Gas Statement of Opportunities

March 2019

For eastern and south-eastern Australia

Important notice

PURPOSE

AEMO publishes the Gas Statement of Opportunities under the National Gas Law and Part 15D of the National Gas Rules.

This publication has been prepared by AEMO using information available at 10 December 2018, although AEMO has endeavoured to incorporate more recent information where practical.

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VERSION CONTROL

Version	Release date	Changes
1.0	28/03/2019	New document

Executive summary

The 2019 Gas Statement of Opportunities (GSOO) contains AEMO's projections for demand, and information from gas producers about reserves and forecast production, to assess the projected supply-demand balance and potential supply gaps under a range of plausible scenarios for the outlook period to 2038, for the eastern and south-eastern Australian gas markets.

The 2019 GSOO highlights that the gas supply-demand balance remains tight, with gas production in southern Australia continuing to decline, and supplies from Queensland limited by pipeline capacity:

- Supply from existing and committed gas developments is forecast to provide adequate supply to meet gas demands until 2023. However, risks remain that any weather-driven variances in consumption or electricity market activity could increase gas demand, creating potential peak-day shortages as outlined in AEMO's 2019 Victorian Gas Planning Report[1].
- While new gas development is continuing in Victoria, reserve estimates have reduced, and producers are declaring more gas resources commercially unviable. Consequently, production from the southern gas fields is expected to decline over the 20-year outlook.
  - From 2021 to 2023, this decline in production will reduce Victoria's ability to export surplus gas supplies to South Australia and New South Wales, placing more reliance on Queensland supplies to meet gas demand in these states. It will also increase reliance on the Iona underground gas storage facility to meet winter demand in Victoria.
  - From 2024, major southbound pipeline infrastructure upgrades would be required to deliver more gas from northern to southern states (predominantly over the winter months when southern demand is highest). AEMO forecasts potential for supply gaps from 2024 onwards, unless additional southern reserves and resources, or alternative infrastructure, are developed.
- This GSOO confirms trends identified in the 2018 GSOO, including short-term reductions in demand for gas for gas-powered generation of electricity (GPG) and increases in demand for liquefied natural gas (LNG) exports. Longer-term, based on updated industry data and advice, this GSOO projects reduced demand and production in the LNG sector compared to the 2018 forecasts.
- The Northern Gas Pipeline (NGP) has commenced operation and has started flowing gas from Northern Territory to Mount Isa, Queensland at up to 90 terajoules (TJ) per day, with delivery contracts locked in for around 26 petajoules (PJ) per year. This frees up equivalent capacity on the South West Queensland Pipeline (SWQP) to supply the southern states (New South Wales, Victoria, South Australia, and Tasmania) as the capacity is no longer required to supply Mount Isa. However, the pipeline capacities into Sydney and Adelaide then start limiting imports from Queensland.
- Continued interest in LNG import terminals, particularly in Victoria, New South Wales, and South Australia, would be expected to help relieve pressure on meeting southern gas demand during peak periods and assist in reducing pipeline constraints, but may do little to ease gas pricing pressures.

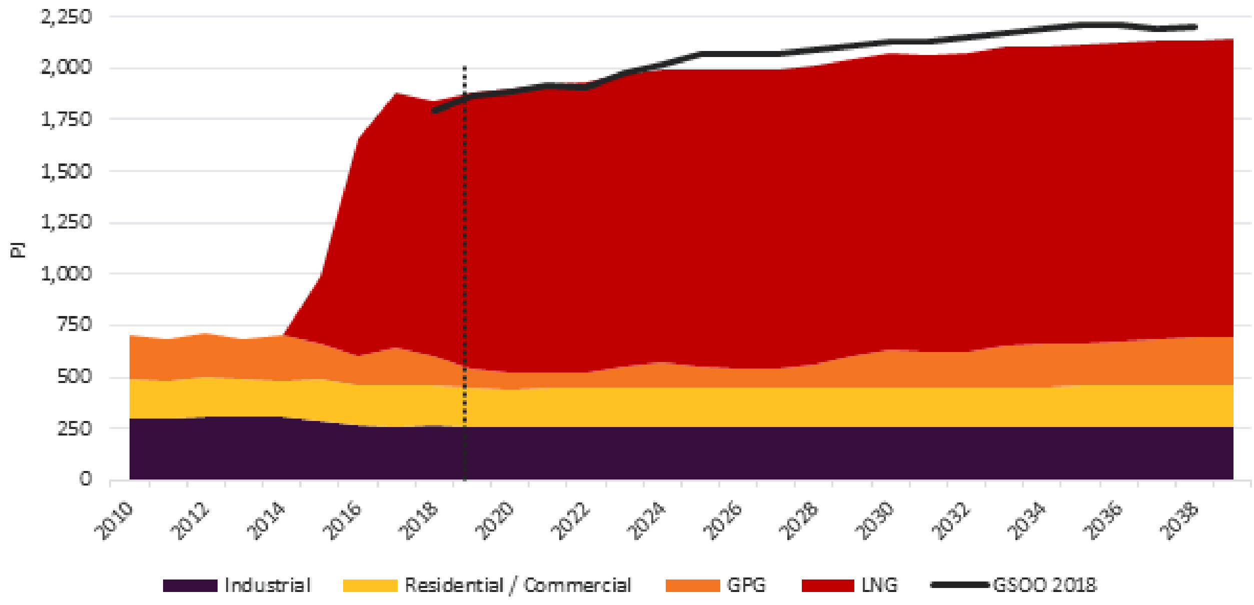
[1] See AEMO's 2019 Victorian Gas Planning Report for more discussion on peak day gas concerns in Victoria. Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

Forecast demand

Figure 1 shows gas consumption forecasts by demand sector for the 2019 GSOO[2]. It highlights that:

- Total demand trends continue to be driven by trends in LNG export demand, given its relative volume.
- Short-term trends in the total east coast gas consumption forecasts are for a small total increase, similar to those forecast in the 2018 GSOO, mainly due to an increase in projected LNG exports.
- Longer-term forecasts show a reduction in total demand projected, and a lower total forecast than in the 2018 GSOO from the mid-2020s, mainly due to a decrease in projected LNG exports.

Figure 1 Gas consumption actual and forecast, 2019-38, all sectors, Neutral scenario (PJ)



Short-term trends in east coast gas consumption forecasts are:

- LNG exports are forecast to increase slightly in the short term to capitalise on global spot market opportunities beyond their long-term contractual obligations.
- Industrial consumption continues to be relatively flat as this sector seeks ways to maintain current operating levels in an increasingly challenging economic environment.
- Residential and commercial sector consumption is projected to have stronger growth than forecast in the 2018 GSOO. Drivers of this change include updated population projections from the Australian Bureau of Statistics (ABS)[3] and greater consideration of consumption patterns impacting residential forecasts. However, the materiality to total trends is relatively small, given the size of the residential and commercial sector relative to the total consumption forecast.
- As forecast in the 2018 GSOO, demand for GPG is declining, due to increased penetration of renewable generation. In the 2018 calendar year, nearly 2,000 megawatts (MW)[4] of new utility-scale renewable capacity was installed in the National Electricity Market (NEM), while distributed energy resources such as rooftop photovoltaics (PV) continued to grow. This contributed to reduced demand for GPG of 130 PJ in

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[2] Demand forecasts are available on the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2019' from the publication drop-down.

[3] This projection reflects the latest census population projections released by the ABS in 2018.

[4] See AEMO's generation information page, 21 January 2019 compared to 29 December 29 2017, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

2018, 54 PJ (29%) lower than in 2017. This trend is forecast to continue in the short term, with over 7,000 MW[5] of additional renewable generation either committed or under construction.

In the medium to longer term, although growth is expected from higher population projections, there is a slight reduction in forecast total gas demand relative to the 2018 GSOO, arising from:

- Slowing growth in demand for international LNG as well as more international competition to supply LNG, reducing the incentive for east coast LNG to ramp up to full train capacity.
- Increased vulnerability of some industrial loads in the face of increasing gas prices.

GPG is expected to continue to provide a reliability and security role to complement variable renewable energy, therefore demand for gas from this sector is expected to stabilise in the medium term, with slight growth forecast in the longer term.

Forecast supply

AEMO has been provided with updated production forecasts and gas reserve and resource information from gas producers to inform the 2019 GSOO. This new information reflects the industry's current best view of gas resources and production expectations as at December 2018.

Table 1 shows the production forecast between 2019 and 2022 provided to AEMO by gas producers as their current best estimate.

These production forecasts contain volumes of undeveloped reserves and contingent resources. Some of these reserves and resources are associated with anticipated projects that are actively under development planning utilising existing production infrastructure (and therefore considered reasonably likely to proceed), while others have increased uncertainty, because they are not as far along the path to development.

Gas production from the southern states includes new gas projects, such as Cooper Energy's Sole project and Esso-BHP's West Barracouta project (which are forecast to begin production in 2019 and 2021 respectively), offsetting the continued decline in southern production. Northern production is expected to continue increasing between 2019 and 2022.

Production forecasts as provided by producers are very similar to those provided for the 2018 GSOO. The largest difference between the forecasts in the next four years is in 2020, where the net production forecast is 31 PJ lower than in the 2018 GSOO, with the forecasts from fields in the northern states decreasing by 23 PJ, and the forecasts from fields in the southern states decreasing by 8 PJ. The smallest difference is in 2019, which is 5 PJ lower than the 2018 forecast, as the southern fields are 8 PJ lower while the northern fields see an increase of 3 PJ forecast in that year.

Table 1 Production forecasts to 2022 (PJ) as provided by gas producers, with 2018 actual production

	2018 actual production	2019	2020	2021	2022
VIC/NSW/SA[A]	433	444	475	480	456
Southern states difference from 2018 GSOO forecast		-8	-8	17	-23
QLD/NT[A]	1,386	1,489	1,538	1,593	1,607
Northern states difference from 2018 GSOO forecast		3	-23	-43	4
Total production	1,818	1,933	2,013	2,072	2,063
Total difference from 2018 GSOO forecast		-5	-31	-27	-19

A. The Queensland component of the Cooper Eromanga basin appears in the SA category.

[5] See AEMO's generation information page, 21 January 2019, new wind and solar projects with commitment status 'Committed' and 'Com*' in regional spreadsheets under "New developments" tab, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Producers also advise that rates of drilling in coal seam gas (CSG) fields continue to increase, while production rates are holding steady, or only increasing at a slower rate. That is, increasing amounts of investment are required to keep the same amount of production. Unless new sources of gas are discovered, this trend is unlikely to change.

Meeting northern producers' forecasts of production by 2022 will require a 17% increase in annual production relative to actual levels observed in 2018. If these annual production increases are not achievable, spot quantities of LNG export demand may need to be foregone, reducing the flex in LNG exports if increased quantities are needed to supply domestic demand. As pipeline constraints are expected to limit the quantity of Queensland supply that can be sent south, the overall impact on LNG exports is expected to be limited.

As forecast in the 2018 GSOO, the NGP was commissioned in December 2018, and began commercial operation on 3 January 2019. Following the Northern Territory government's decision in 2018 to lift a moratorium on hydraulic fracturing, gas supply certainty has increased. This has led to speculation of an upgrade of the NGP, which may be able to send up to 700 TJ per day of gas to the eastern gas markets. While not included in the GSOO's base modelling, this expansion – and others – have been tested as sensitivities to the GSOO outcomes.

Quantities of 2P[6] developed and undeveloped reserves have reduced slightly (roughly 5% and 6%, respectively) compared to the reserves reported in the 2018 GSOO. The reported 2C[7] contingent resources have increased by around 27% as some 2P reserves have been downgraded as less economical, and further exploration drilling has increased quantities of contingent resources. While it is positive that an increasing amount of contingent resources has been recorded, these resources are not yet considered by producers to be commercially viable, and there is no guarantee that these quantities will become economic and developed by the time they are required to meet demand.

This shift from 2P reserves to 2C resources is most noticeable in the southern states, where quantities of 2P developed reserves have dropped by 32% – nearly 1,100 PJ in the past year – with only a 270 PJ rise in 2P undeveloped reserves. This pushes forward the time when contingent resources from southern basins, or alternatively gas imports from northern states or LNG imports, will be required to meet domestic demand. Based on information provided by producers, reported 2C contingent resources in southern states have increased 71% compared to the 2018 GSOO.

Supply and infrastructure adequacy assessment

Supply from existing and committed gas developments[8] is forecast to provide adequate supply to meet gas demands until 2023 under Neutral scenario demand conditions, although supply-demand conditions are finely balanced.

Victoria has supplied, on average, 150 PJ per year to Tasmania, New South Wales, and South Australia from production surplus to Victorian gas consumption requirements over the last five years. Without new reserves and resources being developed in Victoria, this production surplus is projected to erode to 23 PJ in 2023. As a result, New South Wales and South Australia will need to source more gas from Queensland. Pipeline infrastructure constraints (particularly the Moomba to Sydney Pipeline, Moomba to Adelaide Pipeline, and later the SWQP if Moomba production is reduced) start limiting the amount of gas able to be transported from the north to meet southern domestic demand or refill storages.

As production from southern fields further declines, and pipeline capacity from Queensland becomes fully constrained, AEMO forecasts supply gaps from 2024, requiring new infrastructure development, new commitments to develop reserves and contingent resources, or the discovery and development of

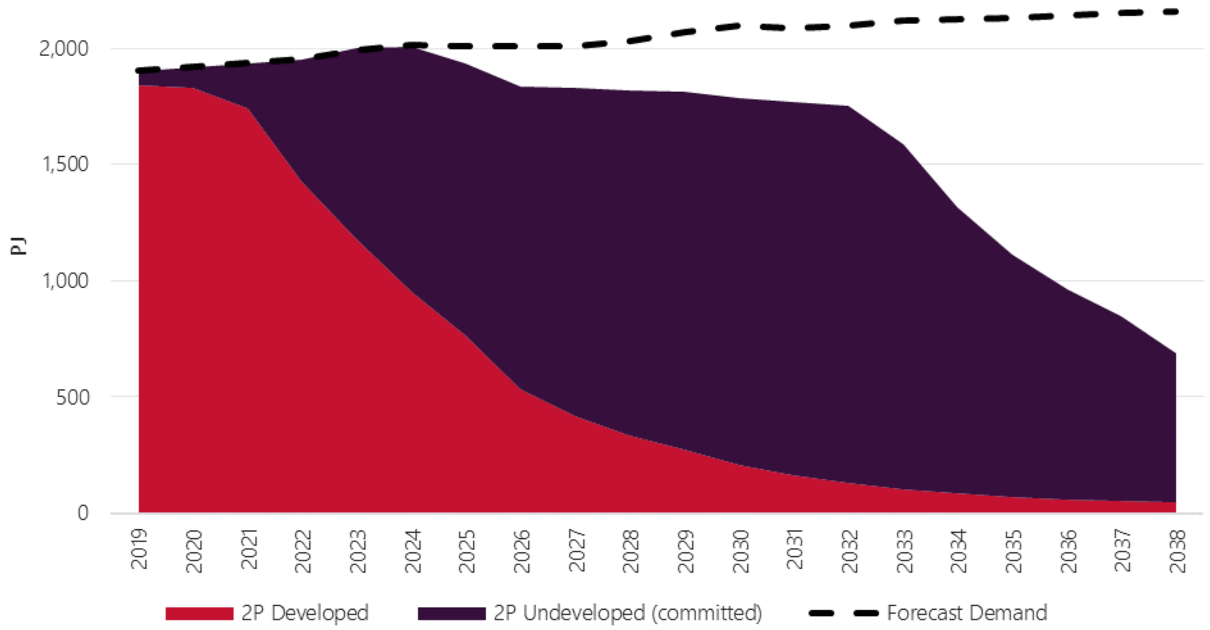
[6] Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with developing them. Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations, and proved and probable (2P) is considered the best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

[7] Contingent resources are not yet considered commercially viable, and 2C is considered the best estimate of those sub-commercial resources.

[8] For the purpose of this assessment, committed projects are those that have reached final investment decision.

prospective resources[9] in the south to meet forecast demand. Figure 2 shows the expected production forecast if only existing and committed projects eventuate.

Figure 2 Projected eastern and south-eastern Australia gas production (export LNG and domestic), 2019-38; supply from existing projects and committed developments



Producers have indicated to AEMO that 34 PJ of gas from anticipated projects[10], or uncertain, not yet commercial, contingent resources, may become available for production in 2020, increasing up to 87 PJ by 2023. These resources are included in Table 1, but are not included in the above assessment due to the development uncertainty. Approximately 90% of these uncertain reserves and resources are located in the south.

The reserve mix required to meet forecast demand is shown in Figure 3 below, for the case that assumes all anticipated projects and uncertain reserves and resources are developed as needed to avoid early shortfalls. This projection of forecast production is directly comparable to the supply adequacy assessment presented in the 2018 GSOO.

Figure 3 shows:

- The rapid decline in production from 2P developed reserves forecast by producers, mostly from fields located within the southern states.
- Projected reliance on less certain 2C contingent and prospective resources to meet demand, beginning in 2024 and increasing over time.

Assuming all projects are developed, supply gaps are projected to emerge from 2030, as also forecast in the 2018 GSOO.

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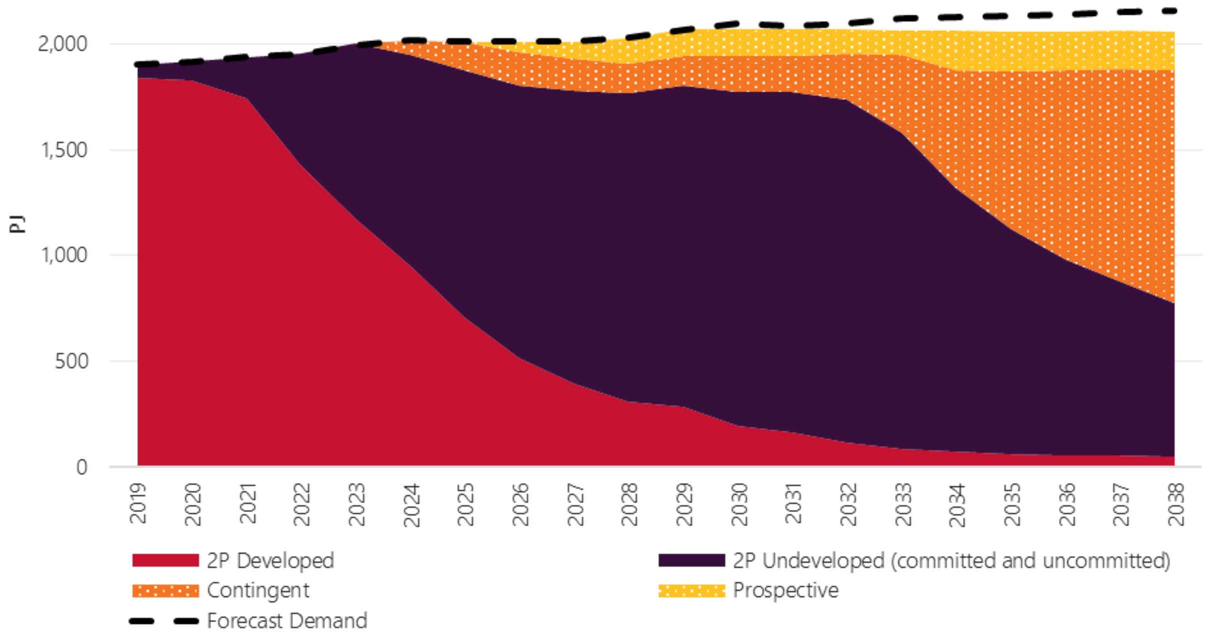
[9] Prospective resources are even more uncertain than contingent resources, with exploratory drilling required to confirm presence and develop reserve estimates.

[10] For the purpose of this assessment, anticipated projects are defined as projects actively under development planning, utilising existing production infrastructure.

Figure 3 Projected eastern and south-eastern Australia gas production (export LNG and domestic), 2019-38; supply from all available resources (including uncertain undeveloped projects)



As existing fields decline, exploration and development will be needed to deliver these contingent and prospective resources to market. These new gas supplies will help improve adequacy of supply but, as flagged in the 2018 GSOO, supply from these fields is likely to be more costly than existing production. Within the next five years, domestic gas demand, particularly in the southern states, will be difficult to meet in its entirety without either:

- Exploration and development of new southern resources, or
- New gas supplies delivered via LNG import terminal, or
- Major pipeline infrastructure expansions to deliver Queensland and Northern Territory gas southwards, or
- A combination of all three.

Further storage facilities may help meet peak demand once increased gas is made available.

Uncertainties that may impact supply adequacy

While no shortfalls are forecast in the next several years under expected conditions, uncertainties that may impact gas consumption trends in all demand sectors may further tighten the supply-demand balance, and create issues with meeting peak demand.

Table 2 highlights some of these risks facing the short-term gas supply adequacy outlook.

The key uncertainty that could have a material impact on gas supply adequacy in the short-term is the level of GPG demand. Demand for GPG in the NEM is highly variable, and is influenced by weather conditions, the reliability of coal-fired generation and coal supplies, the timing of new generation and transmission development, and the retirement of ageing thermal generation.

The gas supply-demand outlook is finely balanced by 2023, just after the closure of the Liddell coal-fired power station. If the initial transmission developments identified in AEMO's 2018 Integrated System Plan (ISP) are not operational prior to Liddell's closure, this will place greater demand on GPG at a time when gas supply sources are scarce.

Table 2 Risks, likelihood, and probable impact of uncertainties to supply adequacy in the short term

Risk	Likelihood	Impact
Higher than expected GPG demand	Possible	Analysis takes into account current drought conditions, but if generation from wind farms or solar generators is lower than expected (within the normal range of annual variability), or 10% of committed renewable generation projects are delayed, GPG demand could be up to 22 PJ higher. An unexpected six-month unavailability of coal-fired generation, or reductions in coal supplies for generation, could increase GPG demand by up to 10 PJ.
Higher than expected gas demand (excluding GPG)	Low	Minor impact, as significant increases in demand (LNG or industrial sector) are unlikely without discovery of new lower-cost gas supply sources.
Faster than expected decline in southern production	Possible	Depending on the rate of decline, this could have a major impact on domestic gas supply adequacy if new sources of gas are not developed in time to fill the decline.
Underperforming Queensland CSG fields	Possible	In the short term to 2023, CSG underperformance is not likely to have an impact on meeting domestic demand, although LNG exports may have to be reduced to ensure domestic demand is met.
Failure of critical gas infrastructure	Low	Any failure of a critical gas supply infrastructure could also have short-term impacts on supply adequacy, depending on the exact nature of the failure.

About 27 PJ of additional gas is forecast to be available in 2019, should demand be higher than forecast. If demand increases further than that, or further development or exploration of new supply is delayed, then increased rates of production would be required, or spot quantities of LNG export demand may need to be foregone, to ensure all domestic demand is met.

The growing importance of integrated system planning

The 2019 GSOO highlights the growing importance of a fully integrated planning view to be taken across the energy sector, to ensure efficient, reliable, and secure supply of both gas and electricity, as the two sectors are intrinsically linked.

Investment decisions in either sector impact supply adequacy in the other:

- Availability of gas reserves, resources and pipeline capacities influence the cost and availability of gas and consequently the viability of future GPG to supply electricity consumption in volume.
- Timings of new transmission and renewable generation development in the power system influence GPG forecasts and gas supply adequacy.

AEMO's modelling approach therefore provides a fully integrated perspective across both demand and supply across the electricity and gas sectors, through publications such as the Electricity Statement of Opportunities, GSOO, and ISP.

Within the gas sector, there is also a growing need to take a holistic planning view, so future gas demand can be met in an efficient and timely manner. The 2019 GSOO analysis indicates there is no one single new supply source or infrastructure development that would be able to fill the gap to meet all Australia's domestic and export gas demand over the next 20 years. Instead, a combination of developments to the gas system is projected to be needed to improve both infrastructure and resource adequacy and avoid shortfalls.

To facilitate more co-ordinated planning, greater information transparency is required, as highlighted in recommendations from the Australian Competition and Consumer Commission (ACCC) and Gas Market Reform Group on east coast gas market transparency[11]. In 2019, AEMO will explore use of mechanisms that improve access to, and the quality of, information made available for future GSOOs.

[11] Further details are available on the website of the Council of Australian Governments (COAG) Energy Council, at http://www.coagenergycouncil.gov.au/publications/energy-council-web-text-%E2%80%93-accc-gmrg-recommendations-east-coast-gas-market-transparency.

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1. Introduction

The 2019 Gas Statement of Opportunities (GSOO) assesses the adequacy of eastern and south-eastern Australian gas markets to meet forecast domestic gas demand while delivering expected export quantities to international markets, over a 20-year outlook period.

The GSOO analyses a range of potential futures that may impact the gas market in the next 20 years. It is focused on providing an adequacy assessment in the short to medium term, and identifying longer-term development needs.

This report is based on information available to AEMO as of December 2018, although AEMO has endeavoured to incorporate more recent information where practical.

