 1,407 PJ, a 70 PJ increase from 2020, as global economic growth recovered from the initial downturn in 2020 following the restrictions put in place to mitigate against COVID-19. **Figure 17** shows recent and forecast consumption for LNG exports for different scenarios and compared to the 2021 GSOO.

The *Step Change* and *Progressive Change* scenarios forecast 1,444 PJ of consumption in 2022, 37 PJ higher than forecast for the 2021 GSOO Central scenario. This is driven by higher LNG demand and thus LNG prices

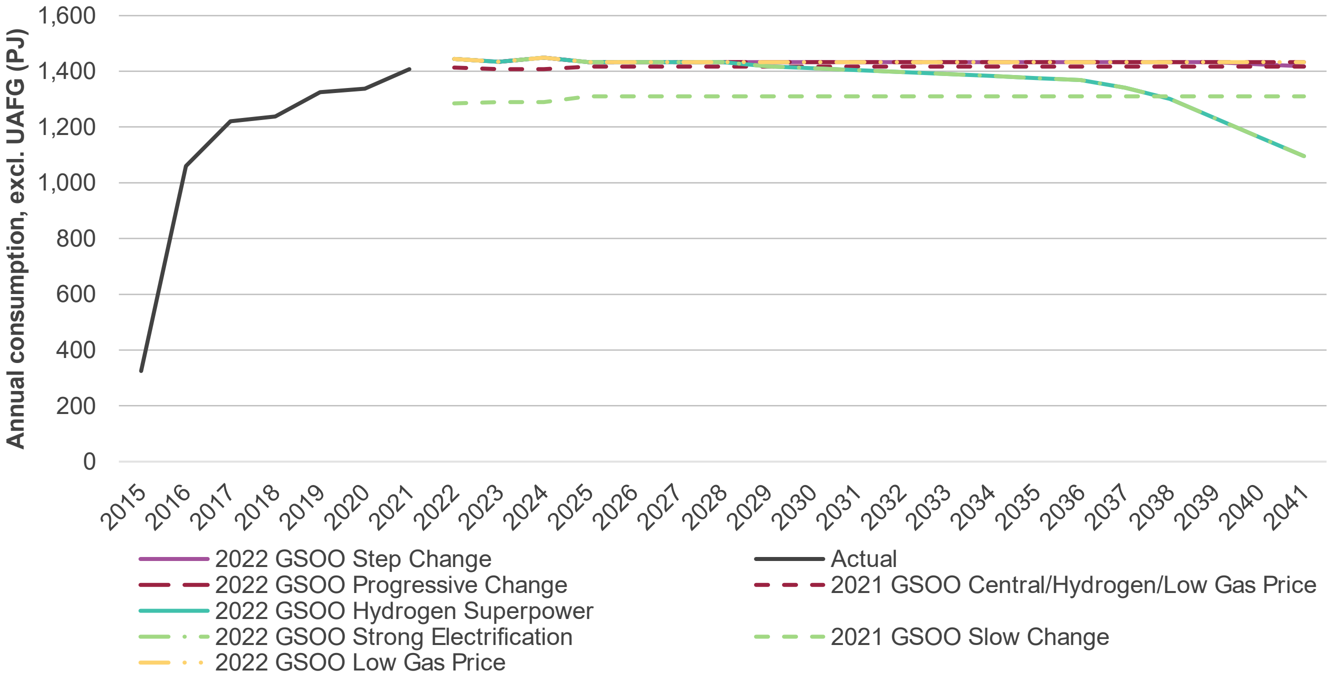
[32] SMR forecast assumptions can be found at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf.

worldwide, following the European energy crisis over the 2021-22 winter[33] and the subsequent conflict between Russia and Ukraine, further destabilising energy markets. Based on responses from LNG producers, the forecast is provided up to 2026, then the 2026 level of consumption is maintained across the forecast horizon. The impact of global decarbonisation in the *Step Change* scenario (resulting in reduced LNG exports compared to *Progressive Change*) is forecast beyond the GSOO's 20-year horizon and it is not depicted in the figure.

In the *Hydrogen Superpower* scenario and *Strong Electrification* sensitivity, from 2029, LNG exports are forecast to decline, due to a global shift to alternative low emissions fuels. This forecast decline represents the loss of one-third of the LNG export volume for Australia, equivalent to two LNG trains or one export facility for the East Coast of Australia.

The *Low Gas Price* sensitivity applies the same forecast LNG consumption as *Progressive Change*.

Figure 17 Actual and forecast liquefied natural gas consumption, by scenario and compared to 2021 GSOO, 2015-41 (PJ)



2.2.4 Gas consumption for electricity generation

AEMO's Draft 2022 ISP reiterated the importance of flexible and firm energy supplies as the transition of Australia's energy sector accelerates. As coal generation retires, gas generation (particularly peaking gas plants) will be crucial both to respond to sudden changes in the supply demand balance as well as to provide critical power system services to maintain grid security and stability (complementing other forms of dispatchable capacity, including storage). In a high renewable penetration grid, gas generation and storage technologies will be needed to effectively manage resource variability and provide backup capacity over extended periods of low VRE output.

[33] The forecasts reflect the increasing LNG prices seen late 2021. The later increase following the conflict between Russia and Ukraine has added to short-term expectations of LNG prices and will further increase the uncertainty in the LNG market.

All gas generation forecasts in the 2022 GSOO are based on the optimal development path (ODP) of the Draft 2022 ISP, incorporating all committed, actionable and future transmission projects and all forecast generation developments and retirements associated with the ODP.

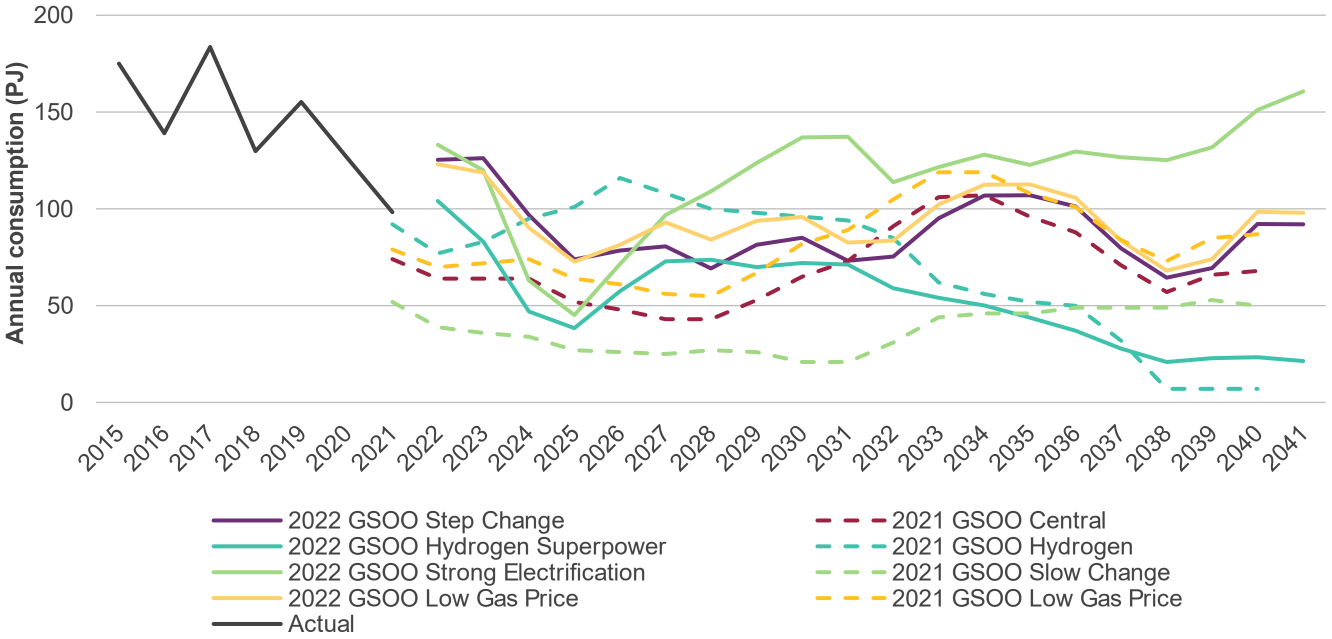
The recently announced[34] retirement of Eraring Power Station in August 2025 is reflected in these gas generation forecasts.

Gas generation dispatch volumes will depend on participants' bidding strategies, and how they change over time as the portfolio of generation changes to incorporate more VRE. AEMO uses a bidding model (trained on past portfolio behaviour) to model likely future market outcomes in the NEM. This model takes account of the availability of VRE that operates at relatively low cost but is subject to weather variability, while respecting the technical capabilities of all generator technologies to respond to demand and supply variations.

Forecast trend in gas generation consumption

Figure 18 shows actual NEM gas use for gas generators between 2015 and 2021, and the average forecast gas use from gas generators across the scenarios and sensitivities explored between 2022 and 2041.

Figure 18 Actual and forecast NEM gas generation consumption, all scenarios and compared to 2021 GSOO, 2015-41 (PJ)



Since 2014, gas generation has generally declined in its consumption of gas. In 2020 the NEM recorded its lowest gas generation consumption in over a decade. The decline continued in 2021, which saw gas consumption settling at just over 98 PJ, approximately 22% lower than 2020 and setting a new record low. A key driver of the low gas generation operation observed in recent history is increasing penetration of renewable generation, both large-scale and distributed, which is continuing at pace. Market dynamics such as subdued spot prices and elevated wholesale gas prices also contributed to the decline in gas generation consumption.

[34] See https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

However gas generation is still forecast to provide critical dispatchable capacity, providing a firming role to support variable renewable generation, and also meet the NEM's needs if coal generation and other dispatchable sources are unavailable. For example, in 2021 major outages at Callide and Yallourn power stations drove higher reliance on gas generation in the NEM to cover for the sudden reduction in coal availability. The importance of this role will continue, and the Draft 2022 ISP emphasises this:

> *Gas-fired generation will play a crucial role as significant coal generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability*[35].

As Figure 18 shows, in most cases the 2022 GSOO forecasts are higher than forecast in the 2021 GSOO.

In consultation for the 2022 ISP, stakeholders identified *Step Change* as the most likely scenario. The electricity sector in particular has demonstrated momentum similar to the *Step Change* scenario, with strong growth in distributed energy resources (DER) investments by consumers, and early retirements of coal generators (as noted earlier with Eraring Power Station). AEMO has therefore used *Step Change* gas generation forecasts in the GSOO to forecast gas generation consumption in both *Step Change* and *Progressive Change* scenarios.

Step Change forecasts a short-term increase in gas generation compared to consumption in 2021, with electricity consumption forecast to rise with continuing electrification, and inclusion of unexpected NEM events (discussed further in the next section).

New renewable generation and storage projects are forecast to reduce consumption for gas generation until the forecast retirement of Eraring Power Station stabilises the gas generation forecast. As coal capacity declines, gas generators are projected to start more frequently and run for longer periods of time, with an increasingly important role in firming intermittent renewable energy generation.

In the longer term, from 2038 onwards, further investment in longer duration storage is projected to reduce the need for gas generators to operate for extended periods, but gas generators are forecast to continue to play a pivotal role during challenging weather conditions and when other infrastructure is unavailable. In these circumstances, high gas generation may be needed, impacting the flexibility requirements of gas infrastructure to enable flexible operation of gas generation.

Key items to note in the other scenarios are:

- The *Hydrogen Superpower* scenario forecasts a significant uptake of renewable generation and storage in the NEM, beyond that in the *Step Change* scenario. Increased flexibility from new dispatchable loads is projected to lower reliance on gas generation to supply electricity in the long term, but peak events will likely call upon gas generation to maintain reliability and operability. The scenario does not assume a greater-than-average level of events or failures in the NEM (such as floods, bushfires or events leading to major coal outages) to provide a scenario with a lower bound for the forecast level of gas generation consumption.
- Slightly lower gas prices, forecast in the *Low Gas Price* sensitivity, are not expected to drive significantly greater gas generation, with around 10 PJ per annum higher consumption than *Step Change* on average, although less so towards the end of the horizon.
- *Strong Electrification* forecasts a very sharp downturn in gas generation until the mid-2020s following an accelerated installation of VRE capacity, but recovers in the long term to a level higher than the *Step Change* scenario, driven by increasing electrification from the transport sector and heating loads.

[35] AEMO, Draft 2022 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf.

Future gas generation consumption is highly uncertain

Long-term forecasts of gas generation are highly uncertain and depend on many factors in the NEM. Gas generation can be significantly affected by events in the NEM including power station failures, coal supply chain disruptions, and major environmental interruptions (such as bushfires and flooding).

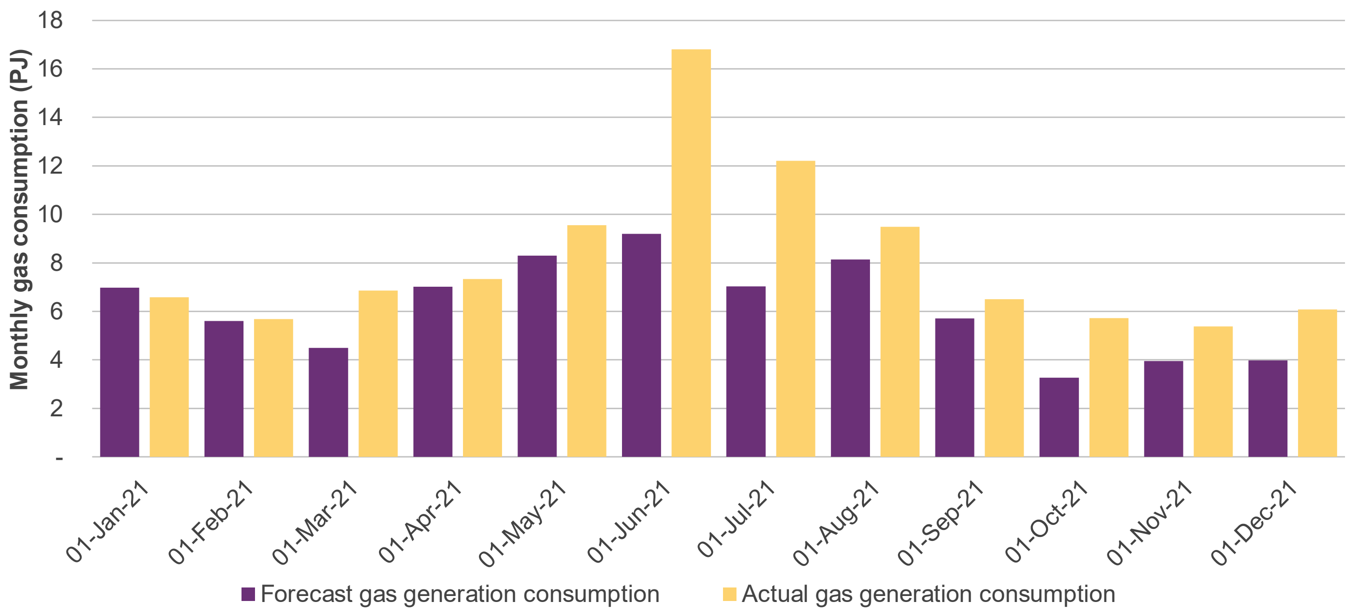
Impact of unforeseen events

The historical actuals in Figure 18 above show a general decline from 2015, but also several spikes in consumption, especially from 2017 onwards, when the NEM faced multiple unforeseen events:

- 2017 – the closure of the coal-fired Hazelwood Power Station with short notice and extended outage at the coal-fired Yallourn Power Station.
- 2019 – outages at Victorian coal generators, coal shortages affecting New South Wales coal generators, extended hot weather particularly in Victoria, and bushfires affecting New South Wales and Victoria.
- 2020 – long coal-fired generation outages affecting Queensland power stations, transmission outages affecting the Heywood interconnector (connecting South Australia and Victoria).
- 2021 – coal plant failures at Callide in Queensland (one unit still offline), coal mine flooding at Yallourn in Victoria affecting generation.

Figure 19 shows the difference in the 2021 calendar year between the 2021 GSOO's gas generation forecasts (which incorporated no major outages or events), and the monthly gas consumption that actually occurred.

Figure 19 Monthly gas generation consumption, actual versus system normal forecast in calendar year 2021 (PJ)



The figure shows an under-forecast of gas generation, as unexpected events at Yallourn and Callide were not forecast. This was particularly evident from June 2021, as multiple coal generators were out of service and gas generators were required to step in to fill the gap. The unexpected outages accounted for 21 PJ of gas consumption above what was previously forecast for the periods between June and December 2021. This saw a rapid draw down of the Iona Underground Gas Storage (UGS) inventory, resulting in supply concerns for the south-east region (discussed further in the 2022 VGPR Update).

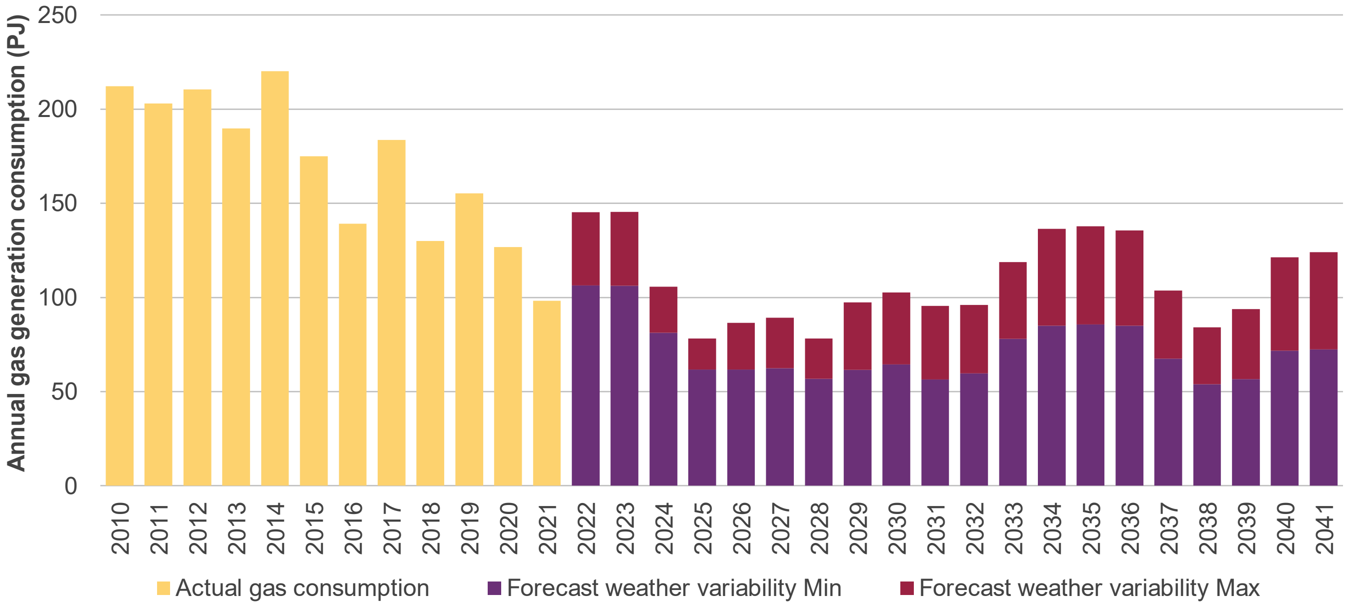
Given the trend of major unexpected events occurring in the NEM in four of the last five years, AEMO has considered these unexpected events in the 2022 GSOO by incorporating reductions in coal availability. As these events are by their nature uncertain, the forecasts represent a reasonable approximation of the impact of an event or events of this nature.

Weather variability

Another major uncertainty affecting gas generation is weather variability, due to the NEM's increasing use of VRE technologies for electricity generation. This GSOO considers a range of weather events, applying a spread of historical weather conditions. Based on these conditions, **Figure 20** shows the range of possible gas generation consumption outcomes as the NEM, depending on the availability of wind, solar and hydro generation technologies.

The variability of annual gas consumption for gas generation is expected to increase through the forecast horizon as the combination of more coal retirements and more VRE capacity in the NEM makes generation patterns increasingly dependent on weather. Weather variations will increase the value of flexible and dispatchable forms of generation less exposed to intermittency, such as hydro, storage and gas generation.

Figure 20 Actual gas generation consumption and forecast variation in consumption due to weather conditions, *Step Change* scenario, 2010-41 (PJ)



Sensitivities testing impacts of extended drought and major coal generation outages

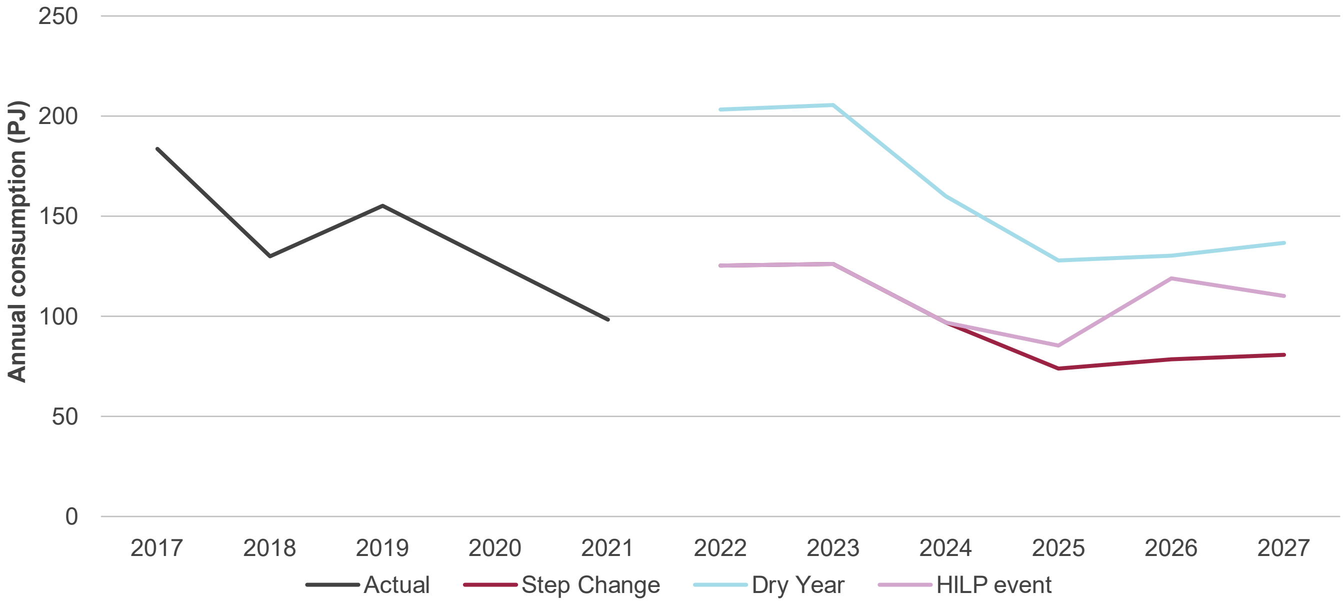
This 2022 GSOO includes two further gas generation sensitivities:

- **Dry year** – assessing the impact of extended drought conditions. The sensitivity was applied to the years between 2022 and 2027, demonstrating the impact in any of these years of drought conditions affecting rainfall inflows to large hydro schemes in the NEM. The reduction in rainfall assumed in this sensitivity is in line with levels recorded during the millennium drought of 2006-07, with 45% less inflow yield relative to average years.

- **High Impact Low Probability (HILP) event** – assessing the impact of major, extended coal generation outages (above and beyond the coal availability already assumed, as discussed above) from mid-2025, which could also approximate an unexpected coal-fired power station closure (in addition to the committed closures of the Liddell and Eraring power stations).

Figure 21 shows the range of outcomes when these sensitivities were applied to the *Step Change* scenario. The figure demonstrates that reduced rainfall leading to reduced hydro yields is projected to have a large impact on gas generation, resulting in up to 80 PJ of increased gas consumption, although the exposure to hydro availability would lower marginally over time with greater penetration of VRE. The unavailability of coal (HILP event sensitivity) may also lead to a large increase in gas generation (by up to 40 PJ), although the impact is forecast to be less significant than extended drought.

Figure 21 Actual and forecast NEM gas generation consumption, sensitivities to *Step Change* scenario, 2017-27 (PJ)



2.3 Maximum daily gas demand forecasts

Across the regions in the GSOO's scope, maximum daily demand for domestic consumers[36] is strongly seasonal and generally driven by heating demand in winter. Much of this variation comes from residential and commercial consumers in the southern states, with industrial consumers having a smaller influence.

Changes in maximum demand forecasts compared to the 2021 GSOO are due to the net effect of revisions in drivers of gas consumption outlined in sections 2.1 and 2.2.

For the *Step Change* scenario, key regional observations in winter maximum daily gas demands (excluding gas generation) are listed below. Similar trends are observed for *Progressive Change,* although the timings of the inflection points in peak gas demand tend to be later in the horizon. For *Step Change,* differences between regions are largely explained by different drivers in LILs (particularly in New South Wales and Tasmania), SMR,

[36] Excludes the gas consumption from LNG exporters.

and electrification for other industrial customers. For residential and commercial customers, the differences can be largely explained by different drivers in energy efficiency and electrification (particularly in Victoria).

Generally, regional trends for *Step Change* are:

- **New South Wales** is projected to initially increase its maximum daily demand and peak in 2023, then slowly decline to the end of the forecast horizon.
- **Queensland** is projected to decrease its maximum daily demand until 2029, then slowly decline until 2038 and then further decline to the end of the forecast horizon.
- **South Australia** is projected to decrease its maximum daily demand to the end of the forecast horizon.
- **Tasmania** is projected to initially increase its maximum daily demand until 2026, then flatten until 2036 and then decline to the end of the forecast horizon.
- **Victoria** is projected to decrease its maximum daily demand to the end of the forecast horizon.

Over the forecast horizon, compared to the 2021 GSOO *Step Change* scenario, the 2022 GSOO *Step Change* winter maximum daily demand forecasts:

- Initially start a little lower and generally decrease over the forecast horizon in New South Wales, Queensland, South Australia and Victoria.
- In Tasmania, initially start higher and increase to a higher maximum daily demand.

Table 4 and **Table 5** show the seasonal forecasts for residential, commercial, and industrial maximum daily gas demand in the *Step Change* and *Progressive Change* scenarios 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 likelihood the forecast will be met or exceeded. A one-in-20 forecast is expected to be exceeded, on average, only once in 20 years, while a one-in-two forecast is expected, on average, to be exceeded every second year.

Regional forecasts are available on AEMO's National Electricity and Gas Forecasting portal[37].

[37] At http://forecasting.aemo.com.au/.

Table 4 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	
	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
2019*	270		4,369		335		103		20		655	
2020*	229		4,611		336		94		21		489	
2021*	286		4,501		343		97		21		516	
Step Change												
2022	291	316	4,305	4,325	348	368	104	112	26	29	448	579
2023	308	332	4,232	4,250	305	322	102	109	30	33	433	567
2025	305	329	4,219	4,236	293	310	88	94	33	36	415	531
2030	283	306	4,139	4,151	214	227	80	85	35	38	383	467
2040	267	288	4,061	4,070	156	165	66	69	21	23	309	353
Progressive Change												
2022	295	320	4,306	4,326	348	369	106	113	26	29	452	592
2023	316	341	4,235	4,253	307	325	105	113	30	33	448	582
2025	331	359	4,230	4,247	304	321	100	107	33	36	465	596
2030	342	370	4,164	4,178	240	253	101	108	35	39	495	625
2040	345	371	4,184	4,198	260	274	91	96	28	31	491	586

* Actual maximum demand.

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

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	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
2019*	452		3,989		354		156		25		1,203	
2020*	438		3,869		340		147		22		1,213	
2021*	469		4,136		346		149		23		1,134	
Step Change												
2022	460	488	4,313	4,332	355	374	152	160	28	31	1,146	1,252
2023	475	504	4,240	4,257	312	329	147	155	32	35	1,107	1,212
2025	454	483	4,227	4,243	301	318	120	127	35	38	1,010	1,106
2030	403	428	4,145	4,156	220	232	97	101	37	40	866	943
2040	357	379	4,065	4,073	160	168	74	78	23	25	593	640
Progressive Change												
2022	466	495	4,313	4,332	356	375	155	164	28	31	1,151	1,262
2023	491	520	4,243	4,260	315	332	154	164	32	35	1,146	1,250
2025	508	538	4,237	4,254	312	328	146	155	35	38	1,145	1,246
2030	516	548	4,171	4,184	247	260	142	150	38	41	1,193	1,302
2040	455	483	4,189	4,203	264	278	104	109	30	33	1,031	1,120

* Actual maximum demand.

2.3.1 Seasonal variance and extreme peaks

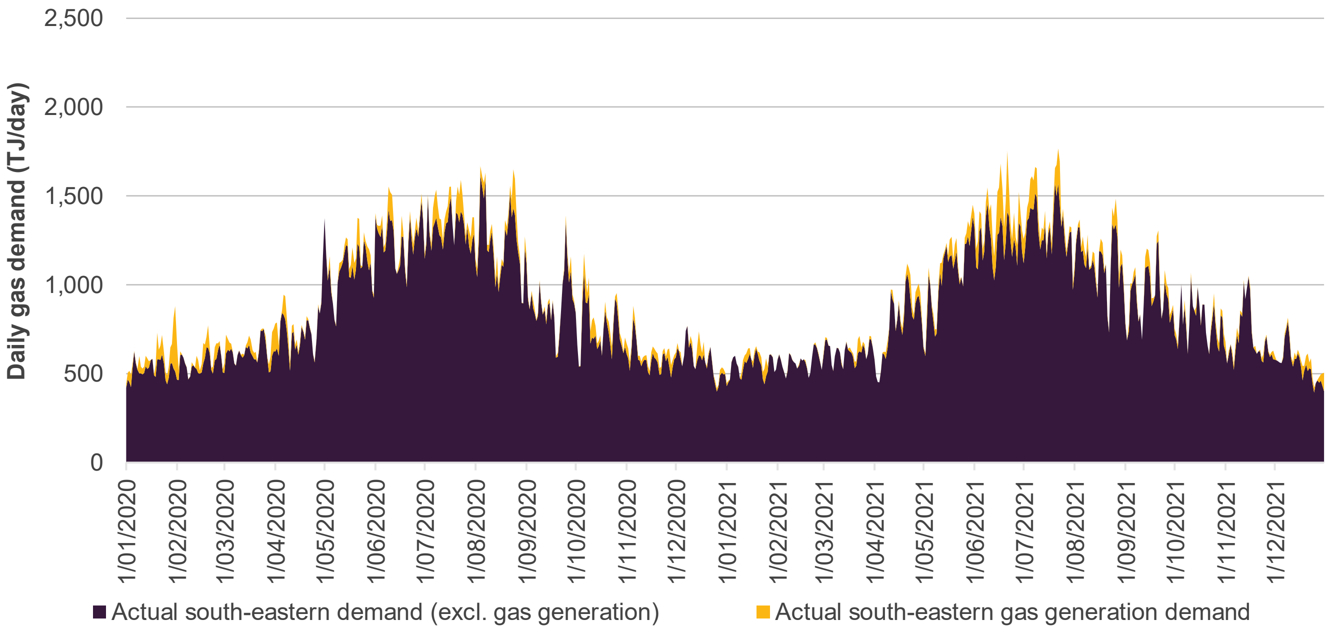
The most extreme southern daily gas demands observed each year typically only occur on a relatively small number of days, when conditions compound to lead to very high utilisation of residential and commercial heating appliances.

Figure 22 below demonstrates the historical volatility of gas demand and the strong seasonality of daily peak demand in the south-eastern regions of New South Wales, the Australian Capital Territory, Victoria and Tasmania. This is the area of the gas network most likely to be affected by constrained supply as local production declines.

The daily demand by residential, commercial and industrial consumers is shown as the dark purple area in the chart. Industrial loads such as aluminium and chemical production, as well as some household and commercial loads such as cooking and hot water, operate consistently across the year. Over the winter months, additional gas is used for heating in households and business premises. On average, winter peaks in the south-east are two to three times higher than summer peaks, due to heating load, dominated by Victoria.

Gas used for electricity generation (yellow in chart) is typically, but not always, high at time of 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. As outlined in Section 2.3.3, while traditionally winter peak gas generation demands have been less significant than summer peaks, the relative magnitude of winter peaks for gas generation is forecast to grow and gas generation is likely to become winter peaking, with increased electrification.

Figure 22 Actual domestic daily gas demand in south-eastern regions since January 2020, showing seasonality and peakiness (TJ)



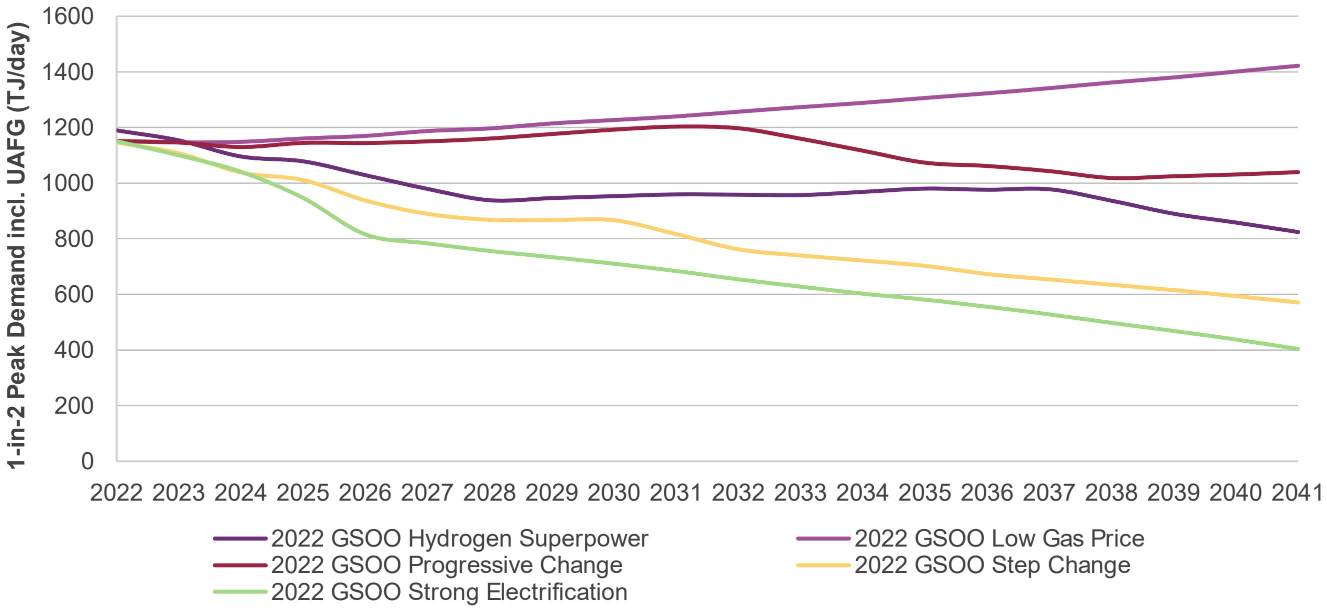
Note: This excludes Victorian demand west of Port Campbell (including Mortlake Power Station). While those customers are geographically in Victoria, they have access to gas that is upstream (or to the west) of the South West Pipeline (SWP) capacity constraint which limits flow to Melbourne, and thus outside the constrained south-eastern regions.

2.3.2 Maximum daily demand trends follow regional consumption trends

The scenarios capture uncertainty across forecast connections, energy efficiency, energy prices, electrification, and emission reduction ambitions, leading to variance in daily maximum demands. The regional maximum daily demand variance across scenarios is generally consistent with the consumption forecast scenario variance, as both are driven by the same underlying drivers.

Figure 23 shows peak day gas demand forecasts, excluding gas generation, trending differently between scenarios in Victoria, the state with the highest maximum daily gas demand and greatest residential demand[38]. The trends are similar to the residential and commercial annual consumption trends described in Section 2.1.1.

Figure 23 Victorian regional winter 1-in-2 peak demand, excluding gas generation, all scenarios including UAFG, 2022-41 (TJ/d)



2.3.3 Trends in peak demand for gas used in electricity generation

While gas generation is forecast to reduce gas consumption in *Step Change* (outlined in Section 2.2.4), peak gas demand for gas generation is projected to remain significant and to become peakier. This is because gas generation provides a flexible form of dispatchable capacity and can quickly ramp production up and down to balance fluctuations in electricity supply from other sources. As the system transitions and this role becomes increasingly valuable, an increasing proportion of gas generators' annual consumption is expected to be driven by their firming role in the NEM. This is forecast to result in very high utilisation days coexisting with declining average capacity factors.

Gas generation becomes winter peaking

The seasonality of gas generation is also projected to change. **Figure 24** shows forecast annual gas generation consumption in *Step Change* (previously shown in Figure 18) alongside the summer and winter maximum daily gas generation demand. All three forecasts have been averaged across a range of weather reference years.