Information on the demand and supply forecasting methodologies used for this GSOO is available on the 2019 GSOO webpage[12].

1.1 Demand forecasts for eastern and south-eastern Australia

The GSOO provides updated forecasts of annual gas consumption and maximum daily demand, over a 20-year outlook period, for consumers in eastern and south-eastern Australia.

Chapter 2 summarises the forecasts and key demand drivers affecting forecast gas demand to 2038. Detailed data is available on AEMO's forecasting portal[13]. AEMO's gas demand forecasting performance since 2014 is summarised in Appendix A1.

1.2 The Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) was introduced by way of regulations[14] which empower the Federal Minister to impose liquefied natural gas (LNG) export restrictions in a 'domestic shortfall year'. That is, a calendar year where the Minister has reasonable grounds to believe that the export of LNG would contribute to a lack of supply of natural gas for consumers and that there will not be a sufficient supply unless exports are controlled. Guidelines[15] made under those Regulations provide that, unless the Minister determines that it is not necessary to consider whether a year is a domestic shortfall year, the Minister commences the process between July and October by issuing a notification of his intention to consider whether the following calendar year will be a domestic shortfall year, and consulting with a range of stakeholders to seek their views.

The objective of the ADGSM is to ensure there is sufficient supply of natural gas to meet the forecast needs of

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[12] AEMO's 2019 GSOO and supporting documents, and previous GSOOs, are available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[13] Gas demand forecasts are available on the forecasting data portal http://forecasting.aemo.com.au/. Select 'GSOO 2019' from the publication drop-down.

[14] Introduced in 2017 by way of the insertion of a new Division 6 in Part 3 of the *Customs (Prohibited Exports) Regulations 1958*.

[15] *Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2017.*

Australian consumers by requiring, if necessary, LNG projects which are drawing gas from the domestic market to limit exports.

In 2018, the Federal Government decided not to apply export controls for the 2019 year following its considerations under the ADGSM. However, a new Heads of Agreement[16] was made between the Prime Minister and the east coast LNG consortia under which they made commitments in relation to the domestic supply of gas in 2019 and 2020 calendar years.

1.3 Scenarios

The demand and supply inputs for the 2019 GSOO present three alternative futures for gas supply and demand in eastern and south-eastern Australia. These alternative futures are based on scenarios considering different rates of change impacting Australia's energy infrastructure, including Australia's eastern and south-eastern gas markets and the National Electricity Market (NEM).

The 2019 GSOO scenarios are a continuation of the themes and drivers considered in AEMO's 2018 Integrated System Plan (ISP)[17], and include a holistic view of the pathway for energy market change as well as the transformation of the physical infrastructure required in the NEM to support this change:

- The **Neutral scenario** reflects an energy system based around central estimates of all key drivers. This scenario ultimately reflects a moderate rate of change in Australia's energy sector. Drivers of energy consumption growth are offset by deployment of distributed energy resources (DER) and increasing energy efficiency advancements, while increasing energy prices are expected to play a role in stifling growth. Significant capacities of ageing coal and gas generation assets require re-investment or replacement over the longer term.
- The **Fast change scenario** is characterised by stronger domestic-led economic and population growth, faster decarbonisation of stationary energy and transportation sectors, faster development of renewable generation, and decentralisation.
  - Importantly, economic growth in the Fast change scenario is primarily driven by growth in the services sector rather than growth in commodities. Despite reasonable resilience to increasing energy costs in recent years, there persists a degree of fragility to rising energy costs affecting Australia's industrial sector, particularly energy-intensive industries with exposure to competitors in mature and emerging economies. A scenario with high commodity prices may lead to increases in gas price and resulting demand destruction of energy-intensive industrials, which would weaken the growth forecast. This represents a change relative to the 2018 scenarios, which considered that industrials' energy cost increases could be more successfully passed through to end consumers.
  - AEMO no longer considers LNG export expansion, through debottlenecking of existing facilities and development of an additional seventh export train, as a reasonable development in this scenario, given alternative international supply opportunities and the relatively high cost of developing only one additional train.
  - Before implementing these changes, AEMO consulted broadly with the industry via a dedicated workshop which, among other focus areas, reflected on the drivers that may increase gas consumption. AEMO's 2019 forecasts now show less difference between the Fast change scenario and the Neutral scenario than was considered reasonable in 2018.
- The **Slow change scenario** is characterised by weaker domestic-led economic and population growth, slower decarbonisation of stationary energy and transport sectors, and less decentralisation.
  - This year AEMO has revised its assumptions regarding LNG minimum export levels, increasing consideration of contractual commitments made by the LNG exporters. This has reduced the

16 See https://www.industry.gov.au/regulations-and-standards/australian-domestic-gas-security-mechanism.

17 AEMO, Integrated System Plan, July 2018, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

bandwidth of uncertainty in the short to medium term as compared to the 2018 GSOO, particularly as the size of the LNG sector dominates any other scenario-driven differences across sectors.

Table 3 below summarises key energy drivers considered across the three scenarios. Where appropriate, the 2019 GSOO also considers various sensitivities of these drivers, to further increase understanding and materiality of key assumptions.

Table 3 Scenario drivers of most relevance to the gas market

Driver	Slow change scenario	Neutral scenario	Fast change scenario
Population growth	Low	Medium	High
Economy	Weak global and domestic demand	Neutral global and domestic demand	Strong global and domestic demand
Energy efficiency	Weak energy efficiency measures adopted	Moderate energy efficiency measures adopted	Aggressive energy efficiency measures adopted
Fuel switching	Weak economic case for fuel switching	Average economic case for fuel switching	Strong economic case for fuel switching
Gas price	Low gas prices	Medium gas prices	Medium gas prices[A]
Commodity price	Low	Medium	Medium
Foreign Exchange Rate – AUD to USD	Weak	Medium	Strong
Large-scale renewable generation uptake	Medium	Medium	High

A. AEMO has identified that high gas prices may lead to price-driven demand destruction, particularly for vulnerable large industrial loads.

The 2019 scenarios are based on different scenario narratives than the scenarios used in the 2018 planning and forecasting publications. Therefore, the 2019 Fast change and 2018 Strong scenarios, and the 2019 Slow change and 2018 Weak scenarios, may not be directly comparable, although the individual drivers that make up the scenarios can be compared.

1.4 New approach to assessing gas supply adequacy

AEMO's approach to projecting supply adequacy has changed this year, making a greater point of acknowledging uncertainties associated with future development of 2P reserves and contingent resources, and the exploration and development of prospective resources.

In the first instance, supply adequacy has been assessed based only on existing and committed supplies that are projected to be developed with a high degree of certainty. This provides readers with clearer information about where future investment is required to meet projected demand.

To allow 2019 GSOO forecasts to be directly comparable with the 2018 GSOO, supply adequacy has also been projected assuming all identified 2P reserves and contingent and prospective resources are developed.

Esso's decision not to proceed with its Dory project after failing to yield commercial quantities of gas demonstrates the inherent uncertainty in forecasts of reserves and resources, and highlights the risk in assuming uncertain reserves and resources will be developed when assessing supply adequacy.

This is discussed further in Section 4.3.

1.4.1 Northern and southern demand and supply

Parts of the analysis in this GSOO provide assessments of demand and supply across northern and southern regions of Australia's eastern and south-eastern gas markets.

The **northern** region includes:

- Demand for all Queensland consumers, including demand for liquefied natural gas (LNG) exported from Curtis Island.
- All gas fields and basins in Queensland, as well as those Northern Territory fields likely to deliver gas to eastern and south-eastern markets.

The **southern** region includes demand and supply sources located in New South Wales, South Australia, Victoria, and Tasmania, although there are no gas basins or fields in Tasmania that have been considered for this GSOO.

2. Demand forecasts

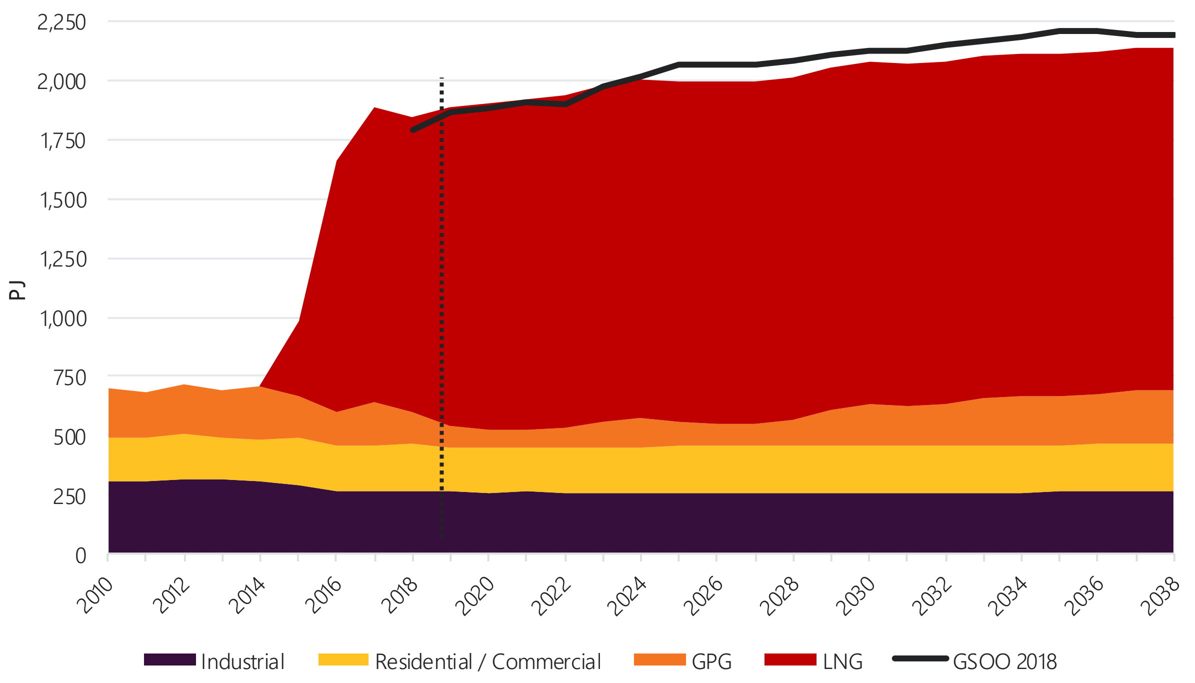
Demand for gas in eastern and south-eastern Australia has evolved in recent years, from mainly serving domestic consumers, to now servicing a growing LNG export market. Export LNG demand will continue to dominate forecast trends, representing approximately 70% of total annual gas consumption across the 20-year outlook.

The demand forecasts for this year's GSOO continue to show modest growth in gas exports, as well as risks and uncertainties around future gas to produce electricity.

2.1 Eastern and south-eastern demand forecast trends

Figure 4 shows the 20-year total demand forecast for eastern and south-eastern gas markets under the Neutral scenario, and the breakdown of the forecasts by consumer types.

Figure 4 Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario (petajoules [PJ])



Data files and further figures for the 2019 GSOO are available on the AEMO Forecasting data portal[18].

[18] Demand forecasts are available on the forecasting data portal at http://forecasting.aemo.com.au/. Select 'GSOO 2019' from the publication drop-down.

Key insights

- The Neutral gas consumption forecasts feature:
  - Moderate growth in the short term (2019-24) from 1,905 petajoules (PJ) to 2,017 PJ, reflecting modest growth in expected LNG exports and relative stability in residential, commercial, and industrial demand, offsetting reductions from gas-powered generation (GPG).
  - Slower growth in the medium term (2025-29), increasing to 2,068 PJ, mainly due to increased GPG demand, with relative stability in the other sectors. LNG exports are no longer expected to reach full production capacity.
  - In the long term (2030-38), consumption continuing to grow slowly to 2,158 PJ, with increased GPG output continuing to drive the majority of this growth.
- The magnitude of potential pathways for GPG represents the largest uncertainty in the forecast, as this will depend directly on the level of electricity consumption in the NEM, the reliability of coal-fired generation and timing of retirements, and future renewable generation developments.

Comparison of 2019 GSOO and 2018 GSOO Neutral gas demand forecasts

The difference in demand forecasts across the 2018 GSOO and the 2019 GSOO is shown in Table 4 (for forecasts of the 2020 calendar year) and Figure 5 (for the 20-year outlook). The key points are:

- Less actual gas was consumed in 2018 than 2017, primarily due to decreased NEM GPG consumption, which dropped from 184 PJ in 2017 to 130 PJ in 2018 (see Section 2.2.3 for more information).
- In the short term (2019-24), the 2019 Neutral forecast is very similar to the 2018 forecast, as AEMO continues to forecast lower consumption from GPG due to higher forecast penetration of renewable electricity generation in the NEM. Refer to Section 4.4 for a detailed discussion on forecast uncertainties for GPG.
- In the medium term (2025-29), the Neutral forecast is slightly lower than the 2018 forecast. This is mainly due to a revised LNG forecast of reduced incentive to increase production to capitalise on further spot market opportunities during this period.
- In the long term (2030-38), AEMO's updated forecasts continue the outlook for growth in the Neutral scenario, as more coal-fired generation is expected to retire, resulting in projected GPG consumption increases, projected growth in the residential and commercial sector, and relative stability in the industrial sector.

Table 4 Comparison of 2018 GSOO and 2019 GSOO Neutral gas consumption forecasts for 2020 (PJ)

Sector	2019 GSOO	2018 GSOO	Change
Residential, commercial, and industrial	448.0	445.6	+ 2.4
GPG	71.9	65.9	+ 6
LNG	1,382.4	1,371.9	+ 10.5
Losses	16.5	16.4	+ 0.1
Total	1,918.8	1,899.8	+ 19

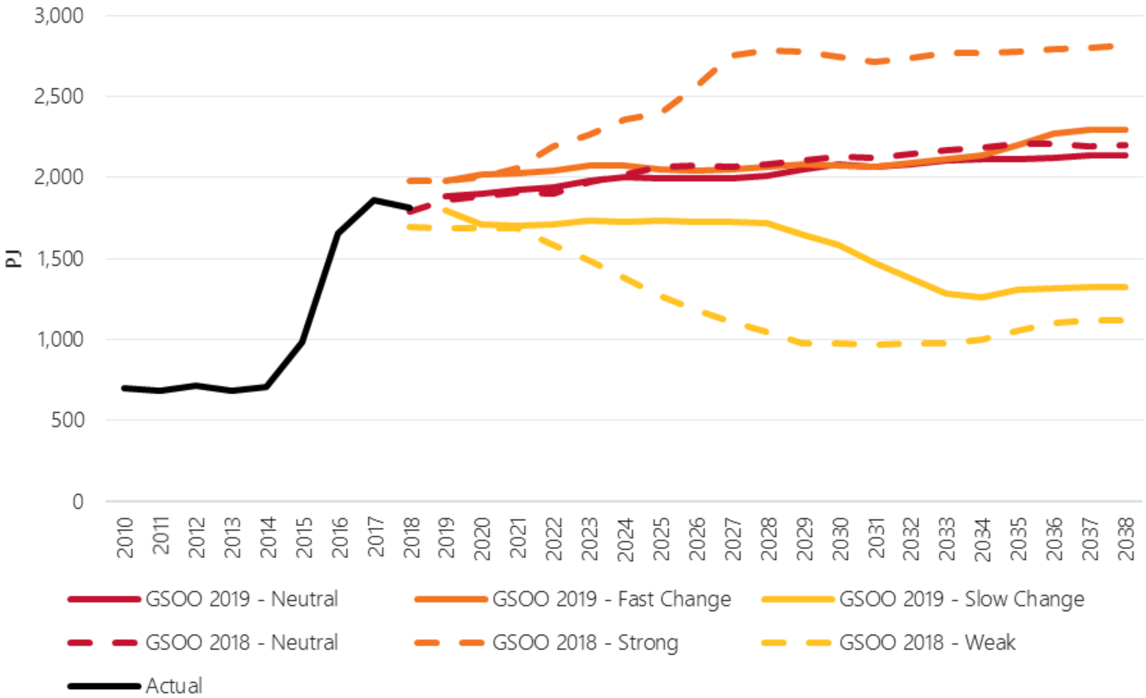
Comparison of 2019 GSOO and 2018 GSOO Fast change and Slow change forecasts

The 2019 Fast change and Slow change scenarios are based on different scenario narratives than the 2018 Strong and Weak scenarios, meaning that the 2019 Fast change and 2018 Strong scenarios, and the 2019 Slow change and 2018 Weak scenarios, may not be directly comparable although the individual drivers that make up the scenarios can be compared.

At a high level, the most obvious difference is that the dispersion between scenarios is now much narrower, with little forecast upside for gas demand above Neutral projections. This is primarily due to:

- Revised assumptions to increase consideration of LNG minimum contracted quantities (MCQ) in all scenarios,
- Consideration that LNG export facility expansion to deliver a seventh export train is no longer a plausible outcome for inclusion in any scenario; and
- A projected stronger role for energy storage to complement intermittent renewable energy, based on updated technology cost assumptions. The strongest effect relative to 2018 is captured in the Fast change scenario, with much lower GPG forecast in response.

Figure 5 Gas consumption forecast in all scenarios, and compared to forecasts in 2018 GSOO (PJ)



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

2.2 Consumption forecasts by sector and region

Gas is used in different ways across Australia. For example, in Victoria, gas consumption is dominated by the residential/commercial sector with heating representing a significant usage proportion, but in Queensland, this sector has a very small proportion of regional gas consumption, with markedly less gas used for heating.

Table 5 shows the breakdown of gas consumption in 2018 for each region by sector.

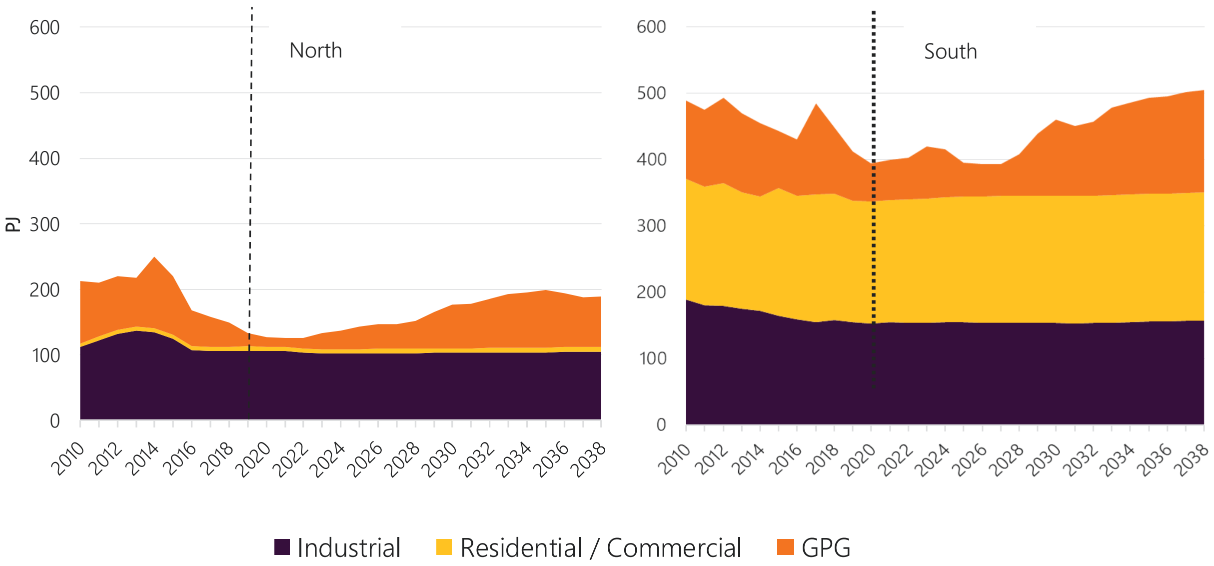
Table 5 Percentage splits of gas consumption by sector (not including UAFG[A]), 2018

Regional	Residential / commercial	Industrial	GPG	LNG	Regional gas consumption[B]
Queensland	< 1%	7%	2%	90%	1,380 PJ
New South Wales	42%	48%	10%	0%	116 PJ
South Australia	12%	27%	62%	0%	93 PJ
Tasmania	8%	51%	41%	0%	10 PJ
Victoria	58%	31%	11%	0%	212 PJ
Total	10%	14%	7%	68%	1,811 PJ

A. UAFG, or Unaccounted for Gas, refers to metered gas that enters the gas network but that does not reach consumers.
B. Consumption totals are based on metered load for the full 2018 calendar year, except for:
- Transmission-connected industrial consumers, based on survey (estimated for October-December 2018).
- GPG, based on estimated gas usage for each plant's metered electricity generation into the NEM.

Figure 6 shows the gas consumption forecast across northern (Queensland[19]) and southern (Victoria/New South Wales/South Australia/Tasmania) regions, and demonstrates the diversity of each consumer sector across geographic boundaries.

Figure 6 Gas consumption actual and forecast, 2010-38, all sectors except LNG, Neutral scenario, for north (left) and south (right) regions



[19] For the purposes of forecasting demand, the 'northern region' includes only Queensland consumers. The Northern Gas Pipeline (NGP) has provided access for Northern Territory producers to export additional gas to Queensland, thus when considering supply available to meet eastern and south-eastern Australian demand, the 'northern region' includes this Northern Territory supply.

2.2.1 Residential and commercial consumption

Key insights

- Residential and commercial sector gas consumption is projected to grow from 190 PJ in 2018 to 201 PJ in 2038, with much of this growth forecast in the short term (2019-24). This forecast by 2038 is approximately 17 PJ higher than projected in the 2018 GSOO, reflecting both:
  - A higher forecast of new dwellings connecting to the gas network.
  - A higher expected average usage for new dwellings. Compared to metro regions, proportionally more new connections in greenfield areas are houses rather than multi-story apartments, requiring larger space conditioning requirements.
- In the medium to long term (2025-38), this growth is forecast to be partly offset by forecast reductions from increasing impacts of expected energy efficiency measures, fuel switching, and price response.
- Despite the increased number of forecast gas connections, residential consumption still represents less than 10% of eastern and south-eastern Australia gas demand through the 20-year outlook period.

AEMO developed residential and commercial forecasts using forward estimates of consumption on a per connection basis. The type and forecast number of new connections therefore drives the growth trajectory, subject to other behavioural influences, such as in response to pricing stimuli, appliance fuel switching, and broader energy efficiency impacts.

Table 6 below summarises the estimated impact of changes in key drivers on the residential gas demand forecasts, compared to the 2018 GSOO forecast.

Table 6 Estimated impact on forecasts due to changes to residential and commercial drivers

Driver	Estimated impact on forecasts by 2038 (PJ)	Explanation
Increase in population forecasts	+9	The new gas connection forecasts reflect higher population forecasts in the November 2018 Australian Bureau of Statistics (ABS) updated forecast. In the Neutral scenario, approximately 150,000 additional new gas connections by 2038 are now modelled, compared to the 2018 GSOO.
Consumer trends	+21	Updated analysis of historical residential meter data shows that recent demand growth in regional greenfield areas has largely offset the long-term reductions observed in metropolitan areas, when averaged on a per connection level. Reflecting this update of the mix in consumer base, the Neutral scenario forecast (for this component) has increased by about 21 PJ in 2038, compared to the 2018 GSOO forecast.
Energy efficiency, fuel switching and price response	-13	AEMO has identified an increased risk of demand reductions of approximately 13 PJ in the Neutral scenario compared to the 2018 GSOO, reflecting price and consumer behaviour influences (see discussion below table).
Net impact on residential forecasts	**+17**	

Details of factors reducing projected consumption, that have been updated in the 2019 GSOO, are:

- Energy efficiency impacts – these are linked to current or planned energy efficiency schemes, as forecast for AEMO by *Strategy.Policy.Research*[20]. The Neutral scenario impact is similar to the 2018 GSOO at the

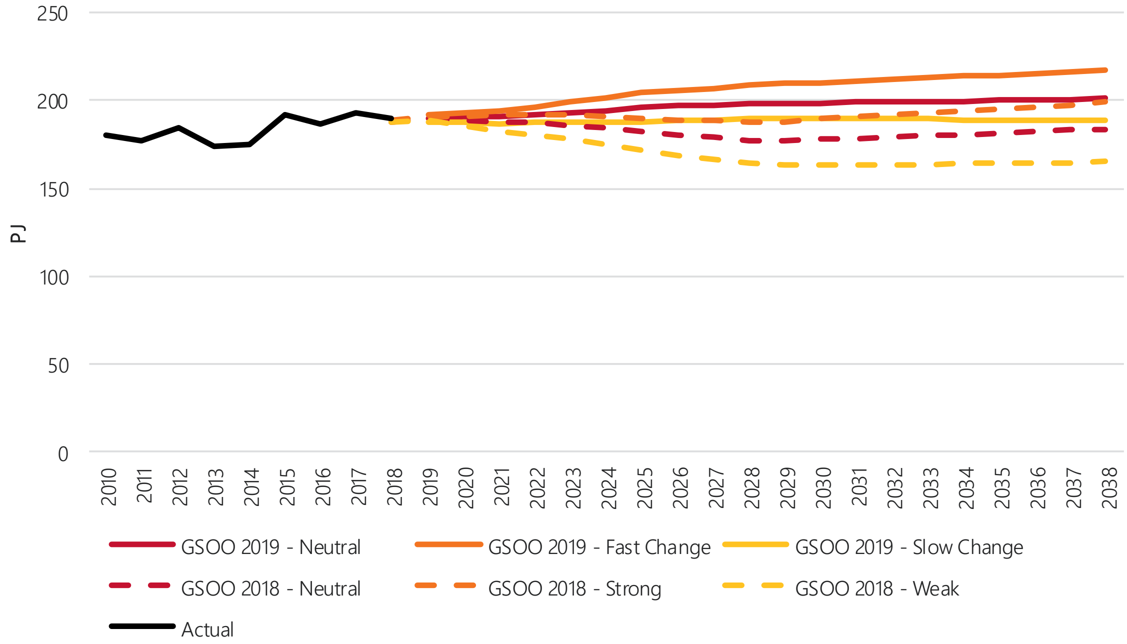
[20] Strategy.Policy.Research, *Energy Efficiency Impacts on Electricity and Gas Demand to 2037-38*, June 2018, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Energy-Efficiency-Impacts-on-Electricity-and-Gas-Demand-to-2037-38-by-Strategy-Policy-Research.pdf.

end of the forecast horizon, although there are year-on-year timing differences between the forecasts. The main areas of increasing energy efficiency are gas heaters, insulation, and instant gas hot water.