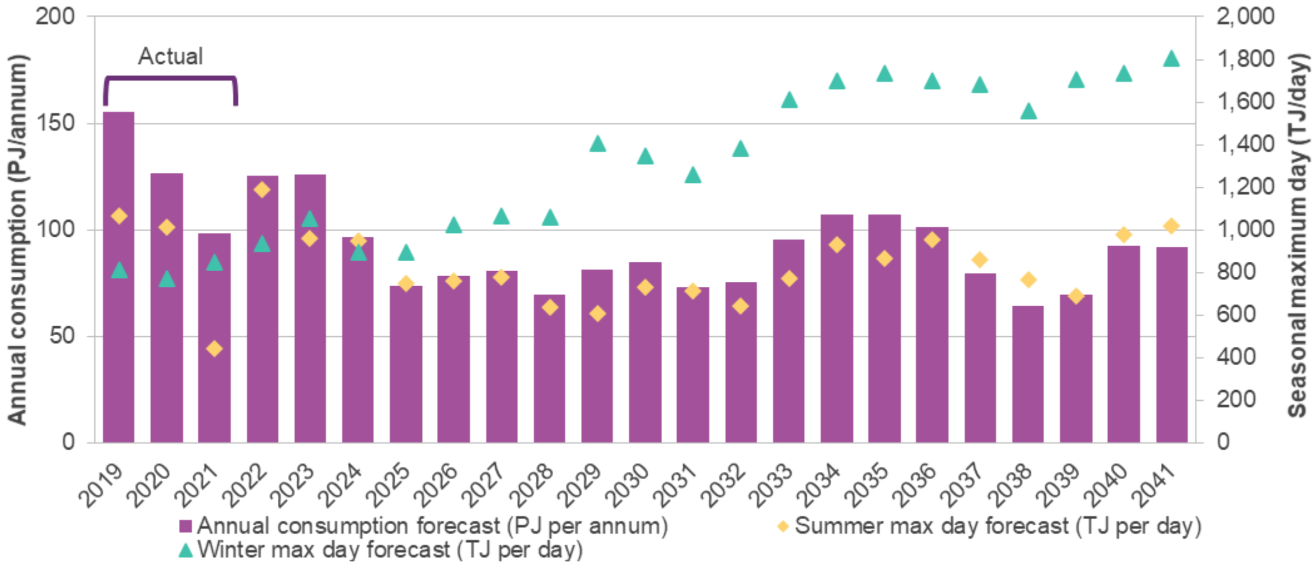
[38] For other regions, see AEMO's Electricity and Gas Forecasting portal at http://forecasting.aemo.com.au/.

This figure clearly shows that the summer maximum daily demand forecast follows similar trends to the annual consumption forecast (although on a different scale), with an initial drop and long-term flattening, whereas the winter maximum daily demand for gas generation is forecast to nearly double between 2022 and 2041 as the NEM's winter load increases with electrification of winter heating loads.

Gas generation historically has been highest in summer, responding to the high summer peaks in the NEM associated with air-conditioning loads to cool high ambient temperatures. As more renewable generation and storage operates in the NEM, gas generation retains a key role in summer, particularly at times of peak demand. Gas generation will continue to firm renewable energy and meet the flexibility needs of the grid during extreme weather conditions and in response to planned and forced outages which may reduce availability from other dispatchable technologies.

Winter is forecast to become an increasingly important season for gas generation to also provide firming support. During gloomy winter days with minimal sunshine and early sunsets, and during periods with low wind, reliance on gas generation is forecast to increase, particularly following the retirement of coal generation.

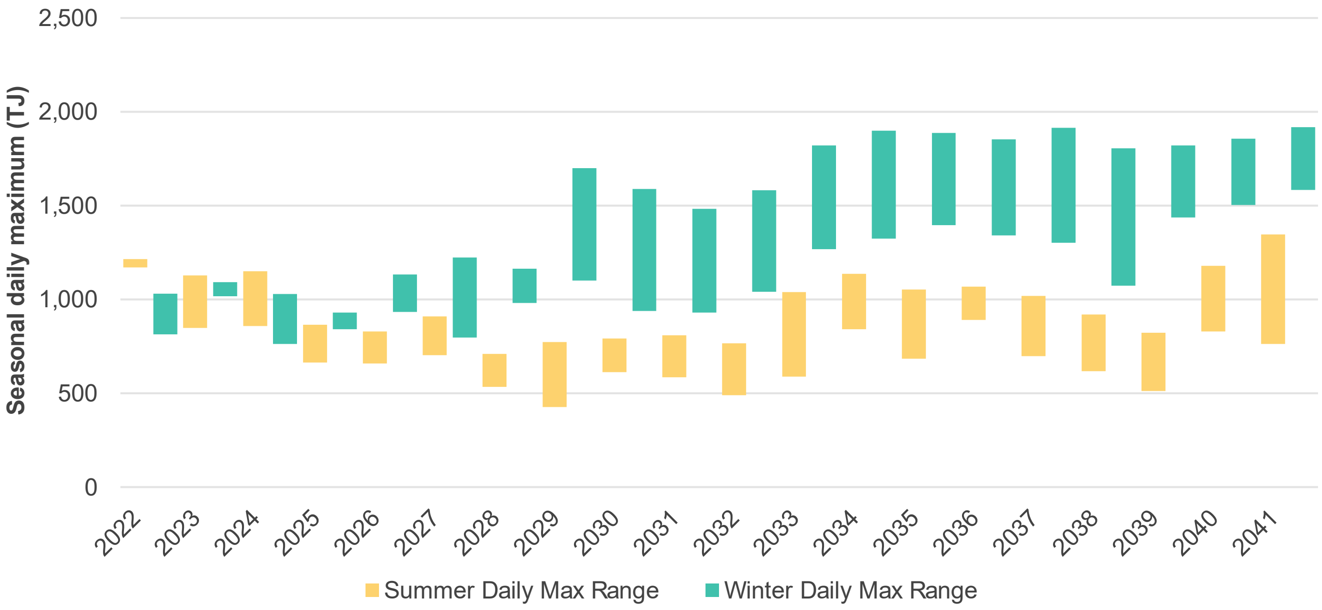
Figure 24 Actual and forecast gas generation annual consumption (PJ/annum) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2019-41



Note: The shown forecast maximum daily demand for summer and winter represents the median across different weather patterns.

Figure 25 shows the forecast seasonal (summer and winter) whole-NEM maximum daily demand for gas generation, across a range of weather conditions, in *Step Change*. As this figure shows, winter peaks are forecast to grow, while summer maximum demand trends flat with a slight near-to-mid-term decline. The emerging coincidence of peak demand for gas generation and from other gas consumers will put further stress on the balance of gas supplies and infrastructure to meet the peak gas demands across the gas system without appropriate investment in flexible infrastructure and resources.

Figure 25 Forecast range of whole-NEM seasonal peak day demand across various weather patterns, *Step Change* scenario, 2022-41 (TJ)



Despite falling consumption, the value of gas generation in firming the NEM increases, increasing volatility

While gas generation annual consumption is forecast to decline or stay flat (see Section 2.2.4), gas generation is projected to have a continuing role for firming the NEM's renewable energy resources. These trends mean less gas is forecast to be consumed for gas generation outside of peak times, leading to increasing variability of operation.

Figure 26 shows the monthly variability of gas generation with New South Wales and Victoria, based on weather conditions historically observed in 2019, referred to as the 2019 reference year[39]. Other reference years studied produced a similar outcome.

The variability is captured with the monthly maximum day index – that is, the peak gas used in a single day within each month divided by the total gas consumed for gas generation in that same month. Where this index shows a low value (for example, 10% or less), it indicates that gas consumption for gas generation is spread fairly evenly throughout the month, with no single day peaking particularly high. Where this index increases, it means that a single day's gas demand increasingly accounts for larger proportions of the total gas consumption in that month.

Figure 26 demonstrates that for increasingly large amounts of the year, gas generation is forecast to be only required at very low levels, but on peak days (which may become more infrequent), these highest consumption events remain significant and likely to occur in winter when the supply and demand balance of gas is tighter.

On these days, the value of the capacity provided by gas generation is important for electricity consumers. Flexible solutions to deliver the gas required under these challenging conditions will become increasingly

[39] AEMO optimises NEM market modelling across multiple historical weather years known as "reference years" to account for short- and medium-term weather diversity. The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coincidence of customer demand, wind, solar and hydro generation outputs.

important, and could include utilisation of the linepack within high-pressure pipelines, local gas storages, and major industrial sites being on interruptible contracts.

Figure 26 Monthly maximum day index and monthly energy for New South Wales (top) and Victoria (bottom), *Step Change* scenario, 2019 reference year (TJ)

3 Gas supply and infrastructure forecasts

This section provides an overview of the reserves, resources and production forecasts for supplies connected to the gas system, as well as an overview of the system's midstream infrastructure (that is, pipelines, storages, and LNG import terminals).

Key insights

- Overall, the **sum of all reserves and resources is virtually unchanged**, with reduction in existing, committed and uncertain fields and mostly balancing increases for anticipated fields.
- Producers' **five-year forecasts for southern available production are higher than in the 2021 GSOO, but still declining**. Existing and committed available production is forecast to reduce from 487 PJ in 2022 to 360 PJ in 2026.
- Pipelines and other infrastructure continue to be important means to deliver supply where it is needed, particularly as southern production declines.
  - Committed upgrades to the MSP/ South West Queensland Pipeline (SWQP) and the Western Outer Ring Main (WORM) will increase the system's capacity to deliver gas to consumers in the south-eastern regions of New South Wales, the Australian Capital Territory, Victoria and Tasmania, including improving the capability to use the Iona UGS facility to supply Melbourne.
  - Utilisation of storage facilities to meet peak day and seasonal gas demand in the south is forecast to increase.
  - LNG import terminals represent an alternative way to supply gas to consumers as gas production declines. A number of these are proposed, in addition to the now anticipated Port Kembla Energy Terminal (PKET) project.

3.1 Reserves, resources, and production facilities

Gas supply to consumers relies on continued investment to identify, prove, and then exploit gas reserves and resources. AEMO's production forecasts in the first five years of the outlook rely mainly on survey responses from producers to project available quantities of gas, plans for extraction, and the capability and capacity of gas processing plants. Forecasts of gas production must consider uncertainties on both technical and commercial grounds.

In this GSOO, the following definitions apply[40]:

- **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.

[40] 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.

- **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.

Under this classification structure, each project represents a specific investment decision, with an associated quantity of recoverable gas reserves and resources, that may be more, or less, certain.

3.1.1 Reserves and resources

Gas developments are categorised according to the level of technical and commercial uncertainty associated with recoverability. These uncertainties could include securing finance, obtaining government approvals, negotiating contracts, overcoming geological challenges, or the quality/purity of the gas.

The following categories are applied across the industry:

- A gas reserve is a quantity of gas expected to be commercially recovered from known accumulations. When estimating the existing, committed, and anticipated gas reserves, the best estimate values are quoted as "proven and probable" (**2P**) reserves. 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.
- Gas resources are defined as less certain, and potentially less commercially viable sources of gas. When estimating these uncertain resources, the best estimate of contingent resources (**2C**) is used.
- More broadly, there are also prospective resources, which are estimated volumes associated with undiscovered accumulations of gas. These resources are highly speculative and have not yet been proven by drilling. The 2022 GSOO does not rely on prospective resources in the estimates of uncertain production.

The gas reserves and resources for the 2022 GSOO[41] include all major fields in Australia excluding Western Australia and the Northern Territory, although it does include those fields in the Northern Territory connected to the Northern Gas Pipeline (NGP) and thus able to supply eastern Australia.

Over time, gas reserves and resources develop, deplete, or are reassessed (particularly against commercial benchmarks), so forecasts of gas reserves and resources change.

Figure 27 shows the best estimate of the gas reserves and resources for this GSOO as at 31 December 2021, compared to that published last year.

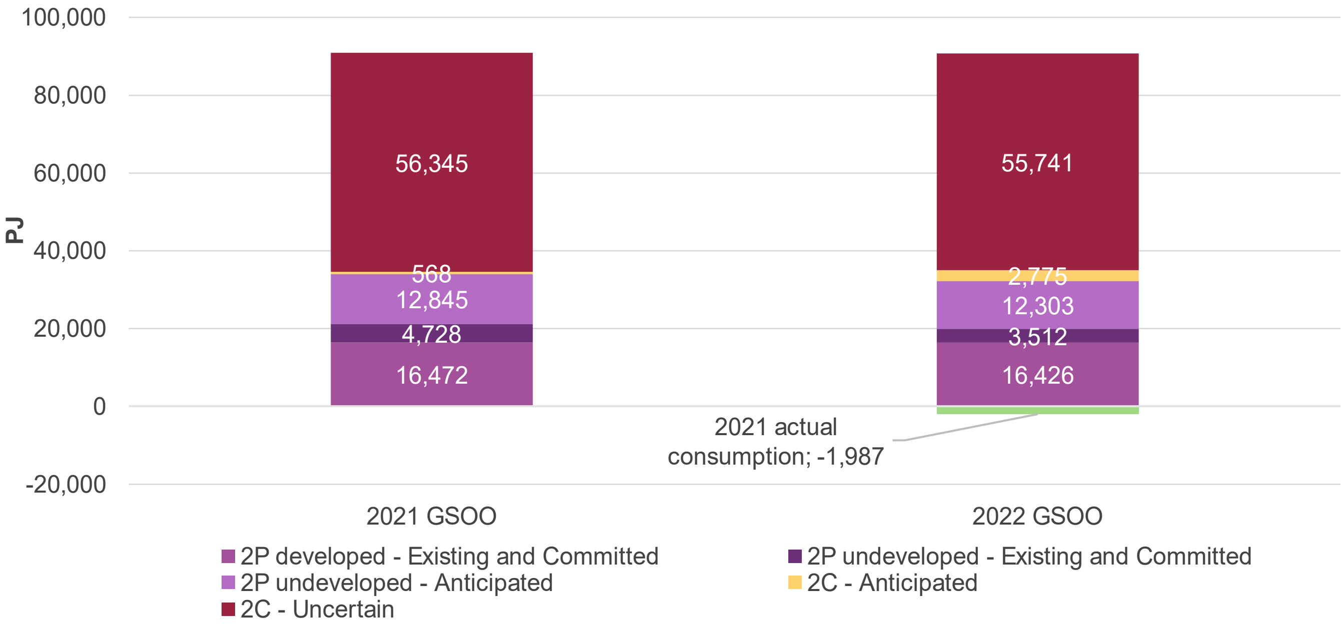
Compared to the 2021 GSOO:

- The sum of all reserves and resources of natural gas is almost unchanged. However, much of this gas is identified as prospective and associated with uncertain projects.
- Considering the reserves and resources categories individually:

[41] The natural gas reserve and resource estimates in the 2022 GSOO used information from gas producers, supported by estimates from research from a wide variety of sources, particularly for the more uncertain gas resources.

- 2P reserves associated with existing and committed projects are 6% (1,262 PJ) lower. This is mainly due to consumption in the last year and absence of committing to developments for full replacement (resulting in partial downgrades to the existing and committed resources).
- Reserves associated with anticipated developments are over 12% higher (1,666 PJ).
- Resources associated with uncertain projects are largely unchanged, being about 1% lower (604 PJ).

Figure 27 Reserves and resources reported in the 2021 GSOO and 2022 GSOO



3.1.2 Available annual production

Gas must be extracted and processed before it can be injected into pipelines for consumers. The rate of production is determined by a variety of factors, including but not limited to:

- 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, determining the rate of flow, particularly for conventional gas.
- The drilling program to access gas pockets, particularly for CSG.
- The quality of the gas, particularly in terms of the need for additional processing.

Table 6 shows the annual forecast of available production from 2022 to 2026[42], provided via surveys to AEMO by gas producers. These estimates provide an upper bound on possible annual production. Actual production will rely on the quantity of gas demand for domestic consumption or international exports. Table 6 also shows that, compared to the 2021 GSOO:

[42] Few producers provide forecasts beyond the first five years for either the voluntary GSOO surveys or the mandatory (five-year) VGPR surveys. The 2022 GSOO has a modelling horizon out to 2041. For GSOO purposes, the producers' last forecast values are projected forward, limited by the remaining volume of gas in a reserve or resource.

- Total projected existing, committed and anticipated available annual production is now lower in 2022 and 2023 and higher in 2024 and 2025 (although higher in southern regions in all years).
- In the north, less development of anticipated projects is now forecast over the next five years.

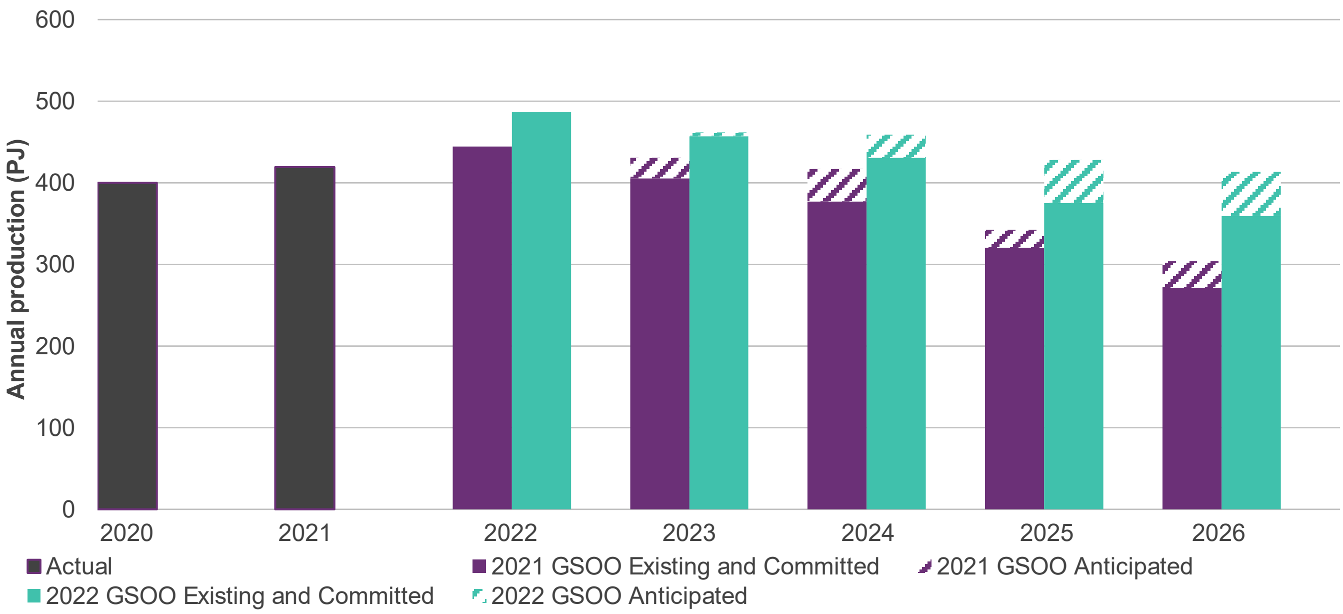
Table 6 Forecast of available annual production as provided by gas producers, 2022-26 (PJ)

	Commitment criteria	2022	2023	2024	2025	2026
Northern (QLD / NT)	Existing and committed	1,521	1,563	1,544	1,480	1,423
	Anticipated	10	50	133	193	260
	Total	1,531	1,614	1,677	1,672	1,682
	Difference from 2021 GSOO*	-84	-52	35	76	N/A
Southern (VIC / NSW / SA^)	Existing and committed	487	457	431	375	360
	Anticipated	0	5	28	53	54
	Total	487	462	459	428	413
	Difference from 2021 GSOO	42	31	42	85	N/A
Total east coast gas production		2,018	2,075	2,136	2,100	2,096
Difference from 2021 GSOO		-42	-21	77	162	N/A

^ The Queensland component of the Cooper Eromanga basin appears in the South Australia category.

Figure 28 shows that despite production estimates in the south being higher than in the 2021 GSOO, gas producers in this part of Australia still forecast a decline over the next five years in available annual production. Production from anticipated fields[43] and the anticipated additional supply from PKET (not shown in the figure) will offset field production decline when commissioned. Much of the reduction is due to the decline of Gippsland basin production, with details provided in the 2022 VGPR Update[44].

Figure 28 Actual and forecast annual production from southern gas fields (excluding LNG imports), 2020-26 (PJ)



[43] Anticipated fields include the Golden Beach development and some additional Victorian offshore field developments.

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

3.1.3 Maximum daily production capacity

The **maximum daily production capacity** defines the quantity of total gas that can be injected into the system each day. This maximum daily production capacity is critical to the operation of the gas markets to ensure sufficient gas is available to meet peak winter demands.

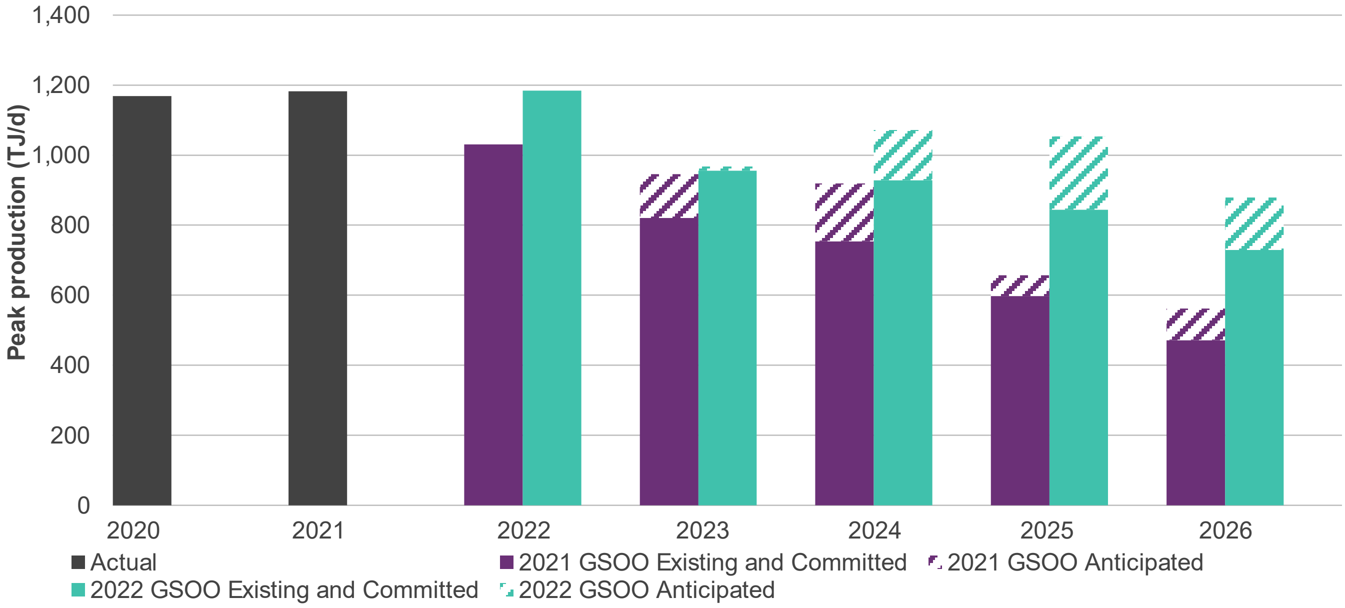
Five-year estimates of daily production capacity have been provided to AEMO by gas producers through the GSOO survey process, and provide an upper bound on possible daily production.

For many facilities, their annual production forecasts are strongly proportional to their peak production capacity, as the processing plant may normally operate near capacity, although this is not exclusively the case.

Southern daily production capacity

Figure 29 shows that daily production forecasts from the south-eastern regions are higher than forecast in the 2021 GSOO, but continue to present an overall decline in existing and committed daily production capacity from 2023.

Figure 29 Actual and forecast maximum daily production capacity from southern-eastern gas fields (excluding LNG imports), 2020-26 (TJ/d)



The largest fall in available production from winter 2023 is from Longford, the most flexible source of Victorian supply. The gas system relies heavily on this flexibility to ramp production up and down as required to match the seasonality of southern demand (this flexibility is illustrated in **Figure 32** in Section 3.2.1). As the size of this resource reduces, other means, such as pipelines connecting gas supply from the north, are needed to provide the flexibility to match gas supply with demand.

Northern daily production capacity

In the north, demand is far less seasonal (dominated by production for LNG exports), and production operates at near full capacity all year around. Any changes in daily production capacity would be proportional to changes in annual production.

3.2 Midstream gas infrastructure

Midstream infrastructure provides the linkage between producers in the various gas producing basins and consumers, and includes pipelines, storages, and LNG import terminals[45].

Figure 30 is a map of the basins, pipelines, and load centres in the GSOO's scope.

As gas production and consumption patterns change, the requirements on midstream infrastructure may also change.

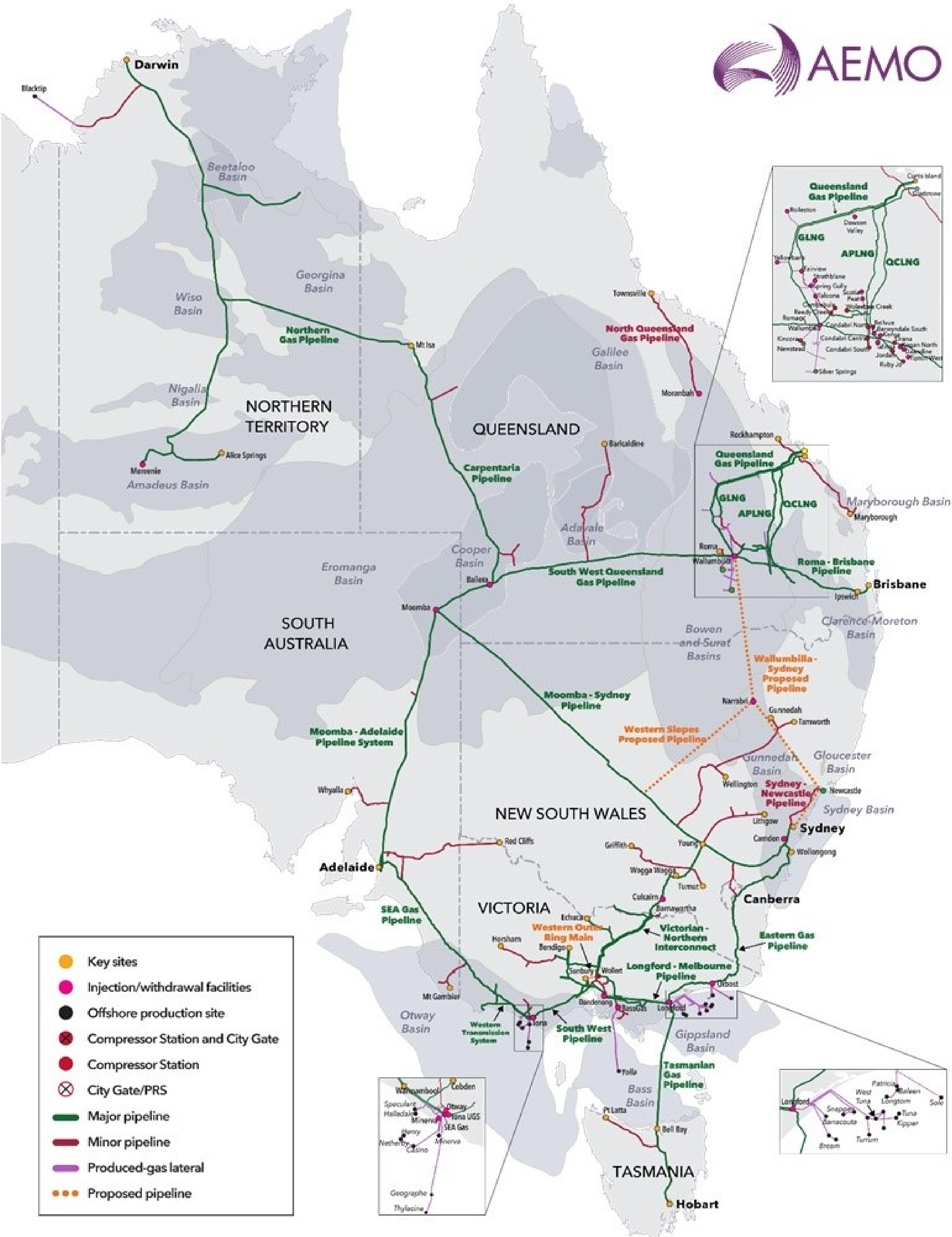
In assessing gas adequacy, AEMO bases its modelling of midstream infrastructure on technical capability and does not consider contracted positions[46]. The ACCC Gas Inquiry 2022 interim report provides valuable context on potential implications of pipeline contracts[47].

[45] LNG export terminals are considered consumers.

[46] The gas price modelling which is used as an input to the demand modelling and gas adequacy modelling does consider contracts and competition.

[47] At https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2025/gas-inquiry-january-2022-interim-report.

Figure 30 Map of basins and major pipelines and load centres



Note: The WORM is a committed project. All other 'proposed pipelines' are potential future projects only, and not included in the GSOO. See Table 7.

3.2.1 Major gas transmission and pipelines

In the geographical area covered by this GSOO, there are a number of major pipelines that connect regions or geographically separated supply and demand centres.

This section does not provide a comprehensive list of all major pipelines. It discusses some key pipelines which are part of the supply demand adequacy discussion in Section 4, particularly impacting north-south flowing gas.

South-West Queensland Pipeline (SWQP)

The SWQP runs from Wallumbilla to Moomba, and connects with the Carpentaria Gas Pipeline (CGP), which can receive gas from the NGP. The SWQP acts as a gateway between the large northern gas fields (including the three Gladstone LNG export plants) and southern regions, where much of the highly seasonal demand is located.

As explained under the MSP section below, availability of this pipeline to enable north-south gas flows is increasingly important.

APA[48] has committed to a Stage 1 expansion of the SWQP and MSP that will increase capacity on the SWQP by 49 terajoules a day (TJ/d) from 404 TJ/d to 453 TJ/d, and on the MSP by 30 TJ/d from 446 TJ/d to 475 TJ/d, before winter 2023, as noted below. This will allow 49 TJ/d of additional northern gas to be supplied to southern markets. This expansion will consist of an additional compressor between Moomba and Young and an additional compressor on the SWQP. The Stage 1 capacity expansion is included in this GSOO modelling.

There are proposed projects that could expand the capacity of the SWQP further, by increasing compression, but these are subject to customer contracting and not yet classified as anticipated or committed.

Moomba – Sydney Pipeline (MSP)

The MSP connects the Moomba Gas Hub in northern South Australia to Sydney. It also intersects with the Victorian Northern Interconnect (VNI) at Young, and therefore also provides for additional gas sharing with Victorian consumers.

At present[49], any gas flowing from northern Australia as well as Moomba into New South Wales, Victoria, or Tasmania must pass through the MSP. Similarly, at times, surplus Victorian gas supply has been piped north to supplement northern supply, and this must also pass through the MSP. As such, the MSP – and the SWQP – are key to maintaining the capability to share gas between northern and southern regions.

Based on enhanced data received by AEMO for this GSOO, there is a seasonal capacity limitation on MSP, limiting capacity by up to 50% at times during off-peak (non-winter) periods for annual maintenance works. Also, the dynamic interaction between Young – Sydney and the VNI lateral may impact the total southern haul capacity of the MSP south of Moomba. The total MSP capacity is generally higher when the quantities delivered south via Sydney are higher. These constraints would impact the capacity to meet demand in peak days and are implemented in the adequacy model in this GSOO.

As noted above, APA has committed to a Stage 1 expansion of the SWQP and MSP that will increase capacity on the SWQP by 49 TJ/d from 404 TJ/d to 453 TJ/d and on the MSP by 30 TJ/d, from 446 TJ/d to 475 TJ/d, prior to winter 2023. This will allow 49 TJ/d of additional northern gas to be supplied to southern markets. This expansion

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

[49] Additional pipelines, such as the Queensland-Hunter Gas Pipeline, or an LNG import terminal in the south, may change this situation.

will consist of an additional compressor between Moomba and Young and an additional compressor on the SWQP. The Stage 1 capacity expansion is included in this GSOO modelling.

The next proposed Stage 2 expansion will provide further capacity from northern to southern markets by construction of an additional compressor station on both the SWQP and MSP. The expansion will increase the nominal capacity of the SWQP by 59 TJ/d from 453 TJ/d to 512 TJ/d and the MSP by 90 TJ/d from 475 TJ/d to 565 TJ/d. This proposed development's execution is subject to customer contracts and is not included in the 2022 GSOO adequacy assessment.

Eastern Gas Pipeline (EGP)

The EGP runs from the Longford and Orbost Gas Plants in the Gippsland Basin in Victoria to Sydney, with Canberra supplied from the EGP at the Hoskinstown connection. The EGP presently only flows north towards Sydney, but the anticipated PKET has associated EGP modifications to allow bi-directional flow, so gas can be transported both north (to Sydney) and south (to Victoria) from PKET simultaneously. See Section 3.2.3 below for more on the PKET project.

South West Pipeline (SWP)

The SWP is a bi-directional pipeline that runs between Port Campbell and Lara in Victoria. At Lara it connects to the Brooklyn–Lara Pipeline (BLP).

The SWP is typically used to:

- Transport gas from the Port Campbell production (including Otway Basin) and Iona UGS facilities towards Melbourne.
- Support Iona UGS reservoir refilling, and provide supply to Victorian demand west of Port Campbell (including Mortlake Power Station) and to South Australia via the South East Australian Gas (SEAGas) Pipeline, during periods of lower Victorian gas demand in the summer and shoulder seasons.

The SWP capacity *from Port Campbell to Melbourne* is dependent on system demand and is maximised on peak demand days. Current maximum capacity is 415 TJ/d on a one-in-20 system demand day. This is expected to increase to 464 TJ/d following completion of the WORM project (see below).

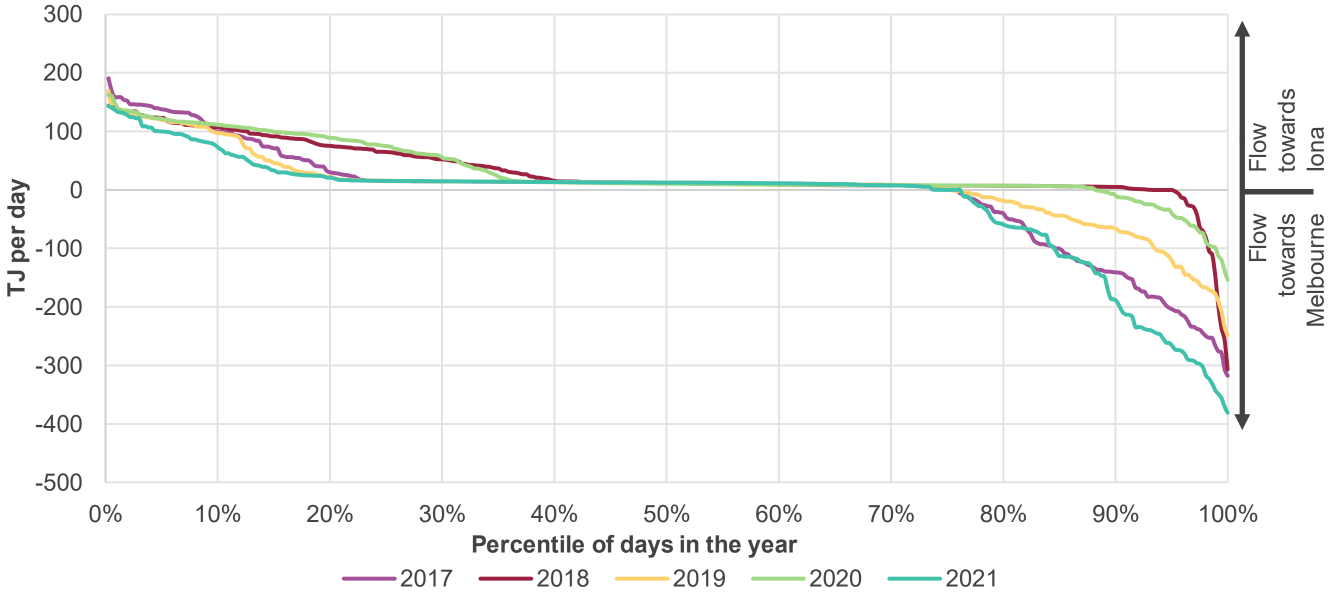
The SWP capacity *from Melbourne to Port Campbell* is also dependent on system demand and is maximised on low demand days. Current maximum capacity is 149 TJ/d on a low demand day. This will increase to 332 TJ/d following completion of the WORM.

Historical flows in the SWP over the last five years are shown in **Figure 31** below.

Forecasts show the SWP constraining flows towards Melbourne during peak demand periods when the full capacity of the Iona UGS is most needed. Additional supply from the Otway Basin will not help support winter peak demand without upgrading or duplicating this pipeline.

Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS, following completion of the WORM. These are not yet committed, as they are subject to approval under APA's Access Arrangement, and have not been included in the 2022 GSOO.

Figure 31 Cumulative distribution of flows along the SWP, 1 January 2017 to 31 December 2021 (TJ/d)



WORM (Western Outer Ring Main)

The WORM is a committed augmentation of the Victorian DTS that will connect the SWP/BLP at Plumpton and the Longford Melbourne Pipeline (LMP) at Wollert. The project will also include the installation of additional compression. It was one of four priority projects highlighted in the Interim NGIP[50] to address shortfall issues flagged in the 2021 GSOO. The scheduled completion date is winter 2023.

Given the tight commissioning schedule, there is a risk the project may not be completed ahead of winter 2023. AEMO has therefore undertaken sensitivity analysis to consider the impact of a one-year delay to this project – see Section 4.1.

Use of mid-stream infrastructure to meet south-eastern demand

Figure 32 highlights the contribution of MSP and SWP to meet south-eastern demand in 2021.