- Electric to gas fuel-switching – the potential has increased approximately 2 PJ, with some schemes encouraging switching from electricity to gas appliances. The larger expectation continues to be that appliance-driven fuel-switching from gas to electricity, particularly affecting space heating and water heating appliances, will have a higher impact on residential consumption compared to other sectors.
- Higher gas prices are forecast to lower overall consumption by approximately 4 PJ per annum by 2038 for the Neutral scenario, relative to the 2018 forecasts.

Figure 7 shows the higher overall trend in forecast residential/commercial gas consumption for all scenarios compared to the 2018 GSOO demand forecast, particularly due to the higher forecast connections.

Figure 7 Residential/commercial annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

2.2.2 Industrial consumption

Key insights

- Minimal change in industrial consumption is forecast in the Neutral scenario over the 20-year outlook, with total industrial consumption projected to be 262 PJ in 2038 compared to 263 PJ in 2018.
  - Minor variations in trends are projected by state, with less industrial demand in Queensland and more in South Australia in the near term, but the net impact of these variations is minimal.
- The Slow change scenario forecasts a degree of decline in the short to medium-term (2019-29), reflecting the perceived increased vulnerability for some industrial loads and risks of closures due to a mild economic outlook.
- The manufacturing sector is projected to be relatively flat, while other industrial businesses (dominated by the services sector) are projected to grow moderately over the 20 years, mostly due to increasing economic activity in the services sector.

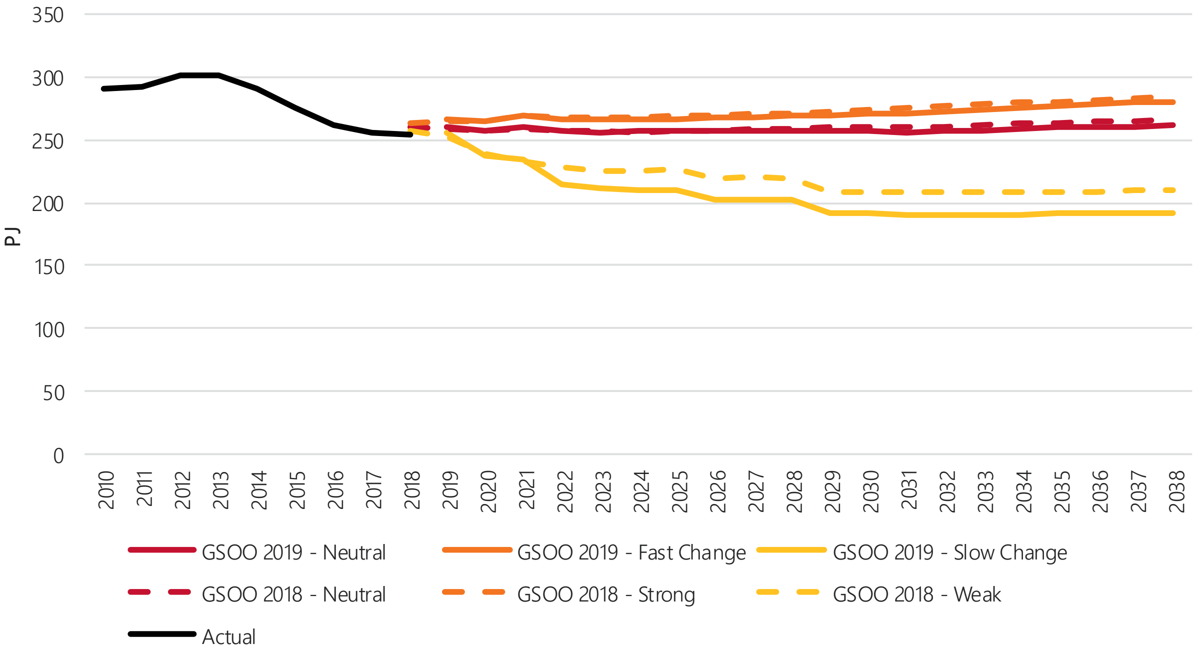
AEMO forecasts the consumption of industrial sector sub-sectors, for:

1. The Manufacturing sector, which is typically more energy-intensive, and
2. 'Other business' sectors.

The underlying drivers affecting these two sectors are discussed separately below.

Figure 8 shows the overall trend in forecast industrial gas consumption for the three scenarios compared to the 2018 GSOO demand forecast.

Figure 8 Industrial annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

Comparison between scenarios shows more downside risk associated with the potential closure of large industrial loads and declining production due to weakening global and domestic demand in the Slow change scenario, compared with the Neutral.

As discussed in Section 1.3, the Fast change scenario deliberately avoids scenario drivers that may increase commodity prices above the Neutral scenario. Strong commodity prices may drive up gas prices, potentially leading to large industrial load closures, which may reduce gas consumption in the Fast change scenario to below the Neutral scenario. Based on surveys conducted with industry, anecdotal evidence suggests that more industrial gas users would suffer from higher energy costs than would benefit from stronger commodity prices. As such, AEMO considers the greatest driver for gas consumption growth is a future which involves greater economic transformation to a services-based economy, given the perceived fragility of many large industrials to pricing risks. This is different to the 2018 GSOO.

Industry feedback suggests there is little incentive currently for major new investments to large industrials users. Therefore, the upside consumption uncertainty is a lot smaller than the downside uncertainty, where industrial loads may close due to milder[21] economic outlook conditions.

While consumption is forecast to be relatively flat in the Neutral scenario, variations are possible across regions, particularly given the different types of manufacturing and industrial processes across eastern and south-eastern gas markets.

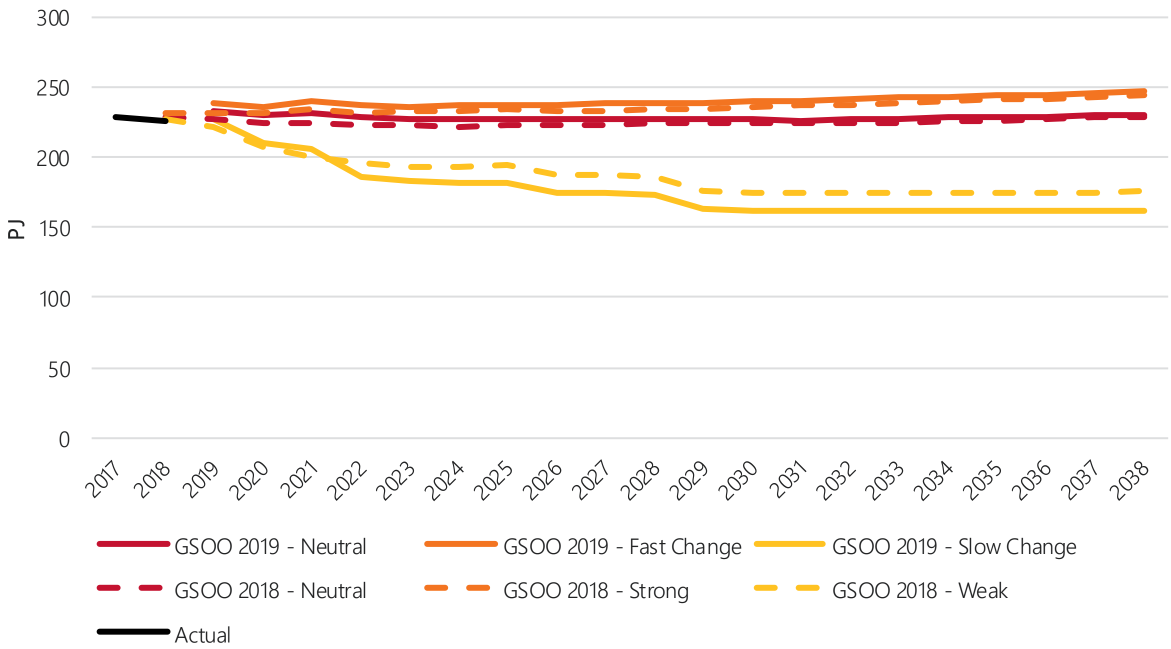
[21] The Slow change scenario does not reflect recessionary conditions as economic growth remains positive, but mild.

Manufacturing sector trends

The manufacturing sector is involved in transforming materials, substances, or components into new products. Key industries in this sector that consume relatively large volumes of gas include basic chemical manufacturers, primary metal manufacturers, food manufacturers, and mining.

Figure 9 shows forecast gas consumption in the Manufacturing sector for the three scenarios, and compared to the 2018 GSOO demand forecast.

Figure 9 Annual consumption actual and forecast for Manufacturing sector, 2017-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

The gas consumption forecasts for the manufacturing sector considered many factors:

- Detailed interviews with large industrial gas users investigated broad gas market dynamics, as well as industry specific opportunities and threats, and revealed that large industrial consumers face challenging decisions about their ongoing domestic operations.
- The Australian Competition and Consumer Commission (ACCC) interim gas market enquiry report[22] has observed that gas prices are now more reflective of supply-demand dynamics. The prices offered in the domestic market for gas supply in 2019 by the end of September 2018 had converged to export parity prices. Although commodity gas prices have fallen, prices offered by retailers to industrial users remain on average higher than commodity gas prices previously charged by gas producers.
- In addition, interviews revealed that many large industrial users are seeking longer-term gas supply agreements (GSAs), but few are receiving offers for terms that match their requested duration. Some of these industrial gas users are increasingly re-contracting for shorter periods (1-3 years), and much closer to the end of their existing contracts, hoping that domestic gas prices may fall.
- Other industrial users are procuring gas by becoming direct market participants in wholesale markets or investigating options for joint ventures with gas producers, expanding their business risks into the

[22] ACCC, Gas inquiry December 2018 interim report, available at https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2020/gas-inquiry-december-2018-interim-report.

upstream domestic gas market. Although these investments appear to reduce the risk of higher energy prices in the medium term, business risks remain unchanged in the short term.

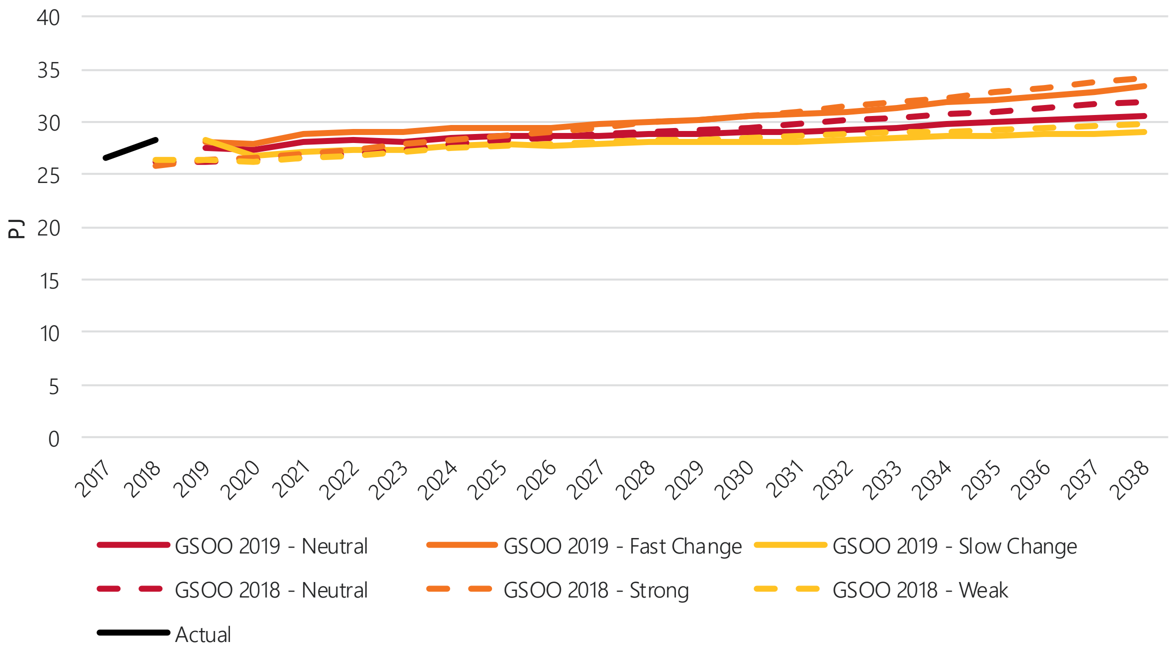
- Economic conditions domestically have also supported large industrials, with an expansionary setting of monetary policy[23], which has helped create the conditions for lower unemployment with little change to wage growth. Financial conditions continue to accommodate most large businesses, with the cash rate expected to remain unchanged over the months ahead. The cost of funding for large businesses remains relatively low, which assists in lowering business costs.
- Improved commodity prices, such as oil price declines that are linked to domestic gas prices, and foreign exchange rates, have strengthened export conditions for some large industrial consumers, which has strengthened their operational resilience to recent increases in gas prices.

Other business sector trends

Other business is defined as industrial consumers outside of the Manufacturing sector, and is dominated by finance services, transport, and services businesses such as education, health care, and telecommunications.

Gas consumption for this sector is projected to grow moderately over the 20-year outlook, as shown in Figure 10, in line with projected economic growth in the services sector. The increasing trend remains unchanged from the 2018 GSOO.

Figure 10 Annual consumption actual and forecast of Other business sector, 2017-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

The key drivers for the Other business sector are:

- Retail gas price – price increases are driven by projected increases in wholesale costs in the long term. The reduction in consumption in response to price increases is lower in this year's forecasts, as updated wholesale forecast prices reflect more stable future gas prices, reducing price-driven demand reduction.
- Increasing economic activity in the services sector – this dominates the forecast trend for Other business sector consumption. This forecast is moderated in the first three years by responses to retail price rises. However, as gas price rises are projected to taper off in subsequent years, the continued growth in the

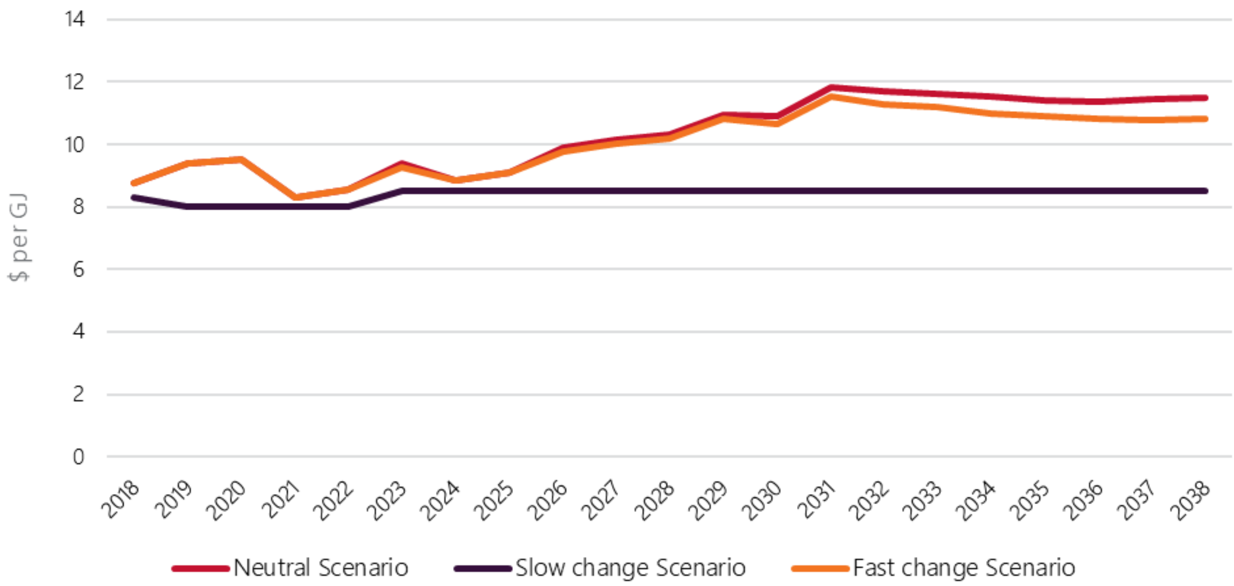
[23] Reserve Bank of Australia, Statement on Monetary Policy, February 2019, available at https://www.rba.gov.au/publications/smp/2019/feb/.

services sector that updated economic modelling shows (by the Gross Value Add indicator) drives the medium- and long-term trends.

Wholesale gas price forecasts

The average eastern and south-eastern Australian domestic wholesale gas prices assumed for the purpose of determining any change in demand in response to price can be seen in Figure 11. While the prices in this figure are averaged across all states, this GSOO's gas demand forecasts incorporate a separate price for each state. These wholesale gas price forecasts have been provided by Core Energy, and details are available on AEMO's website[24].

Figure 11 Wholesale eastern and south-eastern Australian gas prices averaged across all states, 2018-38



2.2.3 GPG

Key insights

- GPG consumption is forecast to continue decreasing from recent historical levels, as new renewable electricity generators are forecast to be installed in the NEM.
- Forecast GPG demand remains below historical levels until approximately 2029, when coal-fired generator retirements in the NEM are projected to increase the potential role for GPG.
- The annual volumes of GPG consumption are highly dependent on weather events, generator outages, and the rate of renewable generation uptake. These factors are changing in both magnitude and frequency of occurrence, increasing the variability and uncertainty of GPG forecasts year-on-year. New electricity transmission and renewable generation development is expected to reduce reliance on GPG, but potential delays in this development also pose risks for gas supply adequacy.

Demand for GPG was as high as 184 PJ in 2017, after the retirement of the coal-fired Hazelwood Power Station in March 2017 and extended coal outages of Yallourn and Loy Yang coal-fired power stations in late 2017.

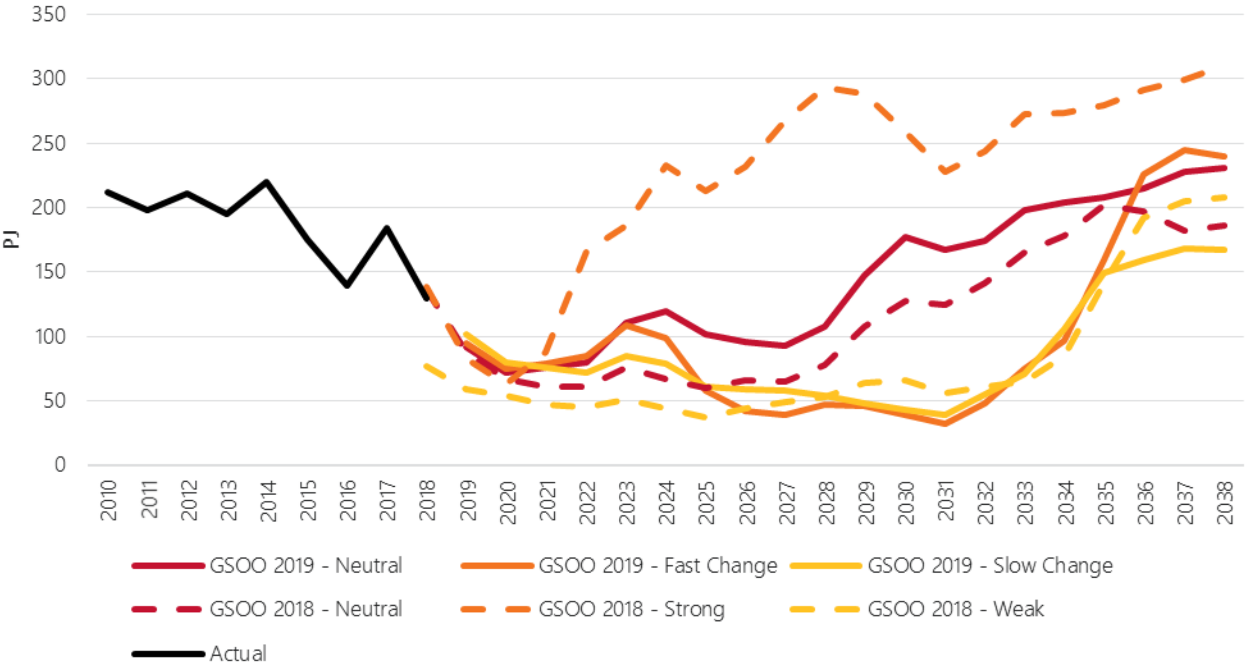
[24] Core Energy, 2019 wholesale gas price outlook report, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

In 2018, gas consumption for GPG decreased by 54 PJ to 130 PJ, which is 29% lower than the previous year.

In 2018, approximately 2,000 MW of new utility-scale renewable capacity was installed in the NEM, as well as an increase in DER[25] such as rooftop photovoltaics (PV), which contributed to the decrease in GPG demand.

Figure 12 shows this actual decline in GPG demand and the forecast consumption for GPG, and a comparison to the 2018 GSOO demand forecast across each of the scenarios.

Figure 12 GPG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

In the short term, AEMO forecasts a continued drop in GPG demand from historical levels, as new renewable developments are developed to meet various state and federal environmental policies and in response to lowering renewable technology capital costs. As at January 2019, over 4,200 MW of new renewable generation has committed to start generating in the NEM, and an additional 2,800 MW have started construction but have not yet fully satisfied AEMO's commitment criteria[26].

For the purposes of these GPG forecasts, AEMO has conservatively assumed that 50% of this 2,800 MW of additional renewable generation capacity under construction commences operation before 2021. Any delays to commissioning of any of these committed or anticipated renewable generation projects would likely lead to greater reliance on GPG.

From 2028, GPG demand is forecast to rise to previously observed historical volumes, as expected coal generator retirements may re-invigorate the role of gas generators. Due to the relatively high operating cost and flexibility of gas generation to respond to changes in supply or demand, the role of GPG in the NEM is projected to shift towards providing a reliability and power system security role, complementing variable renewable energy, hydro generation, and storage to meet demand in the NEM.

AEMO's GPG forecasts are also dependent on the timing of new transmission developments in the power system. Greater interconnection allows more efficient use of existing generation assets (including coal-fired

[25] Distributed energy resources (DER) are resources that either produce electricity, store electricity, or manage consumption, and reside within the electricity distribution system, including resources that sit "behind the meter", on consumers' premises.

[26] See AEMO's generation information page, 21 January 2019, new wind and solar projects with commitment status 'Committed' and 'Com*' in regional spreadsheets under "New developments" tab, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

generation), and better captures the value of geographic diversity in renewable generation sources. As such, greater interconnection between regions in the NEM is forecast to deliver fuel cost savings (among other benefits) by reducing demand for GPG. Changes in timing of new transmission developments (either advancing or delaying the transmission developments recommended in AEMO's 2018 ISP) will have implications for GPG forecasts and gas supply adequacy. This highlights the need for integrated planning of the gas and electricity systems.

Compared to last year's GSOO forecast, projected GPG demand in the Neutral scenario is higher in the 2019 GSOO, due to:

- Increased electricity consumption forecasts for the NEM, driven by projected population growth and an increase in new electricity connections.
- A forecast decrease in hydro generation in 2019, given updated assumptions that also consider the impact of current drought conditions. With less water assumed to be available for hydro generation, more expensive gas generation is projected to replace it to meet electricity demand.

GPG forecast differences in Fast change and Slow change scenarios

A key factor driving the variability across years in forecast GPG demand is the projected retirement of large coal-fired generators[27] without equivalent capacity being available to immediately replace it. Over the study horizon, this includes the announced retirement of Liddell coal-fired power station in 2022[28], and assumed retirements as power stations reach the end of their technical life[29]. Assumed age-driven coal-fired retirements in the outlook period are:

- Vales Point power station in New South Wales in 2028.
- Gladstone power station in Queensland in 2029.
- Yallourn power station in Victoria in 2032.
- Eraring power station in New South Wales in 2034.
- Bayswater power station in New South Wales in 2035.
- Tarong power station in Queensland in 2036.
- Callide B power station in Queensland in 2038.

GPG continues to be very sensitive to changes in the market, particularly timing of new renewable generation development, and this can be seen with the crossover of the Fast change and Slow change scenario forecasts in Figure 12.

In the Fast change scenario, projected GPG demand is lower than the Strong scenario forecast in the 2018 GSOO. The role for GPG in the Fast change scenario is reduced, due to a more aggressive projected penetration of renewable generation projects, and a forecast increase in storage technologies of various sizes to support renewable generation intermittency, rather than GPG. As more intermittent renewable generation enters the system, storage will play an important role in smoothing and firming up[30] generation across all scenarios, at a lower cost than existing or new GPG, given current assumptions.

With renewable generation and storage build costs assumed to fall faster in the Fast change scenario than in the Neutral or Slow change scenarios, the generation mix in the NEM is projected to change more quickly, eroding the forecast utilisation of GPG.

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[27] The retirements of coal-fired power stations are highly complex and the outcome of a wide range of commercial and financial factors in the market. As a result, the projected timing of retirements is highly uncertain. AEMO's approach and key assumptions are discussed in Section 2.4 of the ISP, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf.

[28] AGL website, "AGL Macquarie Power Stations", available at https://www.agl.com.au/about-agl/how-we-source-energy/agl-macquarie. Viewed 6 January 2019.

[29] The projected timing of coal-fired generation retirements in the NEM is examined in Section 2.4 of the 2018 ISP. For more information, see http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[30] Generation firmness is a measure of the likely energy availability of the resource mix at some time in the future.

For more information on risks and uncertainties related to GPG demand forecasts, refer to Section 4.4.

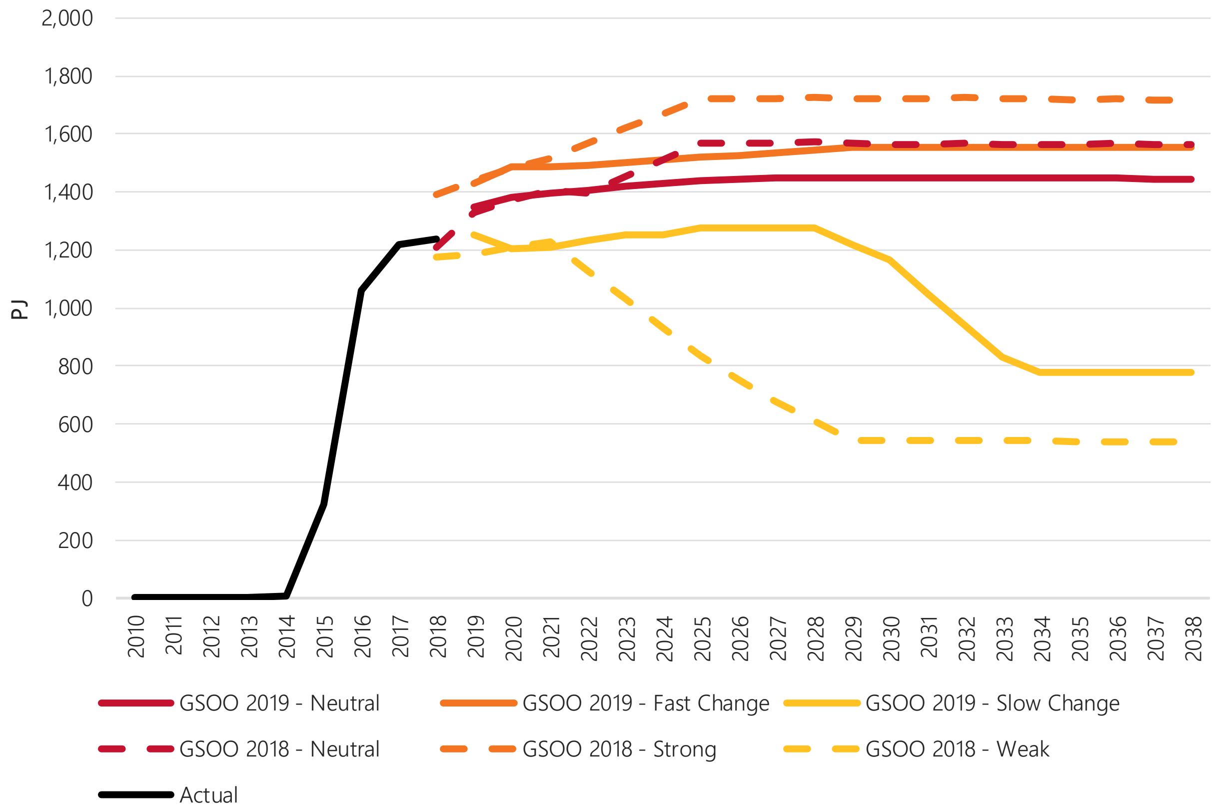
2.2.4 LNG

Key insights

- LNG demand is forecast to reach levels forecast in the 2018 GSOO in the short term (2019-24), with some small rises allowing producers to capitalise on spot market opportunities.
- In the medium to long term (2025-38), LNG exports are projected to remain at these levels, which are forecast to be sufficient to meet contractual obligations. Increasing global competition reduces the incentive to increase production to capitalise on further spot market opportunities.

AEMO considered stakeholder guidance and assessed key changes in long-term trends to update the LNG forecasts used in this 2019 GSOO. The forecasts are shown in Figure 13 for all scenarios, and with a comparison to the 2018 GSOO forecasts.

Figure 13 LNG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2018 GSOO



Note: 2019 scenarios are not directly comparable to 2018 scenarios due to changes in scenario formulation.

The Neutral scenario forecast reflects:

- In the short term (2019-24), demand is projected to remain relatively stable, with some rises to capitalise on spot market opportunities.
- Beyond 2024, exports are forecast to stabilise, at a level lower than the 2018 GSOO forecast. This is due to:
  - Current exports being forecast to be sufficient to meet contractual obligations.
  - Projected slowing growth in demand for international LNG as traditional buyers of LNG transition to lower carbon economies.

  - Emerging competition from new international sources of natural gas, as well as producers from Western Australia and Northern Territory with lower costs of production, reducing the incentive to increase exports above current levels.
  - Lower prices, along with increasing international supply, disincentivising the costly debottlenecking of the LNG trains that was assumed in the 2018 GSOO.
  - Coal seam gas (CSG) wells have been underperforming[31] compared to original forecasts, meaning LNG producers have been forced to drill more wells to maintain current levels of supply, therefore increasing the cost of production.
- Collectively, these changes result in lower forecast demand in the medium to long term, compared with last year's GSOO.

For the Fast change scenario:

- The large decrease compared to 2018 GSOO forecasts in the medium to long term is due to the removal of the seventh train assumption from last year. This revised assumption is underpinned by the combination of effects that make a seventh train implausible across the scenarios:
  - The seventh train is no longer considered economical, as the capital investment required to develop one more train is excessive without the economies of scale of the original projects.
  - Stronger global demand is expected to be met by increased production from international supply, which has a relatively lower cost of production.
- Similar to the Neutral scenario, there is no longer sufficient incentive for further debottlenecking to increase production throughput on the existing LNG trains.
- Forecast demand is higher than in the Neutral forecast, due to spot cargo increases to near full train capacity.
- It is assumed that any increase in LNG export demand above the Neutral scenario would be driven by a corresponding increase in new Queensland CSG production, as it is unlikely that increased contracts for export demand would be agreed upon without a related source of gas supply.

For the Slow change scenario:

- Over the short to medium term (2019-29), the forecast decline in LNG demand occurs later than was assumed in the 2018 GSOO, as it is considered reasonable that minimum contract levels will be met regardless of whether this is filled by eastern Australian supply, or international alternatives.
- In the long term, the supply outlook is such that existing wells are projected to decline to minimum production levels by 2033, equivalent to a minimum capacity of approximately three trains.

[31] Based on Queensland Government dataset, *Petroleum and gas production statistics (June 2018)* – CSG wells compared to CSG production, available at https://data.qld.gov.au/dataset/petroleum-gas-production-and-reserve-statistics/resource/9746212a-e0c6-484d-95ad-b2be1c46027d. Viewed 4 March 2019.

2.3 Maximum daily demand forecasts

Key insights

- Maximum daily demand, excluding GPG, is forecast to be relatively flat for most states in the short term (2019-24), as increases in gas consumption due to new connections growth are expected to be offset by the combined reductions in consumption due to energy efficiency, gas to electric appliance switching, and behavioural price response impacts.
- Long-term (2030-38), the forecast maximum daily demand, excluding GPG, is expected to marginally increase in all states except South Australia and Tasmania. This is primarily the result of projected increases in consumption, due to new connections growth being forecast to start outweighing reductions due to other drivers in household and commercial consumption.
  - In South Australia, growth drivers are not forecast to outweigh these other drivers, leading to reductions over the forecasting horizon.
  - A slight decline is forecast for Tasmania, primarily due to the projected price impact on industrial consumption.

For most NEM regions, maximum daily demand is determined by weather driving households and commercial businesses and, to a smaller degree, industrial use, to consume more gas for heating in winter.

Maximum daily demand is measured at the regional level, because demand peaks at different times in different regions. There is no system-wide coincident maximum against which supply is assessed.

Drivers for growth in maximum daily demand are similar to those of the annual consumption forecasts.

Key regional observations in the maximum demand forecasts are:

- Trends in maximum daily demand, excluding GPG, show relatively flat forecasts in Queensland, South Australia, and Tasmania.
- A slight upward trend is forecast in New South Wales and Victoria. This slight increase is primarily due to the projected impact of new connections growth in households and commercial businesses. Industrial consumption is expected to remain relatively flat in these states at the time of regional peak over the forecasting horizon.
- Maximum daily demand in Queensland (excluding GPG and LNG) is forecast to decline to 2024, due to projected reductions in industrial consumption, then to increase slightly for the remainder of the 20-year forecast horizon, due to a rise in industrial production and household and commercial business consumption (from new connections growth).
- Maximum daily demand for LNG in Queensland, at the time of system peak, is forecast to increase modestly until 2024. Beyond 2024, the forecast is expected to remain at a stable level as current exports are projected to be sufficient to meet contractual obligations while increasing global competition is forecast to reduce incentives for increasing production to capitalise on further spot market opportunities.
- In South Australia, the maximum daily demand (excluding GPG) is forecast to increase slightly to 2024, due to a forecast increase in industrial production and commercial services, before declining. The decline aligns with projected reductions (due to energy efficiency, gas to electric appliance switching, and behavioural price response impact) becoming greater in magnitude than increases due to growth in new connections.
- Tasmania is also forecast to have flat maximum daily demand. A marginal reduction is observed near the end of the forecast horizon, due to projected industrial consumption reductions from businesses responding to gas price.
- Over the forecast horizon, the impact of new connections on household and commercial business gas consumption is greater at the time of maximum daily demand in all regions than that previously projected

in the 2018 GSOO. These changes reflect an updated analysis of residential gas meter data, whereby the average consumption of a residential consumer is forecast to increase and the number of consumers (from updated ABS forecasts) is also forecast to rise. Other demand drivers have also been revised for household and commercial business consumption in each state. The net effect of these revisions has lessened the reductions in maximum daily demand observed in the 2018 GSOO after 2023 in all states except Tasmania.

Table 7 and Table 8 show the seasonal forecasts[32] for all sectors combined, excluding GPG[33]. These forecast totals include unaccounted for gas (UAFG) that is lost while being transported through the network[34].

The tables show that:

- The difference between 1 in 2 and 1 in 20 forecasts is smaller in Queensland and Tasmania than other regions because Queensland and Tasmania are less sensitive to weather at the time of regional peaks and have proportionally higher demand from large industrial loads.
- Victoria and South Australia have a greater degree of weather sensitivity, due to the proportionally higher residential and commercial demand.

Table 7 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding GPG, including UAFG (terajoules (TJ)/day)

	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	288	313	3,941	3,956	328	343	109	118	20	21	484	621
2023	286	309	4,532	4,547	317	332	110	119	20	21	487	627
2028	290	314	4,480	4,503	321	335	110	118	20	21	496	644
2038	299	326	4,503	4,517	329	343	109	117	19	20	504	649

Table 8 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding GPG, including UAFG (TJ/day)

	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	462	484	3,949	3,963	336	350	156	167	22	23	1,151	1,248
2023	462	487	4,540	4,553	325	338	157	167	22	23	1,169	1,264
2028	471	495	4,488	4,511	329	343	156	167	22	23	1,193	1,298
2038	486	512	4,512	4,526	338	352	152	162	21	22	1,205	1,307

[32] Maximum daily demand is forecast with a probability of exceedance (POE), meaning the likelihood the forecast will be met or exceeded. A 1-in-20 (or 5% POE) forecast is expected to be exceeded, on average, only once in 20 years, while a 1-in-2 (50% POE) forecast is expected, on average, to be exceeded every second year.

[33] All maximum daily demand forecasts can be accessed from the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2019' from the publication drop-down.

[34] UAFG is metered entering the network but does not reach consumers.

3. Supply outlook

This chapter provides an assessment of the changes in reserves and resources in eastern and south-eastern Australia compared to the 2018 GSOO, highlighting a decline in southern reserves, reduced levels of 2P reserves more generally and increased contingent resources.

It also presents the outlook for gas supply (provided by gas producers) in the next several years (2019-22)[35], which is slightly lower than the 2018 GSOO supply forecast.

3.1 Production categories

Gas reserves and resources 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, or overcoming geological challenges.

The following categories are applied across the industry:

- **Reserves** are quantities of gas which are anticipated to be commercially recovered from known accumulations.
  - **Proved and probable reserves (2P)** are considered the best estimate of commercially recoverable reserves. When probabilistic methods are used, 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.
- **Contingent resources** are considered less viable than reserves, either due to current economics or other contingent factors that need to be overcome. Contingent resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.
  - **2C resources** are considered the best estimate of those sub-commercial resources.
- **Prospective resources** are estimated volumes associated with undiscovered accumulations of gas. These resources are estimated to exist in the prospect areas, but have not yet been proven by drilling.

For the GSOO, AEMO further categorises reserves as either:

- **Developed** (supply from existing wells), or
- **Undeveloped** (wells yet to be drilled).

The probability of gas existing in the ground and being considered commercially viable is not the only uncertainty related to future production. AEMO has further considered the level of certainty around whether projects will proceed to develop the identified volumes of reserves or resources.

For the purposes of this GSOO, AEMO has considered the following definitions[36]:

[35] Supply information from producers is only available to 2022.

[36] AEMO intends to consult with industry across 2019 to clarify these definitions.

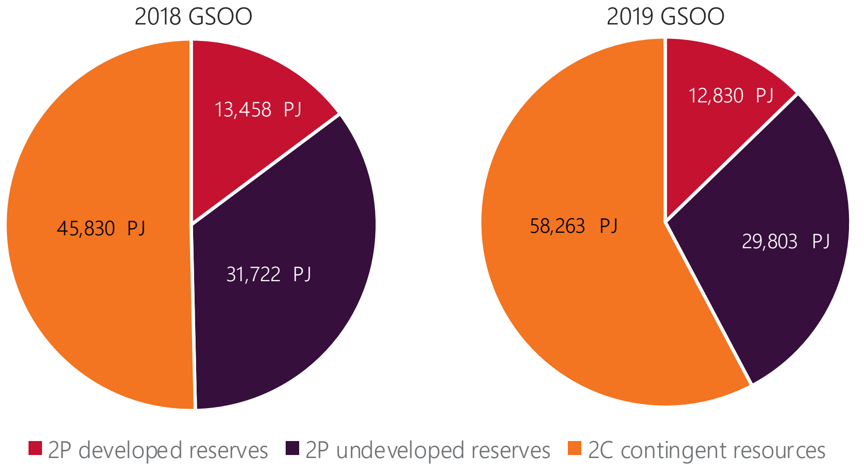
- **Committed** projects are actively under development planning and have passed final investment decision (FID).
- **Anticipated** projects are actively under development planning utilising existing production infrastructure, so there is a reasonable likelihood of them proceeding. These anticipated projects may include quantities of undeveloped reserves and contingent resources.
- **Uncertain** projects are those projects that are considered much more uncertain to be developed, and are not as far along the development planning path. In the long term to 2038, uncertain projects include uncertain 2C contingent and prospective resources that are accessible by existing pipeline and processing infrastructure.

3.2 Status of reserves and resources

Eastern and south-eastern Australian natural gas 2P reserves (developed and undeveloped) have decreased relative to the 2018 GSOO estimates by just over 2,500 PJ (5.6%). Over the same time, 2C contingent resources have increased by nearly 12,500 PJ (27%), as some 2P reserves have been downgraded as less economical, and some prospective resources been explored and increased certainty.

Figure 14 provides a breakdown of 2P developed and undeveloped reserves and 2C contingent resources reported in both the 2018 GSOO and this 2019 GSOO[37].

Figure 14 Reserves and resources reported in the 2018 GSOO and 2019 GSOO



The increase in contingent resources indicates that exploration and development of resources is continuing and that quantities of gas believed to be available for production is growing. However, by definition, these contingent resources are not yet considered commercially viable. Therefore, the decrease in 2P reserves increases the urgency for discovery of new, commercially viable sources of gas, or alternatively, LNG imports.

Figure 15 shows how total quantities of reserves are split between fields in the northern region (Queensland, and those Northern Territory fields likely to deliver gas to eastern and south-eastern markets) and the southern region (South Australia, New South Wales, and Victoria)[38]. It highlights that the reliance on 2C resources is particularly problematic for the southern region.

[37] The 2019 GSOO reserves and resources were assessed as at 31 December 2017, with the 2P developed reserves reduced to take into account actual production throughout the 2018 calendar year. This is consistent with the reported 2018 GSOO reserves and resources, which were reported as at 31 December 2016, and the 2P developed reserves reduced to take into account actual production throughout the 2017 calendar year. A summary of the reserves and resources for the 2019 GSOO is available at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[38] While Tasmania is considered part of the southern states, and is part of the southern demand aggregation, there are no gas basins or fields in Tasmania that have been considered for this GSOO.

In the south, 2P developed reserves have decreased by nearly 1,100 PJ (from 3,475 PJ to 2,378 PJ, or 32%), compared to the 2018 GSOO, while 2P undeveloped reserves have only increased by 270 PJ (from 1,138 PJ to 1,408 PJ, or 24%).

With much lower quantities of 2P reserves available for production in the south, work will need to progress on ensuring 2C resources (which have increased by 3,870 PJ from 5,476 PJ to 9,354 PJ, or 71%) are commercially viable and able to meet demand before the 2P reserves run out, or access to alternative sources of supply will be necessary.

Figure 15 Percentage change in reserve and resource quantities from northern and southern natural gas reserves, 2019 GSOO compared to 2018 GSOO

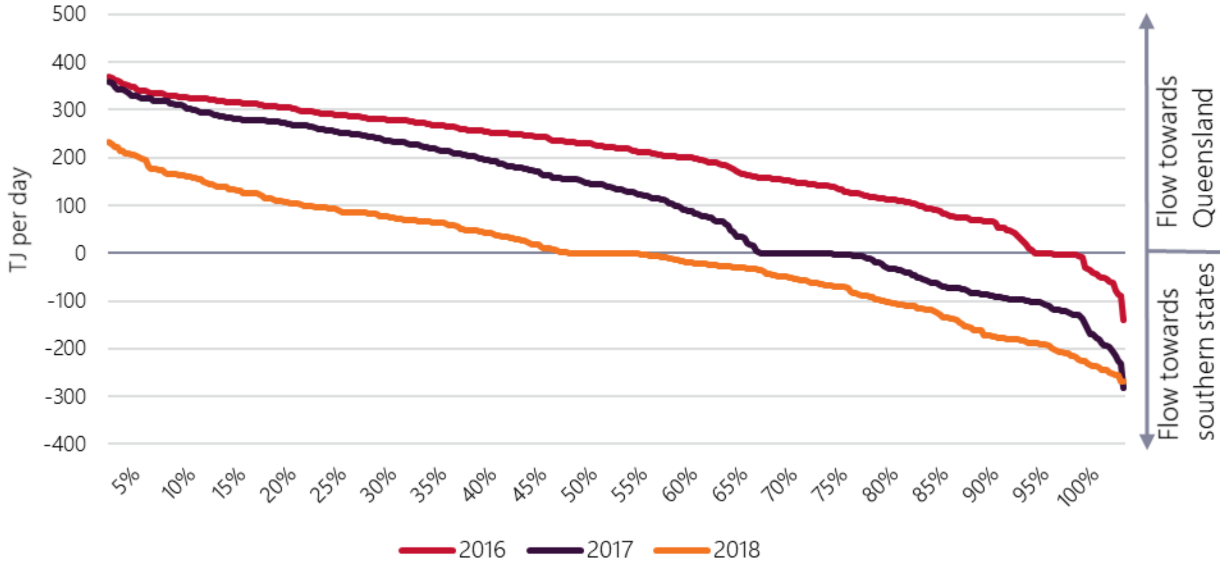
3.3 Changing infrastructure limitations

Historically, there have been strong levels of production from the Victorian gas basins – Gippsland, Otway, and Bass. On average over the last five years, gas from these basins has supplied 150 PJ per year to Tasmania, New South Wales, and South Australia, from production surplus to Victorian gas consumption requirements. Further surplus gas has been used to fill storage facilities and, when required, sent north via the South West Queensland Pipeline (SWQP) to support demand in Queensland.

On peak demand days in the southern region, or times of low supply, the SWQP has been utilised to transport gas from Queensland fields south to meet southern demand.

Figure 16 shows daily flow of the SWQP, ranked from most positive (flow towards Queensland) to most negative (flow towards the southern states) each year since 2016, highlighting that the SWQP has been increasingly used to help meet demand in the southern states.

Figure 16 **Flows along the SWQP from 1 January 2016 to 31 December 2018**



Gas demand at Mount Isa has historically been supplied via the Carpentaria Gas Pipeline (CGP) either from:

- Southern supply sent north-east along the SWQP from Moomba to Ballera, or
- Queensland supply sent west along the SWQP to Ballera.

The Northern Gas Pipeline (NGP) has been constructed, connecting Tennant Creek in the Northern Territory to Mount Isa. The NGP had its first day of commercial operation on 3 January 2019[39], and provides eastern Australia with access to up to 90 terajoules (TJ) per day of gas from Northern Territory gas sources, including the Blacktip and Mereenie gas fields.

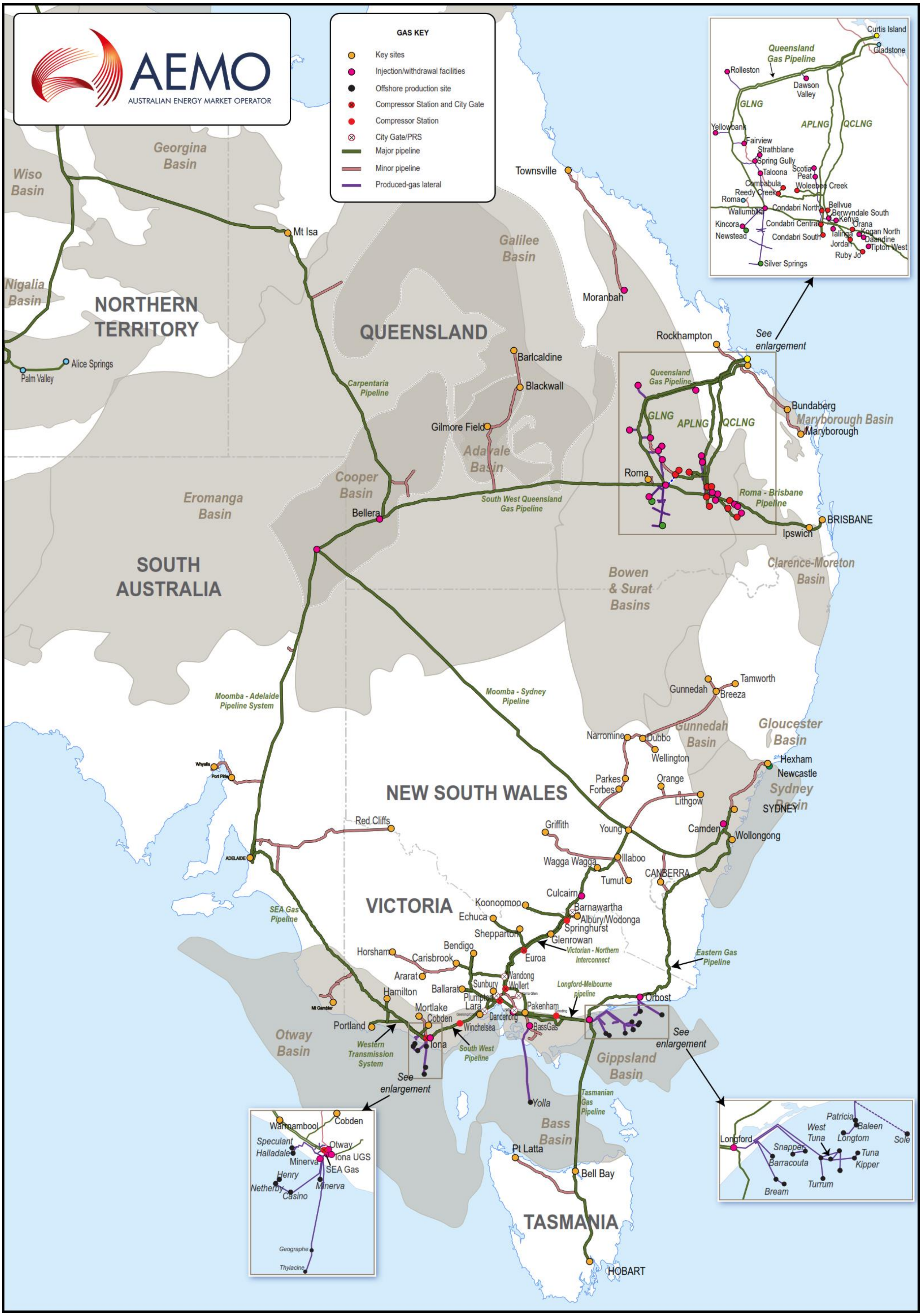
This new supply source, primarily meeting Mount Isa demand, has freed up capacity on the SWQP to deliver gas to the southern states.