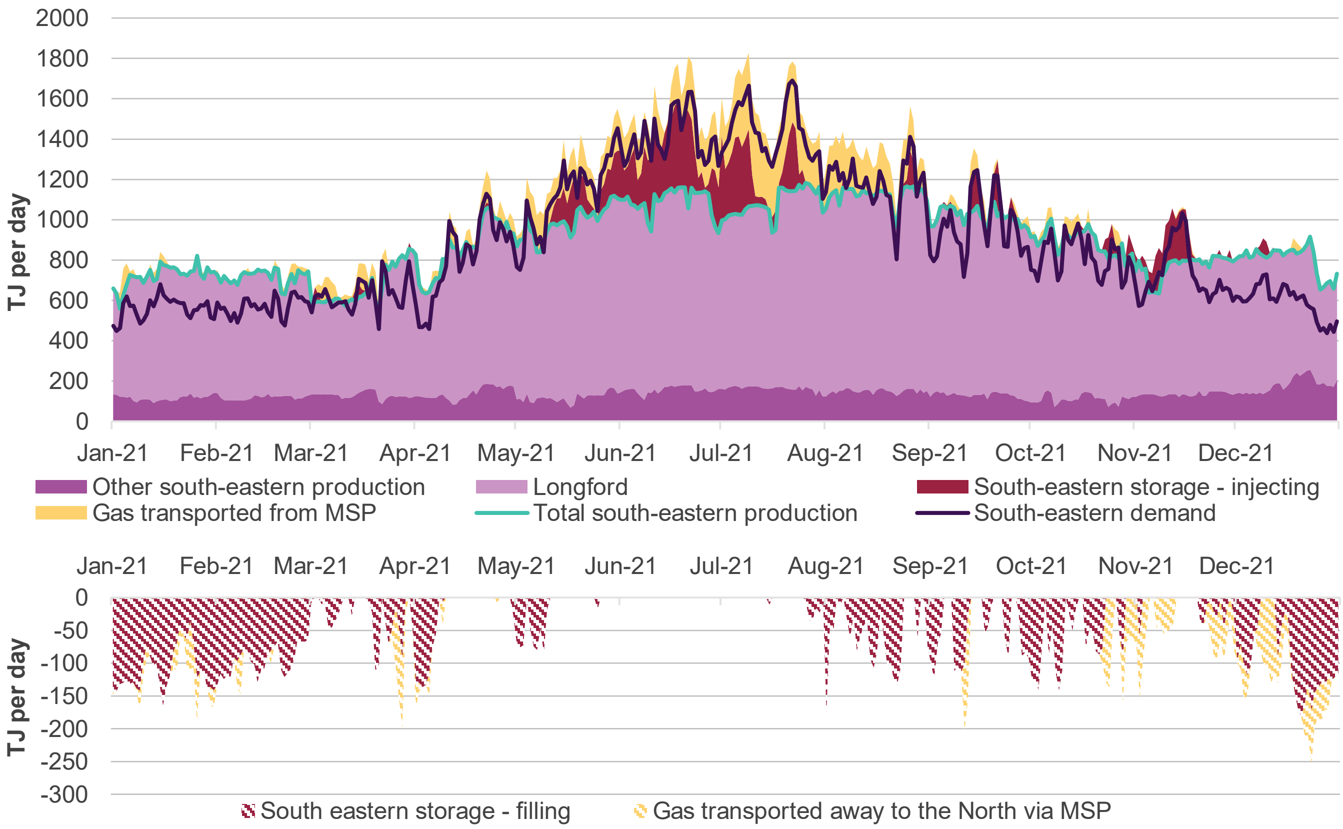
As shown in the figure, MSP had a significant contribution to meet the winter peak demands in 2021.

The figure also shows the daily profile of supply sources used to meet south-eastern demand across 2021, including:

- Gas produced in Longford and other southern fields.
- Withdrawal (and injection) from gas storages within the southern regions.
- Gas flow through Moomba from the north to the south-east via MSP.
- Gas flow from the south-east regions toward Moomba via MSP.

[50] At https://www.energy.gov.au/sites/default/files/National%20Gas%20Infrastructure%20Plan%20-%20Interim%20Report.pdf.

Figure 32 Observed gas supply used to meet peak south-eastern demand in 2021 (TJ/d)



Where total supply exceeds the shown demand, it reflects gas used to meet demand west of Port Campbell in Victoria (including Mortlake Power Station) and/or supplied to South Australia via SEAGas.

Other pipelines

Table 7 lists other major midstream infrastructure servicing domestic consumers.

Table 7 Additional major midstream infrastructure (existing and proposed)

Name	Description and relevant information
Existing	
Moomba – Adelaide Pipeline System (MAPS)	Connects Adelaide to the Moomba gas production facility in northern South Australia.
South East Australian Gas Pipeline (SEAGas)	Connects Adelaide to supply from Otway Basin in Victoria, including Iona UGS. There is a limited capability for gas to flow from SEAGas into the MAPS, but gas cannot flow from the MAPS into SEAGas.
Northern Gas Pipeline (NGP)	Connects the Blacktip and Mereenie gas fields in the Northern Territory to Mt Isa and the CGP (described below). Has potential to increase capacity to as high as 1,000 TJ/d with additional compression and looping*.
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.

Name	Description and relevant information
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.
Proposed developments	
Western Slopes Pipeline	Would connect the proposed Narrabri Gas Plant to the MSP at Mount Hope.
Queensland – Hunter Gas Pipeline (QHGP)	A new Wallumbilla to Sydney connection, which would connect the proposed Narrabri Gas Plant to Newcastle in the south and Wallumbilla in the north, providing a new pathway for north/south gas transfer. If the QHGP progressed it is likely that expansion of the SNP would also be required to connect down to the EGP, which would also be developed to be bidirectional.

* At https://jemena.com.au/about/newsroom/media-release/2020/jemena-partners-with-shale-gas-experts-to-develop.

3.2.2 Storage facilities

Storage facilities store surplus gas supplies produced in summer for use in winter, when the demand is higher. They provide additional flexibility and peak capacity to help the gas system meet peak demand requirements. At times, pipeline capacity limitations can affect the ability of storages to:

- Be refilled to capacity, and/or
- Deliver gas to the system at maximum withdrawal rate.

Table 8 lists the existing market-facing storage facilities and proposed upgrades or facilities. Two of these developments, Golden Beach and the committed Iona UGS upgrade, featured as priority projects in the Interim NGIP to address identified shortfall risks in the south-east.

Table 8 Key existing market-facing and proposed storage infrastructure

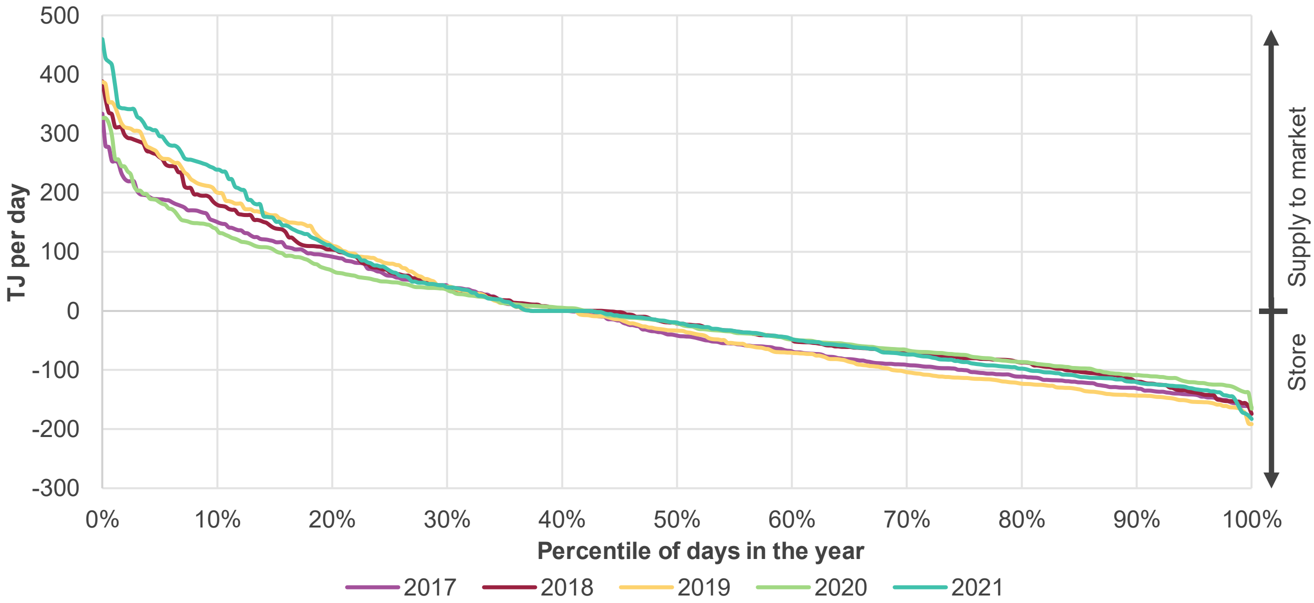
Name	Connecting location	Storage capacity (PJ)	Maximum withdrawal rate (TJ/d)
Silver Springs	Wallumbilla, Queensland	46	25
Iona UGS	Otway Basin, Victoria		
• **Existing**		23.5	520
• **Committed upgrade (+50 TJ/d + 1 PJ storage by winter 2023)**		24.5	570
• **Proposed upgrade (+ 50 TJ/d, +5.5 PJ storage, not included in this GSOO)**		30	620
Newcastle LNG Storage	Newcastle, New South Wales	1.5	120
Dandenong LNG Storage	Melbourne, Victoria	0.68	87*
Other proposed developments or upgrades			
Golden Beach Storage	Gippsland Basin, Victoria	12.5^	250^

* 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.
^ The data for this storage is based on the interim NGIP.

In recent years, as maximum daily production capacity in southern regions has reduced, there has been an increased reliance on southern storages. **Figure 33** demonstrates this, showing that each year from 2017 to 2021 (except 2020) saw the system draw on Iona UGS more often to help supply peak and seasonal demands, with 2021 observing the greatest daily withdrawal in the past five years, above 400 TJ/d.

Shallow storages at Dandenong and Newcastle will need careful operational management so they hold enough gas when it is needed to help mitigate shortfall risks. While these storages have relatively high withdrawal rates, the volumes they hold are small, so withdrawals cannot be sustained for many days, and the refilling speed is slow. Further detail on the Dandenong facility can be found in the 2022 VGPR Update[51].

Figure 33 Cumulative distribution of net changes in storage level for Iona UGS, 1 January 2017 to 31 December 2021 (TJ/d)



3.2.3 LNG import terminals

LNG import terminals represent an alternative way to supply gas to consumers, and an import terminal was highlighted in the Interim NGIP as a priority project to address forecast shortfalls. They could effectively operate as virtual pipelines, sourcing gas from both international and domestic markets and delivering it to demand centres – for example, bringing from the north to the southern regions. The total annual volume that could be supplied would depend on shipment schedules and approvals.

PKET[52] was considered committed in the 2021 GSOO before winter 2023. Its developers, AIE and Jemena, remain committed to the construction of the wharf and associated pipeline infrastructure, although AEMO has been advised that the project works will now not be completed until late 2023. While noting that construction is committed, AEMO has reclassified PKET as anticipated supply for winter 2024, due to the uncertainty around customer contracted volumes, which may not be sufficient to justify the relocation and operation of the floating storage and regasification unit (FSRU).

Table 9 lists PKET and other proposed LNG import terminals, with important considerations about each. These proposals are at various stages of development.

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

[52] In the 2021 GSOO, this project was called by its previous name of Port Kembla Gas Terminal (PKGT).

Table 9 Proposed LNG import terminals

Name	Region	Earliest assumed timing	Capacity	Additional considerations
Port Kembla Energy Terminal (PKET)[A] ***Anticipated project***	New South Wales	Ready for winter 2024	500 TJ/d	• Modelled as anticipated from 2024. Annual production limitation of approximately 130 PJ.[B] • Located near Sydney with a pipeline connecting into the EGP. • EGP to be upgraded to become bidirectional. Upgrade of the EGP to allow initially 200 TJ/d in reverse flows south to Victoria concurrently with the PKET development is considered 'anticipated'. A potential future expansion to 323 TJ/d can be achieved with additional compression.
Proposed developments (not committed, and therefore not included in GSOO adequacy assessments)				
Geelong[C]	Victoria	2024	500-600 TJ/d	• Located at the site of the Geelong Oil Refinery. • Would require pipeline duplication of the SWP.
Newcastle[D]	New South Wales	Timing not clear	Capacity not clear	• Declared New South Wales Critical State Significant Infrastructure (August 2019). • Would require multiple pipeline upgrades, expansions, or duplications.
Port Adelaide[E]	South Australia	2024	Up to 160 PJ/yr	• Construction approval granted Dec 2021, commissioning Q4 2023 to Q1 2024, subject to FID. • The floating terminal will operate as a take-or-pay tolling facility, with foundation gas customers to source their own LNG. • Would likely need pipeline expansions, upgrades, or duplication to be able to move gas directly into Victoria (for example, reversing the SEAGas pipeline).
Port Phillip Bay[F]	Victoria	2024	Capacity not clear	• Details still to be clarified.

A. For more, see https://ausindenergy.com/. Modelled as available from Q2 2024.
B. AEMO understands that the PKET has environmental restrictions that will limit water discharge and reduce the volume of imports to 130 PJ per annum.
C. For more, see https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project.
D. For more, see https://www.epiklng.com/ngdc.html.
E. For more, see https://veniceenergy.com/south-australian-power-project/.
F. For more, see https://www.vopak.com/newsroom/news/news-vopak-lng-studies-feasibility-develop-lng-import-terminal-victoria and https://www.argusmedia.com/en/news/2197082-vopak-eyes-lng-import-terminal-in-australias-victoria.

4 Gas supply adequacy assessment

Based on the demand and supply forecasts presented in Sections 2 and 3, this section provides a gas supply adequacy assessment for all Australian jurisdictions other than Western Australia and the Northern Territory.

Key insights

- **Gas supply adequacy is tight in the short term in south-eastern regions**. A gas shortfall is forecast to be narrowly avoided if actions to reduce gas demand included in *Step Change* are taken quickly. If gas transformation takes a slower pace, as in *Progressive Change*, small and infrequent gas shortfalls are forecast in extreme one-in-20 year weather conditions.
  - These shortfall risks in *Progressive Change* in 2023, 2024 and 2025 could be avoided if gas generation demand was reduced at peak times of gas demand. From 2026 the forecast peaks exceed available supply more often, and may exceed available supply even without any gas generation demand.
  - Pipeline capacity constraints affect the deliverability of northern gas supplies and key southern storages to south-eastern customers (including the SWQP, MSP and SWP). On-schedule completion of committed infrastructure upgrades is key to mitigate forecast peak day shortfall risks in 2023 and beyond. Delay to the WORM would increase the forecast risk of south-eastern shortfalls in winter 2023.
  - Demand side solutions, particularly for gas generation, will be important to mitigate risk next year, although brownfield infrastructure solutions, such as duplication of the Winchelsea compressor on the SWP, may still be able to address the risk.
- Longer term, existing, committed and anticipated supply is projected to meet declining domestic consumption until 2033 in *Step Change* (or sooner if consumption declines more slowly).
  - The timing and size of emerging supply gaps is uncertain across the scenarios, meaning scalable solutions with delivery flexibility may be preferred while the pace of gas sector transformation is unclear.
- Increasing peakiness of gas demand means that resource and infrastructure solutions will need to support gas demand hitting infrequent but significant daily peaks.
- Overall, to meet forecast supply gaps:
  - Greater resource development is needed (to offset declining production),
  - Infrastructure solutions must be developed to get the gas to where and when it is needed (such as local shallow storage, increased compression – expanding both pipeline capacity and linepack – and larger deep storage), and/or
  - Demand side options (which would take time and consultation to develop) can supplement infrastructure to meet the infrequent peaks.

Defining a shortfall

For GSOO purposes, an inability to supply gas to meet domestic (industrial, commercial, residential or gas generation) demand is identified as a supply gap, and is referred to as a shortfall if projected in the next five years.

There are two classes of shortfall (or supply gap) identified:

- A **peak day shortfall or supply gap** is driven by insufficient capacity to meet demand on an extreme peak day.
- A **seasonal shortfall or supply gap** is driven by a broader lack of available gas, rather than just capacity on a single day. They can also be caused by prolonged infrastructure constraints.

In this GSOO, AEMO has modelled total production, including from LNG exporters, but only domestic supply gaps and shortfalls are identified. LNG exporters are assumed to offer any available production above minimum contracted volumes to domestic consumers, in accordance with the Heads of Agreement[53]. While the current Heads of Agreement is in place until 1 January 2023, AEMO's modelling has assumed that this agreement is extended indefinitely.

The supply adequacy assessment takes into account all pipeline transmission capacity and constraints, and energy limitations from production facilities, storage and PKET.

4.1 Short-term supply adequacy

This 2022 GSOO analysis highlights that gas adequacy is tight in both *Step Change* and *Progressive Change* scenarios in the south-eastern regions[54] in the short term, with emerging supply gaps in the longer term. These two scenarios span the range of outcomes seen across all scenario forecasts up to 2026, so only these two scenarios are presented here.

Figure 34 illustrates[55] the ability of south-eastern production, pipeline capacity, and stored gas to meet actual gas demand in 2020 and 2021, and one-in-20 demand forecasts under 2019 reference year weather conditions to 2026 in *Step Change* and *Progressive Change*.