As available reserves decline in the southern states, more supply will be expected to be transported along the SWQP towards the southern states. Depending on the rate and magnitude of decline of southern supply, capacity limitations along the SWQP, the Moomba to Sydney pipeline (MSP), and the Moomba to Adelaide pipeline (MAP) will be key factors in determining how much supply from northern fields will be available to meet demand in the southern states.

The gas basins and pipeline infrastructure that supply gas to eastern and south-eastern Australian gas consumers are shown in Figure 17.

[39] Jemena website, "Northern Gas Pipeline", at https://jemena.com.au/pipelines/northern-gas-pipeline. Viewed 4 March 2019.

Figure 17 Gas producing basins and infrastructure supplying eastern and south-eastern Australia



3.4 Short-term supply outlook

For the 2019 GSOO, AEMO has obtained producers' forecast production from 2019 to 2022.

Annual field output is forecast by producers to increase by 130 PJ between 2019 and 2022 across both southern and northern fields. The largest increases are forecast in northern gas fields, to meet forecast growth in LNG exports. This increased forecast of CSG production from the north is highly reliant on large numbers of wells continuing to be drilled and constructed annually.

Table 9 shows the production forecast between 2019 and 2022 provided to AEMO by gas producers as their current best estimate. The outlook is similar to the production forecasts received for the 2018 GSOO, with minor decreases in forecast production:

- A net decrease of 5 PJ in 2019 and 31 PJ in 2020 is projected in total from eastern and south-eastern production.
- Forecast production from southern fields in 2019 is 8 PJ lower compared to the forecasts for the 2018 GSOO, while forecast production from both Queensland and Northern Territory is 3 PJ higher.

These production forecasts comprise committed, anticipated, and uncertain projects, as defined in Section 3.1.

Table 9 Actual 2018 production and production forecasts to 2022 (PJ), as provided by gas producers, including undeveloped and contingent resources

	2018 actual	2019	2020	2021	2022
VIC/NSW/SA[A]	433	444	475	480	456
Difference from 2018 GSOO		-8	-8	17	-23
QLD/NT[A]	1,386	1,489	1,538	1,593	1,607
Difference from 2018 GSOO		3	-23	-43	4
Total production	1,818	1,933	2,013	2,072	2,063
Total difference from 2018 GSOO		-5	-31	-27	-19

A. The Queensland component of the Cooper Eromanga basin appears in the SA category.

Given the projected decline in reserves available from southern fields, AEMO has implemented a more comprehensive breakdown to consider the likelihood of projects actually progressing. Table 10 shows production forecasts from the southern states, further broken down into projects AEMO has classified as committed and projects that are anticipated. Further production from uncertain projects is forecast by producers over the GSOO horizon, but AEMO assumes these projects are not available before 2023, given typical lead times for developing these projects.

Table 10 Breakdown of production forecast in southern fields, between existing and committed projects and anticipated projects to 2022 (PJ)

	2019	2020	2021	2022
Southern production – existing and committed projects	444	442	417	378
Southern production – anticipated projects	-	33	63	79
Southern production – total	444	475	480	456

Committed projects from the southern states include Cooper Energy's Sole project and Esso-BHP's West Barracouta project, which are forecast to begin production in 2019 and 2021 respectively.

Projects considered under the anticipated category (that is, projects that are under active development planning utilising existing infrastructure, with a reasonably likelihood of proceeding) include:

- The Kipper Unit Joint Venture proposed project to drill additional wells in to the Kipper gas field. These wells were part of the original Kipper plan and are referred to as Stage 1B. The current schedule is for the Kipper 1B wells to be drilled in 2020.
- Beach Energy's proposed development of the Blackwatch gas field in Port Campbell.
- Beach Energy's proposed further development of the Otway Gas Project, for the Thylacine and Geographe fields.

These anticipated projects – categorised as undeveloped reserves and contingent resources – are expected to be required to meet demand over the outlook period, notably from 2024. The contingent resources, by definition, are not yet economical to be produced or are otherwise contingent on other factors. These contingent factors will need to be overcome before the gas can be developed and brought to market.

For further detail regarding anticipated and uncertain projects in Victoria, see AEMO's 2019 Victorian Gas Planning Report[40].

[40] Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

4. Supply adequacy

This section presents the outlook for supply adequacy in eastern and south-eastern Australian gas markets in the next 20 years. In assessing supply against forecast demand, AEMO has modelled both:

- The impact on the supply-demand balance of only existing and committed gas developments – under this assessment, shortfalls are forecast in the south from 2024.
- Supply adequacy if all anticipated and uncertain projects are considered in addition to existing and committed gas developments – under this assessment, which is directly comparable to the 2018 GSOO assessment, no gas shortfalls are forecast before 2030.

4.1 Supply from existing and committed gas developments

There are no supply gaps forecast before 2024 in the Neutral scenario, although the forecast supply-demand balance is tight from 2021 to 2023, and supply adequacy relies on some committed projects which are not yet producing.

If all supply from existing and committed projects is available for production:

- Supply for 2019 is forecast to be slightly in excess of demand. The 27 PJ of excess supply forecast accounts for only 1.5% of total demand, or 5% of domestic demand.
- Excess supply is forecast to increase to 69 PJ in 2021 (accounting for 3.5% of total demand, and 12.6% of domestic demand).
- Decline in gas production from southern fields is projected to lead to southern states being unable to entirely meet their own demand from 2022, with an increasing reliance on additional gas from northern regions.

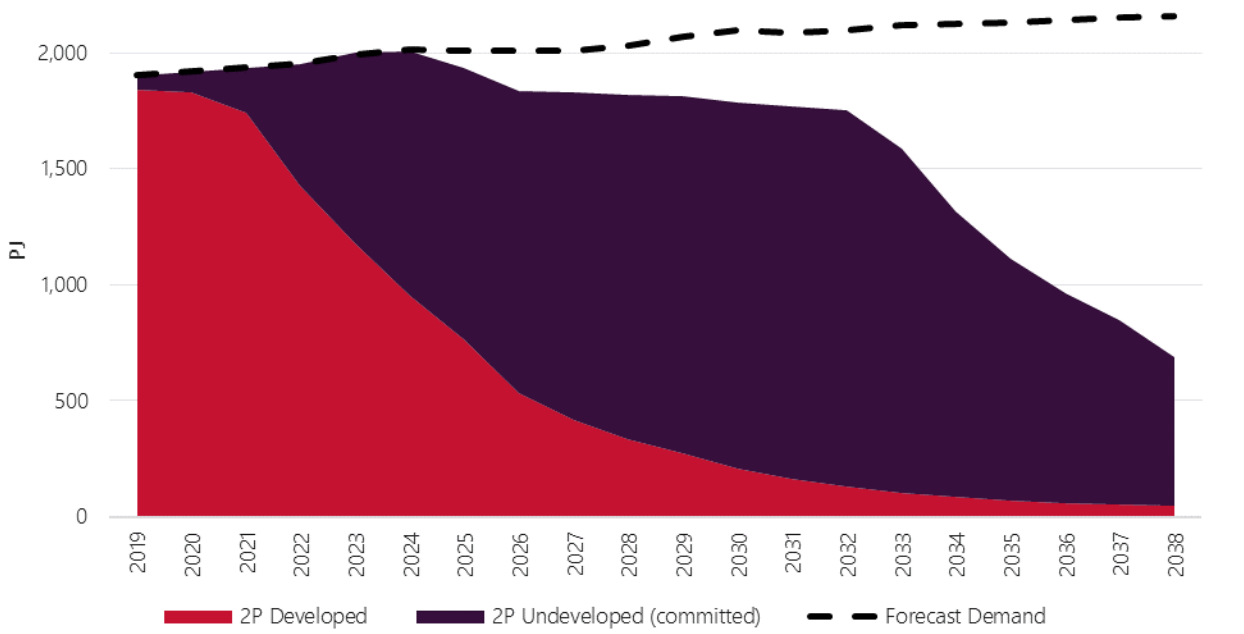
During this period to 2023, pipeline constraints increasingly limit the amount of gas that can be provided from Queensland to meet southern domestic demand, irrespective of production rates. If demand increases above forecast levels, or development of new supply is delayed, increased rates of production would be required, or spot quantities of LNG export demand may need to be foregone, to ensure all domestic demand is met.

From 2024, the forecast southern supply (including committed gas projects) is projected to be insufficient to meet forecast demand if no further sources of gas or alternative infrastructure are developed. Furthermore, infrastructure constraints will mean additional gas cannot be transported from Queensland or the Northern Territory to southern states. Supply shortfalls are observed in southern states, driven by forecast decline from southern fields and infrastructure limitations.

From 2029, assuming no further developments beyond existing and committed projects, supply limitations across eastern and south-eastern gas production facilities are also forecast to drive shortfalls in Queensland LNG exports, with 8 PJ of CSG production needed to be diverted to ensure Queensland domestic demand is met in 2029, and 25 PJ in 2030.

Projected eastern and south-eastern Australian gas production to 2038 is shown in Figure 18.

Figure 18 Projected gas production, 2019-38 – supply from existing projects and committed developments

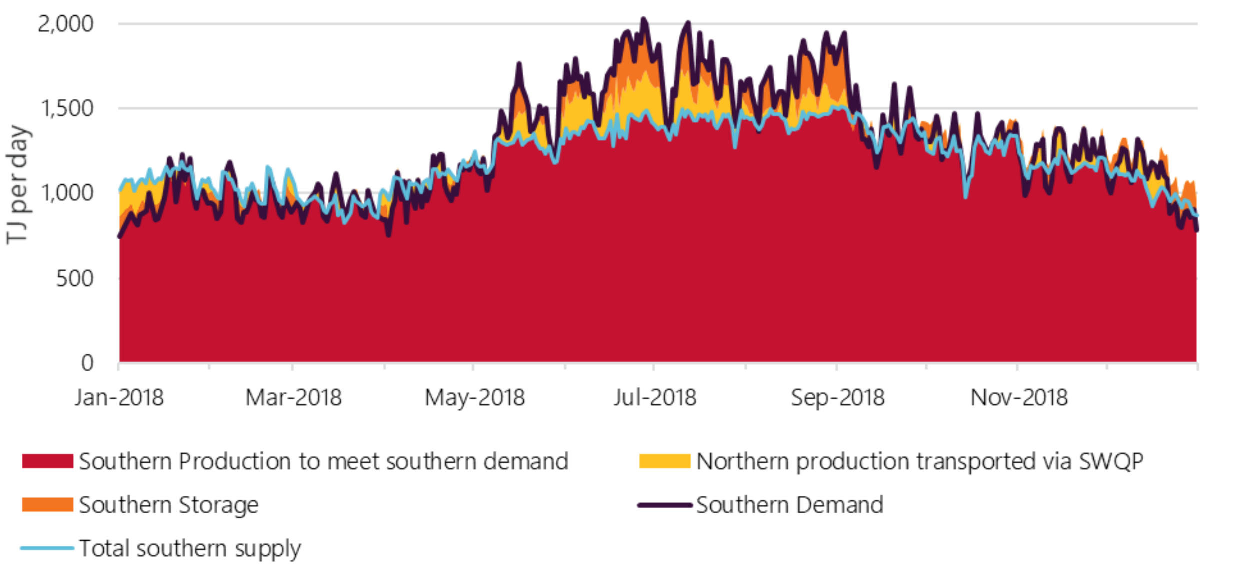


During low southern domestic demand periods, the SWQP, MSP, and MAP are still heavily utilised to transport northern production so storage facilities may be refilled, but from 2024, even this northern production and infrastructure utilisation is forecast to be insufficient to meet southern demand.

Figure 19 shows the daily profile of how southern demand is currently met (based on actual system flows in 2018), by a combination of:

- Southern production.
- Southern storage.
- Gas from northern fields sent via the SWQP.

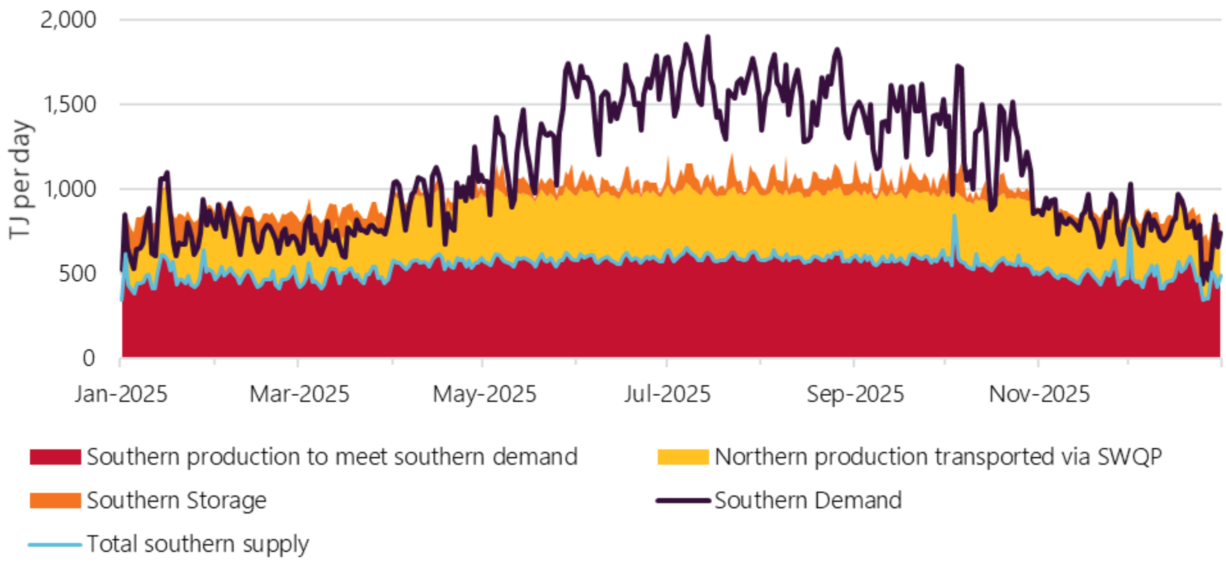
Figure 19 Historical actual daily supply and demand balance in the southern states, 2018



In contrast, Figure 20 shows the projected daily profile of supply in 2025. It highlights that:

- Daily southern production is forecast to be far less than daily southern demand across the entire year.
- Northern gas supplies can be transported south along the SWQP in excess of demand across lower demand periods of the year (from mid-November to April), allowing storage facilities to fill over these months. A combination of storage facilities limited by their daily filling capacities, and pipeline constraints in reaching those storage facilities, limit the amount of excess northern production able to be transported along the SWQP during these lower demand periods.
- The combination of southern production, northern supplies, and withdrawals from storage facilities is forecast to be insufficient to completely meet demand from May to November.
- New supplies – whether imported from the north, developed locally, or imported as LNG – are generally only needed during the winter months when gas consumption is heavily utilised for heating. This may affect the business case of various development options, favouring developments that can be utilised more flexibly, or combined with storage to smooth out demand.

Figure 20 Forecast daily supply and demand balance in the southern states including existing and committed projects, 2025



If all infrastructure limitations were alleviated from 2024, there is forecast to be sufficient excess northern supply to help meet all demand in both the northern and southern regions until 2027. From 2028, existing and committed reserves, regardless of where located, are forecast to be insufficient to meet all demand across the eastern and south-eastern Australian system.

4.1.1 Outcomes of other scenarios

The Fast change scenario assumes that any increase in LNG demand is driven by increased production rates from Queensland CSG fields – that is, the three LNG projects do not draw on increased domestic production rates to increase export quantities of LNG.

Similarly, in the Slow change scenario, the associated reduction in LNG export demand is linked to underperforming CSG production.

As such, the Fast change and Slow change scenarios assume a higher and lower rate of production from CSG fields respectively, and commensurate levels of LNG export. No other supply differences exist between the three scenarios. Therefore, the main drivers of difference between the Fast change, Neutral, and Slow change scenarios are the domestic demand forecasts.

Figure 21 shows the magnitude and timing of shortfalls forecast under the Fast change, Neutral, and Slow change scenarios, assuming only existing projects and currently committed developments are available for production.

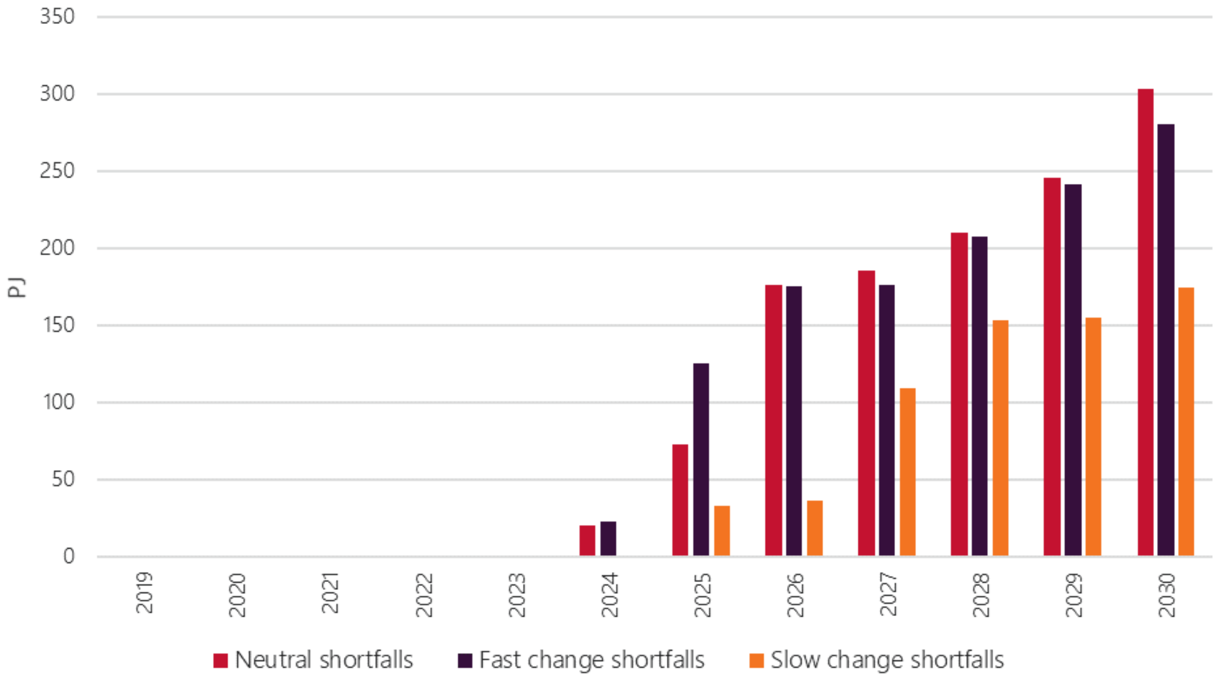
While all scenarios face shortfalls, under the Slow change scenario:

- The first shortfalls appear one year later than in the Neutral and Fast change scenarios.
- The magnitude of the shortfalls is also much smaller in the Slow change scenario, rising up to 80 PJ per year in 2030 if only existing and committed gas developments are available.
- Shortfalls are reduced, because demand is lower throughout the entire outlook, resulting in the southern gas fields declining at a slower rate.

Under the Fast change scenario:

- Shortfalls are similar to the Neutral scenario but are projected to be lower than the Neutral scenario between 2027 and 2030, due to lower GPG consumption as projected higher renewable energy uptake in the NEM reduces forecast reliance on GPG.
- In the longer term, shortfalls are projected to increase, as demand for GPG is forecast to grow again.

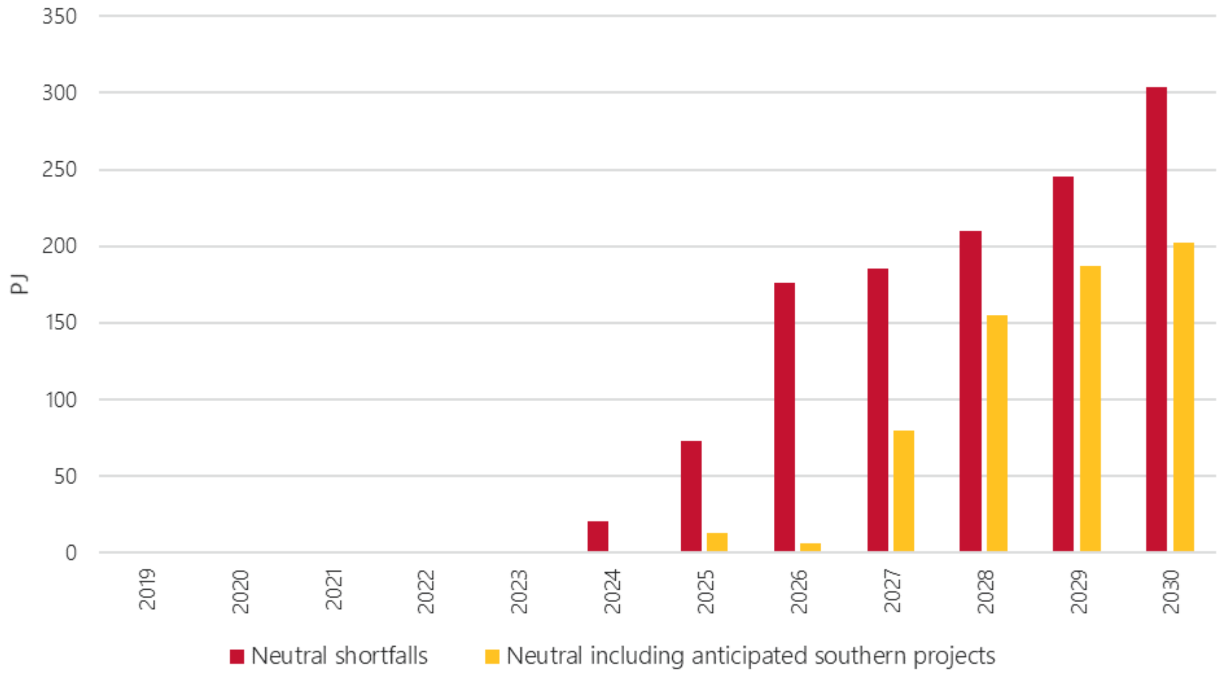
Figure 21 Shortfalls forecast to 2030 in all scenarios if only existing projects and committed developments are available



4.2 Supply from existing, committed, and anticipated gas developments

As Figure 22 shows, if anticipated projects (as defined in Section 3.1) eventuate as forecast by producers, the impact to the southern supply-demand balance is projected to be small. Shortfalls from 2024 to 2026 are reduced but not entirely eliminated, and issues meeting peak demand over winter are forecast to remain.

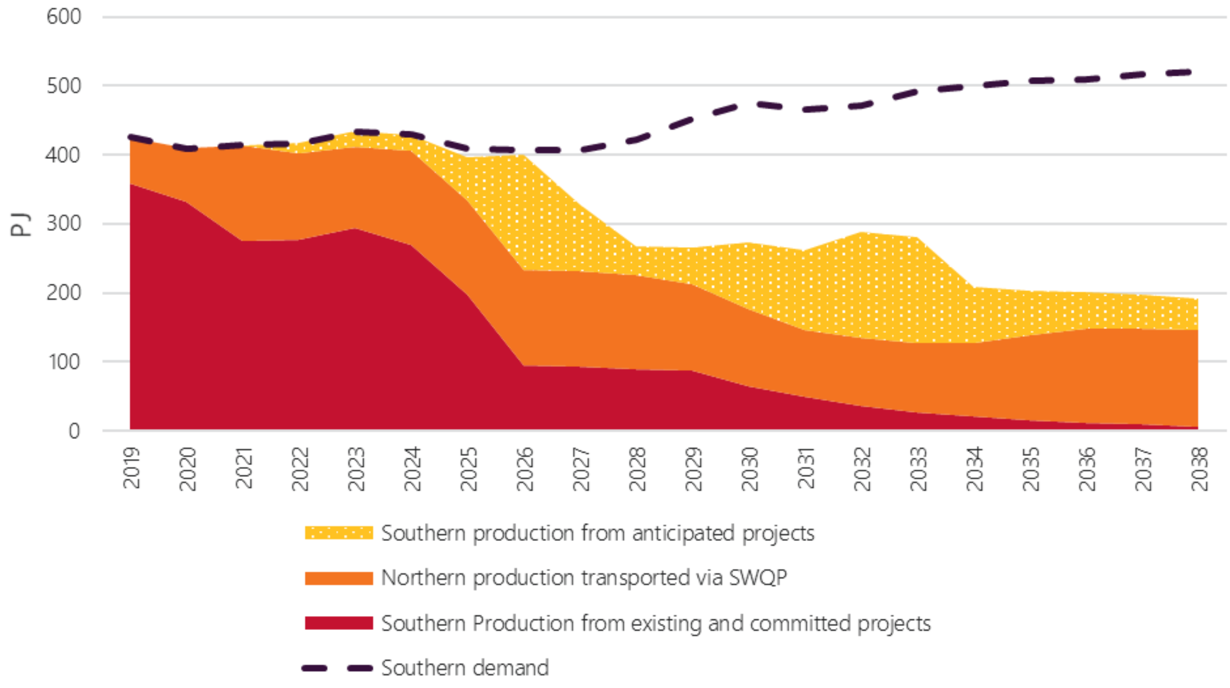
Figure 22 Shortfalls forecast if supply from anticipated southern projects is available, 2019-30[A]



A. Anticipated southern projects reduce shortfall quantities in 2024 to just under 1 PJ, so may not be visible on the chart. Shortfalls in this case are limited to only peak demand days across winter.

Figure 23 highlights the projected challenges in meeting southern demand once supply from fields located in the south depletes. From 2027, the size of the projected shortfall increases dramatically, as these additional anticipated southern projects are unable to sufficiently offset the projected decline in existing and committed southern production. Additional projects, beyond those currently planned, are forecast to be needed to ensure supply is available throughout the outlook horizon.

Figure 23 Projected supply to meet demand in the southern states, considering existing, committed, and anticipated gas projects, 2019-38



With anticipated projects available to help meet southern demand, there is forecast to be sufficient excess supply on a daily basis during low demand periods to ensure utilisation of storage facilities until 2026 is high. From 2027 onwards, the amount of daily excess supply is forecast to be limited, even during low demand periods in the summer, with nearly all available supply projected to be required to meet forecast daily demand instead of being stored for winter peak usage.

In summary, AEMO's assessment based on existing, committed, and anticipated production indicates that domestic gas demand, particularly in the southern states, will be difficult to meet in its entirety over the next 10 years without either:

- Exploration and development of new southern resources, or
- New gas supplies delivered via LNG import terminal(s), or
- Major pipeline infrastructure expansions to deliver Queensland and Northern Territory gas southwards, or
- A combination of all three.

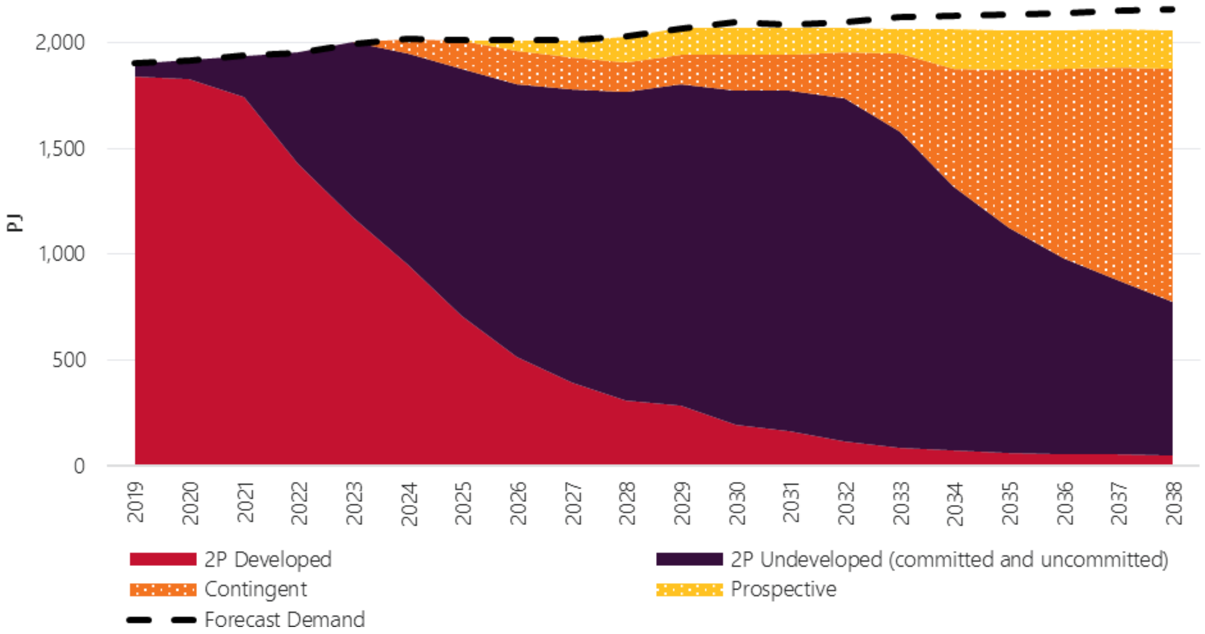
Given development timeframes, progress on these developments will need to commence shortly. These options are investigated in more detail in the next chapter.

Further, the tightness of supply highlights the importance of obtaining the best available information for assessing supply adequacy. In 2019, AEMO will explore use of mechanisms that improve access to, and the quality of, information made available for GSOOs.

4.3 Supply from all projects including uncertain developments

Figure 24 shows the reserve mix required to meet forecast demand if all existing, committed, anticipated, and uncertain gas developments are available for production.

Figure 24 Projected gas production, 2019-38 – supply from all available resources (including anticipated and uncertain projects)



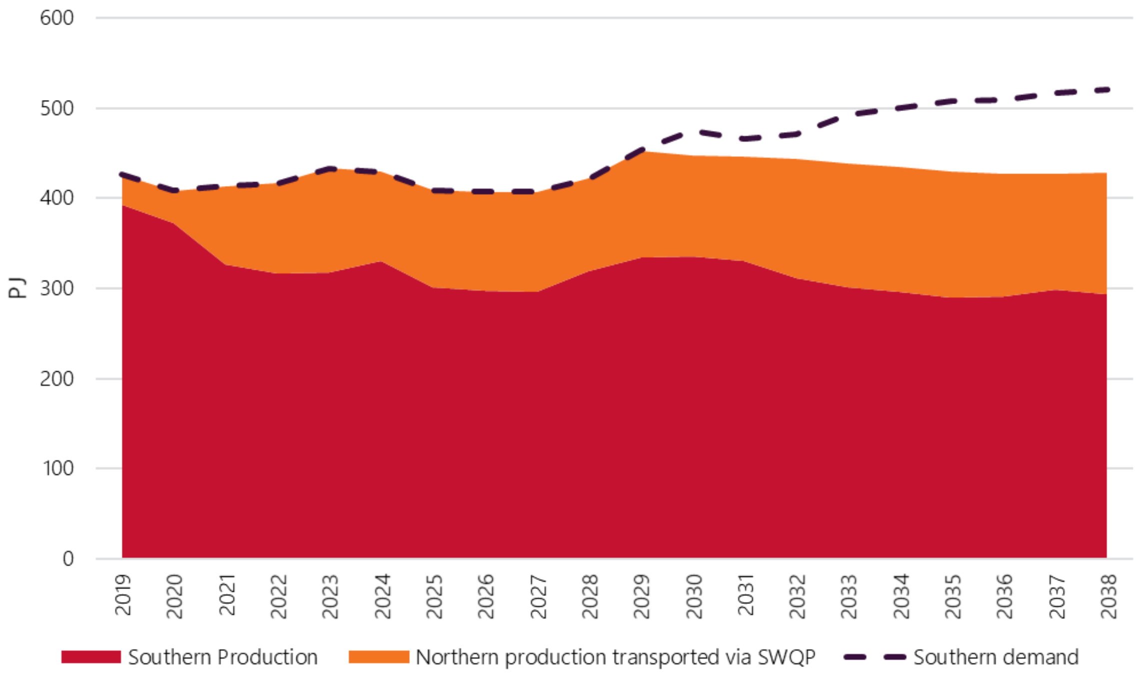
In the long term to 2038, access to uncertain 2C contingent and prospective resources is assumed:

- At the rates provided by producers.
- To the degree accessible from existing pipeline and processing infrastructure.

This projection of forecast production is directly comparable to the supply adequacy assessment presented in the 2018 GSOO, and under this projection, as was forecast in the 2018 GSOO, no gas shortfalls are expected in eastern and south-eastern Australian gas markets before 2030. Shortfalls of up to 27 PJ are forecast in 2030, rising to 92 PJ in 2038.

While the inclusion of uncertain reserves and resources increases forecast total gas production, southern production is still projected to decline. In this case, additional infrastructure or alternative southern production facilities are projected to be required from 2030 to avoid shortfalls. Without infrastructure development, northern production will be constrained from assisting southern consumers, as shown in Figure 25.

Figure 25 Projected supply available to meet demand in the southern states, 2019-38 – supply from all available resources (including anticipated and uncertain projects)



In Figure 25, the fluctuations visible in southern production across the outlook are due to producer assumptions around when new supply would come online, in aggregate, being slightly out of step with the timing of other fields declining.

AEMO acknowledges the uncertainties around the gas prices required to incentivise development of uncertain 2C contingent and prospective resources and the delivery of new gas supplies, and around the economic impacts of these prices to the long-term viability of gas consumers. Projections of demand destruction as a result of uneconomical sources of gas are, however, beyond the scope of the GSOO.

4.3.1 Outcomes of other scenarios with uncertain developments

If all existing, committed, anticipated, and uncertain gas developments are available for production under the Slow change scenario:

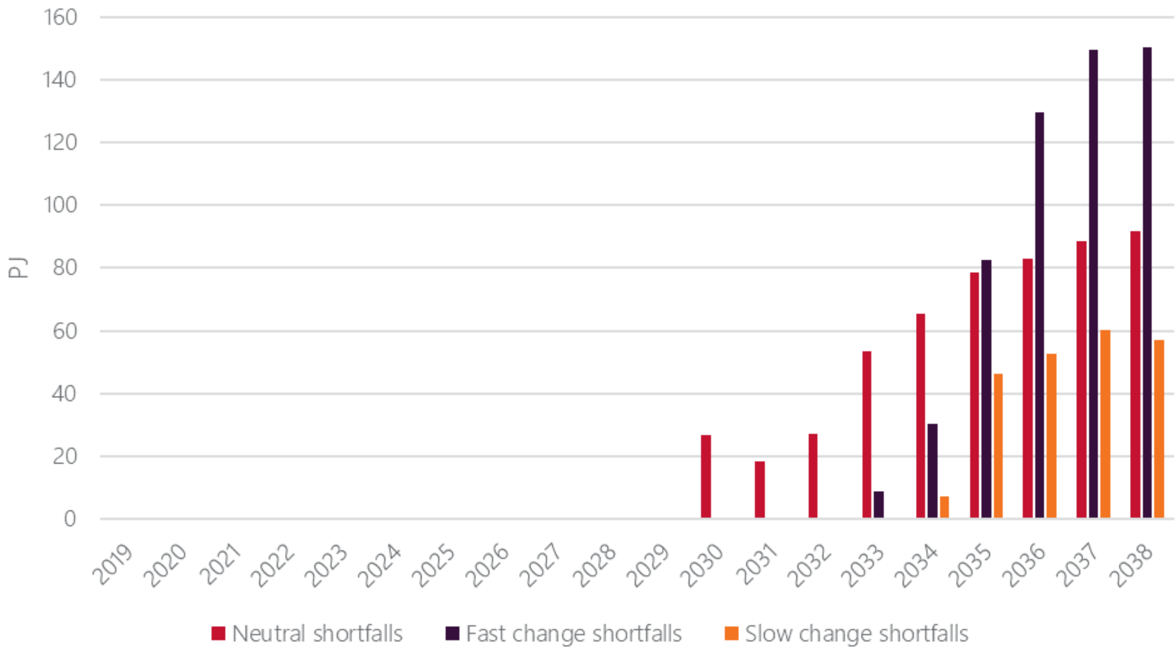
- Shortfalls are not observed until 2035.
- The maximum shortfall in any single year is 30 PJ.
- All shortfalls are forecast in southern domestic demand, as pipeline delivery constraints become the limiting factor to deliver gas from northern facilities once southern production declines in the long term.

Under a Fast change scenario, assuming all these developments are available for production:

- Shortfalls are not observed until 2033[41].
- In the long term, by 2038, shortfalls are nearly 60 PJ higher than in the Neutral scenario but are lower before 2035 due to projected changes in GPG operation in the NEM. Forecast changes in GPG overshadow growth in the other demand sectors.
- Shortfalls occur across all domestic and export demand sectors, both north and south, as there is insufficient supply across the whole system to meet demand in the long term.

The shortfall outcomes for all three scenarios for supply available from all resources, are shown in Figure 26.

Figure 26 Shortfalls forecast where supply is from all available resources (including uncertain undeveloped projects), 2019-38



Regardless of the scenario, unless further gas supplies are located and developed in the southern states, infrastructure constraints in shifting gas from north to south are forecast to be the limiting factor in avoiding shortfalls.

4.4 Short-term uncertainties that may impact supply adequacy

The forecast consumption trends for gas in all demand sectors depend on a range of assumptions and drivers. Changes in these will affect demand in any scenario.

This section focuses on factors in demand and supply forecasts that can create uncertainty in supply adequacy projections, specifically:

- Variable drivers of demand for the GPG, residential, commercial, and industrial sectors.
- Uncertainty in performance of Queensland CSG and southern fields.
- Impacts of any failure of critical gas supply infrastructure.

[41] There is little difference in the timing of first shortfalls between scenarios, although the magnitude of these shortfalls does differ.

4.4.1 GPG demand

Annual consumption of gas for GPG will depend directly on the level of electricity consumption in the NEM, and the operation of GPG relative to other sources supplying electricity (such as coal-fired, hydro, wind, and solar generation).

GPG has a relatively high operating cost compared with other generation technologies, but generally has greater operating flexibility. It therefore plays a role in filling any gap from coal-fired, hydro, and renewable energy to meet demand in the NEM. As such, it is at greater risk of large swings in output than other generation sources. Some of the key factors that influence GPG are listed in Table 11, with the estimated impact of each factor on forecast GPG demand for gas in the next five years. These risk factors are described in more detail below the table.

Table 11 Impacts of considered risks and uncertainties on GPG demand between 2019 and 2023

Drivers of additional GPG demand	Lower bound estimate (PJ)	Upper bound estimate (PJ)
Weather variability impacting wind and solar farm output	+15	+20
Reduced rainfall impacting hydro generation (beyond current drought conditions)	+15	+20
Extended unavailability of coal-fired generation (one unit for six months) or reduced availability of coal (at one coal station)	+4	+10
Return to service of Tamar Valley Power Station	+3	+7
Delays in installation of new renewable generation (12-month delay in 10% of currently committed wind and solar projects)	+ 16	+ 22

While sufficient excess supply (approximately 27 PJ) is projected in 2019 to cope with any one of these uncertain events (as discussed in Section 4.1), a combination of these events concurrently may lead to earlier shortfalls, or require diversion of LNG spot cargoes to meet GPG demand.

Weather variability impacting wind and solar farm output

Electricity generation from wind and solar farms is inherently dependant on prevailing weather conditions, with lower wind speeds and extended cloud cover leading to lower electricity generation. Reduced contribution from these sources would lead to increased GPG production, and vice versa.

AEMO has analysed recent historical weather conditions to forecast GPG generation variance over the short term, attributable to weather variations. This analysis projects that less favourable weather conditions for wind and solar generation could reasonably lead to between 15 PJ and 20 PJ extra annual gas demand for GPG, compared to an average year[42].

Reduced rainfall impacting hydro generation

In extended drought conditions, hydro generators can be expected to reduce electricity generation, conserving water resources where possible for peak demand periods. This reduced hydro generation would likely lead to increased GPG operation, depending on the available energy from other lower-cost sources such as underutilised coal-fired generation.

The first year of the GPG forecast for financial year 2019 assumed lower inflows to reflect the current low hydro storage levels and low chances of drought-relieving rainfall before autumn 2019, as advised by the Bureau of Meteorology and reported in AEMO's Summer 2018-19 Readiness Plan[43].

[42] This results from projected additional annual GPG generation of between 1,350 gigawatt hours (GWh) and 1,800 GWh.

[43] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/AEMO-2018-19-Summer-Readiness-Plan.pdf.

AEMO has also assessed the impact if drought conditions increased further, with rainfall up to 15% lower than the long-term average, leading to less hydro generation than previously forecast. All other weather conditions – temperatures, wind speeds, and solar radiation – were assumed to remain at expected levels.

These lower hydro generation levels are forecast to increase reliance on GPG in the NEM, leading to increased gas consumption by between 15 PJ and 20 PJ.

Extended unavailability of coal-fired generation

Forecast levels of GPG reflect expected levels of coal-fired generation availability, including unplanned outages and average annual maintenance needs. However, as observed in AEMO's 2018 Electricity Statement of Opportunities[44], the reliability of the ageing coal-fired generation fleet is deteriorating. Increases in unplanned generation outages are likely to lead to more GPG consumption.

Occasionally, plant operators may need to withdraw generating units for extended periods, to perform extended maintenance or to correct operating issues. As outlined in the 2018 GSOO, examples of extended coal-fired generation outages in the NEM include the Yallourn mine flood (2012), Hazelwood fire (2014), Eraring outage (2016), and Loy Yang and Yallourn outages (2017).

AEMO has tested the impact of the extended withdrawal of a single coal-fired generator for up to six months as a proxy for either reduced reliability or unanticipated long-duration outages, and estimates that this would increase gas consumption for GPG by between 4 PJ and 10 PJ.

The unexpected retirement of a coal-fired power station would have a much greater impact, and, depending on alternative generation developments, would be expected to put pressure on gas supply adequacy. The recent addition to the National Electricity Rules[45] requiring large electricity generators to provide at least three years' notice to the market before closing should reduce the risks associated with sudden closures, allowing energy markets time to respond to any heightened risks affecting either electricity or gas networks.

Reduced availability of coal volumes

The quality of coal resources can vary across coal seams, and the energy content of coal can vary. This variance in coal quality may mean that more or fewer tonnes of coal would be required to be combusted to maintain a consistent level of generation. Issues may also occur during the coal mining process that may reduce the quantities able to be delivered[46].

If coal supply arrangements do not allow sufficient flex for increases in shipping between mine and power station, this variability may impact on GPG.

If the energy able to be generated by a single black coal-fired power station were to reduce by approximately 10% and be an ongoing problem, it would be expected that the increased gas supply required for GPG would be between 4 PJ and 10 PJ a year.

Return to service of Tamar Valley power station[47]

The Tamar Valley combined-cycle gas turbine (CCGT) in Tasmania is not in regular service. Its owner, Hydro Tasmania, may return the CCGT to service at its discretion with less than three months' lead time. This may occur if Tamar Valley was considered needed to support hydro generation in Tasmania, or if there were reliability risks to Tasmania. It was last in service in summer 2018-19.

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[44] Available at http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

[45] AEMC final rule determination, published November 2018. Available at https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

[46] For example, differences in forecast coal supply and actual delivery can be calculated. See https://www.banpu.com/backoffice/upload/presentations_84_7638c5c1bba84feae508505dfb803554.pdf and https://www.banpu.com/backoffice/upload/presentations_86_0a759ec5d45ebba81326d277b26222b5.pdf.

[47] This GPG plant was withdrawn from the NEM from April 2018, after being recalled for summer 2017-18, and Hydro Tasmania has advised that it could be recalled for operation again with less than three months' notice. See AEMO's generation information page, Tasmania spreadsheets, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

AEMO's forecasts of GPG consumption assume no generation from Tamar Valley CCGT. Based on historical generation patterns, this unit could be expected to consume between 3 PJ and 7 PJ if returned to service again to operate over a summer season.

Delays in installation of new renewable generation

The NEM continues to see strong levels of investment in renewable generation technologies, with nearly 2,000 MW of renewable generation becoming operational in the NEM in 2018[48], and an additional 7,000 MW[49] of renewable generation having made a formal commitment to construct. Approximately 2,800 MW of this additional renewable generation is under construction but has not yet fully satisfied AEMO's commitment criteria.

As mentioned in section 2.2.3, for the purposes of forecasting gas consumption for GPG, AEMO conservatively assumed that, of this additional renewable generation capacity that has begun construction but not yet reached official commitment status, only 50% would commence operation before 2021. Therefore, these 2019 GSOO GPG forecasts assumed a total new renewable generation capacity of 5,600 MW will commence operation before 2021.

There is a risk that GPG gas consumption may be greater than forecast if any of this assumed new generation is delayed in commissioning or development:

Generally, the volume of electricity produced by renewable energy projects reduces the amount of gas consumed by GPG in a year. For example:

- A 100 MW solar farm would offset potentially up to 3 PJ of gas consumed by GPG a year.
- A 100 MW wind farm would offset potentially up to 4 PJ of gas consumed by GPG a year.

If up to 10% of the additional 5,600 MW of additional new renewable projects were delayed by 12 months and were not replaced by similar projects in the same timeframe, there may be between 17 PJ and 22 PJ additional gas demand if GPG was relied upon to fill the gap entirely[50].

Irrespective of potential timing delays, geographically clustered renewable investments may be impacted by congestion in the electricity grid, depending on the connection location. AEMO's assessment of GPG includes consideration of network constraints (assuming system normal conditions), and planned transmission network developments that will relieve some grid congestion in areas of high renewable generation penetration (such as north-west Victoria).

In any assessment, there are risks that network conditions may not match the forecast conditions, or transmission developments may not proceed as planned. If new renewable generators are unable to export all energy when it is available, or if planned network augmentations from electricity transmission network service providers (TNSPs) are delayed, then gas needed by GPG may increase.

Gas Supply Guarantee

Gas producers and pipeline operators made a commitment to the Federal Government to make gas available to electricity generators during peak NEM periods. The Gas Supply Guarantee mechanism has been developed by industry to facilitate the delivery of these commitments.

While the Australian Domestic Gas Supply Mechanism (ADGSM) is intended to provide means to manage the risks of annual domestic energy imbalance, the Gas Supply Guarantee is directed to address short-term deliverability and supply issues for GPG, and as such is most appropriate to address operational risks or major unplanned events.

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[48] See AEMO's generation information page, 21 January 2019 compared to 29 December 2017, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[49] See AEMO's generation information page, 21 January 2019, new wind and solar projects with commitment status 'Committed' and 'Com*', in regional spreadsheets under "New developments" tab, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[50] The actual impact would depend on the availability of other generation technologies (such as coal and hydro), the specific energy expected to be generated by the renewable facility, and the length of time associated with any delay.

However, as the southern fields further decline in the future and if no more southern resources are developed, pipeline constraints (particularly on the SWQP, MSP, and MAP) may limit the amount of gas that can be sent from northern gas fields to assist in meeting southern demand as required by the Gas Supply Guarantee, or ADGSM.

4.4.2 Residential, commercial, and industrial consumption

Residential, commercial, and industrial consumption forecasts are subject to risk and uncertainty arising from variation in key drivers that may impact demand, such as:

- Weather variation – while AEMO forecasts consumption on normalised weather conditions, actual consumption may be different if the weather deviates from average conditions.
  - Residential and commercial sector gas consumption forecasts and maximum daily demand forecasts are most impacted by this.
  - As an example of the impact of weather variation on forecast consumption, typical system demand in Victoria is around 200 PJ per year. A relatively mild winter in 2014 saw system demand drop by 2.5% (5 PJ), while in 2015, the coldest recorded winter in the last 26 years, system demand increased by 4% (8 PJ).
- Economy – shocks could have a significant impact on industrial consumers, particularly the export-facing manufacturing sector. The industrial sector forecasts do not consider major shocks to business cycles such as the Global Financial Crisis or the mining boom.

While these two drivers are the main uncertainties with potential to substantially impact forecast residential, commercial, and industrial consumption in the short term, risks to the longer-term forecast also arise due to deviations in the projections of key input drivers:

- Population variation.
- Demographic changes.
- Energy efficiency measures.
- Gas to electric appliance switching.
- Gas price forecasts.
- Changes in policy, technology, and consumer preferences.

4.4.3 Queensland CSG production lower than forecast

Recent industry publications[51] have speculated that the outlook for CSG production may be less favourable than has been assumed in the Neutral scenario of this GSOO. AEMO has assumed that any decrease in CSG production would cause a corresponding decrease in LNG exports. This risk has been studied under the Slow change scenario.