In this figure, the horizontal lines show, for each year, how much supply has been and is forecast to be available to meet projected daily demands, based on:

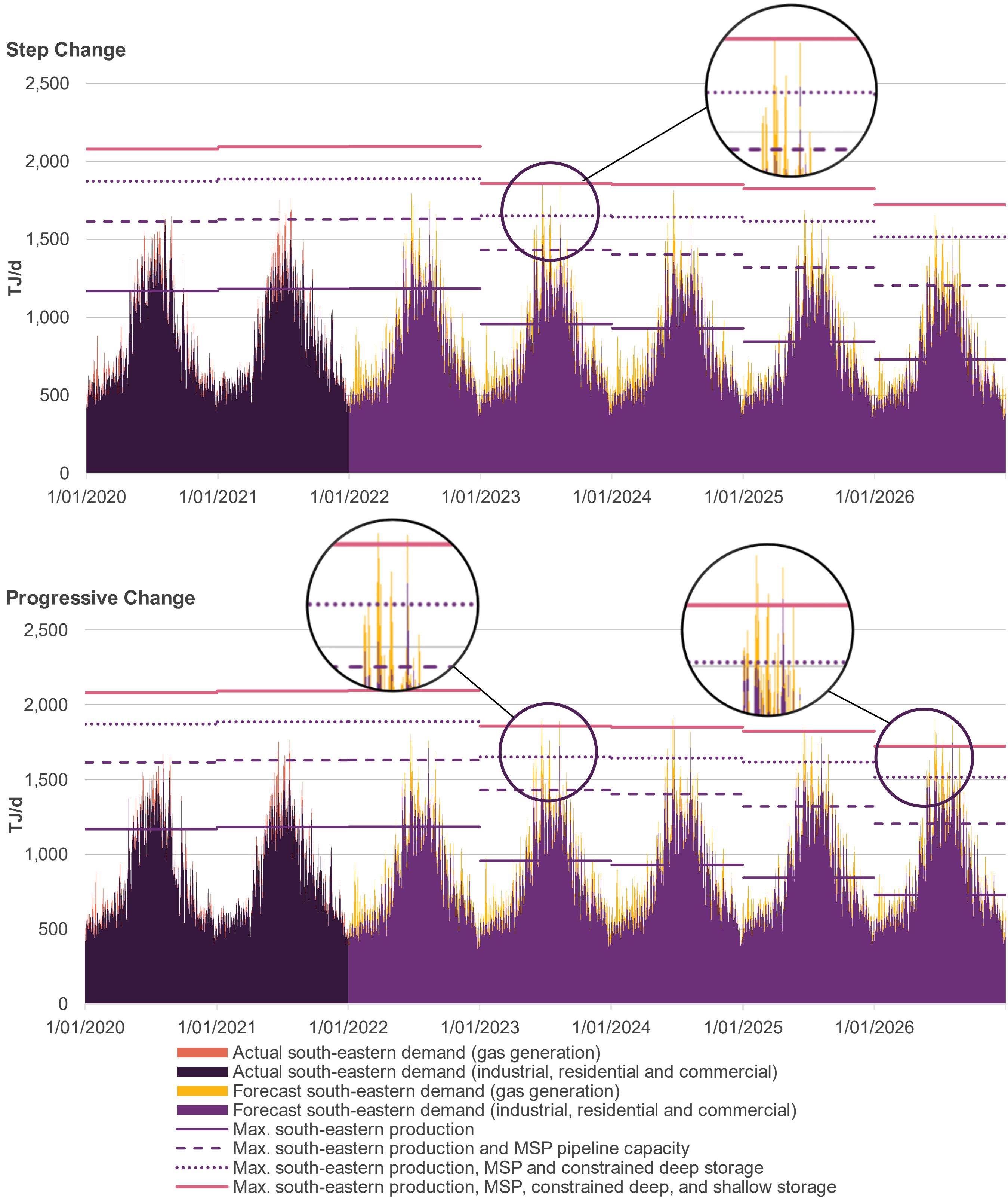
- Maximum gas production in the south-eastern regions only (solid purple line), plus
- Gas supplied from Moomba and imported from Queensland through the MSP (dashed purple line) assuming the pipeline is operating at maximum capacity, plus
- Deep storage (with supply from Iona UGS constrained by the SWP's capacity to flow into Melbourne – dotted purple line), plus
- Shallow LNG storages at Dandenong and Newcastle (solid red line).

[53] At https://www.industry.gov.au/regulations-and-standards/securing-australian-domestic-gas-supply.

[54] Victorian gas customers west of Port Campbell, including Mortlake Power Station, are excluded from this geographical definition, as they are outside the area with constrained supply.

[55] The figure provides an illustration of available supply, demonstrating the maximum supply capacity as a fixed value for each supply category (that is, for each horizontal line). AEMO's gas adequacy methodology calculates the adequacy of supply on a daily basis, allowing for dynamic infrastructure limits and the energy available in storage, and supply capacity may differ from this illustration.

Figure 34 Actual and forecast daily gas demand, *Step Change* (top) and *Progressive Change* (bottom), and production capability in south-eastern regions with existing and committed projects only, 2020-26 (TJ/d)



Source: Gas Bulletin Board (GBB), GSOO surveys, and AEMO forecasts of one-in-20 and 2019 reference year weather patterns south-eastern demand.

The key points highlighted in Figure 34 are that, in the south-east:

- Gas adequacy is tight in both scenarios in 2023.
  - In *Step Change*, a gas shortfall can be narrowly avoided. Actions and investments that reduce gas demand (like switching residential gas heating to electric and improving buildings' energy efficiency) are needed quickly to deliver the forecast demand reductions. While these may be likely over time, the pace so far has been relatively slow, and urgent action would be needed to put south-eastern regions on the *Step Change* path by next winter.
  - *Progressive Change's* slower gas transformation assumptions mean its forecast one-in--20 peak demand in 2023 is 54 TJ/d (equal to the demand of ~100,000 residential households[56]) higher than in *Step Change*. If in winter 2023 the transformation assumed in *Step Change* has not happened, the higher demand peaks create some risk of gas shortfalls. These risks are relatively small and infrequent, and apply only in extreme weather conditions. The risks also only arise when sufficient demand for gas generation coincides with peak gas demand by industrial, business and household consumers.
- South-eastern gas production (the solid purple lines) will fall significantly in 2023 and stay at lower levels (and with additional moderate drops both in 2025 and 2026). With reduced local production, operational management of shallow LNG storages will be increasingly important, to ensure these facilities have sufficient stored energy to mitigate shortfall risks.
- Gas consumed for electricity generation (actuals shown in dark orange, forecasts in yellow) is forecast to remain a significant contributor to total peak day demand. In *Progressive Change*, it is forecast to create peaks where demand exceeds available supply already from 2023, driven by the needs of the NEM and the availability of alternative generation sources.
- From 2026, in *Progressive Change*, forecast peaks start to exceed projected supply capacity more frequently, and also start exceeding supply capacity even with no gas generation.

Magnitude of shortfall risks

Table 10 lists the south-eastern shortfall risks for *Step Change* and *Progressive Change*. It shows the lowest and highest outcomes in peak day shortfalls forecast across the different demand cases (one-in-two and one-in-20 year peak day forecasts) and weather reference years (see Section 2.3.3), with and without anticipated supply.

The table shows that:

- In 2023-26, *Step Change* is not forecast to have a shortfall, even for a one-in-20 winter, regardless of whether anticipated supply has been assumed, although as shown in Figure 34, adequacy is tight in these years).
- In 2023, *Progressive Change* (assuming existing and committed supply only) forecasts peak day shortfalls as high as 36 TJ during extreme weather conditions, happening a few days in the year, as shown in Figure 34. *Progressive Change* continues to forecast risks of minor peak day shortfalls in 2024 and 2025, and more substantial seasonal shortfalls in 2026, even for one-in-two demand outcomes, with the additional decline in south-eastern production that year.

[56] Industrial fuel-switching is expected to contribute to a portion of this difference between the scenarios.

- There is no anticipated supply available in the south-eastern regions to address the peak day risks in 2023. However, anticipated supplies (including PKET) reduce the risk of peak day shortfalls after 2023 for several years, until seasonal supply gaps are forecast (see Section 4.2 below).

Table 10 Maximum magnitude and timing of forecast daily shortfalls, *Step Change* and *Progressive Change*, 2023-26 (TJ/d)

Scenario	2023	2024	2025	2026
***Step Change*, existing and committed supply**	0 - 0	0 - 0	0 - 0	0 - 0
***Step Change*, existing, committed and anticipated supply**	0 - 0	0 - 0	0 - 0	0 - 0
***Progressive Change*, existing and committed supply**	0 - 36	0 - 50	0 - 35	157 - 614
***Progressive Change*, existing, committed and anticipated supply**	0 - 36	0 - 0	0 - 0	0 - 0

4.1.1 Addressing shortfall risks in the short term

With scarcity risks now just over a year away, committed infrastructure developments, such as the WORM and the Stage 1 upgrade of the MSP/SWQP, are important to deliver on schedule. These developments will increase both supply capability during peak days and the operability of existing flexible solutions (such as existing gas and LNG storages) to meet a variable and infrequent need under extreme circumstances. Any construction delays to these projects will increase the shortfall risks.

Given the lead time needed to plan, obtain approval for and build new infrastructure, greenfield investments are unlikely to be in place to address the identified shortfall risk in winter 2023. There may however be options at existing “brownfield” sites, such as duplication of the Winchelsea compressor on the SWP. AEMO will continue to work closely with governments and participants to identify appropriate solutions to address the scarcity risks for winter 2023. More information on expansion options for the SWP are provided in the 2022 VGPR Update[57].

With limited opportunities for infrastructure solutions in the short term, and uncertainty regarding the scale of future gas infrastructure needs, the use of demand flexibility may be appropriate to address forecast supply scarcity risks in the short term. These can include:

- Curtailment of gas generation could avoid gas shortfalls during extreme conditions. Pipeline operators need to ensure supply and demand is balanced for the safe operation of their assets and would direct customer curtailments, including gas generation, if required. Depending on the availability of alternative electricity supplies, reducing gas generation may not compromise electricity reliability:
  - Some gas generators have dual-fuel capability, which means they can switch to alternative fuels, such as diesel if available, to generate electricity even if they are subject to gas curtailment.
  - Curtailment of gas generators without dual-fuel capability may not impact electricity reliability if electricity instead can be generated by other generation technologies (such as coal-fired generators or hydro). On extreme electricity demand days or days with reduced supply in the NEM, curtailing gas generation could lead to reliability being compromised.

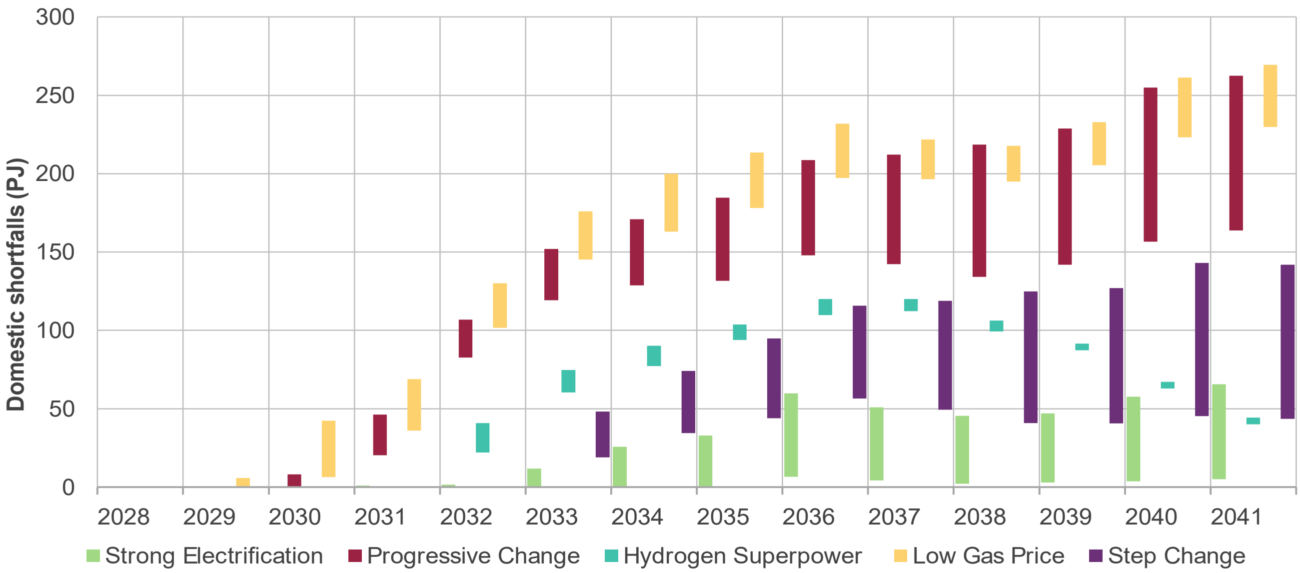
[57] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

    - Such curtailments are not counter to the intent of the Gas Supply Guarantee. This is a mechanism to ensure that gas supply and gas pipeline capacities are maximised to support gas generation, which is documented in the AEMO Gas Supply Guarantee Guidelines[58]. This additional gas supply will be limited by the physical capacity of gas supply facilities and pipelines, and should a shortfall remain, the GSG does not provide priority access to gas generation over other customers. This is a matter for the pipeline operator and the relevant jurisdiction.
  - The reliability in the NEM is typically only at risk on extreme electricity demand days, which are currently most likely to occur in summer. During winter, there may often be flexibility in the electricity system that could allow gas generation to self-curtail and lower gas demand.
- In extreme conditions, demand side participation and voluntary curtailment of electricity demand could be used to reduce how much gas is required for generation and reducing the risk of gas supply shortfalls.
- Jurisdictions could ask household consumers through the media to voluntarily reduce their use of gas during forecast extreme peak day events, as has occurred during tight conditions in the NEM.

4.2 Longer-term supply adequacy

Figure 35 shows the forecast range of domestic gas supply gaps out to 2041 under each scenario, assessed across a range of modelled weather conditions and POEs. These forecasts assume gas is available from existing, committed and anticipated developments.

Figure 35 Range of domestic annual supply gaps forecast under different scenarios, with existing, committed, and anticipated developments, all scenarios, 2028-41 (PJ)



As the figure demonstrates:

- Scenarios with slow transformation of the gas sector, with the lowest electrification (as in *Progressive Change* and *Low Gas Price*), forecast earlier supply gaps than other scenarios, as early as 2029.

[58] At https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee.

- There is a wide spread between the outcomes, and therefore the preferred timing, type and size of investments in new gas supply and any supporting infrastructure required is uncertain. Funding of capital-intensive investments may be challenging until it is clearer what is required and how big the investment gap is.
  - As the scenarios capture differences in the pace of gas sector transformation, uncertainty may reduce if governments and gas sector participants provide clearer commitments than presently exist. The Victorian Gas Substitution Roadmap, for example, will detail transition pathways and mechanisms to decarbonise the gas sector. As the development of the roadmap matures, [59] the spread between scenarios in future gas adequacy assessments may reduce.
- Each scenario presents a large variance depending on weather conditions and peak demand POEs.

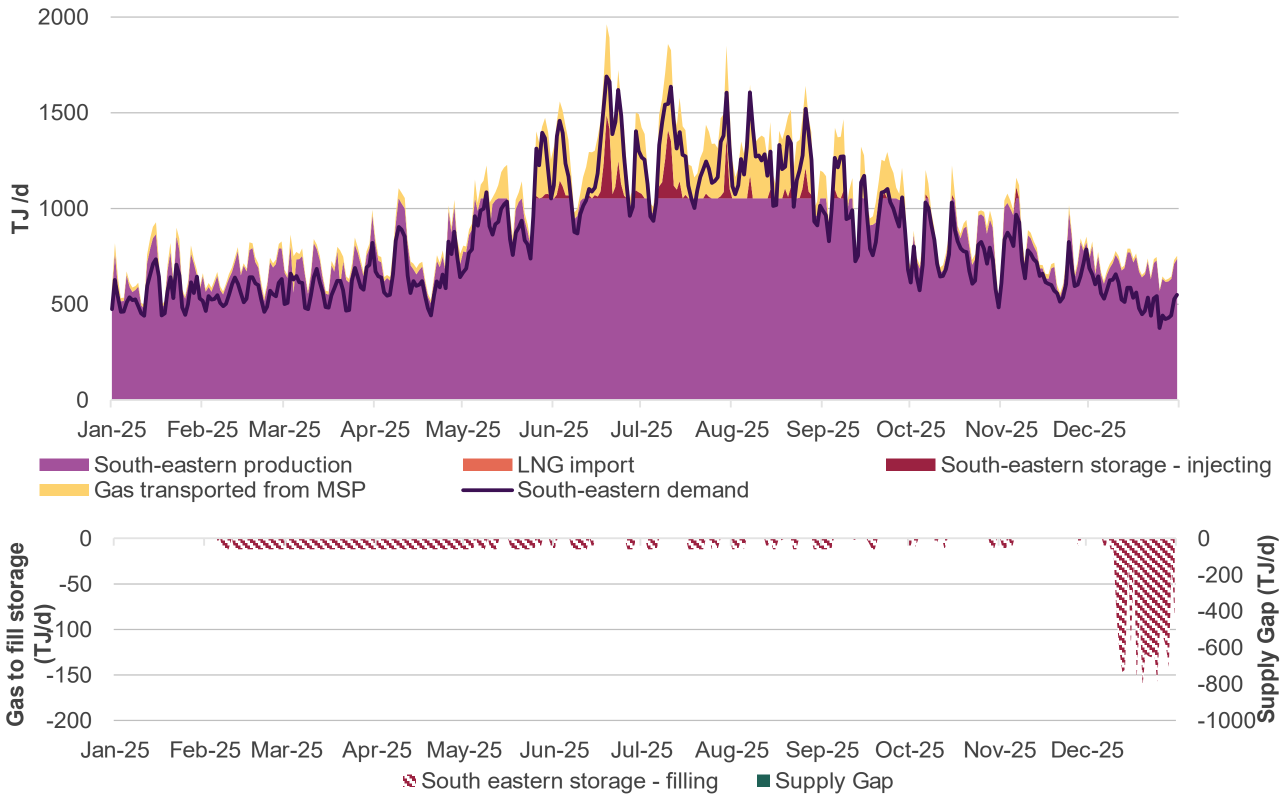
4.2.1 Annual adequacy assessment for the *Step Change* and *Progressive Change* scenarios

Figure 36 to **Figure 38** show how existing, committed, and anticipated supplies are forecast to be utilised in 2025, 2030, and 2035 to minimise supply gaps in *Step Change*, as south-eastern seasonal production declines:

- In 2025, AEMO forecasts that the amount of gas transported south via MSP and utilisation of storages will be sufficient to meet projected demand in the south-eastern region. At other times, excess production allows gas to flow to western Victoria and South Australia. This is on days where the total shown supply exceeds south-eastern demand.
- In 2030, despite increased supply from PKET, there is projected to be insufficient flexible production, including storage, to meet all winter peak days.
- In 2035, seasonal supply gaps are forecast. The south-eastern region is completely reliant on imported gas transported from northern supplies and PKET, and storage cannot fill the gap as there is insufficient supply surplus available in summer to manage storage depletion across the season when needed.