However, LNG export demand may not decrease in line with reduced CSG production:

- Should the existing Queensland CSG fields underperform, and the rate of drilling new wells not increase enough to backfill the underperforming fields, demand shortfalls are forecast from 2020 under Neutral demand forecasts.
- In this scenario, if LNG cargoes are able to be diverted to support domestic demand, then there continues to be no domestic shortfalls expected before 2024. Domestic consumers would require up to 20 PJ of redirected cargoes in 2020, increasing to 56 PJ in 2023.

[51] In particular, the EnergyQuest, report - *Queensland Coal Seam Gas: Performance and Outlook to 2036*, released February 2019, available at https://www.energyquest.com.au/reports.php?id=2.

- If reduced CSG production was to continue in the long term, from 2024 insufficient supply is projected across the entire system, and domestic shortfalls are forecast to increase as the northern production decline impacts the available gas to support southern consumers.

4.4.4 Faster than expected decline in southern production

The rates of decline of the fields in southern states are in line with producers' best estimates. Should actual rates of production be even more pessimistic than assumed, this could have a major impact on domestic gas supply adequacy if new sources of gas are not developed in time to backfill this decline.

4.4.5 Failure of critical gas infrastructure

Any failure of critical gas supply infrastructure could also have impacts on supply adequacy, depending on the exact nature of the failure.

For example, on 30 November 2017, Longford production plant experienced a plant equipment issue that limited Longford injections into the Distributed Wholesale Gas Market (DWGM) to 350 TJ for the gas day and led to a supply shortfall[52].

The unplanned outage meant there was insufficient time for a market response to alleviate the potential threat of breaching minimum system pressure. AEMO, as operator of the DWGM, was forced to intervene and order additional injections from supplies of 174 TJ throughout the day, and was required to reduce consumer withdrawals by 33 TJ.

This outage occurred in November, which is typically a lower demand period. If a similar outage reducing Longford's available supply to 350 TJ occurred during a peak day in winter, over 800 TJ of additional supply may need to be sourced each day for the duration of the outage to meet consumer demand and ensure system security.

[52] The details of this event are available on AEMO's website at http://aemo.com.au/-/media/Files/Gas/DWGM/2017/DWGM-ER-17-003-30-Nov-2017.pdf.

5. Potential new sources of supply

The 2019 GSOO forecasts a tight balance between supply and domestic demand (particularly in the southern states), starting in the next five years, unless there is investment in new gas supplies and infrastructure. Options currently being considered across industry include LNG import terminals, major pipeline infrastructure expansions, and new Queensland and Northern Territory supply sources.

As already discussed in previous chapters, within the next five years, domestic gas demand in the southern states, will be difficult to meet in its entirety without either:

- Exploration and development of new southern resources, or
- New gas supplies delivered via LNG import terminal, or
- Major pipeline infrastructure expansions to deliver Queensland and Northern Territory gas southwards, or
- A combination of all three.

Many new supply options are currently under consideration by the gas industry. In the 2019 GSOO, AEMO has investigated some of these current industry proposed options, and the projected impact of these projects on supply adequacy compared to the case where only existing and committed projects proceed. The options studied are shown in Figure 27, and include:

- Increases in supply through new field development (Galilee Basin and/or Narrabri) or LNG import terminals.
- Expansion or extension of pipeline infrastructure (NGP, Queensland Hunter Gas Pipeline or Western Slopes Pipeline).

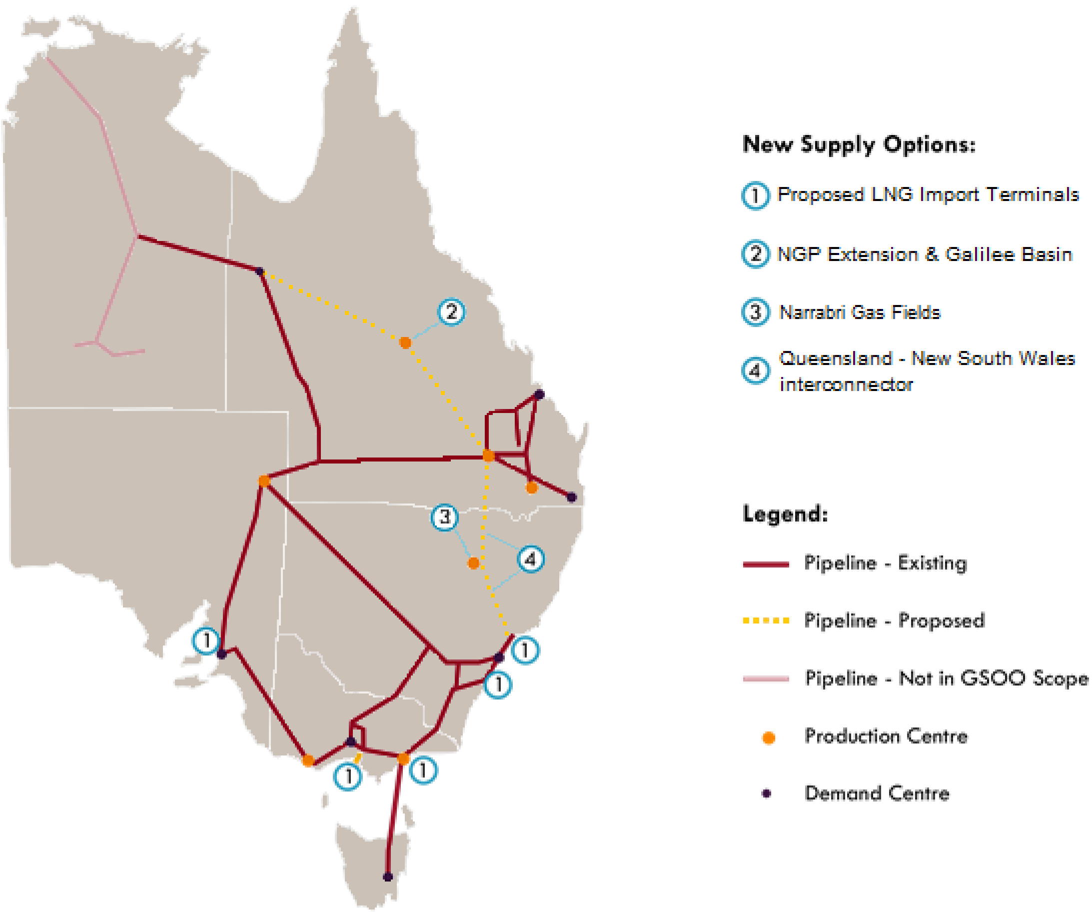
This analysis is not intended to represent any commercial assessment of the economic value of any particular option, or combination of options.

From AEMO's analysis, no single new supply source or infrastructure development is projected to be able to fill the gap to meet all Australia's domestic and export demand over the next 20 years, or even before 2030. Instead, a combination of developments to the gas system would be needed to avoid shortfalls. This potentially may include other supply or infrastructure options not considered here.

Diversification of many new supply sources and infrastructure developments would reduce the risk of a single supply option underperforming, and new supply options across multiple locations, whether local supply or LNG imports, would reduce pipeline congestion.

This highlights the growing need for a holistic planning view to be taken across industry to ensure future gas demand can be met in an efficient and timely manner. To do this, greater information transparency is required, as highlighted in the ACCC and Gas Market Reform Group recommendations on east coast gas market transparency[53].

Figure 27 Potential new supply options



5.1 LNG import terminals

Floating regasification and storage units (FRSUs) are being considered by the gas industry as potential sources of additional supply to eastern and south-eastern Australia. An FRSU would connect to an import terminal to regasify incoming LNG volumes, which in turn could be injected directly into the pipeline network of the importing region.

Interest in constructing an LNG import terminal in southern Australia has been growing, with several projects being considered near Melbourne[54], Gippsland,[55] Sydney[56], Newcastle[57], and Adelaide[58].

AEMO has investigated the impact of a generic import terminal constructed at each of these locations, assumed to have the capacity to supply up to 200 PJ of gas per year and available by 1 January 2024.

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[53] Further details are available on the website of the Council of Australian Governments (COAG) Energy Council, at http://www.coagenergycouncil.gov.au/publications/energy-council-web-text-%E2%80%93-accc-gmrg-recommendations-east-coast-gas-market-transparency.

[54] AGL webpage at https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project#fsru. Viewed 27 February 2019.

[55] ExxonMobil webpage at https://www.exxonmobil.com.au/en-au/technology/liquefied-natural-gas/lng-technology/lng-fueling-the-future. Viewed 27 February 2019.

[56] AIE webpage at https://ausindenergy.com/need-for-the-project/. Viewed 27 February 2019.

[57] EPIK webpage at https://www.epiklng.com/nlng-471710.html. Viewed 27 February 2019.

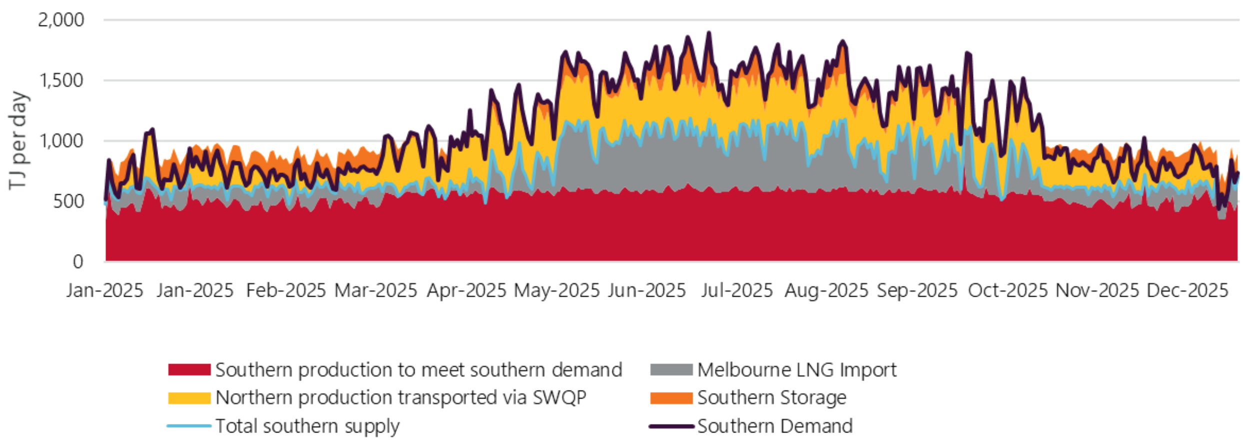
[58] Venice Energy webpage at https://veniceenergy.com/outer-harbor-LNG-project/. Viewed 27 February 2019.

Without any upgrade to the existing pipeline infrastructure:

- An import terminal in Victoria, either Melbourne or Gippsland, has the biggest projected impact to reduce projected shortfalls.
  - In addition to providing an additional unconstrained source of gas for Victoria, this terminal is projected to reduce pipeline and storage infrastructure congestion, enabling greater access to supply from northern fields.
  - This development is projected to reduce total system shortfalls by up to 265 PJ a year by 2030 and delay the timing of the first shortfalls by five years (to 2029).
  - After 2030, the shortfalls are reduced by up to 290 PJ per year.
- An import terminal located in South Australia or New South Wales (either in Sydney or Newcastle) is projected to reduce shortfalls by up to 25 PJ and 43 PJ per year before 2030, respectively, but neither is forecast to delay the first shortfall date of 2024, due to the limitation in pipeline infrastructure.
  - An import terminal located in South Australia is projected to hit limitations, primarily of the MAP from Adelaide towards Moomba, and the South Eastern Australian Pipeline system requiring bi-directional capabilities from Adelaide to Port Campbell for supply to meet more southern domestic demand.
  - An import terminal located in New South Wales is projected to hit limitations, primarily of the MSP from Sydney towards Moomba, and the Eastern Gas Pipeline (EGP) requiring bi-directional capabilities from Sydney to Melbourne for supply to meet more southern domestic demand.
  - After 2030, the shortfalls are projected to be reduced by up to 195 PJ and 354 PJ per year, respectively.
- With all five import terminal projects going ahead at a capacity of 200 PJ per year each, the date of the first shortfall is projected to be delayed by eight years (to 2032). However, due to infrastructure congestion, of all the five projects the terminal located at Melbourne is projected to be the only one to realise full capacity.

The imported LNG storage is projected to be utilised most heavily during winter when gas demand peaks, although small amounts of LNG imports would also add support during low demand periods (Figure 28). This would allow southern storages to get filled and be available during high demand periods in the winter.

Figure 28 Forecast daily supply and demand balance in the southern states in 2025 with additional supply from Melbourne LNG import terminal



The introduction of an LNG import terminal without further infrastructure upgrades provides the greatest benefit when it can take advantage of existing pipeline infrastructure. Existing southern pipeline infrastructure is designed around major gas production from offshore Victoria, to then be delivered throughout Victoria, South Australia, and New South Wales.

If pipeline infrastructure were appropriately upgraded, an import terminal in South Australia or New South Wales would likely have the same impact on shortfalls as an import terminal in Victoria, although the cost of such upgrades, and relative costs of each proposal, has not been considered.

Utilisation of an import terminal depends on various factors, namely cost of the gas, cost of transmission, location of the import terminal, and any constraints around supply or injection into the transmission network.

Owners of LNG import facilities will need to manage varied risks – including contracting, seasonal volume flexibility, oil price, currency exchange rates, and other economic drivers in the LNG international market – which could limit or enhance the extent to which an import terminal can support southern demand.

5.2 Northern Gas Pipeline upgrade and extension

The NGP began commercial operation on 3 January 2019[59] with a transfer capacity of 90 TJ/day. According to Jemena, the pipeline could be expanded to have a capacity of 700 TJ/day[60], to transport more gas from Northern Territory to the eastern and south-eastern states.

Without further infrastructure development – an expansion of the reverse flow direction of the CGP, an expansion of the SWQP from Ballera to Wallumbilla, or a new connection entirely – the bulk of this new supply would be unable to reach the demand centres where forecast to be most needed.

Jemena is therefore also considering an extension to the NGP, connecting Mount Isa to Wallumbilla via the Galilee Basin[61]. This extension could begin supplying gas to the eastern states as early as 2022, as 2P developed production is declining.

Increasing the potential supply from the Northern Territory or Galilee basin to 700 TJ/day into Queensland is projected to have little impact on meeting southern shortfalls, without additional interconnection expansions to deliver to southern consumers, shown in Figure 29. However, it would defer forecast shortfalls in Queensland (8 PJ of shortfalls projected in 2029, and 25 PJ in 2030 without this supply).

- This extra supply would remove any risk of shortfalls in the north before 2030 and provide an alternate source of supply if Queensland CSG production is lower than forecast.
- With these developments, shortfalls observed in LNG demand are delayed by five years (to 2034).

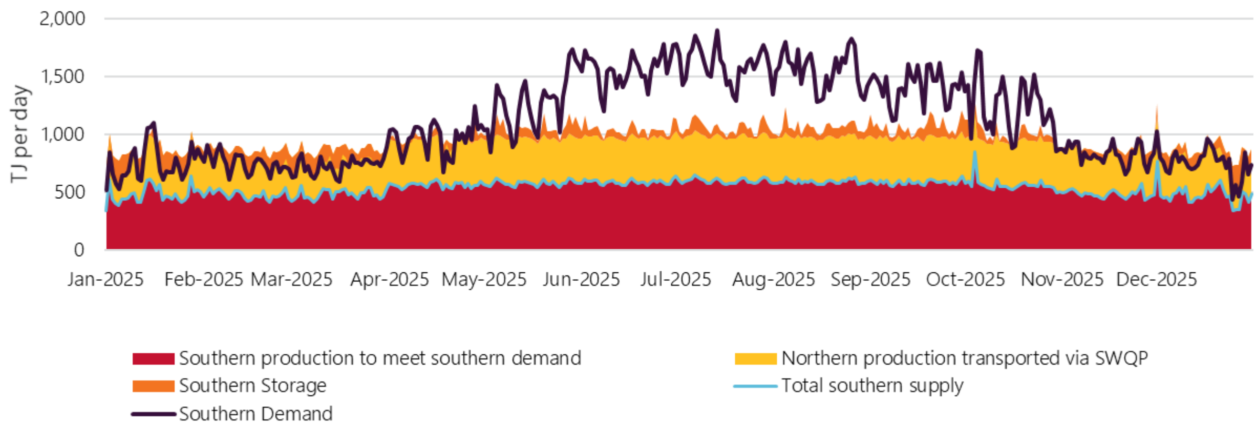
Beyond this point, significant additional northern supply will be required to shift shortfalls as the available quantities of northern 2P reserves rapidly deplete.

[59] Jemena webpage, "Northern Gas Pipeline", at https://jemena.com.au/pipelines/northern-gas-pipeline. Viewed 27 February 2019.

[60] Jemena webpage, "Jemena welcomes decision to lift fracking moratorium", at http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori. Viewed 27 February 2019.

[61] Jemena media release, "Jemena fast-tracks plans to connect Galilee Basin to the east-coast gas market", 17 October 2017, available at https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin.

Figure 29 Forecast daily supply and demand balance in the southern states in 2025 with additional supply from the NGP upgrade and extension



5.3 Further Queensland – New South Wales interconnection

The impact of further interconnection between Queensland and New South Wales, connecting northern gas supply to the southern states, would alleviate southern supply tightness, and has been considered via two sensitivities:

1. A new gas transmission connection from Queensland (Wallumbilla hub) to New South Wales, without considering any new supply to the system. This pipeline has been assumed to have a capacity of 400 TJ/day and be bi-directional between Queensland and New South Wales. Examples of industry interest in this interconnection are the Queensland Hunter Gas Pipeline (planned to connect at Newcastle), or the Western Slopes Pipeline (planned to connect along the MSP).
2. Additional supply of up to 100 TJ/day through the development of gas fields in the Narrabri area[62], in addition to the new pipeline.

5.3.1 Queensland – New South Wales interconnection

AEMO's analysis projects that adding a Queensland – New South Wales transmission pipeline to further connect northern gas to the southern states would not delay first gas shortfalls from 2024, as pipeline constraints in the southern states (particularly the MSP, and lack of bi-directional flow along the EGP) limit the effectiveness of access to additional Queensland supply.

However, this interconnection is projected to:

- Reduce southern shortfalls by a forecast 9 to 42 PJ per year between 2024-30 as additional Queensland CSG is diverted to meet domestic demand.
- After 2030, decrease southern shortfalls by up to 72 PJ per year.

In the north, the timing of shortages does not change but the magnitude does increase by 22-74 PJ per year from 2029 as more gas is redirected to meet southern domestic demand.

5.3.2 Queensland – New South Wales interconnection in conjunction with Narrabri field production

If Santos' Narrabri gas field is developed in conjunction with a Queensland – New South Wales transmission pipeline, additional supply is projected to be available for transport to meet southern demand.

[62] See the Santos website for more information: https://narrabrigasproject.com.au/about/narrabri-gas-project/. Viewed 4 March 2019.

The extra source of gas from Narrabri is not projected to delay the first gas shortfalls observed from 2024. As mentioned previously, pipeline infrastructure constraints along the EGP and MSP indicate the full impact of these combined projects may not be able to be realised by southern states.

This additional supply is projected to reduce the amount of Queensland CSG needed to be diverted to meet domestic demand. However, the Queensland – New South Wales transmission pipeline would be congested most days throughout the time horizon, and bottlenecks would be expected transporting the gas south.

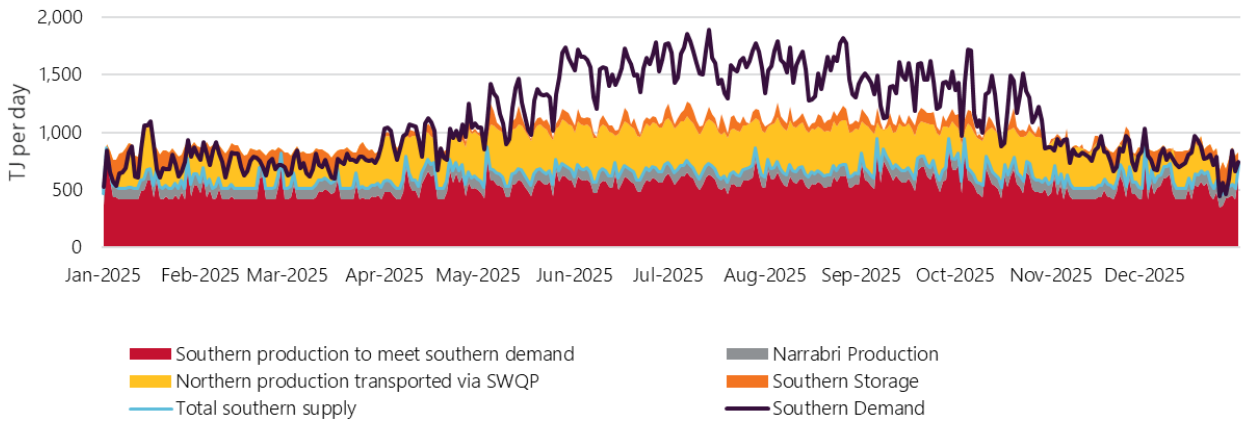
Compared to constructing the Queensland – New South Wales transmission pipeline alone, the extra source of gas from Narrabri is forecast to further reduce total shortfalls by up to:

- 20 PJ per year before 2030.
- 80 PJ per year after 2030.

LNG shortages are forecast to be delayed until 2033.

The daily supply and demand balance across 2025 is shown in Figure 30.

Figure 30 Forecast daily supply and demand balance in the southern states in 2025 with additional supply from the Narrabri project and further Queensland – New South Wales interconnection



5.4 Further Queensland – New South Wales interconnection in addition to NGP/Galilee expansion

Development of both a Queensland – New South Wales transmission pipeline and the NGP pipeline extension, in combination with new supply from Narrabri and the Galilee Basin, would deliver extra gas into the east coast market (whether from Narrabri, Galilee, or Northern Territory).

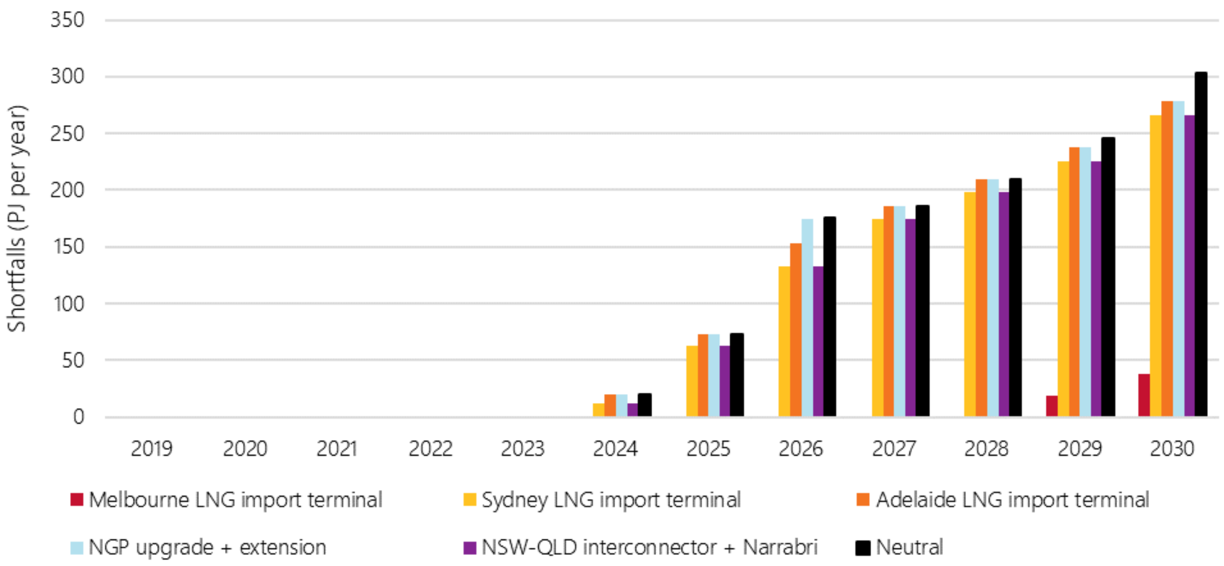
Similar to analysis previously mentioned, pipeline infrastructure in the southern states (namely EGP and MSP) is forecast to be insufficient to transport this additional supply to meet all the forecast southern domestic demand. This means, despite the additional production, first shortfalls are still expected to occur in 2024.

After 2030, total shortfalls are expected to be decreased by up to 416 PJ per year due to the increase in supply and infrastructure upgrades. Queensland CSG fields are still projected to struggle to meet LNG export demand, but the extra supply would help delay LNG shortfalls to 2034, five years later than the Neutral scenario without these developments.

5.5 Supply options comparison

The shortfalls forecast for the new supply options, compared to those shortfalls forecast under the Neutral demand scenario considering only existing and committed projects, are shown in Figure 31. As previously discussed throughout this chapter, existing infrastructure constraints limit the effectiveness of most of these projects before 2030, with an LNG import terminal located at Melbourne having the greatest impact, as it is able to utilise the existing pipeline infrastructure. Upgrades to the EGP, MSP and MAP would likely enable the benefits of these new supply options to be fully realised.

Figure 31 Forecast shortfalls of the new supply options, compared to the Neutral existing and committed projects only shortfalls, 2019-30



A1. Forecast accuracy

The following charts compare AEMO's gas consumption forecasts since 2014[63] and show actual recorded consumption since 2010. These charts can be used to assess the performance of the forecasts by comparing the actual consumption against forecasts in each year. Only the Neutral scenario forecasts are presented.

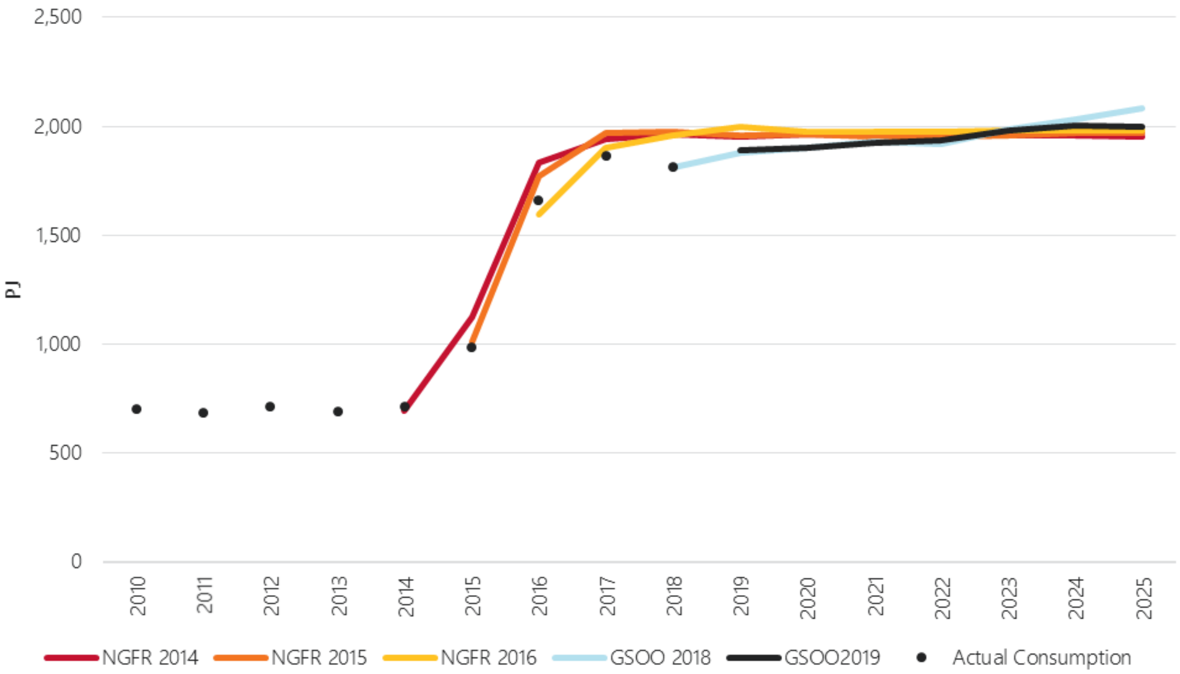
The actual demand is partly driven by weather conditions in a given year. For example, in a very cold year, gas consumption will be higher, due to the increased use of space heating. AEMO's forecasts are developed on a weather-normalised basis that assumes typical weather conditions, so some misalignment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

Assessing forecasting performance and understanding any propensity for bias is critical to AEMO's ability to improve its future forecasting accuracy and/or better understand the forecast uncertainties.

Total gas forecasts for eastern and south-eastern Australia

Figure 32 shows total gas consumption forecasts for eastern and south-eastern Australia.

Figure 32 Gas annual consumption forecast comparison, total for eastern and south-eastern Australia



Key observations include:

- Steep growth is seen from 2014 as LNG facilities ramp up in Queensland.

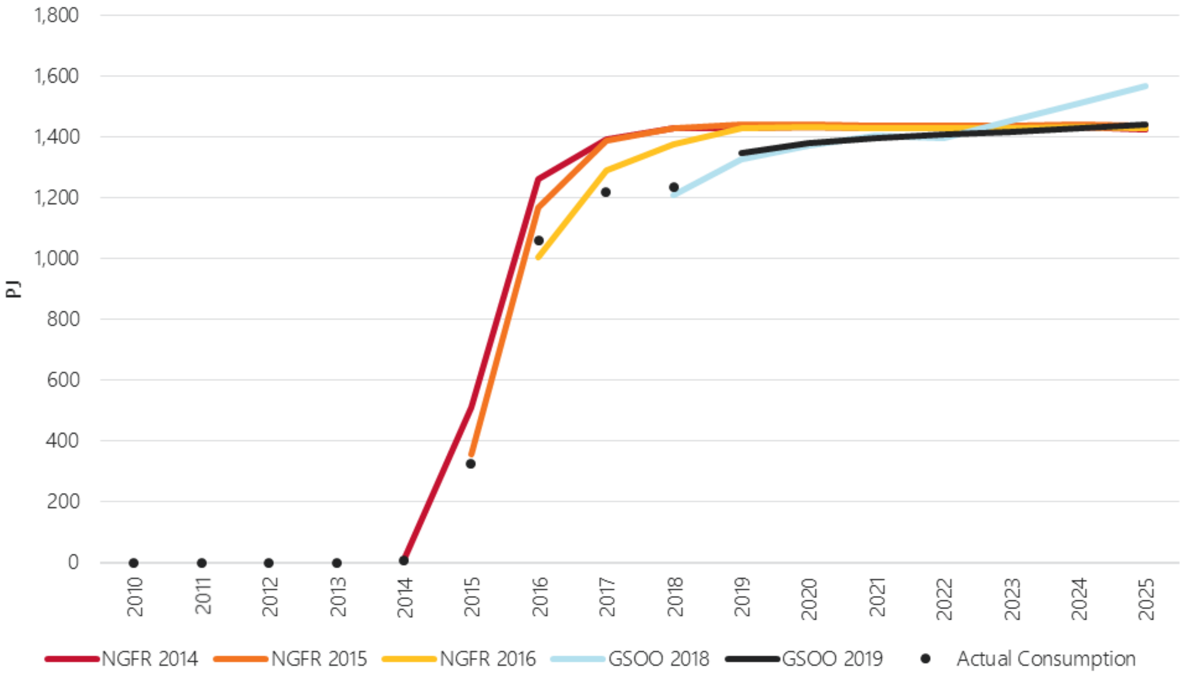
[63] The 2014 NGFR was the first standalone publication by AEMO for eastern and south-eastern 20-year demand forecasts. This was also the first year the forecasts were developed in-house. Before 2014, demand forecasts were produced for AEMO by consultants and published in the GSOO series. For this reason, only forecasts from 2014 onwards are reported in this section.

- There was some overestimation in the forecasts in 2016 and 2017, largely driven by slower than expected ramp-up of LNG exports.
- AEMO's 2018 and 2019 forecasts are similar in the initial years compared to previous forecasts, with slower future LNG ramp-up now assumed. The 2019 forecast is lower than the 2018 forecast from 2023 onwards, largely reflecting a reduction in outlook for the LNG sector, along with a muted outlook for GPG as new utility-scale renewable capacity forecasts are higher.

LNG export segment consumption forecasts

Figure 33 shows AEMO's LNG forecasts only, to more clearly illustrate an overestimation of year-on-year increases, compared to actual LNG exports. AEMO's 2019 GSOO LNG projections incorporate a reduction in later years from a revised outlook of global dynamics and increased international competition of the industry.

Figure 33 Gas annual consumption forecast comparison, LNG

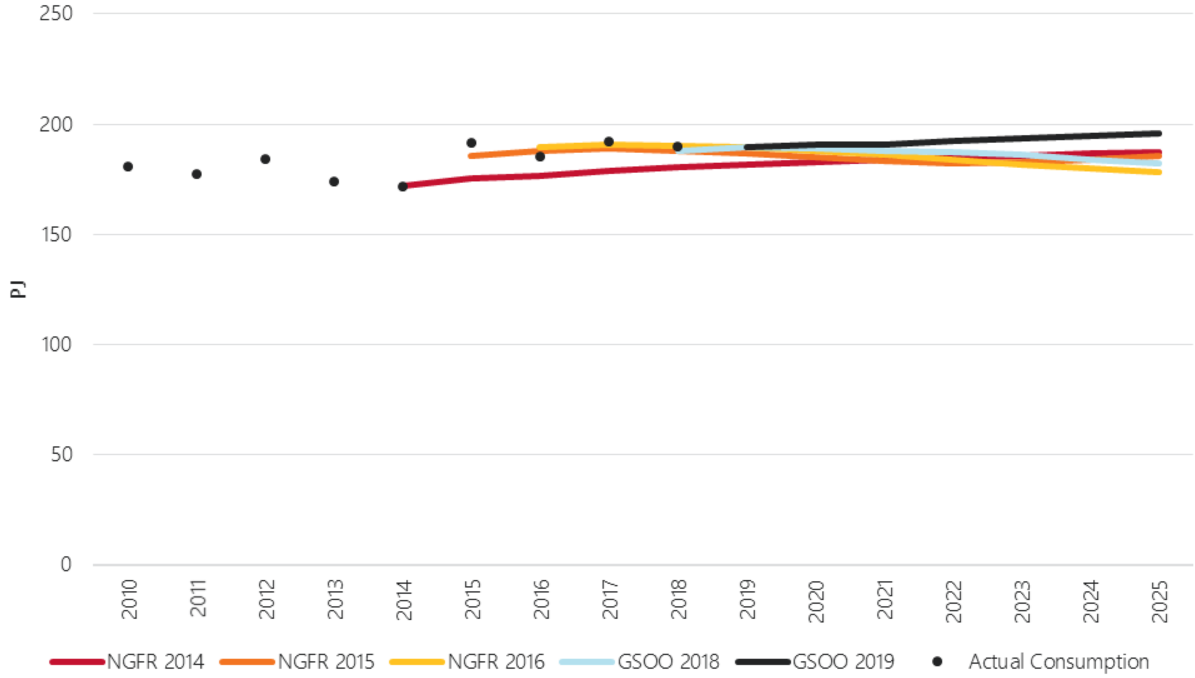


Residential and commercial segment consumption forecasts

Figure 34 shows AEMO's residential and commercial gas consumption forecasts. The starting point is calibrated to recent consumption data, with the overall trend reflecting AEMO's assumptions relating to the impacts of energy efficiency, gas to electric fuel switching, gas prices, and climate change.

AEMO's residential and commercial demand forecasts projected in 2015 and 2016 align reasonably well with historical observations, although some deviations are observed due to influences such as weather.

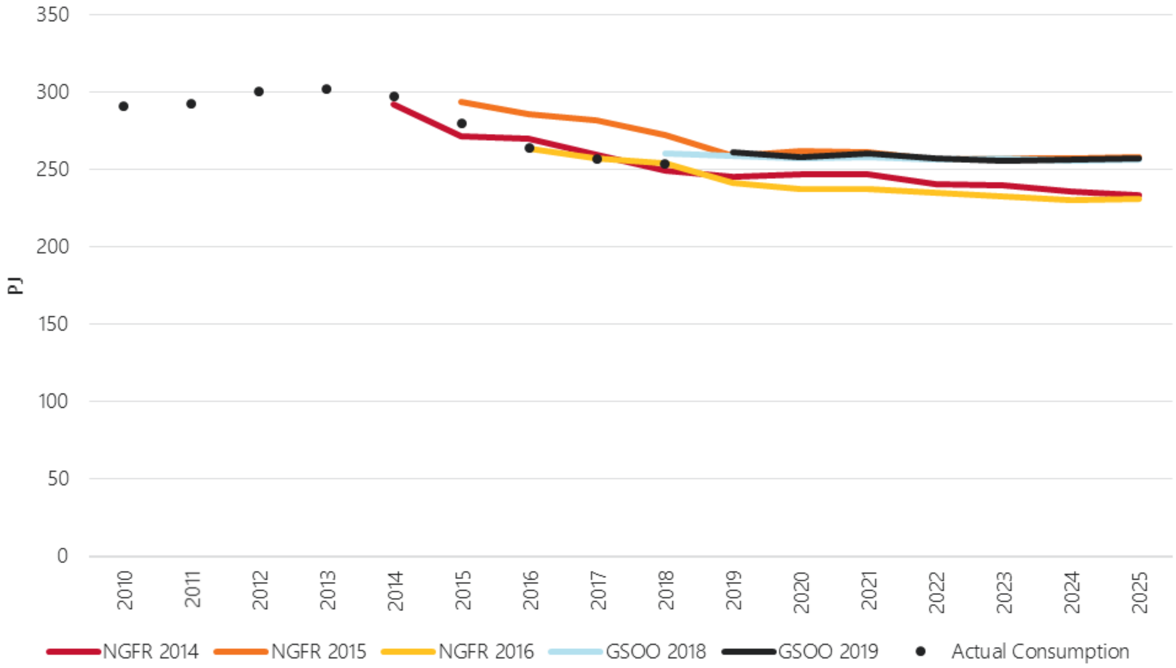
Figure 34 Gas annual consumption forecast comparison, residential/commercial



Industrial segment consumption forecasts

Figure 35 shows AEMO's industrial gas consumption forecasts, incorporating AEMO's assumptions on forecast changes in economic drivers and data obtained by survey from large gas users.

Figure 35 Gas annual consumption forecast comparison, industrial



In the 2014 NGFR, AEMO correctly predicted a turning point in industrial consumption. Key to identifying the turning point in trends was AEMO's increased engagement with large industrial users. This process has helped AEMO develop richer insights into the key trend drivers for this sector and identify structural and behavioural changes.

The 2015 and 2016 NGFRs continued to forecast similar declining trajectories, although the 2015 NGFR overestimated the starting point. The 2019 GSOO has a long-term flattening trend in industrial demand, due to a combination of updated actual consumption data, reflecting increased vulnerability of industrial load to increasing gas prices.

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.

GPG consumption forecasts

Figure 36 compares AEMO's GPG forecasts since 2014 against actuals and highlights that trends have been reasonably well anticipated. The consistent declining trend shown in this figure is due to increasing renewable generation developments in the NEM, and this trend is expected to continue, although the absolute level of GPG in any given year is difficult to predict.

Forecasting gas demand for GPG is highly challenging because (as discussed in Section 2.2.3) it is driven by events, such as extreme weather or generation outages, that can be unexpected and lead to significant variations. For example, AEMO's earliest forecasts (2014 and 2015 NGFRs) did not account for the extended outage of the Eraring Power Station in 2016, or the unforeseen closure of the Hazelwood Power Station in March 2017 and extended outages at Yallourn and Loy Yang A power stations, also in 2017. The 2017 events in particular drove actual GPG demand well above forecast.

Figure 36 Gas annual consumption forecast comparison, GPG

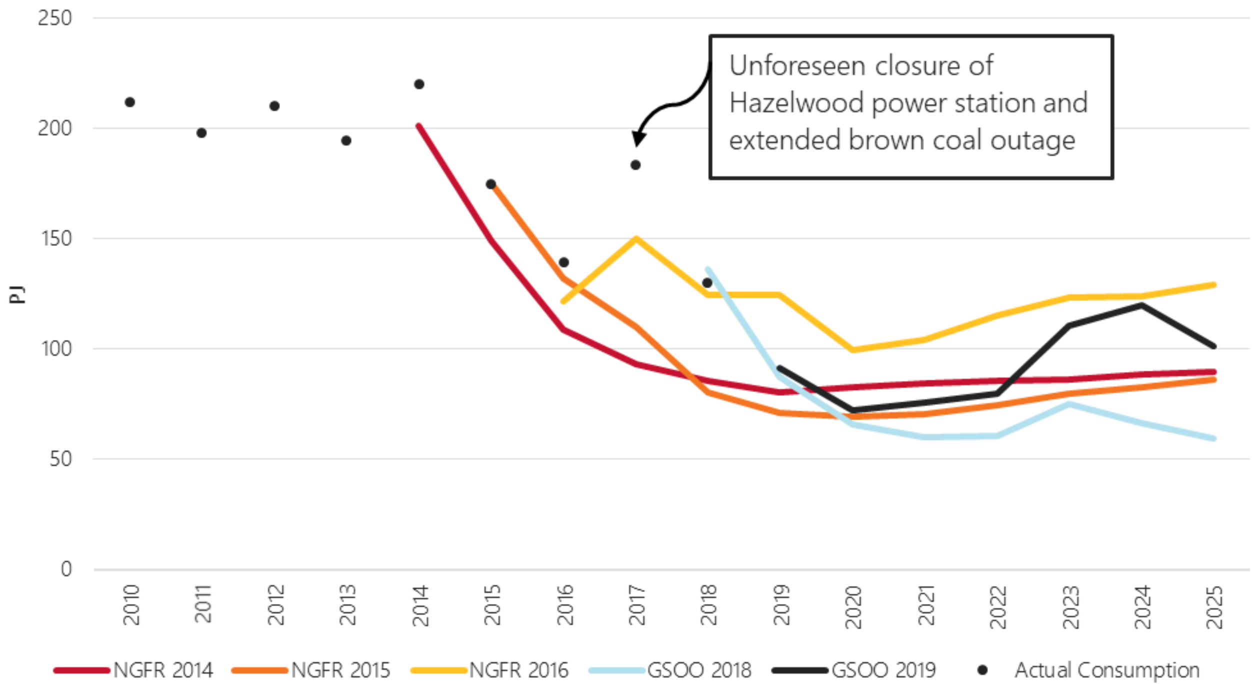
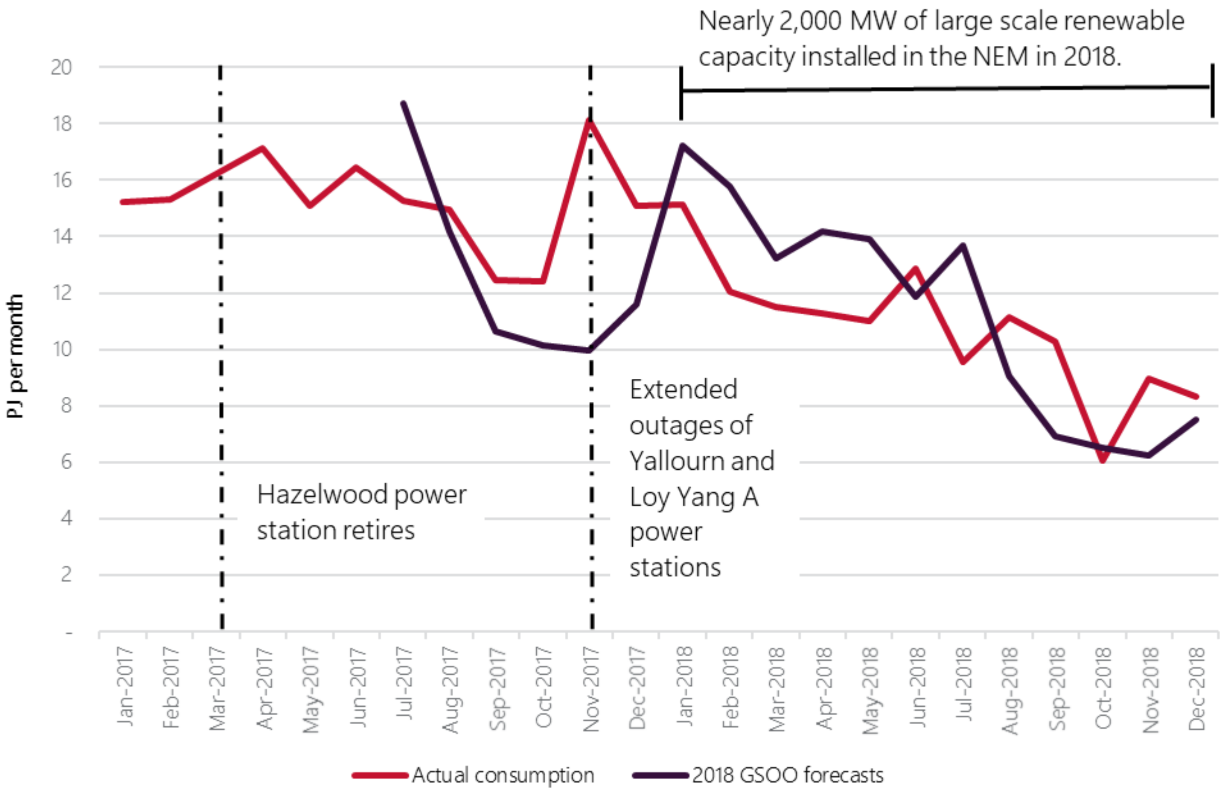


Figure 37 shows the GPG forecasts developed for the 2018 GSOO forecasts at a monthly level to December 2018, compared to actual monthly GPG consumption in the NEM over the same time. While the peak actual GPG consumption caused by the extended outages of Yallourn and Loy Yang A power stations was not captured in the forecast, the monthly behaviour of GPG throughout the NEM was captured well over this time, including the downward trend.

Figure 37 Gas monthly consumption forecast comparison, GPG, 2017-18



Glossary

Term	Definition
1-in-2	The 1-in-2 maximum 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	The 1-in-20 maximum 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.
2C contingent resources	Best estimate of contingent resources – equivalent to 2P reserves, except for one or more contingencies or uncertainties currently impacting the likelihood of development. Can move to 2P classification once the contingencies are resolved.
2P reserves	The sum of proved and probable estimates of gas reserves. The best estimate of commercially recoverable reserves, often used as the basis for reports to share markets, gas contracts, and project economic justification.
annual consumption	Gas consumption reported or forecast for a given year.
basin	A geological formation that may contain coal, gas, and oil.
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
combined-cycle gas turbine (CCGT)	A device utilising a gas turbine and heat recovery/steam generation to efficiently generate electricity. More capital intensive than open-cycle gas turbines and therefore expected to be highly utilised. See also open-cycle gas turbine.
consumption	The measure of gas usage over time, typically one year.
contingent resources	Gas resources that are known but currently considered uncommercial based on one or more uncertainties (contingencies) such as commercial viability, quantities of gas, technical issues, or environmental approvals.
conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also unconventional gas.
demand	Capacity or gas flow on an hourly or daily basis, or the electrical power requirement met by generating units.
developed reserves	Gas supply from existing wells.
domestic gas	Gas that is used within Australia for residences, businesses, power generators, etc. This excludes gas demand for LNG exports.
gas-powered generation (GPG)	The generation of electricity using gas as a fuel for turbines, boilers, or engines.
hydraulic fracturing	Hydraulic fracturing (fraccing or fracking), is a method of increasing the extraction of oil and gas from reservoirs, and more recently coal seam gas, by injecting fluid under high pressure to fracture wells or coal seams.
initial reserves	On a given assessment date (such as 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its entire productive life (for example, from 1975 to 2025). See also remaining reserves.
large industrial	A segment of the gas market defined to include businesses that consume more than 10 TJ/yr. See also mass market.
liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.

Term	Definition
LNG netback price	AEMO follows the ACCC definition of LNG Netback price (see "*Gas Enquiry Interim Report 2017-2020*", April 2018, https://www.accc.gov.au/system/files/Gas%20inquiry%20April%202018%20interim%20report.pdf): "A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port."
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
market segments	For purposes of developing gas demand projections, gas consumers are grouped into domestic market segments (residential/commercial, large industrial, and gas demand for GPG), and gas demand for LNG export.
National Electricity Market	The wholesale market for electricity supply in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.
probability of exceedance (POE)	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 5% probability of exceedance (POE) maximum demand will, on average, be exceeded only one year in every 20, and is equivalent to 1-in-20 terminology.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves.
production	In the context of defining gas reserves, gas that has already been recovered and produced.
prospective resources	Gas volumes estimated to be recoverable from a prospective reservoir that has not yet been drilled. These estimates are therefore based on less direct evidence than other categories.
proved and probable	See 2P reserves.
proved reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
ramp-up gas	Coal seam gas produced during the early stages of an LNG export project.
remaining reserves	On a given assessment date (such as 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its remaining productive life (for example, 1 January 2011 to 2025). See also initial reserves.
reserves	Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas. Iona underground storage (UGS) is also referred to as a reservoir for gas storage.
resources	More uncertain and less commercially viable than reserves. See contingent resources and prospective resources.
scenario analysis	Identifying and projecting internally consistent political, economic, social, and technological trends into the future and exploring the implications.
sensitivity analysis	A technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions. For example, in the GSOO, new supply options are tested as a sensitivity to the Neutral scenario.
services sector Gross Value Added (GVA)	Defined as aggregated measure ($'Millions, 2018 real terms) of economic activity in all sectors except agriculture, construction, mining, manufacturing, and utilities. Sector definitions follow the Australia New Zealand Industry Sector Category, published by the Australian Bureau of Statistics: http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/0C2B177A0259E8FFCA257B9500133E10?opendocument.
unconventional gas	Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also conventional gas.
undeveloped reserves	Gas supply from wells yet to be drilled.