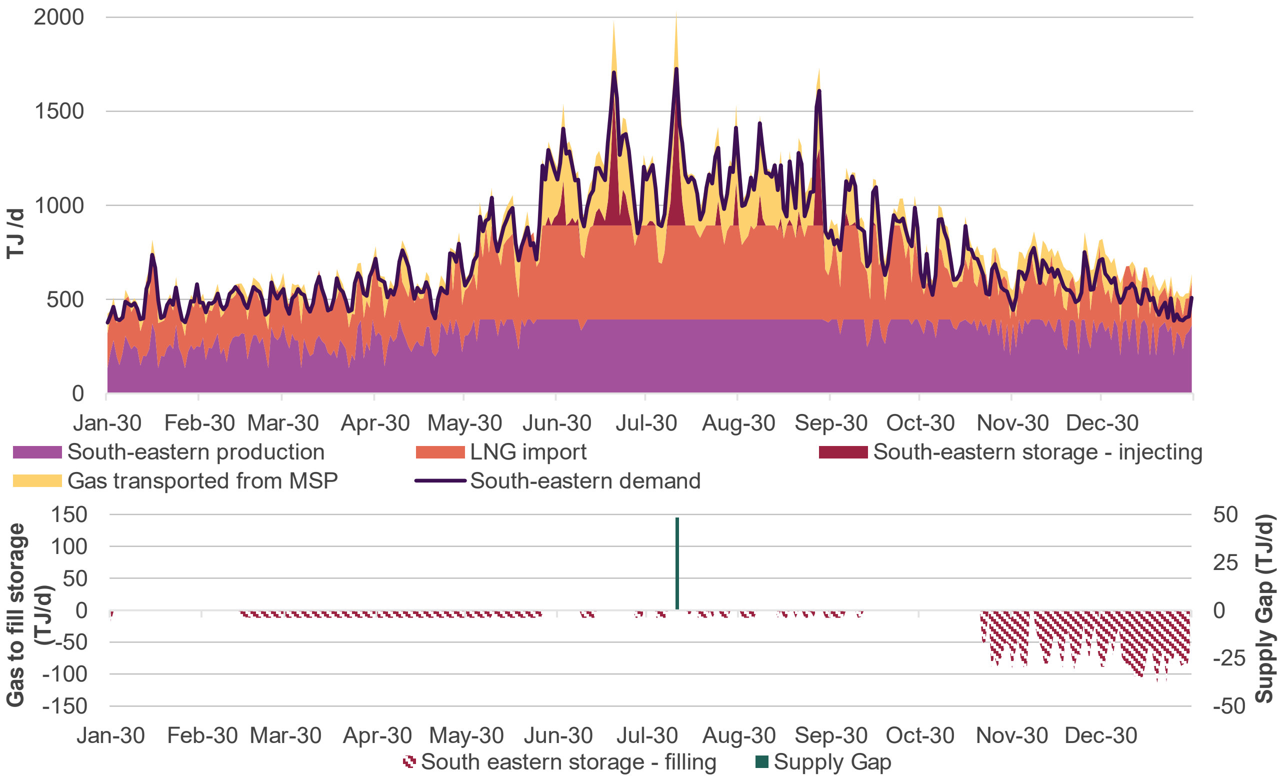
[59] The Victorian Government is currently completing its public consultation on the Gas Substitution Roadmap, with the Roadmap expected to be released in 2022.

Figure 36 Forecast gas supply options to meet south-eastern daily demand, *Step Change* scenario, 2025 (TJ/d)



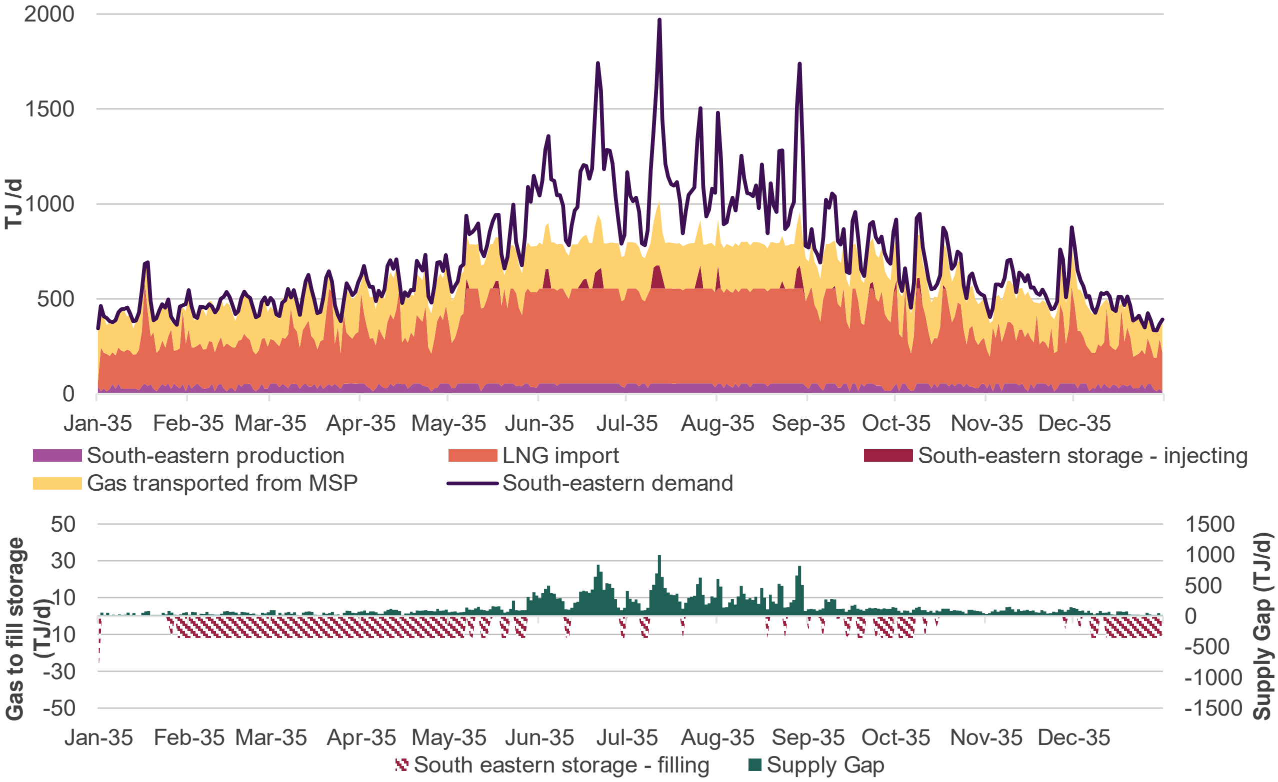
AEMO forecasts of one-in-20 and 2019 reference year weather patterns south-eastern demand.

Figure 37 Forecast gas supply options to meet south-eastern daily demand, *Step Change* scenario, 2030 (TJ/d)



AEMO forecasts of one-in-20 and 2019 reference year weather patterns south-eastern demand.

Figure 38 Forecast gas supply options to meet south-eastern daily demand, *Step Change* scenario, 2035 (TJ/d)



AEMO forecasts of one-in-20 and 2019 reference year weather patterns south-eastern demand.

Figure 39 shows forecast annual gas supply adequacy with existing, committed, and anticipated supplies, (including PKET) and assuming all associated reserves and resources are commercially recoverable to meet demand in the long term in *Step Change*.

Figure 39 Projected annual adequacy in south-eastern regions, *Step Change* scenario, with existing, committed, and anticipated developments, 2022-41 (PJ)

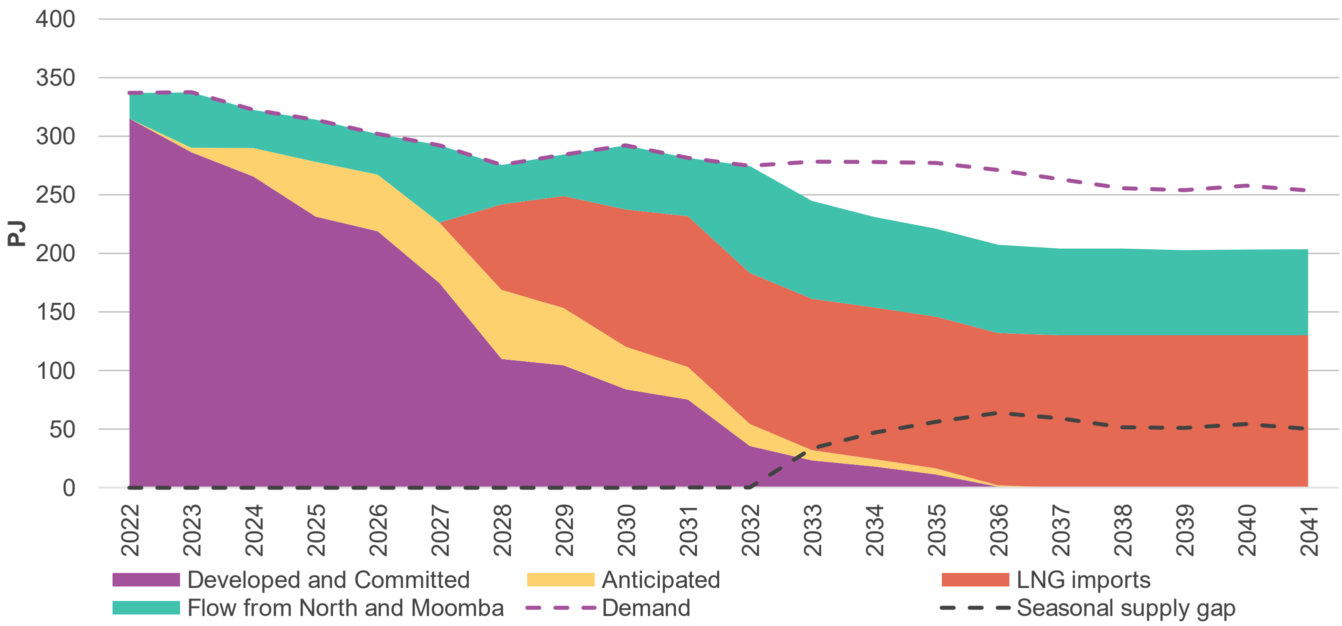
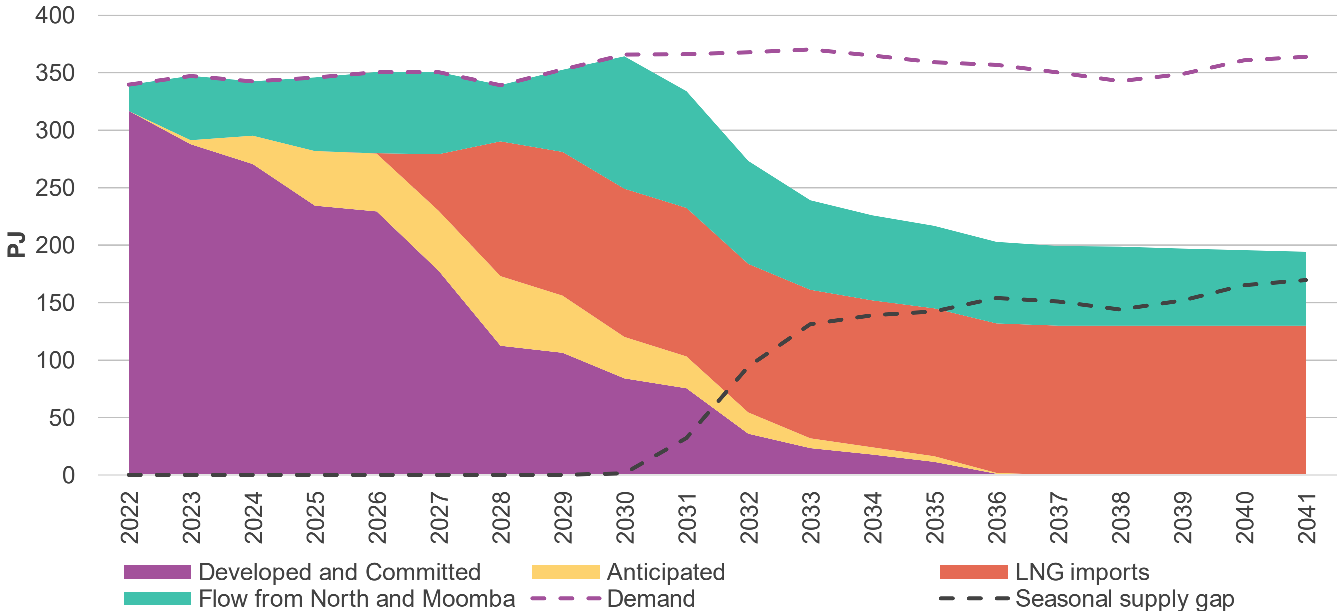


Figure 39 shows that new supply options are forecast to be required to meet south-eastern demand from 2033 to the end of the horizon. The supply gap in 2033 is projected to be 18-45 PJ under the range of demand and weather conditions assessed and increasing in the years to follow.

With only existing and committed projects, supply gaps are forecast to start five years earlier in 2028, with the magnitude ranging from 25-33 PJ under different demand and weather conditions in that year. In *Progressive Change*, as shown in **Figure 40**, seasonal supply gaps are forecast as early as 2030 (up to 8 PJ that year under the range of demand and weather conditions assessed) if existing, committed and anticipated projects (including PKET) are developed.

With only existing and committed projects, seasonal supply gaps are forecast to start four years earlier in 2026 (up to 10 PJ that year under different demand and weather pattern conditions).

Figure 40 Projected annual adequacy in south-eastern region, *Progressive Change* scenario, with existing, committed, and anticipated developments, 2022-41 (PJ)



Beyond domestic consumption, significant levels of LNG export are forecast by the Queensland LNG producers. Sustaining this level of export relies on the LNG producers bringing online significant levels of anticipated and uncertain supply that is not yet committed.

4.2.2 Longer-term investment opportunities in gas supply exist but must consider uncertainty and peakiness

This assessment shows that, even though domestic gas consumption is forecast to decline in most scenarios, new sources of gas supply are required to meet consumers' needs. The 2021 NGIP[60] identifies opportunities for new gas supply ranging from expansions to existing fields to developments of fields in new basins in the north. Future field, basin and infrastructure investments to access available reserves and resources (see Figure 27) will

[60] At https://www.energy.gov.au/sites/default/files/2021%20National%20Gas%20Infrastructure%20Plan.pdf.

need to consider the scale of expansion needed, given the uncertain pace and scale of transformation facing the gas sector in the long term, as outlined in this GSOO.

While more frequent gas supply gaps are evident in all scenarios in future, the timing, profile and magnitude of these gaps varies. Potential new gas resources and infrastructure solutions should consider the pace of gas sector transformation. Flexible and scalable solutions that can be developed in stages may avoid over-investment risks while gas sector transformation uncertainties remain. Increasing “peakiness” of gas demand is likely to require flexible solutions that support high, but infrequent, gas demand.

Demand response measures, if developed, could potentially play a growing role in managing peak gas demand, as they do at times of maximum electricity demand in the NEM.

To enable greater operational control of loads to reduce gas demand during extreme demand events in the south-east, new instruments could be developed that emulate contingency gas in the Short Term Trading Markets (STTMs) or the NEM’s Reliability and Emergency Reserve Trader (RERT). Such an instrument would be a shift from current practice, and would need time for both mechanisms to be appropriately developed, and for contracts to roll over to new terms if customers were willing to accept curtailment under the new mechanisms. New large loads, such as SMR facilities, may be ripe candidates for such arrangements.

Existing instruments such as the Gas Supply Guarantee (a commitment to the Commonwealth Government by gas production facility and pipeline operators to make gas available at times of peak NEM demand[61]) and LNG Heads of Agreement (an agreement between east coast LNG producers and the Commonwealth Government for uncontracted gas to be offered to the domestic market[62]) will also remain important for the gas and electricity sectors to optimally use available energy resources and reduce security and reliability risks in both systems while protecting domestic gas consumers.

[61] At https://aemo.com.au/energy-systems/electricity/emergency-management/gas-supply-guarantee.

[62] At https://www.industry.gov.au/regulations-and-standards/securing-australian-domestic-gas-supply.

A1. Forecast accuracy

Assessing historical forecasting performance and the existence of any bias in recent forecasts is critical to future forecasting improvements including understanding of forecast risks. AEMO publishes data detailing its forecasting accuracy to help inform its approach to continuous improvement and build confidence in the forecasts it produces.

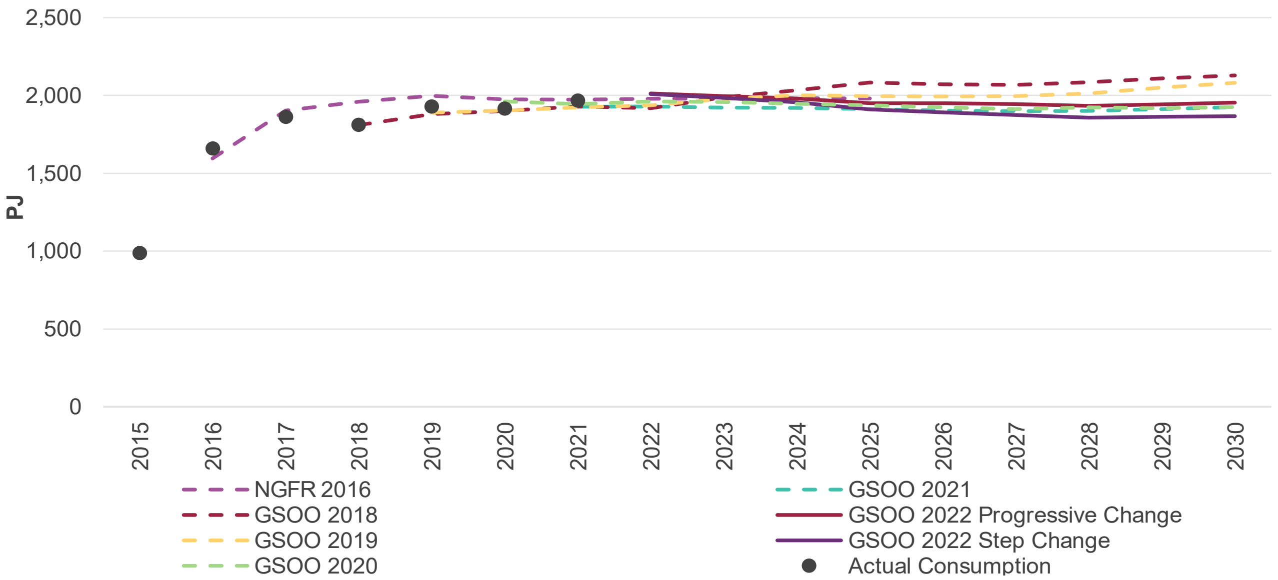
The following charts show AEMO's gas consumption forecasts since 2016 (published in the *National Gas Forecasting Report* [NGFR] in 2016, and the GSOO from 2018 onwards), compared to actual recorded consumption since 2015. These charts can be used to assess the performance of the forecasts by comparing actual consumption against forecasts in each year. Only the historical *Central/Neutral* scenario forecasts are presented. For comparison, the 2022 GSOO *Step Change* and *Progressive Change* forecasts are also included.

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 the 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 41 shows total gas consumption forecasts, including consumption for LNG export.

Figure 41 Total gas annual consumption forecast comparison



Key observations include:

- The 2018 GSOO and 2019 GSOO both forecast gas consumption for calendar year 2018 and 2019 reasonably well, whereas the 2020 GSOO over-estimated gas consumption in the 2020 calendar year, mainly due to the LNG market disruption that occurred in 2020 due to COVID-19.
- The 2021 GSOO under-estimated consumption in that calendar year, mainly due to two major power system events which increased consumption of gas for gas generation in Queensland, New South Wales and Victoria (discussed in Section 2.2.4).

Table 11 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, and calculated as:

Percentage error = (Forecast - Actual) / Actual

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

Table 11 Year ahead historical forecast accuracy, total consumption (PJ)

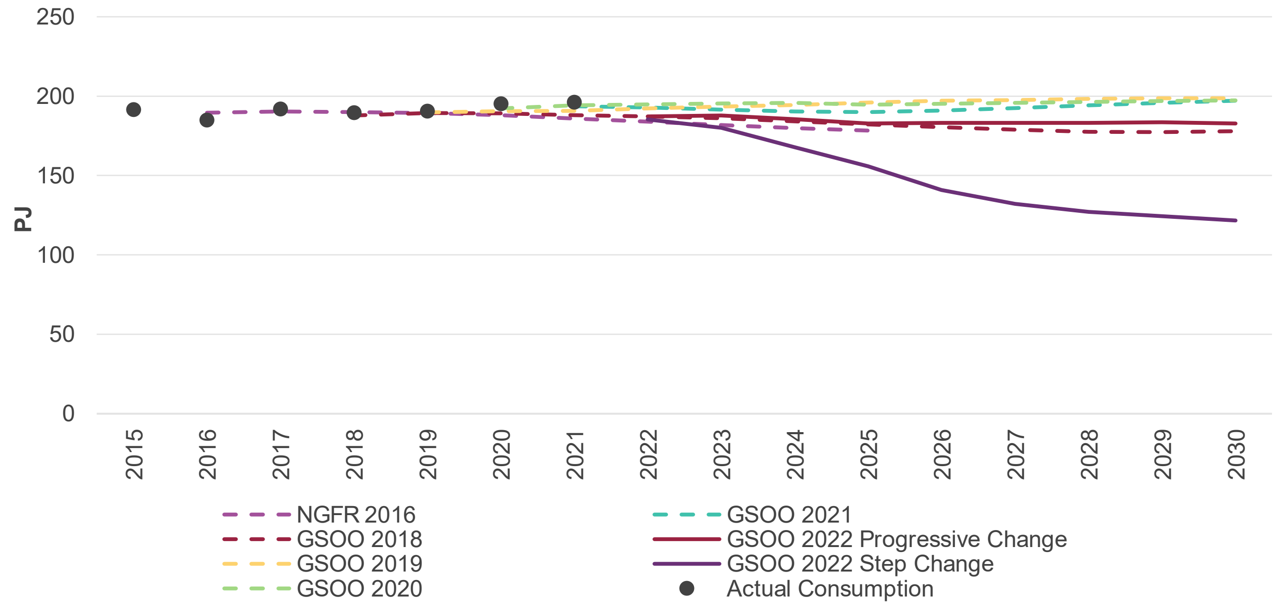
	2017	2018	2019	2020	2021
Year ahead forecast	1,903	1,810	1,889	1,959	1,928
Actual consumption	1,856	1,817	1,931	1,916	1,967
Forecast accuracy	2.6%	-0.4%	-2.2%	2.3%	-2.0%
Source	2016 NGFR	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO

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

A1.2 Residential and commercial segment consumption forecasts

Figure 42 shows AEMO's residential and commercial gas consumption forecasts.

Figure 42 Gas annual consumption forecast comparison, residential/commercial



The starting point of the 2022 GSOO forecast has been calibrated to recent consumption data, with the overall trend reflecting AEMO's assumptions relating to connections and population growth and the impacts of energy efficiency investments, gas fuel-switching (to electricity or hydrogen blended gaseous fuels), gas prices, and climate change. These factors are described in more detail in Section 2.2.1.

Table 12 provides an overview of the residential and commercial gas consumption forecast accuracy of the calendar year immediately following the forecast. AEMO's 2021 GSOO residential and commercial projection was 1.4% lower than actual consumption levels in calendar year 2021. This variance was largely due to weather, with 2021 being Victoria's overall coolest year since 2004[63], resulting in nearly 3.3 PJ of extra consumption compared to a median weather year.[64]

Table 12 Year ahead historical forecast accuracy, residential and commercial total consumption (PJ)

	2017	2018	2019	2020	2021
Year ahead forecast	190	188	190	191	194
Actual consumption	193	190	191	195	196
Forecast accuracy	-1.4%	-0.9%	-0.4%	-2.3%	-1.4%
Source	2016 NGFR	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO

A1.3 Industrial segment consumption forecasts

Figure 43 shows AEMO's industrial gas consumption forecasts, incorporating AEMO's assumptions on forecast changes in economic drivers and data obtained by surveying large gas users. These factors are described in more detail in Section 2.2.2.

Figure 43 Gas annual consumption forecast comparison, industrial

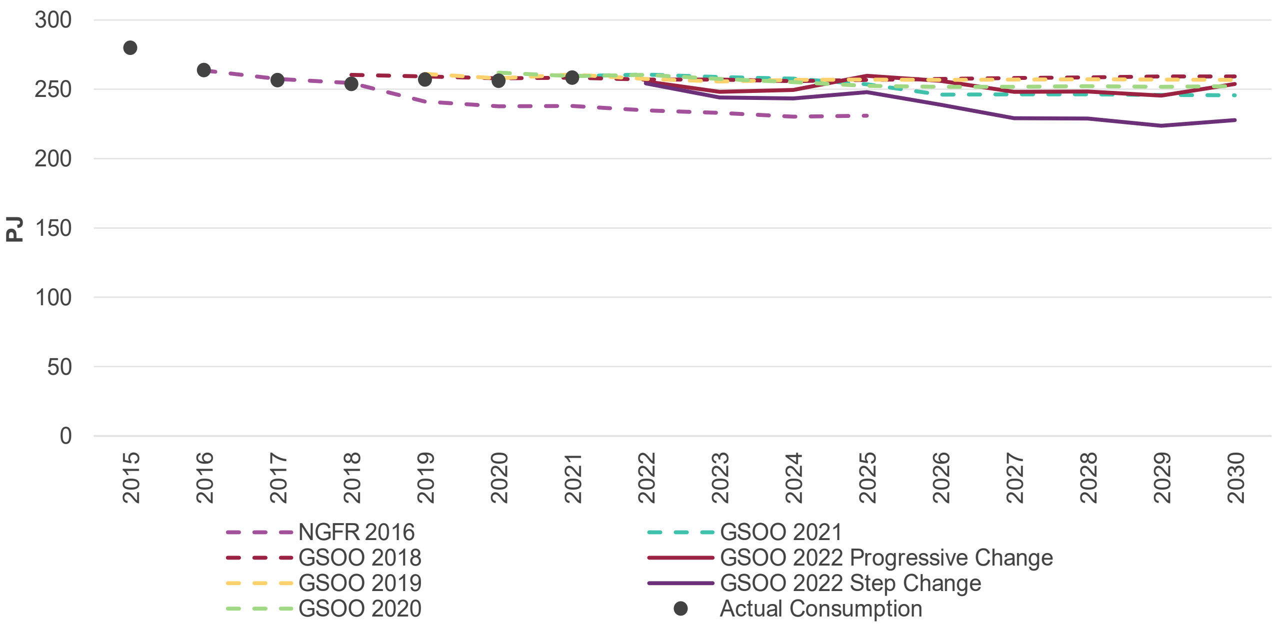


Table 13 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

[63] Refer to the Bureau of Meteorology 2021 Victorian Climate report, at http://www.bom.gov.au/climate/current/annual/vic/summary.shtml.

[64] AEMO uses an Effective Degree Day (EDD) weather standard. The median EDD from 2000-2021 is 1,378 adjusting for climate change. In 2021 the calculated EDD was 1,382. Refer to the AEMO Gas Methodology Paper for details on the EDD formulation, historical climate change adjustment, and use as a weather standard.

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

	2017	2018	2019	2020	2021
Year ahead forecast	257.4	260.4	261.0	261.7	259.6
Actual consumption	257.9	260.0	259.3	256.2	258.5
Forecast accuracy	-0.2%	0.2%	0.7%	2.2%	0.4%
Source	2016 NGFR	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO

Since the 2018 GSOO, AEMO has forecast a long-term flattening trend in industrial demand, reflecting an increased vulnerability of industrial load to higher gas prices, as continually reported in surveys and interviews, supplemented more recently with the potential disruption to gas loads as the sector transforms and contributes to net zero emissions objectives. For the 2021 GSOO, AEMO increased the number of surveys, interviews and separate customer forecasts from previous years, covering approximately 70% of industrial consumption. The 2022 GSOO forecast supplements survey data with estimates of fuel switching to electricity and hydrogen, from multi-sector modelling undertaken by consultants CSIRO and ClimateWorks.

Variations from forecasts to actual industrial consumption arise primarily due to stochastic factors such as weather variations, market shocks, or operational issues that result in unforeseen step changes in large industrial loads, both temporary and permanent. AEMO's 2021 GSOO industrial projection was 0.4% higher than actual consumption level in the 2021 calendar year, an improvement in forecast accuracy relative to the 2020 GSOO. The variation in the 2021 GSOO forecast is mainly due to lower usage in South Australia and Queensland, offset by higher usage in Victoria and Tasmania. It is the net effect of changes to production plans that had been identified in the industrial surveys and incorporated in the forecasts but that did not eventuate.

A1.4 LNG export segment consumption forecasts

The largest proportion of gas consumption in the regions covered by this GSOO is that consumed by LNG facilities in Queensland. LNG operation is informed by various drivers, 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.

Figure 44 and **Table 14** compare AEMO's LNG forecasts against actual consumption by LNG facilities. They show that forecasts have over-estimated consumption for all years except for 2018 and 2021. As the LNG facilities increased their operations in the early years, there were some operational run-in issues that slowed production in the LNG export compared to forecast, for example in 2017. By 2018 and 2019, the forecasts were more accurate, both being within 3% of actuals. In 2020, LNG exports reduced markedly due to COVID-19 lowering economic activity around the globe. As a result, actuals were almost 6% under the 2020 GSOO forecast. The 2021 GSOO produced a far closer forecast of LNG consumption in 2021, under-forecasting by less than 0.5% in the continued global pandemic.

Figure 44 Gas annual consumption forecast comparison, LNG

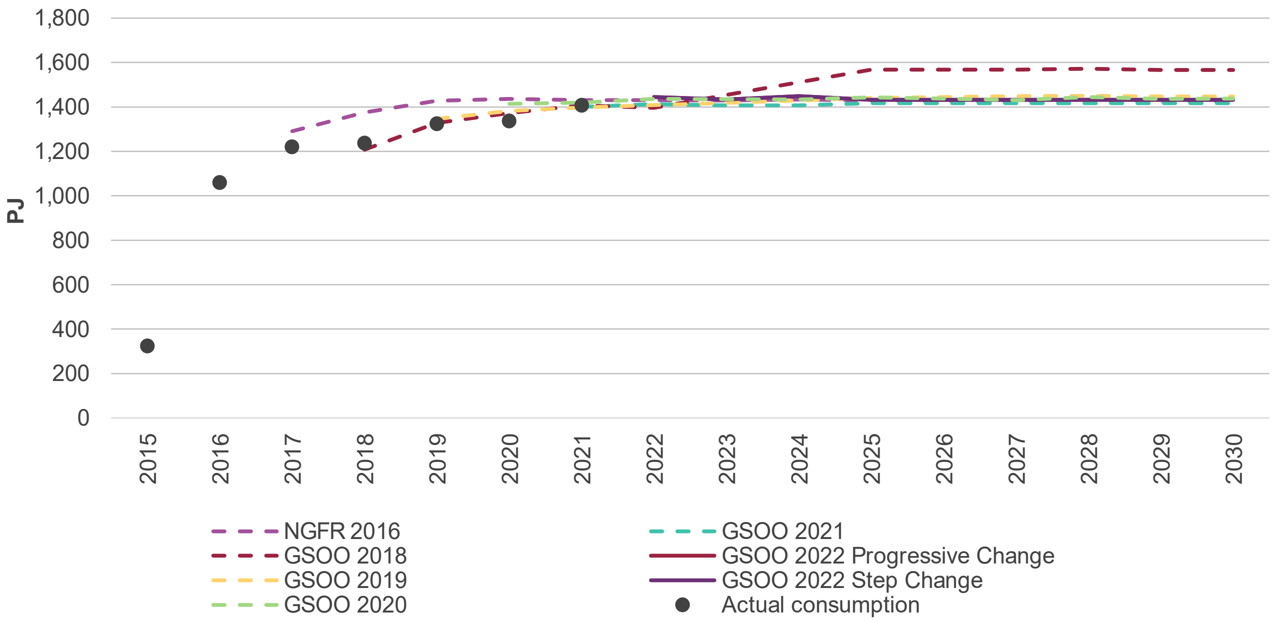


Table 14 Year ahead historical forecast accuracy, all Queensland LNG facilities total consumption (PJ)

	2017	2018	2019	2020	2021
Year ahead forecast	1,291.5	1,208.1	1,346.4	1,414.8	1401.0
Actual consumption	1,220.9	1,237.4	1,325.4	1,337.5	1407.4
Forecast accuracy	5.8%	-2.4%	1.6%	5.8%	-0.5%
Source	2016 NGFR	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO

A1.5 Gas generation consumption forecasts

Forecasting consumption of gas for electricity generation is challenging because it is driven by events, such as extreme weather or outages of major electricity generators, that can be difficult to predict, and that can lead to significant variations in forecasts.

Figure 45 compares AEMO's gas generation forecast accuracy against actual consumption. It shows that all recent forecasts have significantly under-estimated annual consumption, due to a number of events that resulted in higher gas generation than that forecast. As discussed in Section 2.2.4, these events have included interconnector failures, long duration outages at coal power stations, coal supply disruptions, and weather-driven events such as heatwaves, floods, and bushfires which impact the performance of power system equipment. More details on these events and their materiality on the error of historical gas generation forecast can be found in Appendix 2 of the 2021 GSOO[65].

The 2021 GSOO's *Central* scenario forecast was 24.5 PJ (25%) lower than actual 2021 total consumption for gas generation across all GSOO regions:

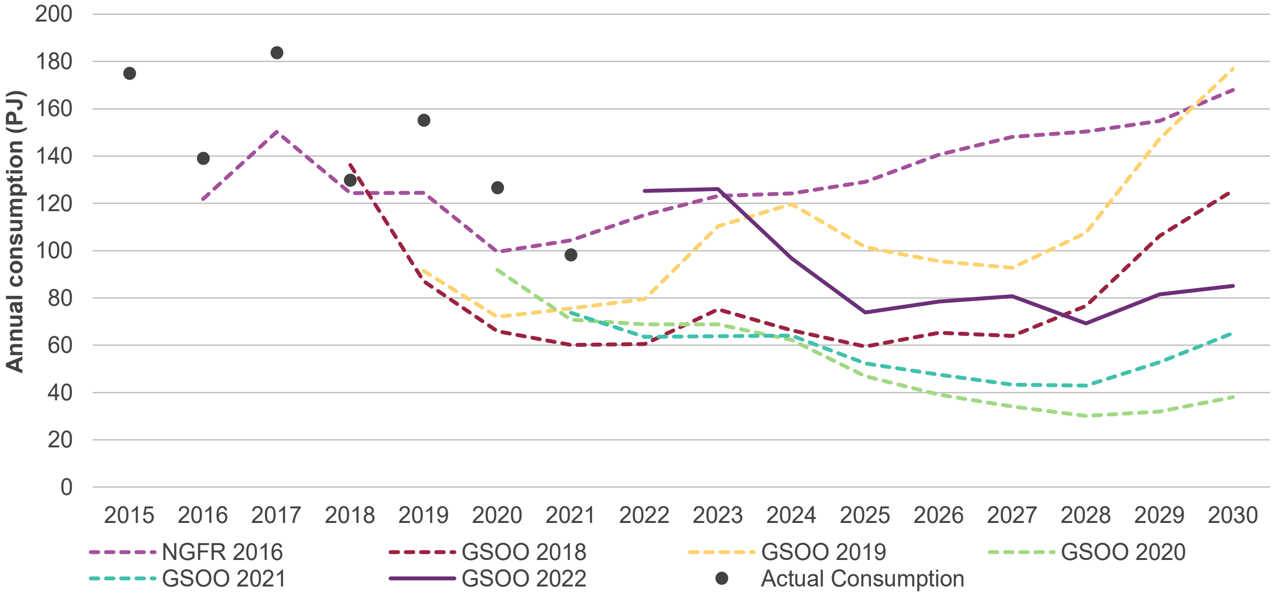
- Higher than forecast gas generation was most notable in Q2 2021 in Queensland, New South Wales and Victoria. Two major power system events – the Callide Power Station outage in Queensland, and the Yallourn

[65] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf.

coal mine floods in Victoria, which significantly reduced coal generation availability from June onwards – resulted in increased gas generation across all three states to offset the reduced availability of coal generation, and a strong rebound from low consumption levels in Q1 2021.

- The forecast inaccuracy reduced in Q3 2021 as coal availability improved and gas generation continued to be displaced by increasing penetration and operation of renewable generation. Full commissioning of four new synchronous condensers in South Australia also contributed to a reduction of gas generation consumption in Q3 2021, as it reduced the need for gas generation to operate continuously in that region to maintain power system security. This was consistent with the forecast.
- Forecast accuracy for gas generation in 2021 was also impacted by weather-driven variability of renewable energy generators. In the southern states, lower than anticipated wind availability in the shoulder and winter months contributed to gas generation consumption above the forecast.

Figure 45 Gas annual consumption forecast comparison, gas generation



For the 2022 GSOO, the Step Change and Progressive Change scenario gas generation forecasts are identical, thus only one is shown in this figure.

Table 15 provides an overview of the forecast accuracy since 2016 of the calendar year immediately following the forecast. The gas generation forecast accuracy ranges from a -41.1% under-forecast for the 2019 calendar year up to a 4.8% over-forecast for the 2018 calendar year. The average forecast error in the past five years was 21.4% under-forecast.

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

	2017	2018	2019	2020	2021
Year ahead forecast	150.2	136.2	91.4	91.9	73.7
Actual consumption	183.7	129.9	155.2	126.7	98.2
Forecast accuracy	-18.3%	4.8%	-41.1%	-27.5%	-25.0%
Source	2016 NGFR	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO

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
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
AIE	Australian Industrial Energy
BLP	Brooklyn–Lara Pipeline
CGP	Carpentaria Gas Pipeline
CSG	coal seam gas
DER	distributed energy resources
DISER	(Commonwealth) Department of Industry, Science, Energy and Resources
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FID	Final investment decision
FSRU	floating storage regasification unit
GSOO	*Gas Statement of Opportunities*
HILP	high impact, low probability
LGA	Lewis Grey Advisory
IASR	*Inputs, Assumptions and Scenarios Report*
ISP	*Integrated System Plan*
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
NGIP	National Gas Infrastructure Plan
NGFR	*National Gas Forecasting Report*

Term	Definition
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NQGP	North Queensland Gas Pipeline
PKET	Port Kembla Energy Terminal
POE	Probability of exceedance
PRMS	Petroleum Resources Management System
PV	Photovoltaic/s
QHGP	Queensland – Hunter Gas Pipeline
RBP	Roma – Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SEAGas	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
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.
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.
connection point	A gas delivery point, transfer point, or receipt point.
consumption	Gas consumed over a period of time, usually a year but sometimes a month.

Term	Definition
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
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.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.
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 (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 (CH_4) (between 95% and 99%) and ethane (C_2H_6).
participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
petajoule	An International System of Units (SI) unit. One PJ equals 1 x 10^{15} joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
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.
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.

Term	Definition
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 coincident peak day	The day of highest system demand (gas). See also system demand.
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	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.